Hawaii Electric Light Company, Inc.

KEAHOLE GENERATING STATION AND AIRPORT SUBSTATION
URBAN RECLASSIFICATION

FINAL
ENVIRONMENTAL IMPACT STATEMENT
APPENDICES

Hawaii Electric Light Company, Inc. retained various consultants and experts to evaluate conditions and assess the probable and potential impacts the improvements of the Keahole Generating Station and Airport Substation would have on the community it serves. These studies, as well as HELCO's Integrated Resource Plan and Evaluations, are attached alphabetically by consultant as Appendices A- P.

STUDIES	APPENDIX
Belt Collins Hawaii Ltd.; *Traffic Impact Analysis Study;* October 2004	A
Bruner, Phillip L. Environmental Consultant; *Avifauna/ and Feral Mammal Field Survey of Keahole Generating Station, North Kona, Island of Hawaii;* July 31, 2003	B
Char & Associates; Botanical Consultants; *Botanical Resources Assessment Study;* August 2003	C
Geohazards Consultants International, Inc., Geological Consultant; *Volcanic Hazards at the HELCO Keahole Generating Station and Airport Substation, North Kona Hawaii;* February 28, 2004	D
Hawaii Electric Light Company, Inc.; *Second Integrated Resource Plan 1999-2018;* September 1, 1998	E
Hawaii Electric Light Company, Inc.; *Evaluation Report of Second Integrated Resource Plan;* March 31, 2004	F
Hawaii Electric Light Company, Inc; *A Review of Alternative Resources Discussed in the IRP;* June 2004.	G
HFP Acoustical Consultants; *Noise Study for Draft Environmental Impact Statement;* September 2004	H
Jim Clary & Associates; *Climate and Air Quality Assessment;* July 2004	I
Marine Research Consultants; *An Assessment of Potential Impacts to the Marine Environment;* April 2004	J
Paul H. Rosendahl, Ph.D. Inc.; *Archaeological and Cultural Impact Assessment Study;* February 2004	K
Paull, Robert E., Ph.D.; *Emission Studies — Impact on Keahole Agricultural Park;* June 27, 2004	L
SMS Research; *Socio-Economic Impact Assessment of Redesignation of Keahole Generating and Transmission Sites;* September 2004	M
Stone & Webster, Inc., A Shaw Group Company; *Naphtha Fuel Study, Keahole Combined Cycle Plant;* February 2004	N
Stone & Webster, Inc., A Shaw Group Company; *SCR System Scope Study — Keahole Combined Cycle Plant;* February 2004	O
Tom Nance Water Resource Engineering; *Potential Impact on Water Resources of the Expansion of the Hawaii Electric Light Company's Power Generating Station at Keahole in North Kona, Hawaii;* December 2003	P

TRAFFIC IMPACT ANALYSIS STUDY

HELCO KEAHOLE GENERATION STATION AND AIRPORT SUBSTATION

KEAHOLE, HAWAII

October 2004

Prepared For:

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HELCO KEAHOLE GENERATION STATION AND AIRPORT SUBSTATION

KEAHOLE, HAWAII

EXECUTIVE SUMMARY

This report summarizes the analysis and findings of a traffic impact study for the proposed improvements by the Hawaii Electric Light Company, Inc. (HELCO) to the existing Keahole Generation Station and Airport Substation in the Keahole area on the island of Hawaii. The potential traffic impacts of the proposed expansion are described and mitigation measures are identified, as needed.

Traffic count data and field observations were collected on March 9 and 10, 2004 at the intersection of Queen Kaahumanu Highway with Keahole Airport Road and at the intersection of Queen Kaahumanu Highway with Kaiminani Drive as well as at the project's north and south gates. Under the existing traffic conditions, fuel trucks utilize the north gates of the Keahole Generation Station while employees and deliveries access the project site through the south gate at Pukiawe Street. During the morning peak hour, 48 vehicles arrived and 11 vehicles departed from the project site. In the afternoon peak hour, there were 7 vehicles that arrived at the project site while 16 vehicles departed from the site. Most of these trips are related to the construction activities and testing of new equipment installed at the Keahole Generation Station. The analytical results of these two signalized intersections indicate the existing traffic conditions operate at Level of C or better during the morning and afternoon peak hour periods.

For future without the project conditions, a growth rate of 4.8 percent was applied to Queen Kaahumanu Highway traffic volumes as well as the addition of project trips from the proposed Palamanui project which has two possible access roads that would connect to Queen Kaahumanu Highway. The analysis results of the signalized intersections of Queen Kaahumanu Highway/Keahole Airport Road

and Queen Kaahumanu Highway/Kaiminani Drive indicates Level of Service F conditions meaning that the existing two-lane highway would be inadequate to serve the future traffic assignment associated with the growth in regional highway traffic and the Palamanui development, but without the HELCO project.

Estimates of HELCO-related project trips were developed for Year 2009 when the project improvements are expected to be completed. During the morning peak hour, there would be approximately 15 entering trips and 6 exiting trips at the project driveways. During the afternoon peak hour, 3 entering trips and 11 exiting trips are expected at the project driveways. The future HELCO project trips would be less than the existing traffic volumes that were counted during current construction activities. The future proportion of HELCO-generated trips at the Keahole Airport Road and Kaiminani Drive intersections with Queen Kaahumanu Highway would be less than one percent during the morning and afternoon peak hour periods. Therefore, no mitigation measures are needed to accommodate the future HELCO project trips.

HELCO KEAHOLE GENERATION STATION
AIRPORT SUBSTATION

KEAHOLE, HAWAII

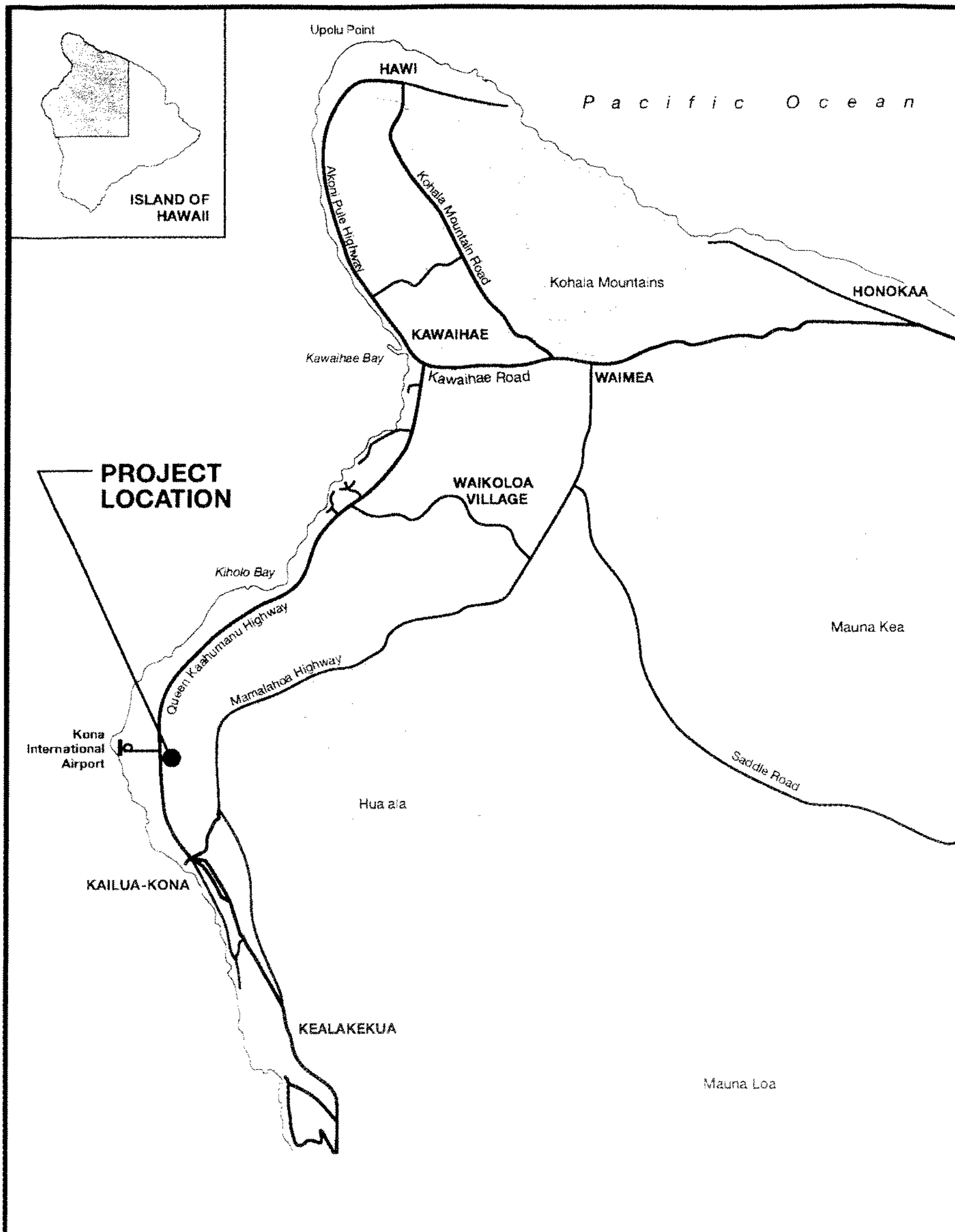
I. INTRODUCTION

This report summarizes the analysis and findings of a traffic impact study for the proposed improvements by the Hawaii Electric Light Company, Inc. (HELCO) to the existing Keahole Generation Station and Airport Substation in Keahole, Hawaii. The potential traffic impacts of the proposed expansion are described and mitigation measures are identified, as needed.

II. PROJECT DESCRIPTION

The general location of the Keahole Generation Station and the Airport Substation is shown on the vicinity map in Figure 1. The project is situated near the intersection of Queen Kaahumanu Highway, Keahole Airport Road and Reservoir Road, as identified in Figure 2. The Keahole Generation Station Tax Map Key is (3) 7-3-049:036 (14.998 acres) and the Airport Substation is located at Tax Map Key (3) 7-3-049:037 (0.645 acres). The project sites are delineated in Figure 3.

The Keahole Generation Station had an original capacity of 30.25 megawatts (MW), which consisted of six nominal 2.75 MW diesel-fueled generating units and one nominal 13.75-MW, simple cycle combustion turbine (CT). Two simple cycle CTs (CT-4 and CT-5) have been recently brought on-line. The proposed project will convert the two CTs to a combined cycle system that will add two heat recovery steam generators, a steam condensing system and a nominal 16-MW steam turbine generator and ancillary equipment. Subsequently, approvals will be sought to utilize brackish water from a groundwater supply well at the Keahole Generation Station.



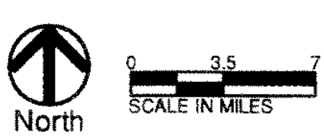


Figure 1
Vicinity Map

Prepared for: Hawaii Electric Light Company, Inc.
Prepared by: Belt Collins Hawaii
October 2004

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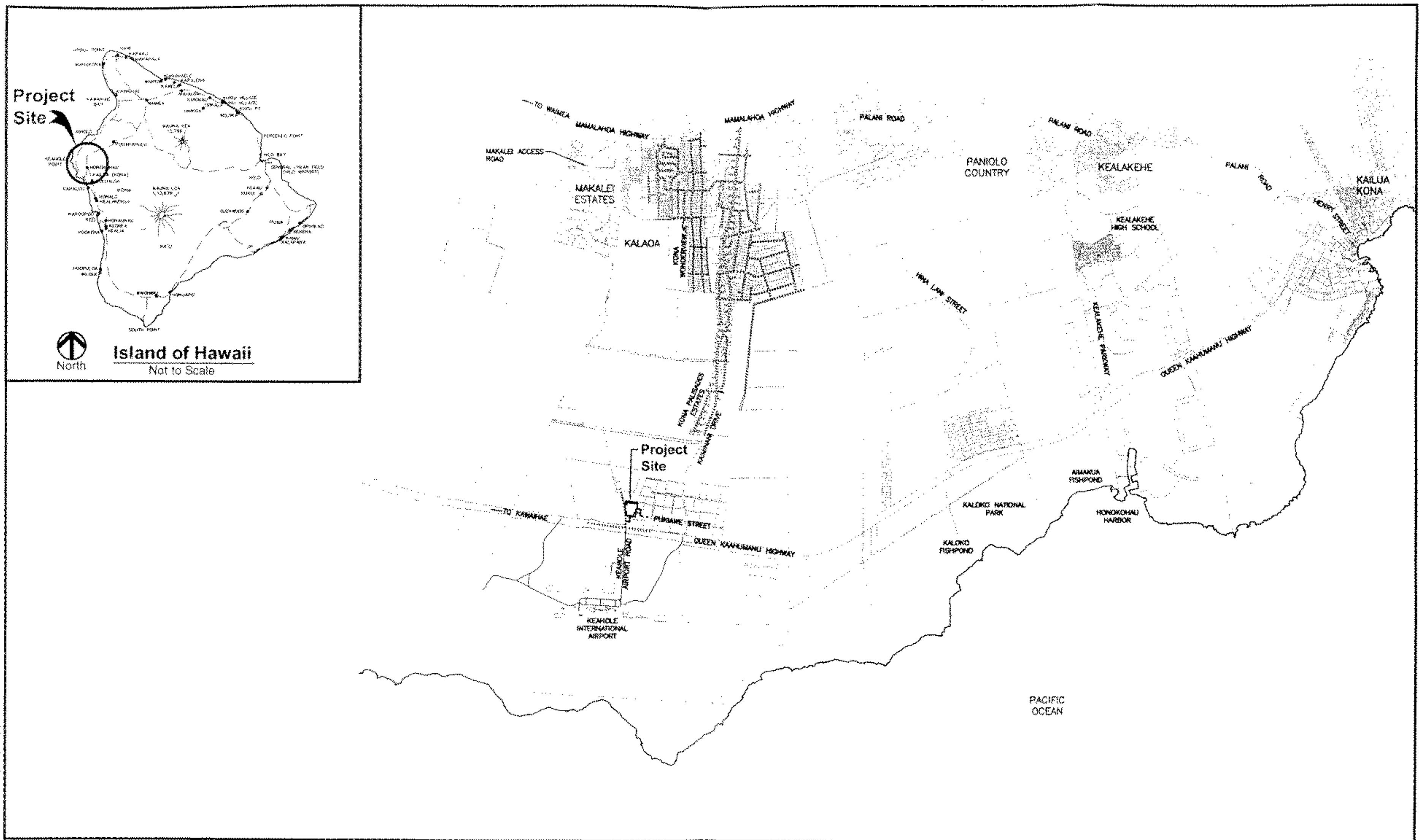
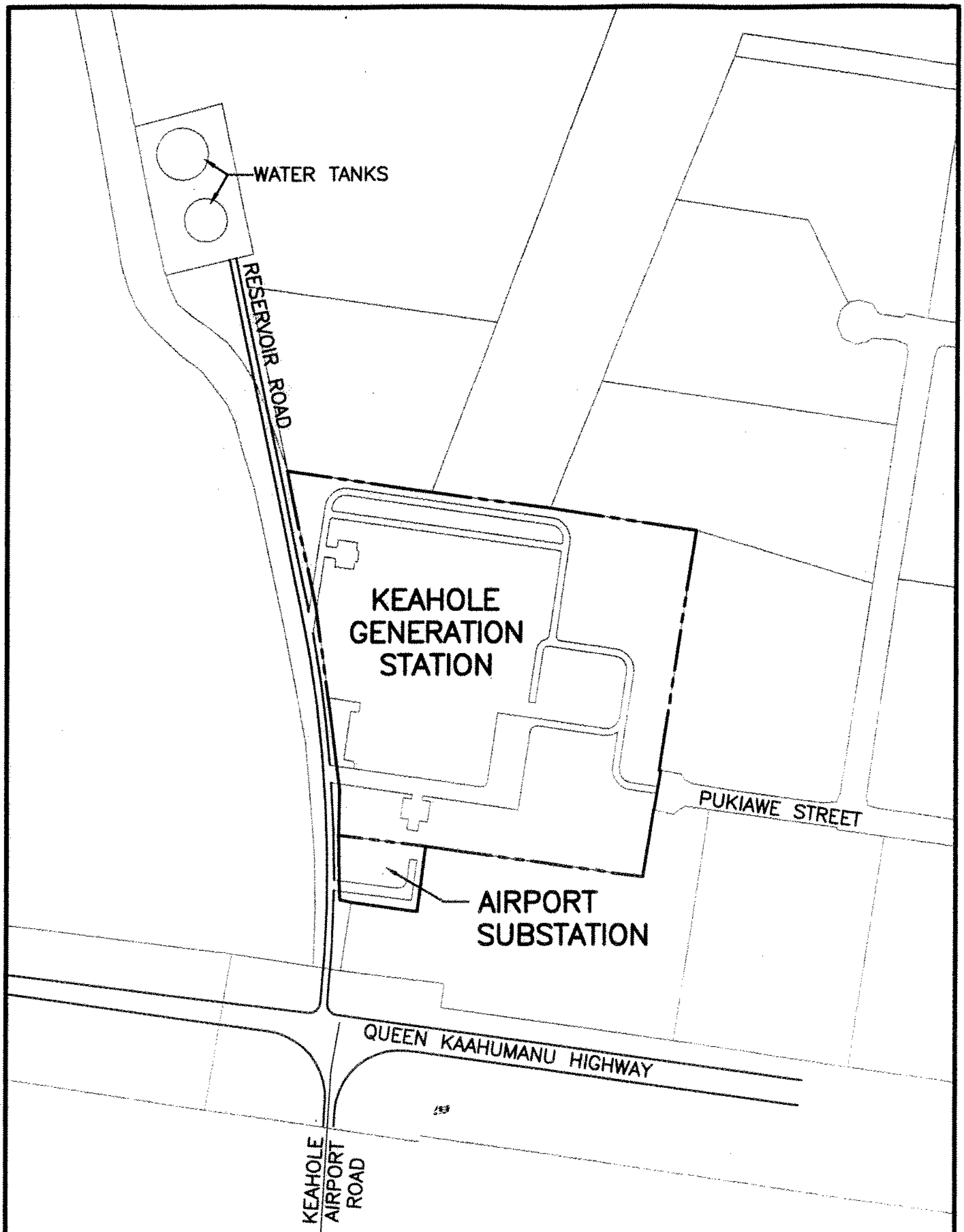


Figure 2
Location Map
Prepared for: Hawaii Electric Light Company, Inc.
Prepared by: Belt Collins Hawaii
October 2004



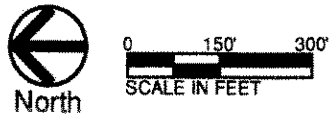


Figure 3
Project Site Map

Prepared for: Hawaii Electric Light Company, Inc.
Prepared by: Belt Collins Hawaii
October 2004

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HELCO is considering the use of alternative fuels, such as naphtha, which may require enlargement of existing fuel storage tanks and tank-yard berm walls as well as addition of storage tanks, fuel distribution pumps/piping and fire protection. New emissions control, possibly a Selective Catalytic Reduction (SCR) system or a SCR alternative that uses ammonia, is also under consideration.

For the Airport Substation, there may be future replacement or addition of transformers and switchgear equipment. Painting and landscaping are proposed to mitigate visual impacts of the Airport Substation. Current plans indicate that the improvements at the Keahole Generation Station and Airport Substation would be completed in Year 2009.

The existing Keahole Generation Station has two driveways onto Reservoir Access Road and a driveway onto Pukiawe Street on the south side of its property. Pukiawe Street connects to Kaiminani Drive which links to Queen Kaahumanu Highway and Mamalahoa Highway.

III. STUDY METHODOLOGY

Various types of information, including traffic volume data, roadway laneage, and intersection operations, are collected to establish existing traffic conditions at the selected study locations. Subsequently, the future traffic forecasts without the project area were developed. Estimates of project traffic are determined and the future traffic assignments with the project traffic are analyzed. The comparison of analytical results of future traffic conditions with and without the project is utilized to determine the project-related traffic impacts and mitigation measures.

IV. EXISTING TRAFFIC CONDITIONS

The analysis of existing traffic conditions establishes the current traffic operating conditions for the traffic study. Existing data, such as traffic volume data, traffic signal phasing and timing and intersection and roadway laneage and signage are collected for this assessment.

A. Existing Roadway System

In the vicinity of the project, Queen Kaahumanu Highway is a two-lane State highway that provides access between Kawaihae and Kailua town. Generally, Queen Kaahumanu Highway has two 12-foot travel lanes, one in each direction, with 10-foot shoulders.

The Keahole Airport Access Road is a two-lane collector road that provides access to the Kona Airport as well as supporting facilities, such as rental car companies and other businesses that support airport operations.

For this project, there are two study intersections:

- Queen Kaahumanu Highway with the Keahole Airport Access Road and Reservoir Access Road.
- Queen Kaahumanu Highway with Kaiminani Drive.

For the signalized intersection of Queen Kaahumanu Highway, Keahole Airport Access Road and Reservoir Road, there are separate left turn lanes on the highway in the northbound and southbound direction and a separate right turn lane in the eastbound direction. There are southbound deceleration and acceleration lanes on the highway for the Keahole Airport Access Road. The Reservoir Access Road is a single lane road and serves the Keahole Generation Station, a substation and terminates at the driveway to two water tanks.

Kaiminani Drive links Queen Kaahumanu Highway and Mamalahoa Highway. Kaiminani Drive serves as a collector road for the Kona Palisades subdivision and meets Queen Kaahumanu Highway in a signlalized T-intersection. There is a separate left turn lane on the highway in the southbound direction. In addition, there are existing deceleration and acceleration lanes in the northbound direction for Kaiminani Drive.

B. Traffic Counts

Manual turning movement count data was collected at the intersection of Queen Kaahumanu Highway with Keahole Airport Road and Reservoir Road as well as the intersection of Queen Kaahumanu Highway and Kaiminani Drive. The traffic counts were conducted on March 9 and 10, 2004.

The manual traffic count data is contained in Appendix A. The weekday morning peak hour is at 6:30 to 7:30 a.m. while the weekday afternoon peak hour occurs at 3:15 to 4:15 p.m. The existing morning and afternoon peak hour traffic volumes are presented in Figure 4.

C. Analysis Results

This report utilizes the Highway Capacity Manual (HCM) 2000 analytical methodology for signalized intersections. The analysis results provide Level of Service conditions, which are rated from A to F (best to worst), and capacity conditions. Level of Service represents a qualitative measure of traffic operating conditions and considers speed, travel time, freedom to manuever, types of traffic controls and interruptions as well as driver comfort and convenience. Level of service definitions for signalized intersections are summarized in Appendix B.

For the intersection of Queen Kaahumanu Highway, Keahole Airport Road and Reservoir Road, the overall intersection is at Level of Service B during the morning peak hour and at Level of Service C during the afternoon peak hour. For the intersection of Queen Kaahumanu Highway and Kaiminani Drive, the overall intersection is at Level of Service B during the morning and afternoon peak hour. Overall, the field observations concur with analysis results of Level of Service C or better for these two study intersections. The summary of the analysis results is presented in Table 1.

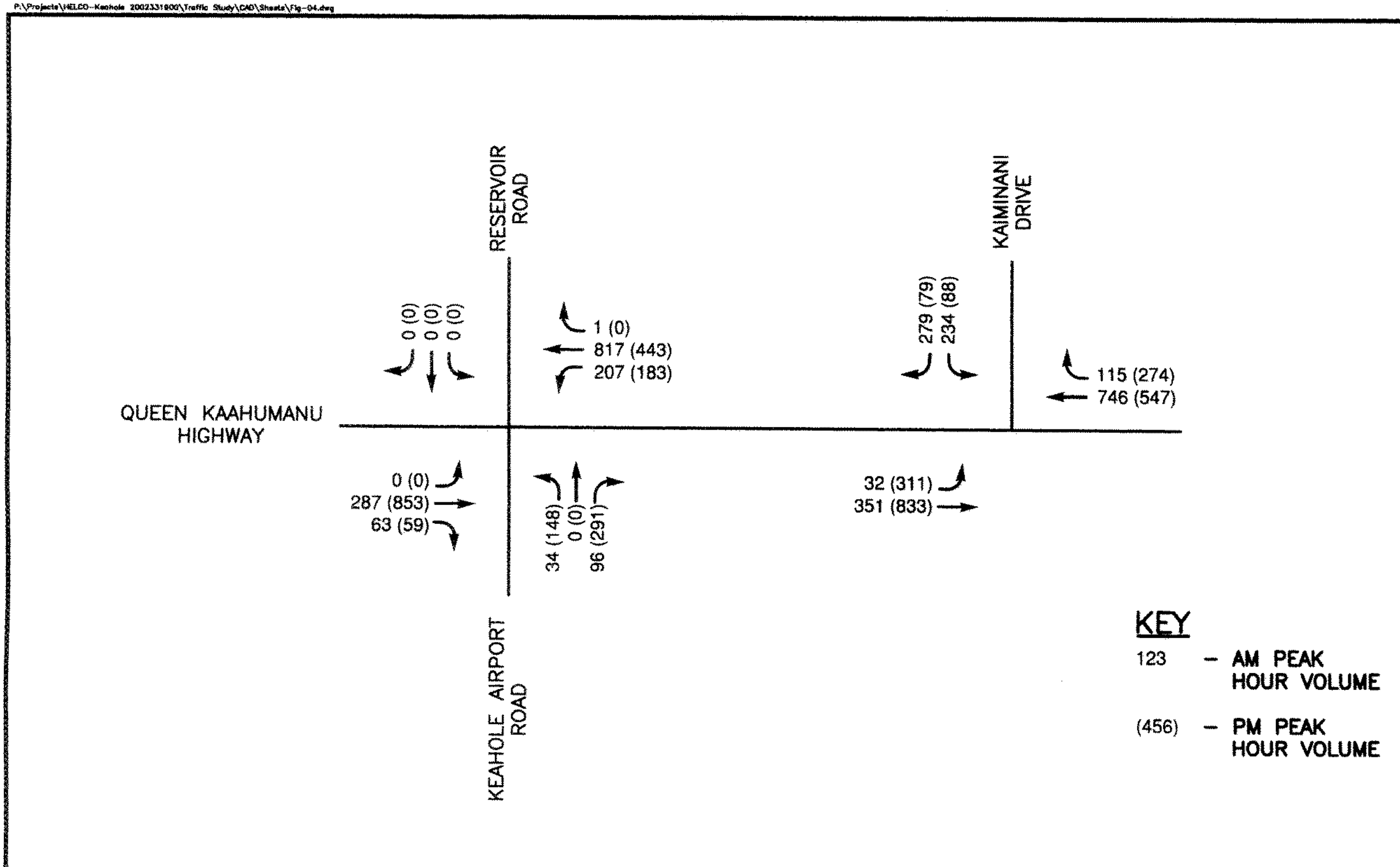

Figure 4
Existing Traffic Volumes
Prepared for: Hawaii Electric Light Company, Inc.
Prepared by: Belt Collins Hawaii
October 2004

Table 1

EXISTING TRAFFIC CONDITIONS

SIGNALIZED INTERSECTION ANALYSIS RESULTS

Intersection	AM Peak Hour v/c Ratio	AM Peak Hour Delay (seconds)	AM Peak Hour Level of Service	PM Peak Hour v/c Ratio	PM Peak Hour Delay (seconds)	PM Peak Hour Level of Service
Queen Kaahumanu Highway/Keahole Airport Road & Reservoir Road						
Queen Kaahumanu Highway						
Northbound Approach	--	12.5	B	--	14.3	B
Left Turn	0.37	6.3	A	0.72	30.5	C
Right Turn/Through Movement	0.76	14.0	B	0.39	7.6	A
Southbound Approach	--	8.1	A	--	30.0	C
Left Turn	0.00	6.5	A	0.00	8.5	A
Through Movement	0.29	8.4	A	0.90	31.5	C
Right Turn	0.08	6.9	A	0.07	9.0	A
Keahole Aiport Road						
Eastbound Approach						
Left Turn	0.12	22.4	C	0.60	34.5	C
Reservoir Road						
Westbound Approach	0.01	21.7	C	0.01	27.3	C
Overall Intersection	0.60	11.6	B	0.92	24.6	C
Queen Kaahumanu Highway/Kaiminani Drive						
Queen Kaahumanu Highway						
Northbound Approach	--	17.9	B	--	10.0-	A
Through Movement	0.82	19.5	B	0.55	10.8	B
Right Turn	0.15	7.5	A	0.32	8.3	A
Southbound Approach	--	7.5	A	--	14.2	B
Left Turn	0.14	7.9	A	0.75	19.6	B
Through Movement	0.35	7.4	A	0.74	12.1	B
Kaiminani Drive						
Westbound Approach						
Left Turn	0.66	25.8	C	0.32	26.0	C
Right Turn		FREE RIGHT TURN			FREE RIGHT TURN	
Overall Intersection	0.86	16.4	B	0.65	13.0	B

V. FUTURE TRAFFIC CONDITIONS WITHOUT THE PROJECT

Research of historical traffic volume data and traffic generated by nearby projects was conducted to develop future Year 2009 traffic forecasts without the proposed project improvements. Regional traffic studies, such as the Hawaii Long Range Land Transportation Plan, Keahole to Kailua Development Plan and the Keahole to Honaunau Regional Circulation Plan, were also reviewed. A growth factor of 4.8 percent was applied to account for historical regional growth in traffic volumes. In addition, traffic volumes generated by the nearby proposed Palamanui project were derived for Year 2009 from the project's traffic study report by Austin, Tsutsumi & Associates, Inc., dated January 27, 2004.

The Palamanui project has proposed two alternate access roads, as shown in Figure 5, and is currently conducting feasibility studies. The north access road for the Palamanui project would create a new T-intersection with Queen Kaahumanu Highway. The south access road would connect to Queen Kaahumanu Highway at the current location of the Reservoir Road. Two future Year 2009 traffic assignments without the proposed project have been developed. If the Palamanui project selects the north access road as its primary access road, then Figure 6 contains the future traffic assignment. However, if the Palamanui project prefers the south access road as its primary access road, then Figure 7 shows the traffic assignment for this proposal.

The State Department of Transportation has proposed the Phase I widening of Queen Kaahumanu Highway from two to four lanes between Henry Street and Kealakehe Parkway; this improvement is scheduled for completion in Year 2008. In addition, the Phase 2 Queen Kaahumanu Highway widening between Kealakehe Parkway and Keahole Airport Road is being programmed for completion in Year 2011.

A. Analysis Results

The analysis results for future conditions without the project are identified in Table 2 with Palamanui north access road and in Table 3 with Palamanui south access road. The signalized intersection analysis show similar results if either the Palamanui north or south access road serves as its primary access road.

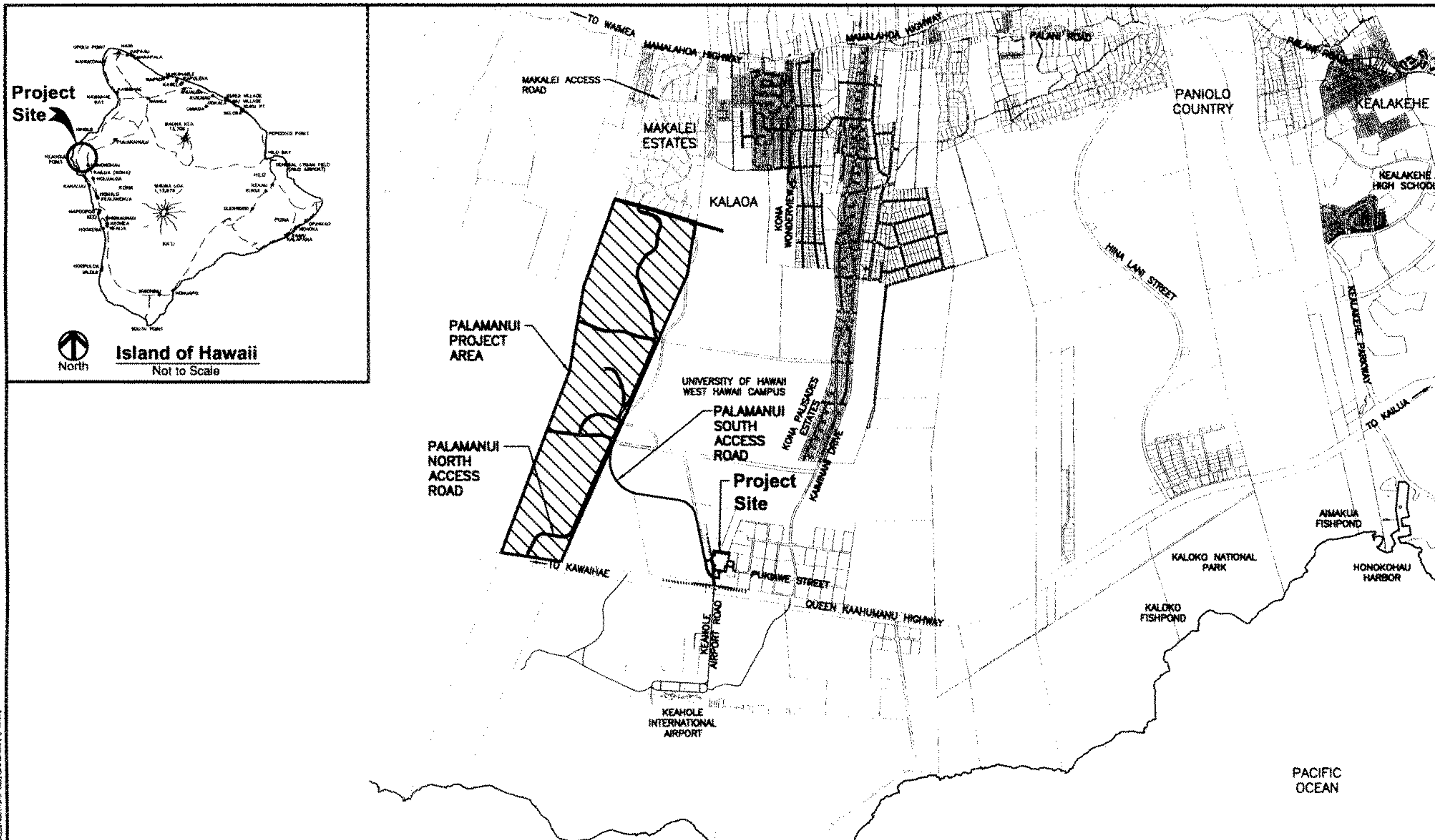

Figure 5
Proposed Palamanui Access Roads
Prepared for: Hawaii Electric Light Company, Inc.
Prepared by: Belt Collins Hawaii
October 2004

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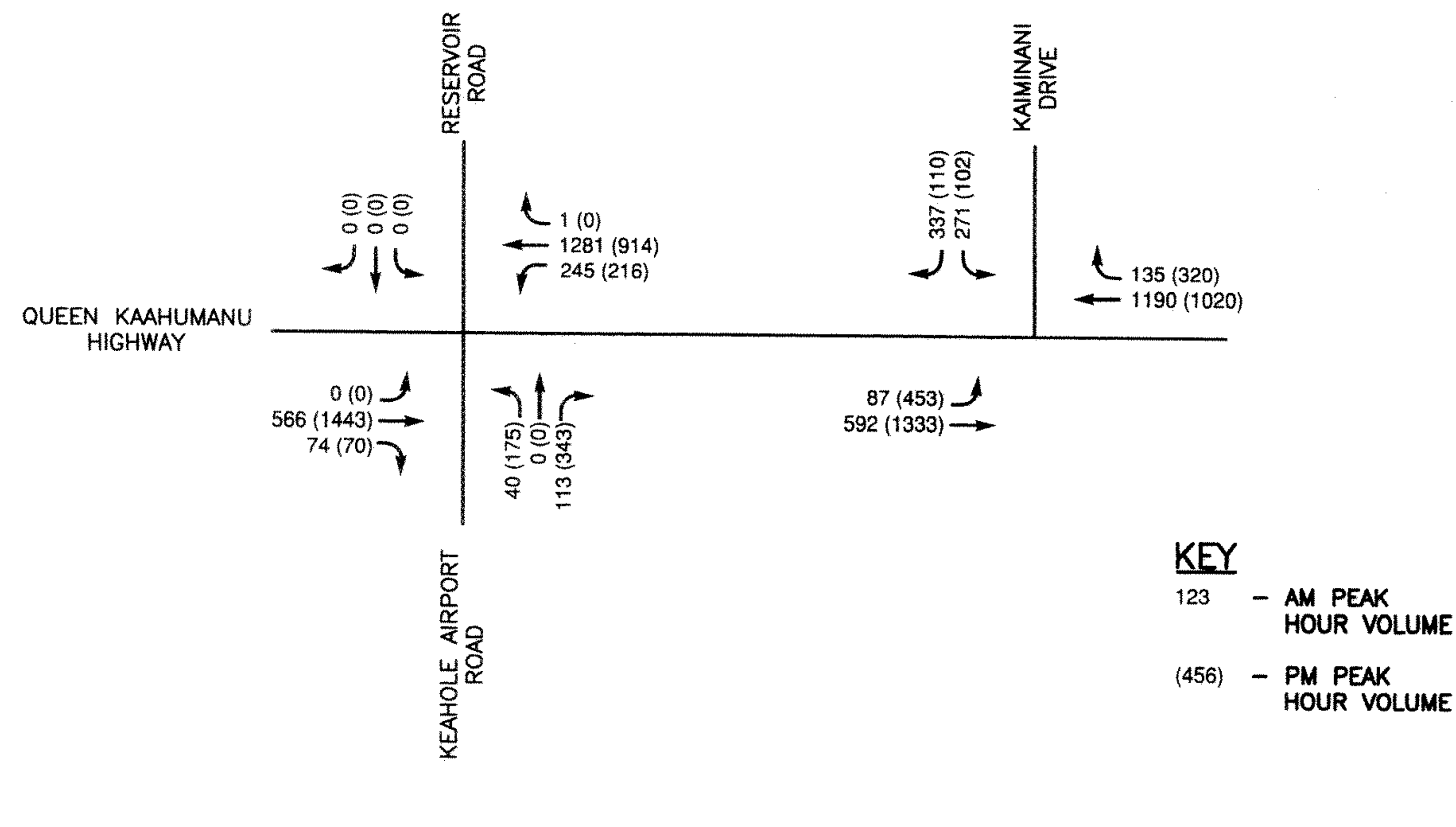

Figure 6
Future Traffic Assignment Without Project and with Palamanui North Access Road

Prepared for: Hawaii Electric Light Company, Inc.
Prepared by: Belt Collins Hawaii
October 2004

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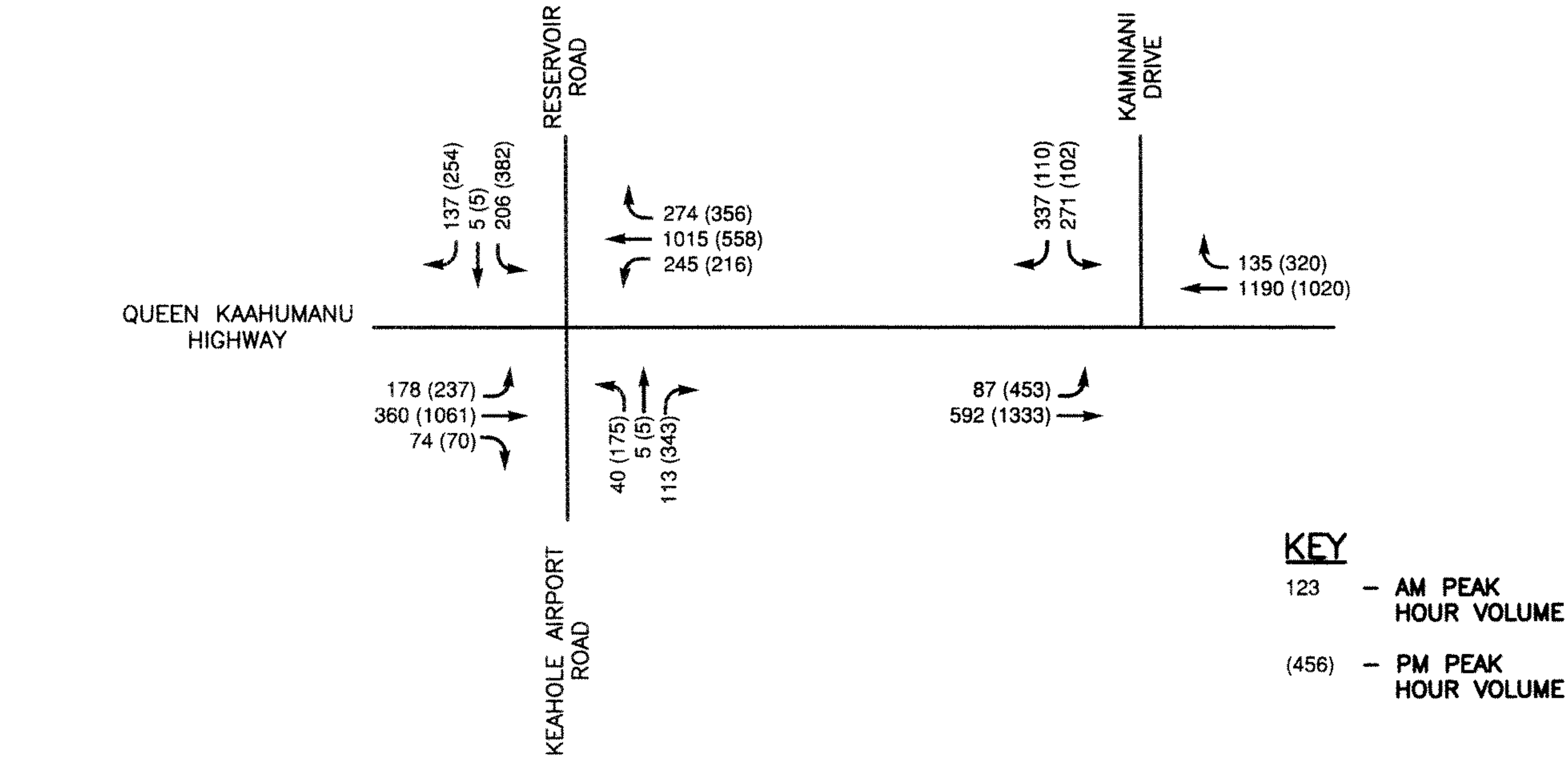

Figure 7

Future Traffic Assignment without Project and with Palamanui South Access Road

Prepared for: Hawaii Electric Light Company, Inc.
Prepared by: Belt Collins Hawaii
October 2004

Table 2

FUTURE WITHOUT PROJECT TRAFFIC CONDITIONS (WITH PALAMANUI NORTH ACCESS ROAD)

SIGNALIZED INTERSECTION ANALYSIS RESULTS

	AM Peak Hour			PM Peak Hour		
Intersection	v/c Ratio	Delay (seconds)	Level of Service	v/c Ratio	Delay (seconds)	Level of Service
Queen Kaahumanu Highway/Keahole Airport Road & Reservoir Road						
Queen Kaahumanu Highway						
Northbound Approach	--	29.6	C	--	69.4	E
Left Turn	0.50	4.0	A	1.12	324.3	F
Right Turn/Through Movement	0.97	34.5	C	0.69	9.3	A
Southbound Approach	--	4.7	A	--	402.3	F
Left Turn	0.01	2.7	A	0.00	5.7	A
Through Movement	0.45	4.9	A	1.22	421.8	F
Right Turn	0.07	2.8	A	0.07	6.1	A
Keahole Aiport Road						
Eastbound Approach						
Left Turn	0.42	33.8	C	1.13	362.2	F
Reservoir Road						
Westbound Approach	0.03	30.3	C	0.01	46.0	D
Overall Intersection	0.92	22.5	C	1.34	266.1	F
Queen Kaahumanu Highway/Kaiminani Drive						
Queen Kaahumanu Highway						
Northbound Approach	--	67.2	E	--	42.2	D
Through Movement	1.01	74.1	E	0.97	51.6	D
Right Turn	0.13	6.5	A	0.36	12.3	B
Southbound Approach	--	8.7	A	--	47.9	D
Left Turn	0.39	9.6	A	0.96	74.5	E
Through Movement	0.48	8.6	A	0.97	38.9	D
Kaiminani Drive						
Westbound Approach						
Left Turn	0.91	86.0	F	0.62	58.6	E
Right Turn	FREE RIGHT TURN			FREE RIGHT TURN		
Overall Intersection	1.04	52.0	D	0.99	45.9	D

Table 3

FUTURE WITHOUT PROJECT TRAFFIC CONDITIONS (WITH PALAMANUI SOUTH ACCESS ROAD)

SIGNALIZED INTERSECTION ANALYSIS RESULTS

	AM Peak Hour			PM Peak Hour		
Intersection	v/c Ratio	Delay (seconds)	Level of Service	v/c Ratio	Delay (seconds)	Level of Service
Queen Kaahumanu Highway/Keahole Airport Road & Reservoir Road						
Queen Kaahumanu Highway						
Northbound Approach	--	106.2	F	--	142.1	F
Left Turn	345.00	5.4	A	1.31	636.6	F
Through Movement	1.07	156.0	F	0.66	26.8	C
Right Turn	0.33	9.4	A	0.50	22.8	C
Southbound Approach	--	31.9	C	--	404.6	F
Left Turn	0.93	87.0	F	0.78	39.6	D
Through Movement	0.38	9.7	A	1.26	511.8	F
Right Turn	0.09	7.4	A	0.10	16.5	B
Keahole Aiport Road						
Eastbound Approach	0.20	26.1	C	1.32	684.3	F
Left Turn	--	--	--	--	--	--
Through Movement	--	--	--	--	--	--
Reservoir Road						
Westbound Approach	1.14	331.8	F	1.30	603.1	F
Left Turn	--	--	--	--	--	--
Left Turn/Through Movement	--	--	--	--	--	--
Overall Intersection	1.05	105.6	F	1.64	349.3	F
Queen Kaahumanu Highway/Kaiminani Drive						
Queen Kaahumanu Highway						
Northbound Approach	--	67.2	E	--	42.2	D
Through Movement	1.01	74.1	E	0.97	51.6	D
Right Turn	0.13	6.5	A	0.36	12.3	B
Southbound Approach	--	8.7	A	--	47.9	D
Left Turn	0.39	9.6	A	0.96	74.5	E
Through Movement	0.48	8.6	A	0.97	38.9	D
Kaiminani Drive						
Westbound Approach						
Left Turn	0.91	86.0	F	0.62	58.6	E
Right Turn	FREE RIGHT TURN			FREE RIGHT TURN		
Overall Intersection	1.04	52.0	D	0.99	45.9	D

Level of Service F conditions or volume-to-capacity ratios that exceed 1.0 are expected at the Queen Kaahumanu Highway/Kaiminani Drive intersection during the morning peak hour and at the Queen Kaahumanu Highway/Keahole Airport Road/Reservoir Road intersection during the afternoon peak hour.

The Level of Service F conditions and the volume-to-capacity ratios greater than 1.0 indicate that the two-lane Queen Kaahumanu Highway intersections would be inadequate to serve the forecasted traffic volumes. If Queen Kaaahumanu Highway were widened to four lanes, the two study intersections would have adequate capacity to serve the forecasted traffic volumes and the intersection would operate at Level of Service E or better, as shown in Table 4 and Table 5.

Table 4

FUTURE WITHOUT PROJECT TRAFFIC CONDITIONS (WITH PALAMANUI NORTH ACCESS ROAD) AND WITH MITIGATION

SIGNALIZED INTERSECTION ANALYSIS RESULTS

	AM Peak Hour			PM Peak Hour		
	v/c Ratio	Delay (seconds)	Level of Service	v/c Ratio	Delay (seconds)	Level of Service
Queen Kaahumanu Highway/Keahole Airport Road & Reservoir Road						
Queen Kaahumanu Highway						
Northbound Approach	--	13.2	B	--	14.3	B
Left Turn	0.65	16.5	B	0.79	36.8	D
Right Turn/Through Movement	0.69	12.6	B	0.45	9.0	A
Southbound Approach	--	10.3	B	--	24.9	C
Left Turn	0.01	8.4	A	0.00	10.4	B
Through Movement	0.34	10.5	B	0.88	25.5	C
Right Turn	0.10	8.9	A	0.10	11.1	B
Keahole Aiport Road						
Eastbound Approach						
Left Turn	0.11	19.3	B	0.60	32.1	C
Reservoir Road						
Westbound Approach	0.01	18.6	B	0.01	24.9	C
Overall Intersection	0.50	12.5	B	0.89	21.1	C
Queen Kaahumanu Highway/Kaiminani Drive						
Queen Kaahumanu Highway						
Northbound Approach	--	12.9	B	--	17.9	B
Through Movement	0.71	13.4	B	0.75	18.5	B
Right Turn	0.18	8.2	A	0.53	16.1	B
Southbound Approach	--	7.7	A	--	12.6	B
Left Turn	0.45	10.7	B	0.87	29.4	C
Through Movement	0.32	7.3	A	0.62	6.8	A
Kaiminani Drive						
Westbound Approach						
Left Turn	0.71	27.1	C	0.47	25.5	C
Right Turn	FREE RIGHT TURN			FREE RIGHT TURN		
Overall Intersection	0.83	13.0	B	0.89	15.2	B

Table 5

FUTURE WITHOUT PROJECT TRAFFIC CONDITIONS (WITH PALAMANUI SOUTH ACCESS ROAD) AND WITH MITIGATION

SIGNALIZED INTERSECTION ANALYSIS RESULTS

	AM Peak Hour			PM Peak Hour		
Intersection	v/c Ratio	Delay (seconds)	Level of Service	v/c Ratio	Delay (seconds)	Level of Service
Queen Kaahumanu Highway/Keahole Airport Road & Reservoir Road						
Queen Kaahumanu Highway						
Northbound Approach	--	22.0	C	--	38.2	D
Left Turn	0.59	13.6	B	0.83	54.4	D
Through Movement	0.85	25.1	C	0.48	31.1	C
Right Turn	0.50	17.8	B	0.68	39.4	D
Southbound Approach	--	19.1	B	--	43.5	D
Left Turn	0.80	31.5	C	0.61	20.2	C
Through Movement	0.30	14.1	B	0.91	49.9	D
Right Turn	0.14	13.2	B	0.13	26.4	C
Keahole Aiport Road						
Eastbound Approach	--	26.7	C	--	62.3	E
Left Turn	0.29	26.9	C	0.76	62.8	E
Through Movement	0.04	25.4	C	0.02	44.4	D
Reservoir Road						
Westbound Approach	--	--	--	--	--	--
Left Turn	0.50	25.0	C	0.61	45.4	D
Left Turn/Through Movement	--	--	--	--	--	--
Overall Intersection	0.74	21.6	C	0.84	42.9	D
Queen Kaahumanu Highway/Kaiminani Drive						
Queen Kaahumanu Highway						
Northbound Approach	--	12.9	B	--	17.9	B
Through Movement	0.71	13.4	B	0.75	18.5	B
Right Turn	0.18	8.2	A	0.53	16.1	B
Southbound Approach	--	7.7	A	--	12.6	B
Left Turn	0.45	10.7	B	0.87	29.4	C
Through Movement	0.32	7.3	A	0.62	6.8	A
Kaiminani Drive						
Westbound Approach						
Left Turn	0.71	27.1	C	0.47	25.5	C
Right Turn	FREE RIGHT TURN			FREE RIGHT TURN		
Overall Intersection	0.83	13.0	B	0.89	15.2	B

VI. PROJECT TRAFFIC

The Keahole Generation Station expansion will add additional equipment and improved facilities at the project site. The traffic forecast of project traffic volumes is developed through a three-step procedure of trip generation, trip distribution and traffic assignment.

A. Trip Generation

In trip generation, the estimates of project traffic volumes are quantified through discussions with the HELCO staff about the number of employees at the site and their shift hours as well as deliveries of fuel trucks and supplies, maintenance services and possible visitors.

With the recently completed installation of the two new CTs the staffing at the Keahole Generation Station has been modified. During the weekday, six maintenance personnel are employed between 6:00 a.m. and 5:30 p.m. while three operating personnel work on the first shift, 6:00 a.m. to 2:00 p.m. and two operating personnel are on the second shift, 2:00 p.m. to 10:00 p.m. During the weekend, there are four operating personnel assigned with two persons in two shifts of 6:00 a.m to 2:00 p.m and 2:00 p.m. to 10:00 p.m. Hence, most of the current shift changes occur at different times than the Queen Kaahumanu Highway peak hours of 6:30 to 7:30 a.m. and 3:15 to 4:15 p.m.

The fuel truck deliveries usually range between 3 to 4 trips per day, Monday through Friday. Fuel is trucked from Hilo Harbor. The Keahole Generation Station receives five mail deliveries per week. Also, other deliveries by vendor/supplier goods and services are likely to increase to between 5 and 10 deliveries per week.

At project completion in Year 2009, the Keahole Generation Station weekday staffing would change to eight maintenance personnel between 6:00 a.m. and 5:30 p.m. and seven operating personnel in three shifts (one person from 7:00 a.m. to 3:30 p.m., two persons from 6:00 a.m. to 2:00 p.m., two persons from 2:00 p.m. to 10:00 p.m. and two persons from 10:00 p.m. to 6:00 a.m.). For the weekend staffing, there would be six operating personnel with two persons in each of the three shifts: 6:00 a.m. - 2:00 p.m., 2:00 p.m. - 10:00 p.m. and 10:00 p.m. - 6:00 a.m.

Fuel deliveries would increase to 7 or 8 fuel trucks per day, Monday through Friday, but deliveries would be from Kawaihae Harbor instead of Hilo Harbor. Also, there would be five mail deliveries and approximately 8 to 12 vendor/ supplier deliveries per week.

For the new emissions control system, ammonia would be delivered by truck from Hilo Harbor once every three weeks. It is expected that ammonia deliveries would arrive at the Keahole Generation Station after the end of the morning peak hour period and depart for the return trip to Hilo prior to the start of the afternoon peak hour period.

The Keahole Generation Station and the Airport Substation would have the largest staffing, fuel truck deliveries and vendor/supplier deliveries at project completion. Although employee shifts are slightly different from the existing morning and afternoon roadway peak hour periods, some of the employee trips are included in the morning and afternoon peak hours since it is possible the project peak hour periods may become coincident to the future highway peak hour periods. The estimated project trips, as given in Table 6, are utilized for the future with project traffic conditions.

Table 6
PROJECT TRIPS

	AM Peak Hour		PM Peak Hour	
	Enter	Exit	Enter	Exit
Staff	13	4	2	10
Fuel Trucks	2	2	1	1
Ammonia Trucks	0	0	0	0
Vendor/Supplier	0	0	0	0
Total	15	6	3	11

B. Trip Distribution

In trip distribution, the general direction of trips traveling to and from the project site is identified. Information about population and employment on the island of Hawaii was utilized to determine the direction of travel for trips entering and exiting the project site. It is estimated that approximately 15 percent of the trips would travel to and from the north, while 60 percent would travel to/from the south and 25 percent of the trips would travel to/from the east. Fuel trucks would arrive and depart from the north side of the project site.

C. Traffic Assignment

Traffic assignment defines the specific roadways that would be utilized by the project traffic as well as the proportion of project traffic volumes on each of these roadways. In addition, two alternatives were developed for the Keahole project.

For Alternative A, if the Palamanui project builds the north access road as its primary roadway, then the Keahole gates would operate in the same fashion as the existing conditions. Fuel trucks would continue to use the north gate via Reservoir Road and the staff and vendors would use the south gate on Pukiawe Street.

For Alternative B, if the Palamanui project constructs the south access road as its primary roadway, then all staff, vendors and fuel trucks would use the north gates of the HELCO generation station and the south gate would be closed. The project traffic volumes for Alternative A and Alternative B are provided in Figures 8 and 9, respectively.

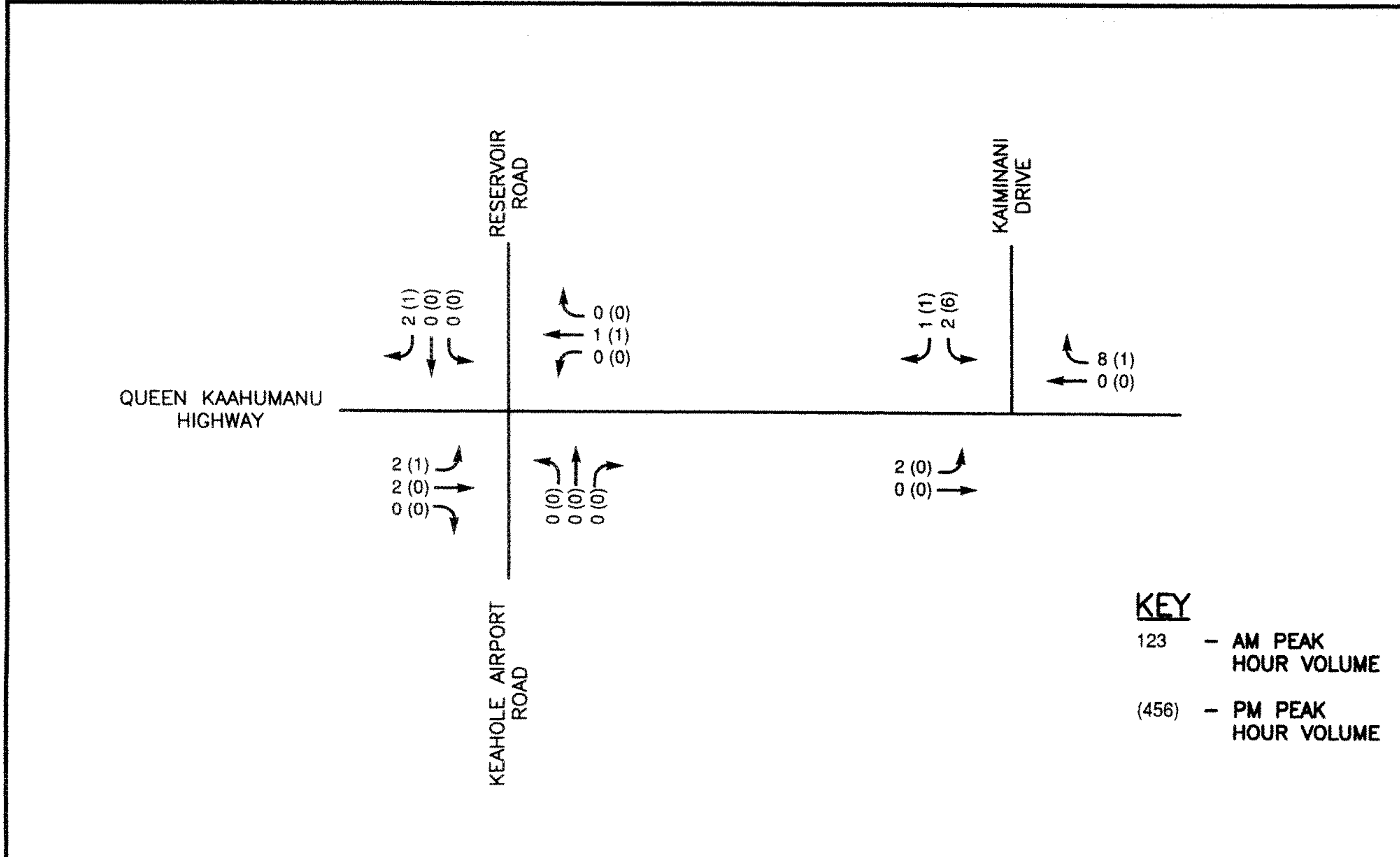

Figure 8
Alternative A Project Traffic Assignment
Prepared for: Hawaii Electric Light Company, Inc.
Prepared by: Belt Collins Hawaii
October 2004

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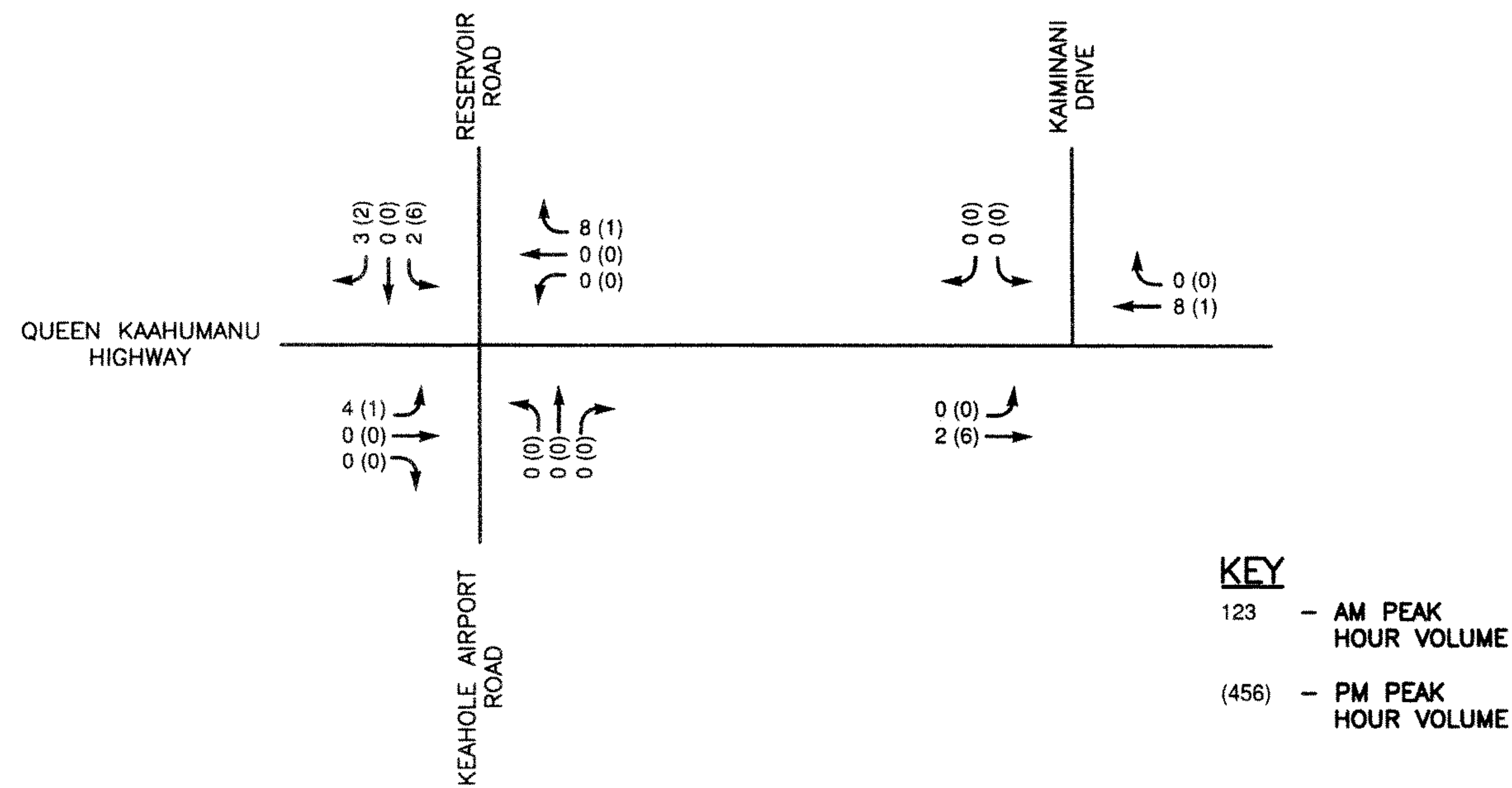

Figure 9

Alternative B Project Traffic Assignment

Prepared for: Hawaii Electric Light Company, Inc.

Prepared by: Belt Collins Hawaii

October 2004

VII. FUTURE TRAFFIC CONDITIONS WITH THE PROJECT

The future Year 2009 traffic forecasts with the project are developed by adding the future project to the projected future conditions. The future traffic assignment with the project volumes with Alternative A and Alternative B is shown in Figure 10 and Figure 11, respectively.

The State Department of Transportation is currently planning to implement the Phase I widening of Queen Kaahumanu Highway from two to four lanes between Henry Street and Kealakehe Parkway by Year 2008. Also, the Phase II widening of Queen Kaahumanu Highway to four lanes between Kealakehe Parkway and the Keahole Airport Road is scheduled for completion by Year 2011.

A. Analysis Results

The analysis results with a two-lane Queen Kaahumanu Highway are similar to the future without project traffic conditions with the Palamanui north access road (Table 7, HELCO Alternative A) or south access road (Table 8, HELCO Alternative B). The intersection of Queen Kaahumanu Highway, Keahole Airport Road and Reservoir would be at Level of Service F and or operate with volume-to-capacity ratios greater than 1.0 during the afternoon peak hour while the intersection of Queen Kaahumanu Highway and Kaiminani Drive would exceed capacity during the morning peak hour. If Queen Kaahumanu Highway were widened to four lanes, then the analysis results in Table 9 and Table 10 indicates that both of these study intersections would operate at Level of Service E conditions of better.

With HELCO Alternative A or Alternative B, the proportion of project trips entering the Queen Kaahumanu Highway intersections with Keahole Airport Road/ Reservoir Road and with Kaiminani Drive ranges between 0.10 percent and 0.64 percent, as identified in Table 11. Hence, the proportion of traffic volumes attributable to the HELCO Keahole Generation Station and Airport Substation at the study intersections is less than one percent during morning and afternoon peak hour periods.

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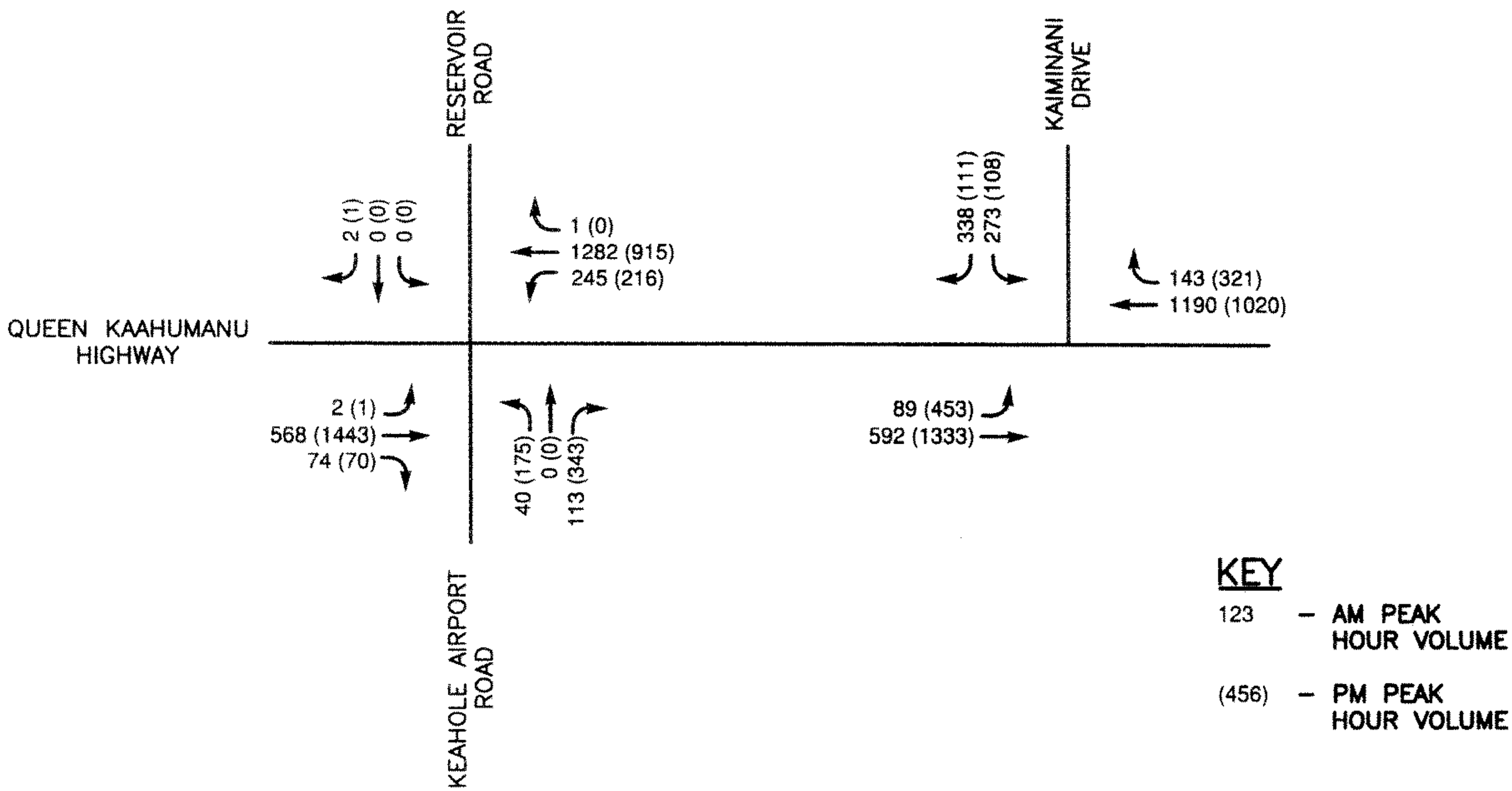

Figure 10
Future Traffic Assignment With Alternative A
Prepared for: Hawaii Electric Light Company, Inc.
Prepared by: Belt Collins Hawaii
October 2004

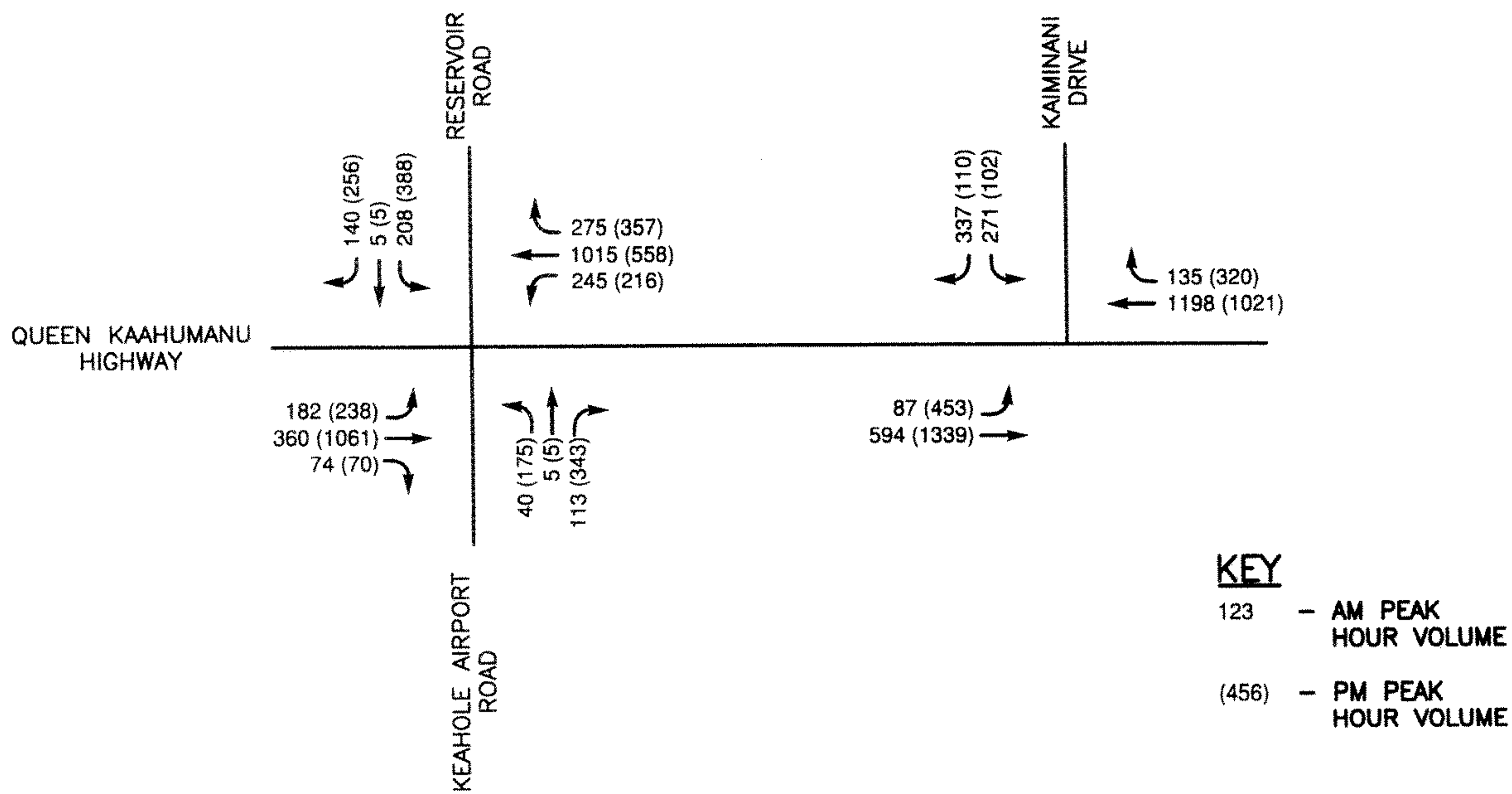

Figure 11
Future Traffic Assignment with Alternative B
Prepared for: Hawaii Electric Light Company, Inc.
Prepared by: Belt Collins Hawaii
October 2004

Table 7

FUTURE TRAFFIC CONDITIONS WITH ALTERNATIVE A

SIGNALIZED INTERSECTION ANALYSIS RESULTS

	AM Peak Hour			PM Peak Hour		
Intersection	v/c Ratio	Delay (seconds)	Level of Service	v/c Ratio	Delay (seconds)	Level of Service
Queen Kaahumanu Highway/Keahole Airport Road & Reservoir Road						
Queen Kaahumanu Highway						
Northbound Approach	--	29.9	C	--	69.4	E
Left Turn	0.50	4.0	A	1.12	324.3	F
Right Turn/Through Movement	0.97	34.9	C	0.69	9.3	A
Southbound Approach	--	4.7	A	--	402.3	F
Left Turn	0.02	2.9	A	0.00	5.7	A
Through Movement	0.46	4.9	A	1.22	421.8	F
Right Turn	0.07	2.8	A	0.07	6.1	A
Keahole Aiport Road						
Eastbound Approach						
Left Turn	0.42	33.8	C	1.13	362.2	F
Reservoir Road						
Westbound Approach	0.04	30.4	C	0.01	46.0	D
Overall Intersection	0.93	22.7	C	1.34	266.0	F
Queen Kaahumanu Highway/Kaiminani Drive						
Queen Kaahumanu Highway						
Northbound Approach	--	66.8	E	--	42.2	D
Through Movement	1.01	74.1	E	0.97	51.6	D
Right Turn	0.14	6.6	A	0.36	12.3	B
Southbound Approach	--	8.7	A	--	47.9	D
Left Turn	0.40	9.7	A	0.96	74.5	E
Through Movement	0.48	8.6	A	0.97	38.9	D
Kaiminani Drive						
Westbound Approach						
Left Turn	0.92	88.5	F	0.66	61.2	E
Right Turn	FREE RIGHT TURN			FREE RIGHT TURN		
Overall Intersection	1.05	52.1	D	1.00	46.0	D

Table 8

FUTURE TRAFFIC CONDITIONS WITH ALTERNATIVE B

SIGNALIZED INTERSECTION ANALYSIS RESULTS

Intersection	AM Peak Hour v/c Ratio	AM Peak Hour Delay (seconds)	AM Peak Hour Level of Service	PM Peak Hour v/c Ratio	PM Peak Hour Delay (seconds)	PM Peak Hour Level of Service
Queen Kaahumanu Highway/Keahole Airport Road & Reservoir Road						
Queen Kaahumanu Highway						
Northbound Approach	--	81.9	F	--	142.0	F
Left Turn	0.42	8.0	A	1.31	636.6	F
Through Movement	1.03	118.0	F	0.66	26.8	C
Right Turn	0.33	14.3	B	0.50	22.8	C
Southbound Approach	--	44.1	D	--	404.5	F
Left Turn	0.94	115.6	F	0.78	40.0	D
Through Movement	0.37	14.7	B	1.26	511.8	F
Right Turn	0.09	11.6	B	0.10	16.5	B
Keahole Aiport Road						
Eastbound Approach	0.82	135.4	F	1.32	684.3	F
Left Turn	--	--	--	--	--	--
Through Movement	--	--	--	--	--	--
Reservoir Road						
Westbound Approach	0.98	147.4	F	1.32	640.0	F
Left Turn	--	--	--	--	--	--
Left Turn/Through Movement	--	--	--	--	--	--
Overall Intersection	1.00	79.0	E	1.65	354.4	F
Queen Kaahumanu Highway/Kaiminani Drive						
Queen Kaahumanu Highway						
Northbound Approach	--	73.9	E	--	42.6	D
Through Movement	1.01	81.5	F	0.97	52.1	D
Right Turn	0.13	6.5	A	0.36	12.3	B
Southbound Approach	--	8.8	A	--	50.2	D
Left Turn	0.40	9.7	A	0.96	75.8	E
Through Movement	0.48	8.6	A	0.98	41.6	D
Kaiminani Drive						
Westbound Approach						
Left Turn	0.91	86.0	F	0.62	58.6	E
Right Turn	FREE RIGHT TURN			FREE RIGHT TURN		
Overall Intersection	1.05	55.9	E	0.94	47.3	D

Table 9

FUTURE TRAFFIC CONDITIONS WITH ALTERNATIVE A AND WITH MITIGATION

SIGNALIZED INTERSECTION ANALYSIS RESULTS

Intersection	AM Peak Hour v/c Ratio	AM Peak Hour Delay (seconds)	AM Peak Hour Level of Service	PM Peak Hour v/c Ratio	PM Peak Hour Delay (seconds)	PM Peak Hour Level of Service
Queen Kaahumanu Highway/Keahole Airport Road & Reservoir Road						
Queen Kaahumanu Highway						
Northbound Approach	--	13.2	B	--	14.3	B
Left Turn	0.65	16.6	B	0.79	36.8	D
Right Turn/Through Movement	0.69	12.6	B	0.45	9.1	A
Southbound Approach	--	10.3	B	--	24.9	C
Left Turn	0.02	8.6	A	0.00	10.4	B
Through Movement	0.34	10.5	B	0.88	25.5	C
Right Turn	0.10	8.9	A	0.10	11.1	B
Keahole Aiport Road						
Eastbound Approach						
Left Turn	0.11	19.3	B	0.60	32.1	C
Reservoir Road						
Westbound Approach	0.01	18.6	B	0.01	24.9	C
Overall Intersection	0.50	12.5	B	0.89	21.1	C
Queen Kaahumanu Highway/Kaiminani Drive						
Queen Kaahumanu Highway						
Northbound Approach	--	12.8	B	--	23.9	C
Through Movement	0.71	13.4	B	0.81	24.8	C
Right Turn	0.19	8.3	A	0.57	20.8	C
Southbound Approach	--	7.8	A	--	13.2	B
Left Turn	0.46	10.8	B	0.84	27.9	C
Through Movement	0.32	7.3	A	0.62	8.2	A
Kaiminani Drive						
Westbound Approach						
Left Turn	0.71	27.1	C	0.39	26.6	C
Right Turn		FREE RIGHT TURN			FREE RIGHT TURN	
Overall Intersection	0.83	13.0	B	0.88	18.1	B

Table 10

FUTURE TRAFFIC CONDITIONS WITH ALTERNATIVE B AND WITH MITIGATION

SIGNALIZED INTERSECTION ANALYSIS RESULTS

Intersection	AM Peak Hour v/c Ratio	AM Peak Hour Delay (seconds)	AM Peak Hour Level of Service	PM Peak Hour v/c Ratio	PM Peak Hour Delay (seconds)	PM Peak Hour Level of Service
Queen Kaahumanu Highway/Keahole Airport Road & Reservoir Road						
Queen Kaahumanu Highway						
Northbound Approach	--	22.0	C	--	38.2	D
Left Turn	0.59	13.6	B	0.83	54.4	D
Through Movement	0.85	25.1	C	0.48	31.1	C
Right Turn	0.52	18.1	B	0.69	39.5	D
Southbound Approach	--	20.0-	B	--	43.5	D
Left Turn	0.82	34.3	C	0.61	20.3	C
Through Movement	0.30	14.1	B	0.91	49.9	D
Right Turn	0.14	13.2	B	0.13	26.4	C
Keahole Aiport Road						
Eastbound Approach	--	26.7	C	--	62.3	E
Left Turn	0.29	26.9	C	0.76	62.8	E
Through Movement	0.04	25.4	C	0.02	44.4	D
Reservoir Road						
Westbound Approach	0.51	25.1	C	0.62	45.6	D
Left Turn	--	--	--	--	--	--
Left Turn/Through Movement	--	--	--	--	--	--
Overall Intersection	0.74	21.9	C	0.84	42.9	D
Queen Kaahumanu Highway/Kaiminani Drive						
Queen Kaahumanu Highway						
Northbound Approach	--	13.0	B	--	17.9	B
Through Movement	0.71	13.5	B	0.75	18.5	B
Right Turn	0.18	8.2	A	0.53	16.1	B
Southbound Approach	--	7.8	A	--	12.6	B
Left Turn	0.45	10.8	B	0.87	29.4	C
Through Movement	0.32	7.3	A	0.62	6.9	A
Kaiminani Drive						
Westbound Approach						
Left Turn	0.71	27.1	C	0.47	25.5	C
Right Turn	FREE RIGHT TURN			FREE RIGHT TURN		
Overall Intersection	0.84	13.1	B	0.90	15.2	B

Table 11

PROJECT TRAFFIC VOLUMES ENTERING STUDY INTERSECTIONS

ALTERNATIVE A: Primary Access at South Gate and Fuel Trucks at North Gates

Intersection	AM Peak Hour	PM Peak Hour
Queen Kaahumanu Highway / Keahole Airport Road / Reservoir Road	0.30%	0.10%
Queen Kaahumanu Highway / Kaiminani Drive	0.50%	0.24%

ALTERNATIVE B: Primary Access at North Gates and South Gate Closed

Intersection	AM Peak Hour	PM Peak Hour
Queen Kaahumanu Highway / Keahole Airport Road / Reservoir Road	0.64%	0.27%
Queen Kaahumanu Highway / Kaiminani Drive	0.38%	0.21%

VIII. FINDINGS AND RECOMMENDATIONS

The existing intersections of Queen Kaahumanu Highway/Keahole Airport Road/ Reservoir Road and Queen Kaahumanu Highway/Kaiminani Drive operate at Level of Service C conditions or better during the morning and afternoon peak hours. During the morning peak hour of the March 2004 traffic counts, there were total of 48 vehicles arriving and 11 vehicles departing at the north and south gates. During the afternoon peak hour, there were 7 vehicles arriving and 16 vehicles departing the north and south gates. Contractor vehicles parked external of the south gate and are included in these traffic counts. Most of the traffic volumes are due to the construction activities and testing of newly installed equipment at the Keahole Generation Station. With the existing traffic conditions, most of the HELCO generation station employees utilize the south gate and the north gates are used by fuel trucks.

For future traffic conditions without the project, there are increases in the forecasted Queen Kaahumanu Highway traffic volumes that would result in Level of Service F conditions or where highway capacity conditions are exceeded. The Palamanui project is currently studying the feasibility of a north access road and a south access road. The analysis results indicate that widening of Queen Kaahumanu Highway to four lanes would mitigate traffic conditions to Level of Service E or better. The proposed laneage configurations at the two study intersections are provided in Figure 12.

For future traffic conditions with the project, the analysis results would be similar to future traffic conditions without the project and the laneage recommendations would be the same as shown in Figure 12.

If Palamanui project chooses to use its north access road as its primary connection to Queen Kaahumanu Highway, then HELCO would continue to utilize their north and south gates in a similar manner as the existing situation. If the Palamanui project selects to construct their south access road so that it connects at the Keahole Airport Road/Reservoir Road intersection, then HELCO would utilize their north gate for all project trips and close the south gates. HELCO is coordinating with the Palamanui developer as part of the Palamanui access feasibility study, but HELCO could continue with its existing gate usage for an indefinite period of time.

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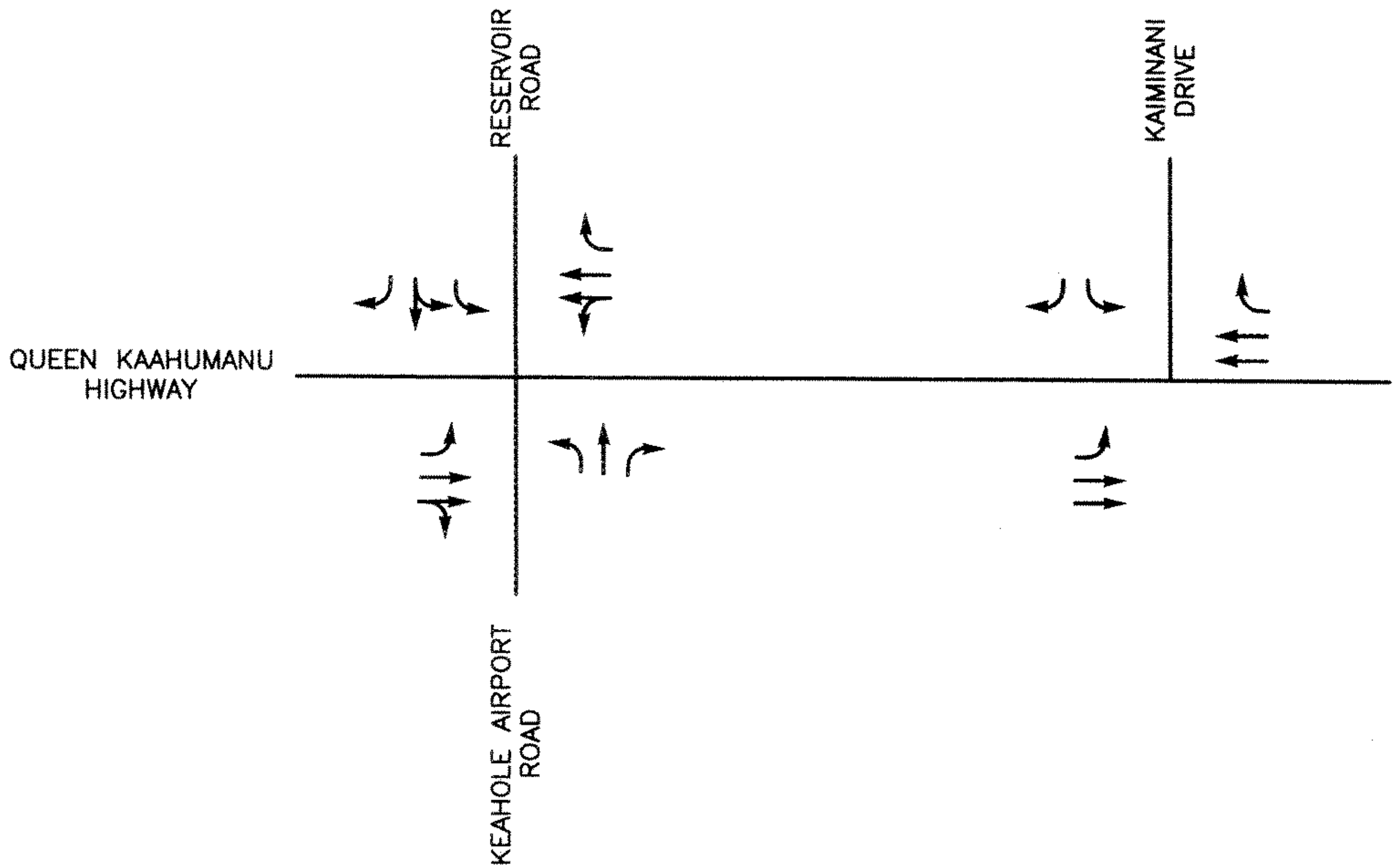

Figure 12

Proposed Intersection Configuration

Prepared for: Hawaii Electric Light Company, Inc.

Prepared by: Belt Collins Hawaii

October 2004

The future HELCO project trips would be less than the existing traffic volumes that were counted at its north and south gates since construction activities have been completed. During the morning peak hour, there would be 15 entering trips and 6 exiting trips at the project site. During the afternoon peak hour, estimated project would be 3 entering trips and 11 exiting trips. Further, the proportion of HELCO project traffic volumes at the Queen Kaahumanu Highway/ Keahole Airport Road/Reservoir Road intersection and Queen Kaahumanu/Kaiminani Drive intersection would be less than one percent during the morning and afternoon peak hour periods. Therefore, no measures to mitigate the impacts of the HELCO project trips are required.

IX. REFERENCES

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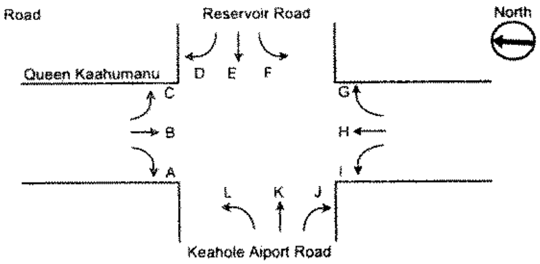
APPENDIX A

MANUAL TRAFFIC COUNT DATA

Intersection: Queen Kaahumanu Highway / Keahole Airport Road
Date: Wednesday, March 10, 2004
Time: AM Peak Period
Counted by: K.W., B R
Weather: Clear

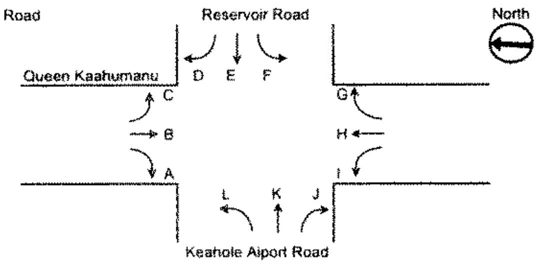


Time Period	A	B	C	D	E	F	G	H	I	J	K	L	Total	Hour
5:45 - 6:00 am	18	25	0	0	0	0	0	100	54	15	0	2	214	
6:00 - 6:15	14	32	0	0	0	0	0	154	41	20	0	5	266	
6:15 - 6:30	10	39	0	0	0	0	0	208	42	18	0	5	322	
6:30 - 6:45	10	73	0	0	0	0	0	242	47	40	0	13	425	1227
6:45 - 7:00	23	43	0	0	0	0	0	212	52	25	0	11	366	1379
7:00 - 7:15	15	82	0	0	0	0	0	176	46	16	0	8	343	1456
7:15 - 7:30	15	89	0	0	0	0	1	187	62	15	0	2	371	1505
7:30 - 7:45	17	100	0	1	0	0	0	153	61	24	0	3	359	1439
7:45 - 8:00	18	79	0	0	0	0	0	130	55	23	0	3	308	1381
8:00 - 8:15	28	94	0	0	0	0	0	132	48	23	0	4	329	1367
8:15 - 8:30	34	103	0	0	0	0	0	114	49	42	0	21	363	1359
TOTAL	202	759	0	1	0	0	1	1808	557	261	0	77	3666	
6:30 - 7:30 am	63	287	0	0	0	0	1	817	207	96	0	34	1505	

Approach and Departure

Time Period	ABC	DEF	GHI	JKL	Hour ABC	Hour DEF	Hour GHI	Hour JKL	AEI	BFJ	CGK	DHL	Hour AEI	Hour BFJ	Hour CGK	Hour DHL
5:45 - 6:00 am	43	0	154	17					72	40	0	102				
6:00 - 6:15	46	0	195	25					55	52	0	159				
6:15 - 6:30	49	0	250	23					52	57	0	213				
6:30 - 6:45	83	0	289	53	221	0	888	118	57	113	0	255	236	262	0	729
6:45 - 7:00	66	0	264	36	244	0	998	137	75	68	0	223	239	290	0	850
7:00 - 7:15	97	0	222	24	295	0	1025	136	61	98	0	184	245	336	0	875
7:15 - 7:30	104	0	250	17	350	0	1025	130	77	104	1	189	270	383	1	851
7:30 - 7:45	117	1	214	27	384	1	950	104	78	124	0	157	291	394	1	753
7:45 - 8:00	97	0	185	26	415	1	871	94	73	102	0	133	289	428	1	663
8:00 - 8:15	122	0	180	27	440	1	829	97	76	117	0	136	304	447	1	615
8:15 - 8:30	137	0	163	63	473	1	742	143	83	145	0	135	310	488	0	561
TOTAL	961	1	2366	338					759	1020	1	1886				
6:30 - 7:30 am	350	0	1025	130					270	383	1	851				

Intersection: Queen Kaahumanu Highway / Keahole Airport Road
Date: Tuesday, March 9, 2004
Time: PM Peak Period
Counted by: K.W., B.R.
Weather: Clear

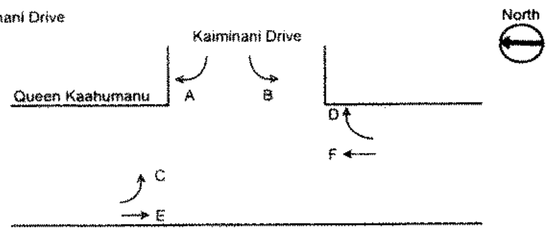


Time Period		A	B	C	D	E	F	G	H	I	J	K	L	Total	Hour
2:45 - 3:00	pm	24	198	0	0	0	0	0	82	63	41	0	19	427	
3:00 - 3:15		17	137	0	0	0	0	0	84	75	77	0	34	424	
3:15 - 3:30		18	188	0	0	0	0	0	108	64	64	0	40	482	
3:30 - 3:45		14	219	0	0	0	0	0	126	47	99	0	46	551	1884
3:45 - 4:00		13	251	0	0	0	0	0	90	50	63	0	30	497	1954
4:00 - 4:15		14	195	0	0	0	0	0	119	22	65	0	32	447	1977
4:15 - 4:30		13	213	1	0	0	0	0	95	24	68	0	29	443	1938
4:30 - 4:45		11	172	0	0	0	0	0	103	28	56	0	25	395	1782
4:45 - 5:00		12	149	0	0	0	0	0	92	32	42	0	13	340	1625
5:00 - 5:15		17	120	0	0	0	0	0	102	35	29	0	12	315	1493
5:15 - 5:30		13	138	0	0	0	0	0	102	34	29	0	9	325	1375
5:30 - 5:45		10	139	0	0	1	0	0	90	31	20	0	5	296	1276
5:45 - 6:00		14	119	0	0	0	0	0	76	46	62	0	16	333	1269
TOTAL		190	2238	1	0	1	0	0	1269	551	715	0	310	5275	
3:15 - 4:15	pm	59	853	0	0	0	0	0	443	183	291	0	148	1977	

Approach and Departure

Time Period		ABC	DEF	GHI	JKL	Hour ABC	Hour DEF	Hour GHI	Hour JKL	AEI	BFJ	CGK	DHL	Hour AEI	Hour BFJ	Hour CGK	Hour DHL
2:45 - 3:00	pm	222	0	145	60					87	239	0	101				
3:00 - 3:15		154	0	159	111					92	214	0	118				
3:15 - 3:30		206	0	172	104					82	252	0	148				
3:30 - 3:45		233	0	173	145	815	0	649	420	61	318	0	172	322	1023	0	539
3:45 - 4:00		264	0	140	93	857	0	644	453	63	314	0	120	298	1098	0	558
4:00 - 4:15		209	0	141	97	912	0	626	439	36	260	0	151	242	1144	0	591
4:15 - 4:30		227	0	119	97	933	0	573	432	37	281	1	124	197	1173	1	567
4:30 - 4:45		183	0	131	81	883	0	531	368	39	228	0	128	175	1083	1	523
4:45 - 5:00		161	0	124	55	780	0	515	330	44	191	0	105	156	960	1	508
5:00 - 5:15		137	0	137	41	708	0	511	274	52	149	0	114	172	849	1	471
5:15 - 5:30		151	0	136	38	632	0	528	215	47	167	0	111	182	735	0	458
5:30 - 5:45		149	1	121	25	598	1	518	159	42	159	0	95	185	666	0	425
5:45 - 6:00		133	0	122	78	570	1	516	182	60	181	0	92	201	656	0	412
TOTAL		2429	1	1820	1025					742	2953	1	1579				
3:15 - 4:15	pm	912	0	626	439					242	1144	0	591				

Intersection: Queen Kaahumanu Highway/ Kaiminani Drive
Date: Wednesday, March 10, 2004
Time: AM Peak Period
Counted by: L.C.
Weather: Clear

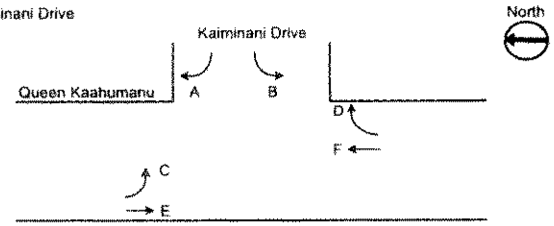


Time Period	A	B	C	D	E	F	Total	Hour
5:45 - 6:00 am	39	25	5	4	35	115	223	
6:00 - 6:15	51	24	7	10	45	144	281	
6:15 - 6:30	65	36	9	21	48	185	364	
6:30 - 6:45	78	59	15	47	98	211	508	1376
6:45 - 7:00	94	51	6	22	62	170	405	1558
7:00 - 7:15	47	60	2	26	96	175	406	1683
7:15 - 7:30	60	64	9	20	95	191	439	1758
7:30 - 7:45	62	90	12	21	112	152	449	1699
7:45 - 8:00	37	78	9	14	93	148	379	1673
8:00 - 8:15	41	74	3	24	114	139	395	1662
8:15 - 8:30	29	60	17	23	128	134	391	1614
TOTAL	603	621	94	232	926	1764	4240	
6:30 - 7:30 am	279	234	32	115	351	747	1758	

Approach and Departure

Time Period	AB	CE	DF	Hour AB	Hour CE	Hour DF	AF	BE	CD	Hour AF	Hour BE	Hour CD
5:45 - 6:00 am	64	40	119				154	60	9			
6:00 - 6:15	75	52	154				195	69	17			
6:15 - 6:30	101	57	206				250	84	30			
6:30 - 6:45	137	113	258	377	262	737	289	157	62	888	370	118
6:45 - 7:00	145	68	192	458	290	810	264	113	28	998	423	137
7:00 - 7:15	107	98	201	490	336	857	222	156	28	1025	510	148
7:15 - 7:30	124	104	211	513	383	862	251	159	29	1026	585	147
7:30 - 7:45	152	124	173	528	394	777	214	202	33	951	630	118
7:45 - 8:00	115	102	162	498	428	747	185	171	23	872	688	113
8:00 - 8:15	115	117	163	506	447	709	180	188	27	830	720	112
8:15 - 8:30	89	145	157	471	488	655	163	188	40	742	749	123
TOTAL	1224	1020	1996				2367	1547	326			
6:30 - 7:30 am	513	383	862				1026	585	147			

Intersection: Queen Kaahumanu Highway / Kaiminani Drive
Date: Tuesday, March 9, 2004
Time: PM Peak Period
Counted by: L.C.
Weather: Clear



Time Period		A	B	C	D	E	F	Total	Hour
2:45 - 3:00	pm	14	17	37	27	202	131	428	
3:00 - 3:15		17	22	34	49	180	142	444	
3:15 - 3:30		20	30	54	66	198	152	520	
3:30 - 3:45		28	20	76	67	242	145	578	1970
3:45 - 4:00		15	18	104	83	210	125	555	2097
4:00 - 4:15		16	20	77	58	183	125	479	2132
4:15 - 4:30		9	7	80	82	201	110	489	2101
4:30 - 4:45		23	20	60	67	168	108	446	1969
4:45 - 5:00		13	14	38	75	153	111	404	1818
5:00 - 5:15		18	14	28	67	121	119	367	1706
5:15 - 5:30		18	19	36	81	131	118	403	1620
5:30 - 5:45		9	24	41	71	118	112	375	1549
5:45 - 6:00		19	29	33	86	148	103	398	1543
TOTAL		219	254	698	859	2255	1601	5886	
3:15 - 4:15	pm	79	88	311	274	833	547	2132	

Approach and Departure

Time Period		AB	CE	DF	Hour AB	Hour CE	Hour DF	AF	BE	CD	Hour AF	Hour BE	Hour CD
2:45 - 3:00	pm	31	239	158				145	219	64			
3:00 - 3:15		39	214	191				159	202	83			
3:15 - 3:30		50	252	218				172	228	120			
3:30 - 3:45		48	318	212	168	1023	779	173	262	143	649	911	410
3:45 - 4:00		33	314	208	170	1098	829	140	228	187	644	920	533
4:00 - 4:15		36	260	183	167	1144	821	141	203	135	626	921	585
4:15 - 4:30		16	281	192	133	1173	795	119	208	162	573	901	627
4:30 - 4:45		43	228	175	128	1083	758	131	188	127	531	827	611
4:45 - 5:00		27	191	186	122	960	736	124	167	113	515	766	537
5:00 - 5:15		32	149	186	118	849	739	137	135	95	511	698	497
5:15 - 5:30		37	167	199	139	735	746	136	150	117	528	640	452
5:30 - 5:45		33	159	183	129	666	754	121	142	112	518	594	437
5:45 - 6:00		48	181	169	150	656	737	122	177	99	516	604	423
TOTAL		473	2953	2460				1820	2509	1557			
3:15 - 4:15	pm	167	1144	821				626	921	585			

APPENDIX B

LEVEL OF SERVICE DEFINITIONS

SIGNALIZED INTERSECTIONS
LEVEL OF SERVICE DEFINITIONS

Level of service for signalized intersections is defined in terms of control delay, which is a measure of driver discomfort, frustration, fuel consumption and increased travel time. Control delay is the component of delay that results when a traffic control signal causes vehicles to reduce speed or to stop at intersection. Total delay is defined as the difference between the actual travel time and the reference travel time that would occur under ideal, base conditions (absent of traffic control, geometric delays, incidents, or presence of other vehicles).

Delay experienced by motorists are affected by a number of factors that relate to control, geometrics, traffic, and incidents. Analytically, control delay is a complex technical measure that considers the quality of progression, cycle length, green phase-to-total cycle ratio, and the volume-to-capacity (v/c) ratio for each lane group.

The v/c ratio provides an indication of the utilization of the lane group capacity. The critical v/c ratio is an approximate indicator of the overall sufficiency of an intersection and is affected by the critical lane flow rates and traffic signal phasing. The six levels of service for signalized intersections are described below and summarized in Table B-3.

Level of Service A describes operations with low control delay between 0 to 10 seconds per vehicle, where there is extremely favorable progression. Most vehicles arrive during the green phase and many vehicles do not stop at all. Short cycle lengths may tend to contribute to low delays.

Level of Service B describes operations with control delays greater than 10 and up to 20 seconds per vehicle. There is generally good progression with short cycle lengths and slightly more vehicles stopping than in Level of Service A.

Level of Service C describes operations with control delays greater than 20 and up to 35 seconds per vehicle. These higher delays may result from fair progression, longer cycle lengths or a combination of both conditions. Cycle failure and overflow begins to occur at this level when a green phase is unable to serve all of the queued vehicles. The number of vehicles stopping increases, although many vehicles are still able to pass through the intersection without stopping.

Level of Service D describes operations with control delays greater than 35 and up to 55 seconds per vehicle. At this level, congestion becomes more noticeable. A combination of unfavorable progression, long cycle lengths and high v/c ratios may result in longer delays. Individual cycle failures become noticeable and the vehicles stopping become significant, although many vehicles pass through the intersection without stopping.

Level of Service E describes operations with control delays greater than 55 and up to 80 seconds per vehicle. Individual cycle failures are frequent and the high delay values are usually an indicator of poor progression, long cycle lengths and high v/c ratios.

Level of Service F describes operation with control delays greater that 80 seconds per vehicle. This level is considered unacceptable to most drivers and oversaturated conditions occur when arrival flow rates are greater than capacity of the lane group. There are many individual cycle failures related to high v/c ratios, poor progression, long cycle lengths or long red phase. The designation of Level of Service F does not automatically imply that the intersection, approach, or lane group is over capacity. Also, a Level of Service better than E does not necessarily imply that unused capacity is available.

Table B-1
LEVEL OF SERVICE CRITERIA
FOR
SIGNALIZED INTERSECTIONS

Level of Service	Average Control Delay (seconds per vehicle)
A	$\leq$ 10
B	> 10 – 20
C	> 20 – 35
D	> 35 – 55
E	> 55 – 80
F	> 80

Source: Highway Capacity Manual 2000

AVIFAUNAL AND FERAL MAMMAL FIELD SURVEY

OF KEAHOLE GENERATING STATION

NORTH KONA, ISLAND OF HAWAII

Prepared for:

BELT COLLINS HAWAII LTD.

31 July 2003

Prepared by:

Phillip L. Bruner
Environmental Consultant

Faunal (Bird & Mammal) Surveys
1775 BYU-H
55-220 Kulanui St.
Laie, Hawaii 96762

INTRODUCTION

The purpose of this report is to provide the findings of a one-day (29 July 2003) field survey of the Keahole Generating Station property and nearby surrounding lands, North Kona, Island of Hawaii (Fig. 1). References to pertinent published and unpublished sources, particularly Bruner (1992a) an earlier survey of this area, are also given in this report in order to provide a broader perspective of the species known from this region of the island. The goals of the survey were to:

1- Document the species of birds and mammals currently on or near the property.

2- Note any features of the site or nearby lands that contain habitat of potential value for native and migratory birds.

SITE DESCRIPTION

This property is developed but does contain ornamental trees around the perimeter fence and a few trees inside the site. Lands to the south are developed into plant nurseries. Lands to the east and north are covered in dry grass while Queen Kaahumanu Highway and the Kona Airport lands lie to the west.

METHODS OF SURVEY

The area of the survey was covered on foot and by car using existing roads to the north and south of the property. Data were taken during the early morning (0545-0930 hours) and late afternoon (1600-1800 hours) when birds are most active and therefore detectable. Count stations were established throughout the survey area (Fig. 1). All birds seen or heard over an eight-minute period at each count station were tallied. Observations made outside these stations were also noted. These data were used to estimate a relative abundance for each species. Data on mammals were obtained from visual observations and scats. No trapping of mammals was conducted. The length and nature of this survey did not warrant trapping. Weather during the survey was partly cloudy with light winds.

The scientific and common names used in this report follow Pyle (2002) and Honacki et al. (1982).

RESULTS

Native Birds:

No native birds were observed on the survey. This finding conforms with the results of the earlier survey of this area (Bruner 1992a). Two native birds are known to occur rather infrequently in this region: Short-eared Owl or Pueo (*Asio flammeus sandwichensis*) and Hawaiian Hawk or 'Io (*Buteo solitarius*). The 'Io is listed as endangered. These two species forage over large areas and utilize a wide variety of habitats: grasslands, agricultural fields, and forests (Pratt et al. 1987, Hawaii Audubon Society 1997).

Migratory Birds:

No migratory birds were observed on the survey. This finding was not unexpected due to the timing of the survey. Migratory birds are on their breeding grounds in the arctic at this time of year. The most abundant migrant to Hawaii is the Pacific Golden-Plover (*Pluvialis fulva*). Extensive, long-term studies have documented many details of their life history (Johnson et al. 1981, 1989, 1993, 2001). This species is not listed as threatened or endangered. They prefer open habitat such as lawns, cleared agricultural fields and short grass habitat along roadsides. It is possible that plover might forage along the access road on the north side of the property when they are wintering in Hawaii from August to the end of April.

Introduced Birds:

A total of 13 species of introduced (non-native) birds were recorded on the survey. Table One gives the names of these species and the total number of each species. This table also provides data from an earlier survey (Bruner 1992a) for comparison purposes. Three species not found on the 1992 survey were: Saffron Finch (*Sicalis flaveola*), Yellow-billed Cardinal (*Paroaria capitata*) and Java Sparrow (*Padda oryzivora*). None of the introduced birds are listed as threatened or endangered. The array of species recorded on the 1992 and current survey are typical of what would be expected in this area (Bruner 1985, 1989a, 1989b, 1990. 1992a, 1992b, 1993).

Mammals:

Two domestic cats (*Felis catus*) and one Small Indian Mongoose (*Herpestes auropunctatus*) were seen on the survey. The cats may not be feral since there are plant nurseries nearby. No rats or mice were observed, however, they likely occur in this area. The only native land mammal in Hawaii is the endangered Hawaiian Hoary Bat (*Lasiurus cinereus semotus*). This species is often seen foraging along the Kona coast (pers. observ.). Tomich (1986) along with Kepler and Scott (1990) provide information about the habits and distribution of this endangered species. They typically roost solitarily in trees and forage for insects in a wide variety of native and non-native habitats, including urban areas. None were seen on this survey. The plant nurseries might attract flying insects that could also attract the bats (pers. obser.).

SUMMARY AND CONCLUSIONS

The field survey examined not only the area containing the electrical generating plant but also nearby lands. The findings of this survey supplement and support the earlier study (Bruner 1992a). The array of species found on both surveys are those expected to occur in this area of the island. The actual generating plant site does not contain any unusual or unique habitat important to native or migratory birds. The endangered Hawaiian Hoary Bat might on occasion be seen in this area since they forage in a wide variety of habitats and are not uncommon on this side of the island.

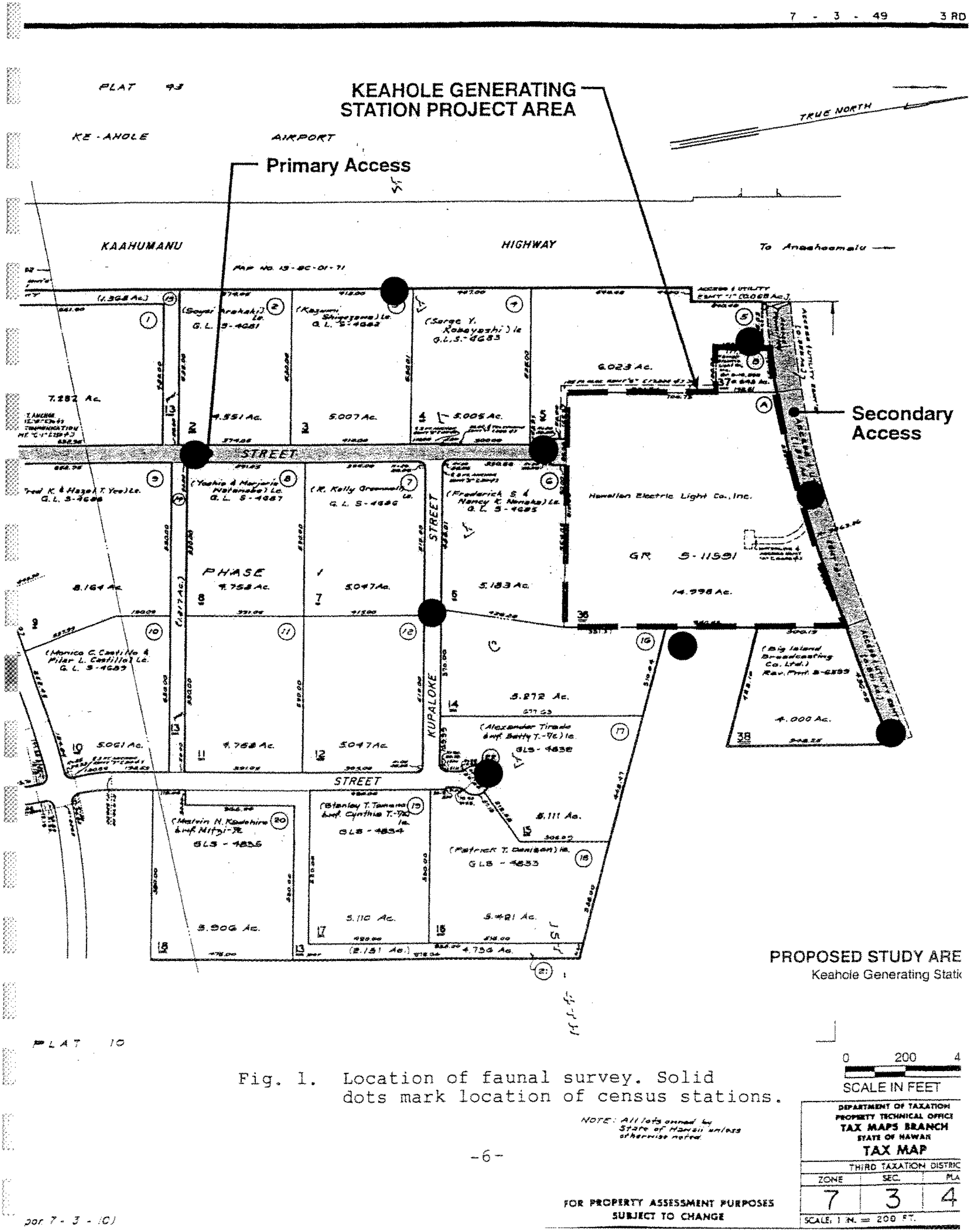


Fig. 1. Location of faunal survey. Solid dots mark location of census stations.

TABLE ONE

Introduced birds recorded on both the 1992 and this current 2003 survey of the Keahole Generating Plant property and surrounding area. Relative abundance estimates are based on the following: A=Abundant – (10+ individuals on a count station), C=Common – (5-9 individuals on a count station), U=Uncommon – (less than 5 on a count station), R=Recorded – (seen or heard at times other than on count stations). Number which follows the status symbol is an average of the data taken from all count stations or the number seen or heard over the duration of the survey for those species not recorded on the count stations. The * symbol designates those species not recorded on the 1992 survey.

COMMON NAME	SCIENTIFIC NAME	RELATIVE ABUNDANCE	
		1992	2003
Black Francolin	*Francolinus francolinus*	C=6	U=2
Gray Francolin	*Francolinus pondicerianus*	R=3	U=1
Spotted Dove	*Streptopelia chinensis*	U=2	U=3
Zebra Dove	*Geopelia striata*	C=6	A=11
Common Myna	*Acridotheres tristis*	C=7	C=9
Japanese White-eye	*Zosterops japonicus*	U=3	A=12
Saffron Finch*	*Sicalis flaveola*	-	U=4
Yellow-billed Cardinal*	*Paroaria capitata*	-	R=3
Northern Cardinal	*Cardinalis cardinalis*	R=2	U=2
House Finch	*Carpodacus mexicanus*	U=4	C=6
House Sparrow	*Passer domesticus*	R=7	C=6
Nutmeg Mannikin	*Lonchura punctulata*	C=8	A=11
Java Sparrow*	*Padda oryzivora*	-	C=7

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BOTANICAL RESOURCES ASSESSMENT STUDY
KEAHOLE GENERATING STATION
NORTH KONA DISTRICT, HAWAI'I

by

Winona P. Char

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Botanical Consultants
Honolulu, Hawai'i

Prepared for: **BELT COLLINS HAWAII LTD.**

August 2003

BOTANICAL RESOURCES ASSESSMENT STUDY
KEAHOLE GENERATING STATION
NORTH KONA DISTRICT, HAWAI'I

INTRODUCTION

HELCO's Keahole Generating Station is presently identified as Conservation District by the State Land Use Commission (LUC). An Environmental Impact Statement (EIS) to support an application to the LUC for a boundary amendment to reclassify the subject property to the State Urban District is being prepared; a County Change of Zone to General Industrial is also being sought.

A botanical survey (Char 1992) was prepared for a Revised Final EIS for the power plant (Parcel 36) as part of HELCO's application to expand the capacity of the generating station in 1993. The adjacent Parcel 37 which now supports a transformer station and the primary and secondary access roads were not included in the 1993 EIS document.

Field studies to update the earlier botanical study and include Parcel 37 and the access roads were conducted on 14 August 2003. The primary objectives of the field survey were to:

1) prepare a general description of the vegetation on the project site;
2) search for threatened and endangered species as well as species of concern; and
3) identify areas of potential environmental problems or concerns and propose appropriate mitigation measures.

DESCRIPTION OF THE VEGETATION

The plant names used in this report follow Wagner et al. (1990) and Wagner and Herbst (1999). The few recent name changes are those reported in the Hawaii Biological Survey series (Evenhuis and Eldredge, editors, 1999-2002).

The vegetation on Parcel 36 consists of landscape plantings with occasional weedy patches, especially along the perimeter fence line. The most commonly used ornamental plants include coconut palms (Cocos nucifera), oleander (Nerium oleander), Erythrina variegata cv. "Tropic Coral", Erythrina sp., and various Bougainvillea hybrids. Weedy patches occur among the landscape plantings. These include Natal redtop grass (Melinis repens), coat buttons (Tridax procumbens), wild bittermelon (Momordica charantia), puncture vine (Tribulus terrestris), wild spider flower (Cleome gynandra), Spanish needle (Bidens pilosa), and Florida beggarweed (Desmodium tortuosum). Weedy shrubs such as sourbush (Pluchea carolinensis), koa haole or 'ekoa (Leucaena leucocephala), Christmas berry (Schinus terebinthifolius), and noni (Morinda citrifolia, a Polynesian introduction) are found along the fence line.

Parcel 37 is located makai (west) of the larger Parcel 36. It has been bulldozed and supports a transformer station which is surrounded by a chainlink fence. There are only a handful of plants, plant cover is less than 1%, on the level, gravel-covered parcel; these include lovegrass (Eragrostis amabilis), fountain grass (Pennisetum setaceum), Natal redtop grass, hairy spurge (Chamaesyce hirta), and red pualele (Emilia fosbergii).

Patches of weedy, mostly annual, herbaceous species line the gravel-covered road shoulder. Clumps of fountain grass are common to abundant. Other plants occasionally observed include Natal redtop grass, hairy spurge, coat buttons, Cuba jute (Sida rhombifolia), puncture vine, Portulaca pilosa, swollen fingergrass (Chloris barbata), and partridge pea (Chamaecrista nictitans). Two native species are occasionally found along the roadside; these are 'uhaloa (Waltheria indica) and 'ilima (Sida fallax). Along the primary access road, a number of ornamental species front the plant nurseries. These include Ficus benjamina, Erythrina variegata, Ficus sp., beach naupaka hedges (Scaevola sericea), and Plumeria hybrids. Rows of noni shrubs are found on a lot close to the generating station.

DISCUSSION

The vegetation on the Keahole Generating Station and the primary and secondary access roads is composed almost exclusively of introduced or alien species. Introduced species are all those plants which were brought to the Hawaiian Islands by humans, intentionally or accidentally, after Western contact, that is, Cook's arrival in the islands in 1778. Three native species were observed during the field studies. All are indigenous, that is, they are native to the Hawaiian Islands and elsewhere. 'Uhaloa and 'ilima are found along the roadsides and other disturbed areas, while the beach naupaka is cultivated as landscape material.

None of the plants observed on the generating station site (Parcels 36 and 37) and along the primary and secondary access roads is a threatened or endangered species or a species of concern (U.S. Fish and Wildlife Service 1999a, 1999b; Wagner et al. 1999). All of the plants can be found in similar lowland, dry habitats throughout the West Hawai'i region. The previous botanical study (Char 1992) also reported similar findings.

Given these findings, the proposed land use change is not expected to have a significant negative impact on the botanical resources. There are no botanical reasons to impose any restrictions, conditions, or impediments to the proposed land use reclassification.

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Volcanic Hazards at the HELCO Keāhole Generating Station, North Kona, Hawai`i

FINAL REPORT

Prepared for:

Belt-Collins Hawaii Ltd.

By

John P. Lockwood
Geohazards Consultants International, Inc.
Volcano, Hawai`i

Michael O. Garcia
Geological Consultant
Honolulu, Hawai`i

February 28, 2004

TABLE OF CONTENTS

EXECUTIVE SUMMARY

- The Keāhole Generating Station (KGS) is located on the western slopes of Hualālai Volcano. The threat of lava flow inundation during future eruptions of Hualālai is the principal volcanic hazard that could impact the KGS. This threat, however, is considered statistically to be very small. The KGS is situated on a lava flow that is over 2,000 years old. Younger lava flows are more than one mile from the facility.

- Hualālai is a geologically active volcano with clusters of eruptions occurring about every 500 years. Although the probability that Hualālai will erupt somewhere within the next few centuries is high, the odds that such an eruption will threaten the KGS are low.

- The most recent flow to enter the 25 square mile area surrounding the KGS (the "Study Area") is the 1801 Hu`ehu`e lava flow. It is located about 1 mile to the northwest of the KGS. The next youngest flow, the "Kona Palisades Flow" (about a mile to the southeast), has an estimated age of about 1,800 years. Other lava flows in the area are more than 2,000 years old.

- Based on the ages of all lava flows less than 5,000 years old in the Study Area, and using a random, Poisson distribution for eruption frequency, the statistical probability that future flows will enter this 25 square mile area within the next 50 years is about 6% and within the next 100 years about 12%. The chance that a flow that entered the Study Area would directly impact the Keāhole Generating Station is much lower.

- Future Hualālai eruptive vents that could threaten the KGS facility are likely to develop 4-6 miles to the east on Hualālai's Northwest Rift Zone, at elevations between 2,000 and 4,200 feet above sea level. Eruptions from vents below 2,000' elevation would send lava flows north of the KGS; eruptions occurring above 4,200' elevation would send flows south of the facility.

- Future eruptions of Hualālai Volcano will likely be preceded by extensive precursory seismic activity. These precursors will allow staff at the KGS adequate time to secure and evacuate the facility if an eruption directly upslope from the KGS appears likely.

- The most likely geologic hazards that could impact the KGS area in the future are large earthquakes. The last major earthquake in the Kona area was the August 21, 1951 magnitude 6.9 on the Richter scale (M=6.9) earthquake, which caused extensive damage to the then largely undeveloped Kona area. Facilities at the KGS must be designed to survive the effects of such large earthquakes.

- Atmospheric pollution derived from the current eruption of Kīlauea Volcano is the principal impact to air quality at the KGS and the surrounding Kona area. These volcanic pollutants consist dominantly of sulphate particulate matter. Compared to Kīlauea Volcano, the atmospheric pollution from the expanded Keāhole Generating Station is expected to be minor.

- No significant hazard to the Keāhole Generating Station is expected from future flooding, tephra fall, or ground instability.

PURPOSE AND SCOPE OF WORK

This report evaluates future geologic, volcanological and other natural hazards that could impact the area of the HELCO Keāhole Generating Station in North Kona, Hawai`i based on the limited published geologic information on the area, new reconnaissance field work, paleomagnetic measurements and carbon 14 age dates, and the extensive volcanological experience of the two authors. Gaps remain in our knowledge of the volcanic history but the following summary is based on the best available evidence that was field checked. This study was initiated on 23 July, 2003, following an authorization to proceed by Belt Collins Hawaii Ltd.

GEOLOGIC HISTORY OF HUALĀLAI VOLCANO

The Keāhole Generating Station area (KGS) is located entirely on the flanks of Hualālai Volcano (Fig. 1), the least active of Hawai'i Island's three active volcanoes[1]. This volcano is representative of the post-shield stage of Hawaiian volcanism, which is characterized by a marked decrease in eruption rate as the volcano drifts off the Hawaiian hotspot (Frey and others, 1990). The estimated lava production rate for Hualālai over the last 3000 years is about 2% of the current rate of Kīlauea volcano (Moore and others, 1987).

Hualālai comprises about half of the Kona district of Hawai`i. It rises to an elevation of 8271 feet and covers about 325 square miles. Most Hualālai eruptions have taken place from vents along two primary rift zones (Fig. 2); the Northwest Rift Zone, extending 15 miles from the sea to the summit, and the Southeast Rift Zone, trending about 8 miles from the summit to the southeast where it is buried by Mauna Loa flows. The less active North Rift Zone, extends northward about 6 miles from the volcano's summit to Pu`u Wa`awa`a (Fig. 2).

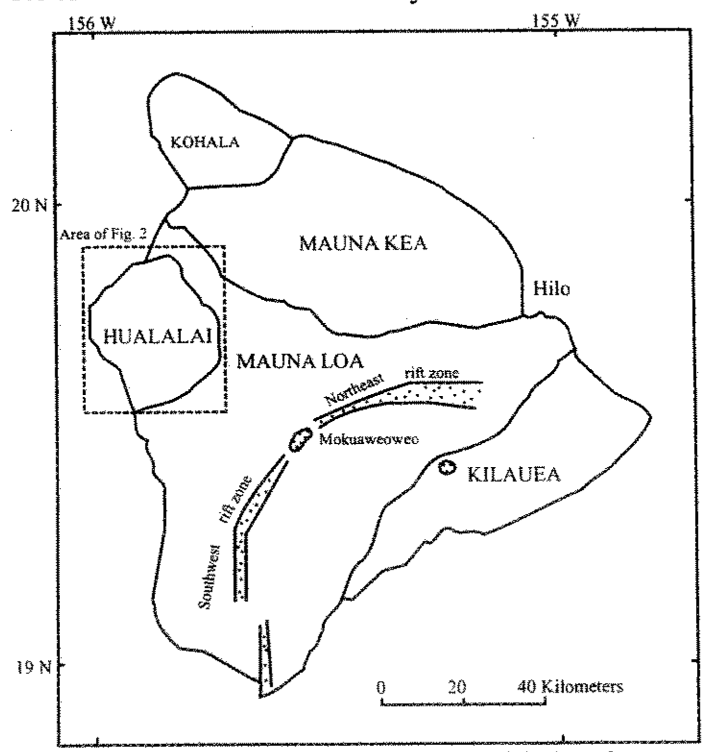

Fig. 1. Map of the island of Hawai'i showing the location of the 5 volcanoes and Figure 2.

Moore and others (1987) concluded that about 25% of the volcano is covered by lavas less than 10,000 years old. In contrast, 90% of Kīlauea volcano has been covered by new lavas flows in the last 10,000 years (Holcolmb, 1987). The most recent Hualālai volcanic activity is thought to have occurred in 1801 (Kauahikaua and others, 2002). The volcanic history of the Hualālai volcano was subdivided in the most recent geologic map of the volcano into 8 basic age groups ranging from the 106,000 year old Pu`u

[1] Volcanologists consider any volcano with humanly-documented eruptions to be "active" and to have the potential to erupt again.

Wa`awa`a cone and flow to the two historic eruptions at about 1800 A.D. (Moore and Clague, 1991) Within these age groups, most of the eruptions apparently occurred in clusters closely related in time, as did the historical eruptions about 200 years ago. Thus, the number of separate eruptive sequences is less than indicated on the geologic map of Moore and Clague (1991). Single eruptive sequences consist of many separate eruptive phases (as exemplified by the ongoing eruption of Kīlauea Volcano, where 55 separate eruptions have occurred during the single eruptive episode that began in 1983). Paleomagnetic studies and radiocarbon dating of many Hualālai lava flows mapped as products of separate eruptions by Moore and Clague show that they were part of eruptive sequences and should be treated as products of single, rather than several, eruptions.

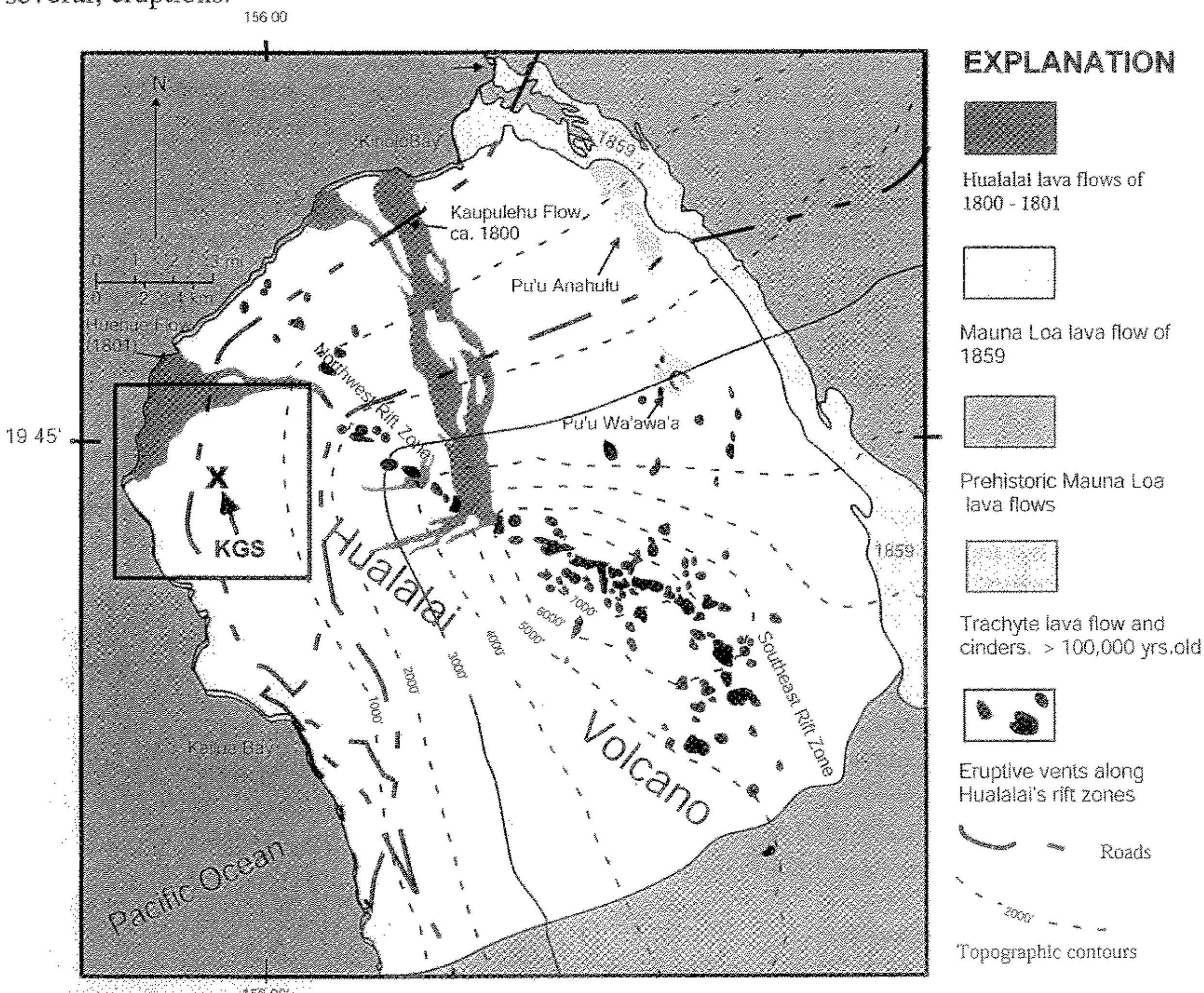

Figure 2. Principal geographic and geologic features of Hualālai Volcano (modified after Macdonald and others, 1983). The box indicates the 25 square mile Study Area surrounding the Keahole Generating Station. Contour interval is 1,000 feet.

Hualālai's most recent eruption occurred along its Northwest Rift Zone (NWRZ) in 1801 from vents at about 1800 feet above sea level. This eruption sent several lava flows, collectively known as the Hu`ehu`e Flow, westward to the sea (Fig. 2). The Hu`ehu`e flow field underlies the north end of Keāhole Airport and is a mile to the northwest of the KGS. A larger historic flow, known as the Ka`ūpūlehu Flow was also erupted from NWRZ but from vents at about 5000 to 6000 feet above sea level. The flow traveled to the north entering the ocean at Ka`ūpūlehu, about seven miles to the northeast of KGS. The precise age of this flow is uncertain. Kauahikaua and others (2002) believe it may have formed a few decades before 1801 based on historic accounts by Hawaiians (Kauahikaua and Camera, 2000). Paleomagnetic data and radiocarbon ages for these two historical flows are, however, identical within analytical error (Kauahikaua and others, 2002). The similar compositions of these two flows (Kauahikaua and others, 2002) indicate that they are related to the same magmatic "pulse" of activity, which ended about 200 years ago.

A seismic swarm on Hualālai in 1929, which lasted over a month (Macdonald and others, 1983) may have been related to an intrusion and thus represent a failed eruption (Moore and others, 1987). This event and an estimate of about 200 eruptions over the past 10,000 years led Moore and others (1987) to conclude that the average recurrence interval for Hualālai eruptions was about 50 years. They predicted that the next eruption could come within the next few decades. We believe this estimate and prediction are incorrect. As noted by Moore and others (1987), Hualālai eruptions have not been periodic. Instead, they occurred in clusters of several eruptions within a few hundred years, separated by several centuries of inactivity. Thus, the absence of a Hualālai eruption in last 200 years does not mean an eruption is "overdue". Nonetheless, the volcano is "active" in geologic terms and will certainly erupt again. There are, however, no seismic or other indicators of an imminent eruption.

METHODOLOGIES

Geologic mapping

The most recent geologic mapping of Hualālai was by Moore and Clague (1991). This mapping was not in sufficient detail to allow for a thorough volcanic hazards analysis of the Keāhole Generating Station. For our analysis, we selected a 25 square mile area surrounding the KGS (the Study Area) as representative of the lava flows that had impacted the area. This area was re-mapped by field inspections, including examination of the mineralogy of the lavas, and by interpretation of both color and black & white aerial photographs. This work added considerable additional detail to our knowledge of the geology of the KGS area.

Figure 3. Drilling rock cores for paleo-Magnetic studies

Paleomagnetic determinations

The orientation of the Earth's magnetic field changes slowly with time (Hagstrum and Champion, 1995). Lava flows record the direction of the ambient magnetic field at the time of their cooling. The differences in magnetic orientation of lava flows may thus be used to distinguish flows from one another if sufficient time elapsed (typically 100 years or more) between the times of their eruptions. To aid us in grouping and separating flows and in assigning approximate eruption ages, we conducted extensive sampling for geomagnetic studies (Fig. 3). Over 100 rock cores were obtained from eight different outcrop areas, precisely oriented with a solar compass, and their magnetic properties analyzed at the Rock Magnetism Laboratory of Western Washington University.

Radiocarbon dating

The best guide to future activity of a volcano is the record of past activity. For this reason, reliable appraisals of future lava flow hazards depend on accurate age determinations of the lava flows in the area under consideration. Radiocarbon dating of charcoal fragments recovered from beneath lava flows is the most reliable means to establish eruption ages for Hualālai lavas. A great deal of effort was expended in searching for datable charcoal beneath the lava flows of the Study Area (Fig. 4). Because the Study Area is extremely arid, however, and soils between lava flows are generally absent (Fig. 5), plant materials necessary for charcoal formation are uncommon and carbonaceous material for dating is difficult to find. Of the four charcoal samples recovered during our study, three were contaminated by later wildfire carbon and gave unusable age dates.

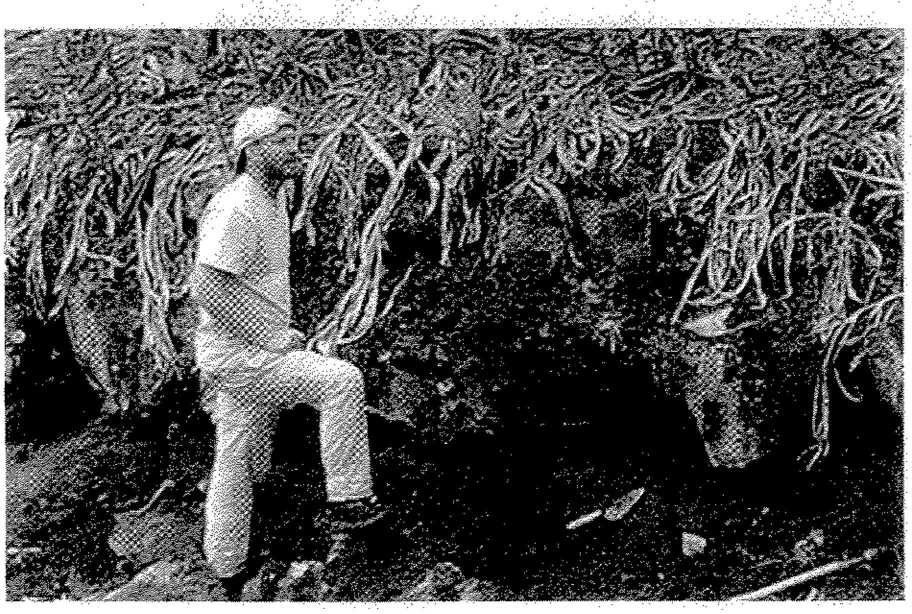

Figure 4. Collecting charcoal from a soil developed on tephra under the Kaloko Flow. A radiocarbon age of 2,410 ± 40 years was obtained on this sample. This sample locality is high on the flanks of Hualālai where soils are more common.

GEOLOGY OF THE KEĀHOLE GENERATING STATION STUDY AREA

The Keāhole Generating Station is located downslope from Hualālai's Northwest Rift Zone (Fig. 2). The surface lavas along the rift zone are almost all less than 10,000 years old and most are less than 3,100 years old (Moore and Clague, 1991). All of the flows on the northwest flanks of the volcano, including those in the KGS area, originated from the Northwest Rift Zone. These flows range widely in texture, from fluid, smooth pāhoehoe to pasty, rough a`ā. All of these flows covered less area than the current eruption of Kīlauea (Moore and others, 1987; Garcia and others, 2000). The main lava flows in the Study Area (Fig. 6) are discussed below.

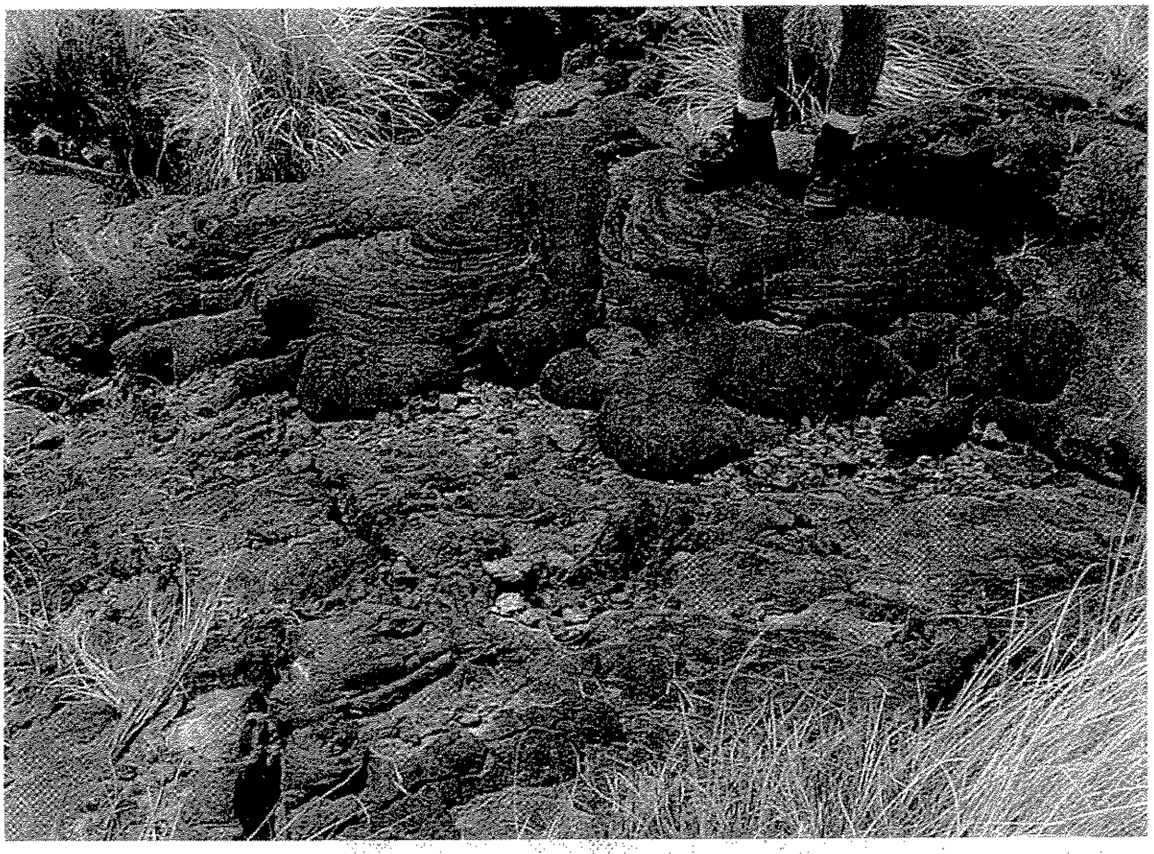

Figure 5. Keāhole Point flow overlying the Kohanaiki flow one mile west of the KGS. Almost 1,000 years separates the emplacement of these two flows. No soils formed nor did tephra accumulate during this time interval.

Keāhole Point flow

The KGS Property is underlain by a single lava flow, here informally named the "Keāhole Point flow" (Fig. 6), which forms Keāhole Point and underlies much of the Keāhole International Airport to the west. Charcoal recovered beneath this flow by Moore and Clague (1991) gave a radiocarbon age of 2,140 ± 100 years. This flow was apparently erupted from 4 or more vents along Hualālai's NWRZ at elevations of 2,000 to 4,200 feet above sea level. The portion of the flow under the KGS consists of dense pāhoehoe at the surface with irregular subsurface \`a\`ā lenses exposed in excavations on the KGS site (Figure 7). These stacked flow lobes each have somewhat variable amounts of small olivine crystals (<1 to 6%) and minor plagioclase (<1%). For a determination of lava flow hazards at the KGS site it was critical to know if these lobes were all emplaced at the same time, or if they were products of separate eruptions. Our paleomagnetic studies show that these internal lobes were erupted at about the same time (Figure 8).

To the north, the Keāhole Point flow consists of rubbly \`a\`ā lava with common xenoliths of gabbro and dunite, and moderate amounts of olivine (3-6%). The flow is bordered by older lava flows to the north and south (Fig. 6). To the west, it is overlain by the 1801 "Hu\`ehu\`e Flow" (Kauahikaua and others, 2002).

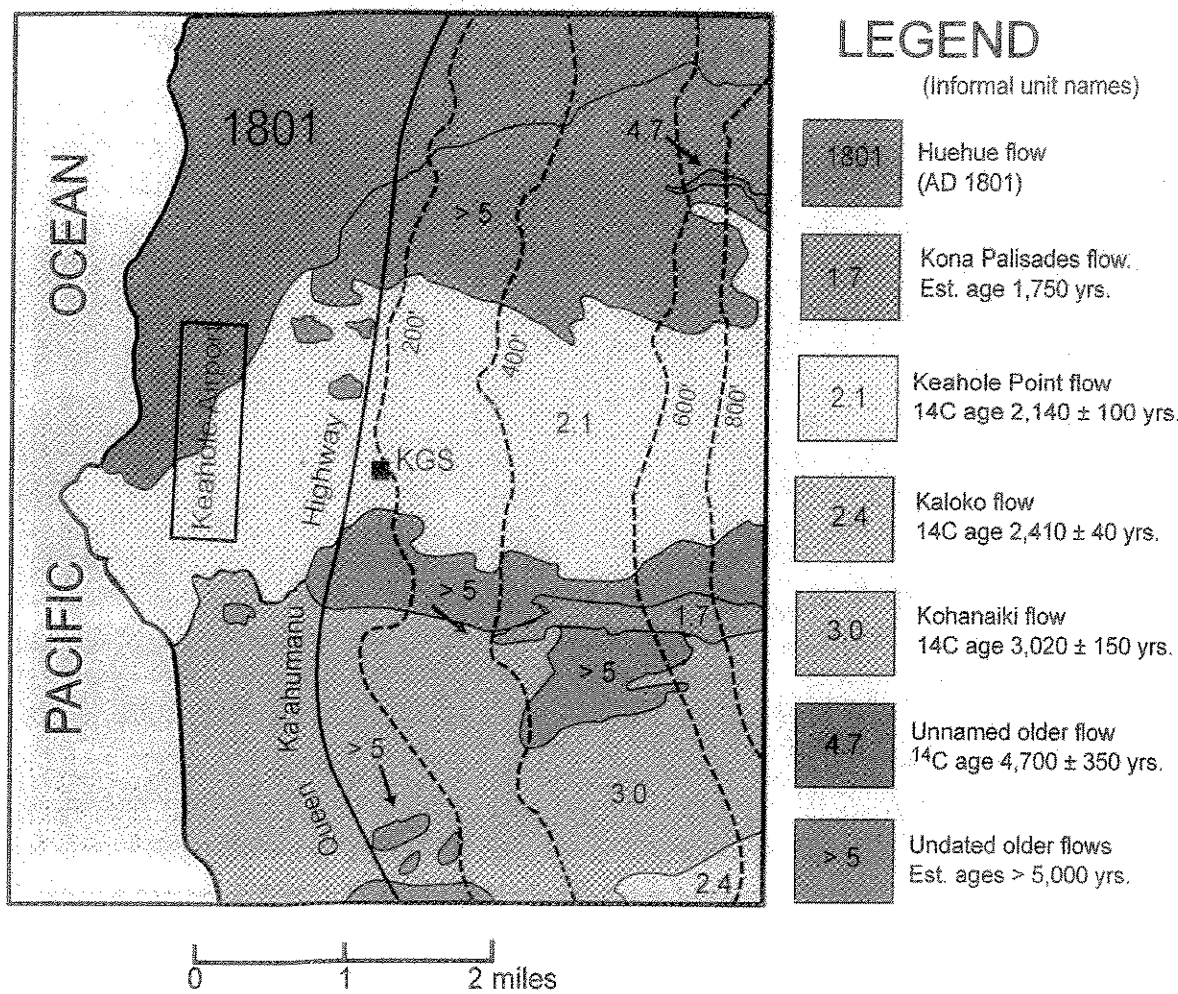

Figure 6. Geologic map of the Keāhole Generating Station Study Area. Geology in part after Clague and Moore (1991). Numbers on map are in thousands of years. Ages for the Kona Palisades and undated older flows are estimated based on field relationships with dated flows and paleomagnetic results.

Hu`ehu`e 1801 Flow

This flow covers the northern portion of the Keāhole International Airport a mile northwest of the KGS. The Hu`ehu`e Flow is a compound flow sequence consisting of two main units: an early, mostly `a`ā flow overlain by pāhoehoe to the south and a northern flow of mostly pāhoehoe with minor `a`ā . These flows have similar mineralogies with sparse olivine crystals. The southern `a`ā flow contains small, scattered fragments ("xenoliths") of gabbro and dunite from the interior of the volcano (Kauahikaua and others, 2002). Eruption temperatures for these flows are estimated to have been about 1180°C (Kauahikaua and others, 2002), which is typical of Hawaiian basalts. The rheology of this flow was been inferred from its glass chemistry and eruption temperatures. Viscosities as high as 60 pascal seconds (Pa s) were estimated (Kauahikaua and others, 2002), which are within the range for the lavas from 1984 Mauna Loa eruption (Moore and others, 1987). Other investigators have calculated much lower viscosities and assumed much higher flow emplacement rates than have been observed during eruptions of Mauna Loa or Kilauea (for example, Baloga and others, 1995; Guest and others, 1995).

Figure 7. Mixed `a`ā and pāhoehoe lavas of the Keāhole Point flow exposed in the northern wall of the Keāhole Generating Station site. Paleomagnetic sampling of similar flows exposed in a roadcut 500 feet south of the KGS site showed that all of these flows were emplaced during the same eruptive period.

Kona Palisades flow

This distinctive `a`ā flow, located about 1.5 miles southeast of KGS, underlies much of the Kona Palisades Subdivision, and is well-exposed in many roadcuts. Where the original surface is preserved, this flow is covered with loose, rubbly `a`ā fragments. The rock contains 2-4% olivine crystals ¼ inch in diameter and sparse (<1-2%) crystals of white plagioclase up to ¼ inch long with aggregates to almost ½ inch in diameter making this flow mineralogically distinct. This flow was considered to be part of the 1801 flow sequence by Moore and Clague (1991) and was, therefore, of particular interest for this study. Our field work revealed that this flow is extensively weathered, indicating that it is much older than 200 years. Our paleomagnetic observations (Fig. 8) clearly show that this flow is not of 1801 age, and comparisons with paleomagnetic data of Clague and others (1999) and Hagstrum and Champion (1995) suggest that it formed about 1,750 years ago. This flow is mineralogically similar to a lava flow exposed on the north side of the NWRZ west of the Ka`ūpūlehu Flow (Fig. 2), and paleomagnetic data obtained on this flow (Fig. 8) show that it likely represents a branch of the "Kona Palisades" flow that traveled north of the NWRZ from a vent that also fed a flow to the south.

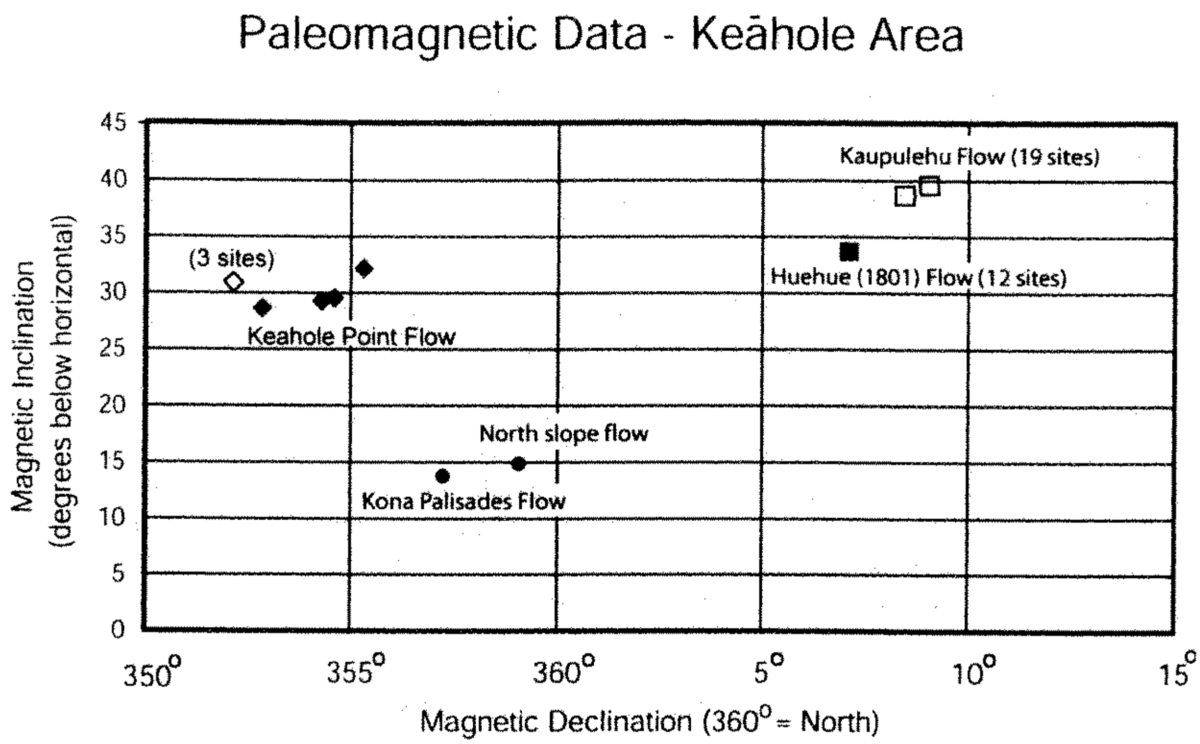

Figure 8. Direction of paleomagnetic fields preserved in lava flows of the Keāhole area, as expressed by magnetic declination and inclination. Solid symbols indicate new data collected during this study (Petro, 2003). Open symbols are averaged paleomagnetic field directions measured in this area by Champion (2004).

Kaloko Flow

This major `a`ā flow is exposed at the southern margin of the Study Area (Fig. 6). We collected a charcoal sample at the base of this flow (Fig. 4) from higher on the flanks of the volcano which yielded a radiocarbon age 2410 ± 40 years. This flow is characterized by sparse (<1%), small olivine crystals.

Kohanaiki Flow

This flow occurs just south of the overlying Keāhole Flow (Figs. 5, 6). It forms the southern boundary of the Keāhole Airport. Charcoal collected beneath this flow near the Kalaoa School at about 1,700 feet above sea level gave an age of 3,020 ± 150 years (Moore and Clague, 1991). The flow consists of dense, tube-fed pāhoehoe characterized by a very fine-grained, tough internal fabric and the presence of rare, small crystals of olivine. This lava flow is also characterized by irregular surfaces with many localized depressions and elevated hillocks (tumuli). The low-lying depressions, up to 100 feet across and 10 feet deep, were formed by the subsurface draining of lava seaward during emplacement of the flow and collapse of the crust. Although about 95% of this unit consists of dense pāhoehoe, several small patches of high-standing, rubbly `a`ā lava were found in the eastern exposures of the Kohanaiki pāhoehoe. These `a`ā patches are slightly older products of the Kohanaiki eruption, and were formed by fragmentation of early pāhoehoe during emplacement.

Unnamed older flow

The oldest dated lava flow in the Study area is a narrow, `a`ā flow exposed along the northeast margin are the area (Fig. 6). This flow was derived from an unnamed, small vent located at 4,000 feet elevation along Hualālai's Northeast Rift Zone, and is characterized by abundant olivine crystals and minor small plagioclase. It was radiocarbon dated at 4,700 ± 350 years before present (Moore and Clague, 1991).

Older Lava flows

About 14% of the Study Area is underlain by remnants of older lava flows (Fig. 6), exposed as "islands" of highly weathered pāhoehoe and `a`ā , surrounded by younger flows. They can commonly be recognized by the presence of lush grass cover, which reflects the development of soil on their surfaces. Their ages are not known except that they are older than the overlying 4,700 flow described above. Judging from degree of weathering, these older lavas are all older than 5,000 radiocarbon years. These older flows consist dominantly of `a`ā in the northern part of the Study Area, although pāhoehoe is more common in the small remnants found in the southern area. Just north of the Keāhole Point Flow, pāhoehoe lavas of this unit are characterized by large tumuli structures. Most of these older flows are characterized by relatively abundant, small crystals of olivine.

GEOLOGIC HAZARDS

Volcanic Hazards

Lava Flows

The KGS property lies entirely within Lava Flow Hazard Zone 4 of Heliker (1997), Mullineaux and others (1987), Wright and others (1992) indicating that less than 15% of this area has been covered by lava flows within the past 750 years. This classification of the entire Hualālai volcano as hazard zone 4 is far too generalized to reflect the variations of relative hazards exposure over the entire volcano. A more detailed classification for Hualālai has not been established, but would obviously show that hazards are greater along the volcano's rift zones, and lessen with increasing distance down the volcano's flanks.

Hualālai is the least active of Hawaii's three "active" volcanoes and its eruptions have been infrequent. Moore and others (1987) suggested that the average recurrence interval for Hualalai eruptions is about 50 years, based on their estimate of about 200 eruptions over the past 10,000 years, but there is ample evidence that indicates Hualālai's eruption recurrence interval is much longer than this. Our reconnaissance geologic mapping and the detailed paleomagnetic studies by Champion (2004) suggest that far fewer than 200 separate eruptions have occurred over the past 10,000 years. It appears that Moore and others (1987) counted many non-contiguous lava outcrops as belonging to separate eruptions, whereas our new paleomagnetic data and the extensive paleomagnetic data of Champion (2004) indicate that many are actually part of the same eruptive period. Furthermore, it appears that Hualālai eruptions have not occurred randomly over time, but instead have been periodic. Eruptions have apparently occurred in clusters separated by several centuries or more of inactivity, as was recognized by Moore and others (1987). Thus, the fact that Hualālai has not erupted in nearly 200 years, does not mean an eruption is overdue.

In evaluating the statistical likelihood of a future eruption threatening the Keāhole Generating Station, our best guide is the record of the past eruptions. This record provides an understanding of how often lava flows have impacted this area. Although the lava flow underlying the KGS is more than 2,000 years old, flows erupted in 1801 lie about a mile to the northwest. Thus, for a statistical evaluation of risk, a broader area than the KGS must be considered. As stated earlier, we selected a 25 square mile area centered on the Keāhole Generating Station for our evaluation (Fig. 6).

Six lava flows entered the KGS Study Area during the past 4,700 years, including five radiocarbon-dated lava flows and one, (Kona Palisades) whose age is inferred from paleomagnetic and field data (Table 1). These flows are randomly distributed in time (Fig. 9), show no periodicity or other time-dependent trends, and by various statistical tests can be shown to follow a Poisson (random) time distribution (Appendix A). Small outcrops of as many as six undated older flows (>5,000 years) are also exposed in the KGS area (Moore and Clague, 1991), but these cannot be used for statistical analyses as they are undated.

Table 1. Ages of dated lava flows within the Keahole Generating Station Study Area.

Informal Lava Flow Name	Age (radiocarbon years b.p.)	Reference
Hu`ehu`e e	AD 1801	Kauahikaua and Camera (2000)
Kona Palisades	1,750 yrs. b.p. (est.)	This Report
Keāhole Point	2,140 +/- 100 yrs. b.p.	Moore and Clague (1991)
Kaloko	2,410 +/- 40 yrs. b.p.	This Report
Kohanaiki	3,020 +/- 150 yrs. b.p.	Moore and Clague (1991)
Unnamed old flow	4,700 +/- 350 yrs. b.p.	Moore and Clague (1991)

The probability of flows from future eruptions reaching the Study Area, assuming that the random time distribution of flows in the past will also characterize the future, can be calculated for various time intervals using a Poisson probability model. The Poisson probability model assumes that: a) eruptions occur independently, b) the probability that an eruption will occur does not change with time, c) the probability that an eruption will occur in a particular time period is proportional to the length of the interval, and d) the probability of more than one eruption occurring at the same time is extremely small (after Davis, 1973).

The following equation from Kauahikaua and others (1998) is useful for calculating probabilities that future events will occur over differing future periods:

$$P = 100\left(1 - e^{\frac{-t}{T}}\right)$$

where t = probability evaluation window in years, and T = lava flow recurrence interval in years. Since six lava flows have entered the KGS area in the past 4,700 years, the recurrence interval T for this period (assuming random Poisson distribution) is 783 years.

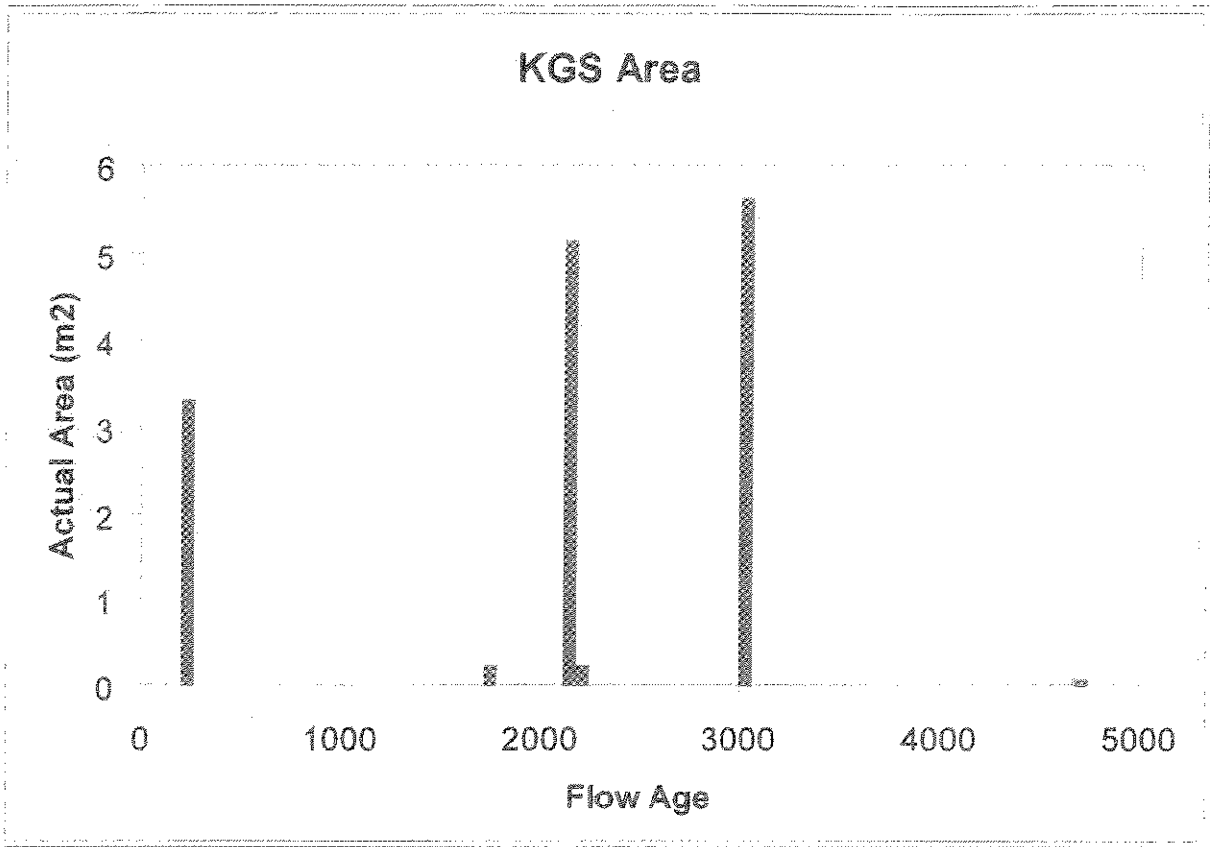

Figure 9. Radiocarbon and paleomagnetically-inferred ages and estimated surface areas of lava flows in the KGS study area. Ages from Moore and Clague (1991) and our new charcoal and paleomagnetic data.

The resulting probabilities that future flows will reach the Study Area (within 2.5 miles of the Keāhole Generating Station) are given in Table 2:

Table 2. Probabilities for future lava flows entering the 25 square mile Study Area

Evaluation Period *t* (years):	10	50	100	250	500	1,000
Probability	1.3%	6.2%	12.0%	27.3%	47.2%	72.1%

Lava flow emplacement rates are another factor to be considered in an evaluation of lava flow hazards. Emplacement rates for Hualālai's recent eruptions have been debated in the scientific literature with rates varying from extremely fluid (up to 120,000 feet per hour for near vent areas; Baloga and others, 1995) to values typical of the recent eruptions of Kīlauea and Mauna Loa (Kauahikaua et al., 2002). Measured flow rates for Mauna Loa and Kīlauea lavas vary from 16 to 30,000 feet per hour (Rowland and Walker, 1990). A typical rate for pāhoehoe flows like those that underlie KGS on a gentle slope might be about 65 feet per hour, whereas for an `a`ā flow on a steep slope the rate would be 3000 to 7000 feet per hour (Rowland and

Walker, 1990). The slopes down rift from the Hualālai vents vary from steep to gentle. Therefore, depending on eruption conditions, a flow might move quickly down the steep slopes for about 3 miles taking 2-5 hours and then more slowly on the gentle slopes above the KGS.

Fortunately, the inferred deep sources of Hualālai lavas (based on the presence of deep crustal accidental blocks that are found in some of these lavas; Clague, 1987) imply that a relatively long period of seismic unrest (weeks to months) is likely to precede an actual eruption. This would give ample time to secure the KGS facility and to allow for precautionary evacuation of staff should a lava flow threaten the KGS.

Volcanic Gases

The most important sources of atmospheric pollutants in Kona area are related to the downwind transport of magmatic gases from Kīlauea Volcano. Kīlauea's shallow summit magma chamber has slowly released large amounts of volcanic gases (principally sulphur dioxide, SO_2, and carbon dioxide, CO_2) into the atmosphere for thousands of years. Kīlauea eruptions bring fresh supplies of gas-rich magma directly to the surface causing dramatic increases in gas emission. During Hawaii's prevailing tradewind conditions these gases travel to the southeast then circulate northward in the lee of Hawaii Island (Fig. 10). Diurnal upslope

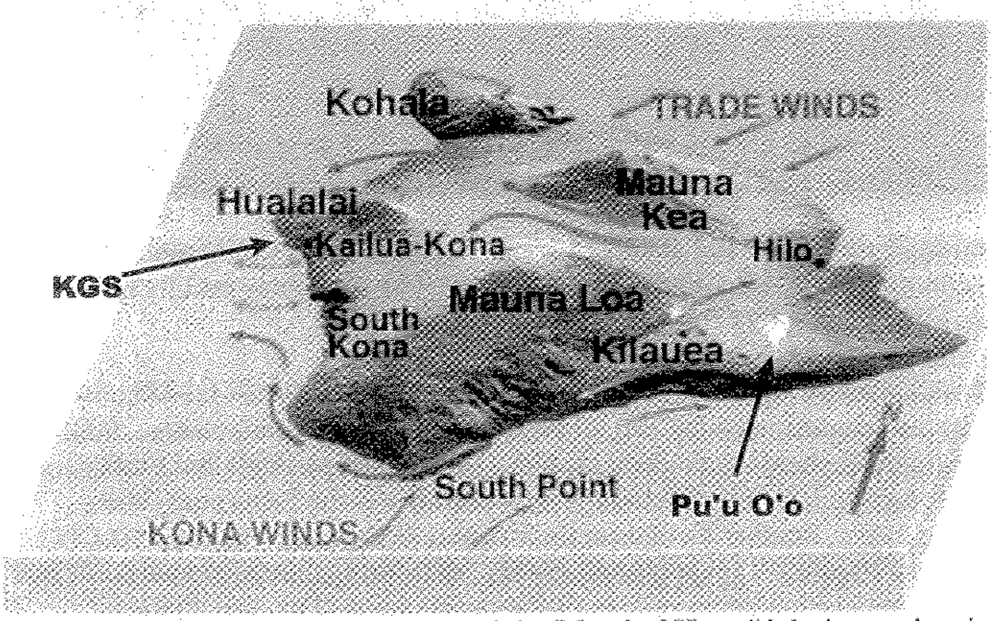

Figure 10. Distribution of winds around the Island of Hawai`i during trade wind (blue) and Kona wind (red) conditions. Figure from Sutton and others (1997).

winds bring these gases on land during daylight hours, and the resultant "vog" causes poor visibility and respiratory distress in many people.

During much of the 20th century, Kīlauea's eruptions have been of short duration, a few days to a few months (Garcia and others, 2003). The quantities of SO_2 were typically around 100-150 metric tons/day during this period (Elias and others, 1998), which are insufficient to greatly impact air quality in the Kona area. Thus, the negative effects on Kona's atmospheric quality were short-lived. This changed dramatically in January, 1983, when the Pu`u O`o eruption began. For the first three years of this eruption, eruptive episodes occurred about once a month and were short-lived (about one day). The atmospheric impact on the Kona area was slight as pollutants quickly dissipated during the month long periods between eruptions. The style of this eruption changed in the summer of 1986, when the eruptions switched to steady-state lava lake activity resulting in the near-continuous emission of large quantities of volcanic gases (Fig. 11; Sutton and others, 2001). The quantities of SO_2 gas released by this eruption are estimated at 1,000-3,000 metric tons/day (Elias and Sutton, 2002).

Figure 11. Typical fuming from Pu`u O`o, Kīlauea Volcano – aerial view to southeast. The fume, which consists dominantly of H_20, SO_2, and CO_2, is being blown to the west by the prevailing tradewinds. USGS photo by Christina Heliker, January, 2003.

The SO_2 gas from Kīlauea eruptions is quickly oxidized to sulphuric acid (H_2SO_4; Sutton and others, 2000), which has an estimated half-life of only six hours (Porter and others, 2002). This acid reacts with airborne elements to produce mixtures of sulphate particles and weak acids, which are the principal components of the volcanic "vog" that impacts the Kona area (Elias, personal communication, 2003). Southerly winds at the Keāhole Generating Station (HELCO Air Quality Impact analysis, Figure 3-1, unpublished report, 2003) bring diluted amounts of this "vog" into the KGS area from accumulation centers further to the south (Fig. 10). Optical photometric and condensation nuclei observations carried out in West Hawaii and Waimea show that vog is present on the leeward side of Hawaii Island during tradewind conditions (Fig. 12), and that vog concentrations vary with diurnal wind directions (Ryan, 2000).

Mauna Loa volcano can also produce large quantities of volcanic gases during eruptions (Ryan, 1995), but the high altitudes of most eruption sites for the past 90 years cause these gases to remain at upper atmospheric levels and to not impact the Kona area. Mauna Loa Southwest Rift Zone eruptions occurred below 5,000 elevation in 1868, 1887, and 1907. It is likely that these eruptions may have impacted the Kona area, although these eruptions were short-lived (a week or two), and their effects on the atmosphere were short-term.

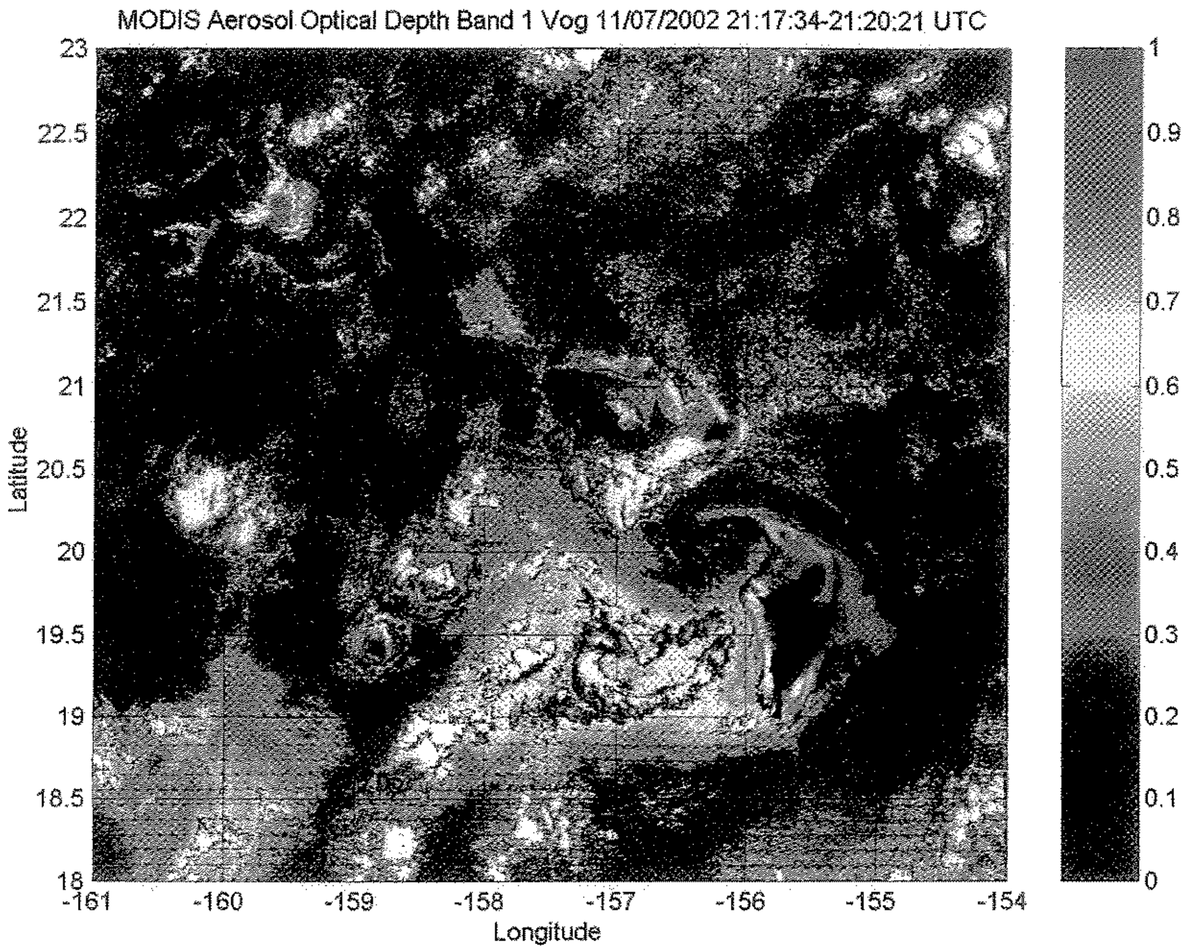

Figure 12. Distribution of sulphur-bearing volcanic pollutants from Kīlauea volcano (yellowish areas) as observed on a MODIS satellite image obtained during tradewind conditions. Image from Porter and others (2002).

Tephra Fall

Tephra deposits on Hualālai are uncommon and are of two basic types: cinder and spatter. These tephra deposits are localized around vents with little dispersal by winds, although phreatic (steam) explosions similar to the 1924 eruption of Kīlauea Volcano (Macdonald and others, 1983) have scattered blocks widely around craters on Hualālai's East Rift Zone. In their review of volcanic hazards in Hawaii, Mullineaux and others (1997) considered the hazard from tephra fall (airborne ashfall) for all of Hualālai Volcano to be "Zone 2", the same as the southern flanks of Kīlauea Volcano. They describe Zone 2 as areas where "tephra falls from lava fountains should be frequent but thin". We disagree with this characterization for Hualālai, since tephra has only been observed along the summit and rift zones of the volcano or high on its flanks, and Hualālai does not have frequent eruptions. We examined many contacts between lava flows in the "Study Area" around the KGS (Fig. 6). No tephra was observed in the vicinity of the KGS and there were no indications that tephra has fallen in these low-lying areas away from the rift zone. While we cannot exclude the possibility that minor amounts of glassy tephra ("Pele's hair") could fall in the future from high fountaining episodes of the volcano, we would expect these amounts to be slight and to have little impact on operations of the KGS facility, although filters on the air intakes at the plant may need to be changed more frequently if such an eruption were to occur. Winds reported at the KGS in year long observation period in 1984 (HELCO EIS, 2003, Section 3; Environmental Setting, Impacts and Mitigation Measures) were mostly (98%) less than 10 knots and usually from southerly directions away from the Northwest Rift Zone.

Earthquake Hazards

The Island of Hawaii is one of the most seismically active areas on Earth, with more destructive earthquakes than in any other comparably sized area in the United States (Wyss and Koyanagi, 1992). Although the most severe historical earthquakes have occurred on the southern flank of Hawaii, Wyss and Koyanagi indicate that the Kona area is subject to earthquakes with intensities up to VIII on the Modified Mercalli Scale. Such intensities can cause moderate to severe damage to unreinforced structures or to buildings with inadequate foundations. Significant vertical ground accelerations are possible in this area, and must be considered in designing buildings. The last major earthquake in the Kona area [M=6.9] occurred on August 21, 1951, with its epicenter about 18 miles to the south of the KGS site. A series of strong earthquakes of uncertain magnitude were apparently epicentered on the north flank of Hualālai in the fall of 1929, and caused extensive damage all over west Hawaii. Describing one particularly strong earthquake on October 5, 1929, Jaggar (1929) wrote:

> *"In Kealakekua the motion was a heavy jerk, somewhat prolonged, and applied very suddenly. Vertical retaining walls broke on the downhill sides of roads and of filled land, stone houses were cracked, water tanks burst or were thrown off their foundations, and some weak structures collapsed. Furniture was moved, and loose objects were thrown about. Puuwa`awa`a Ranch received the brunt of the disturbance as usual, unbraced foundation posts went over, the masonry of the basement of the main house was partly thrown down, new avalanches felling the gulches of Puuwa`awa`a Hill, bowlder fences were generally prostrated, and a chimney stump was broken for a second time."*

The International Conference of Building Officials (ICBO), as expressed in their Uniform Building Code (UBC), has recommended that the entire Island of Hawaii meet the UBC standards for Seismic Zone 4 (ICBO Code Committee, 1996). The recommendations of the ICBO are not binding on local authorities, however, and the County of Hawaii is still requiring the less rigorous standards of Seismic Zone 3, established in 1970. It is recommended that any future construction contemplated at the KGS site meet the more stringent design codes of Seismic Zone 4, with the expectation that the County of Hawaii will eventually adopt these higher standards.

Flooding and Ground Stability

The Keāhole Generating Station is located on the axis of a high-standing mound of pāhoehoe and does not lie in any observed potential flood channel. Therefore, flooding is not expected to be a hazard at the KGS, except at times of extremely heavy rainfall when local accumulations of rainwater may briefly appear at the site. The lava flows underlying the site are highly permeable, and such surface water will quickly percolate downward.

The rocks underlying the KGS consist entirely of pāhoehoe and consolidated 'a'ā. Narrow lenticular voids up to several feet across were observed in the pāhoehoe lavas in the walls on the eastern margin of the KGS, and similar cavities were also reported in the subsurface investigation of KGS by Dames and Moore (1998) based on numerous drill holes at the site. Lava flows are generally well-suited to support properly designed construction. No indications of tectonic ground cracking or other secondary deformation structures were observed in the vicinity of the KGS facility.

CONCLUSIONS

The probabilities that future eruptions of Hualālai Volcano will directly impact the Keāhole Generating Facility are quite low, but still finite. Long-term "forecasting" of future eruptions from dormant volcanoes like Hualālai is impossible (Decker and others, 1995), but as volcanoes become restless before eruptions, geophysical and geological observations make forecasts possible. Forecast precisions improve as eruptions draw nearer and premonitory phenomena become better defined. In the case of Hualālai, it is likely that an extended period of seismic unrest will precede any eruptive outbreak Such earthquake activity, possibly accompanied by surface deformation of the volcano, should give adequate warning for KGS Staff to secure the facility and to evacuate safely, if an eruption above the KGS appears possible.

ACKNOWLEDGMENTS

Gary Petro of the Rock Magnetism Laboratory at Western Washington University performed all the paleomagnetic determinations and Tim Scheffler assisted in all aspects of field work and paleomagnetic sampling. Radiocarbon age determinations were made by the Beta Analytic Corporation. Shane DeMello provided access to the Keahole Generating Station and valuable background on plant operations.

APPENDIX A --- Statistical Analyses of Lava Flow Ages

The six lava flows that have entered the 25 mile square "Study Area" around the Keahole Generating Station in the past 5,000 years (Table 1; Figure 9) appear to have occurred randomly over time, thus satisfying a critical criterion for the Poisson distribution analysis of future lava flow probabilities. To better evaluate this assumption, statistical tests for randomness were performed, using the methods employed by Davis (1973) in his analysis of the time distribution of historical eruptions of Aso volcano, Japan. The sample size to be analyzed for the Study Area is small, but since these six flows include the entire population of flows that entered the Study Area over the past 5,000 years, the sample adequately describes the activity of this period.

To evaluate the possibility that eruptions were entering the Study Area either more or less frequently with time, a trend analysis and regression line analysis were performed to reveal any changes in the rate at which flows have entered the Study Area. Following the method used by Davis (1973) this was done by dividing the 5,000 year time into five equal segments of 1,000 years each and plotting the number of eruptions that occurred in each time interval (Figure A-1). The horizontal regression line indicates the absence of any time-dependent trends.

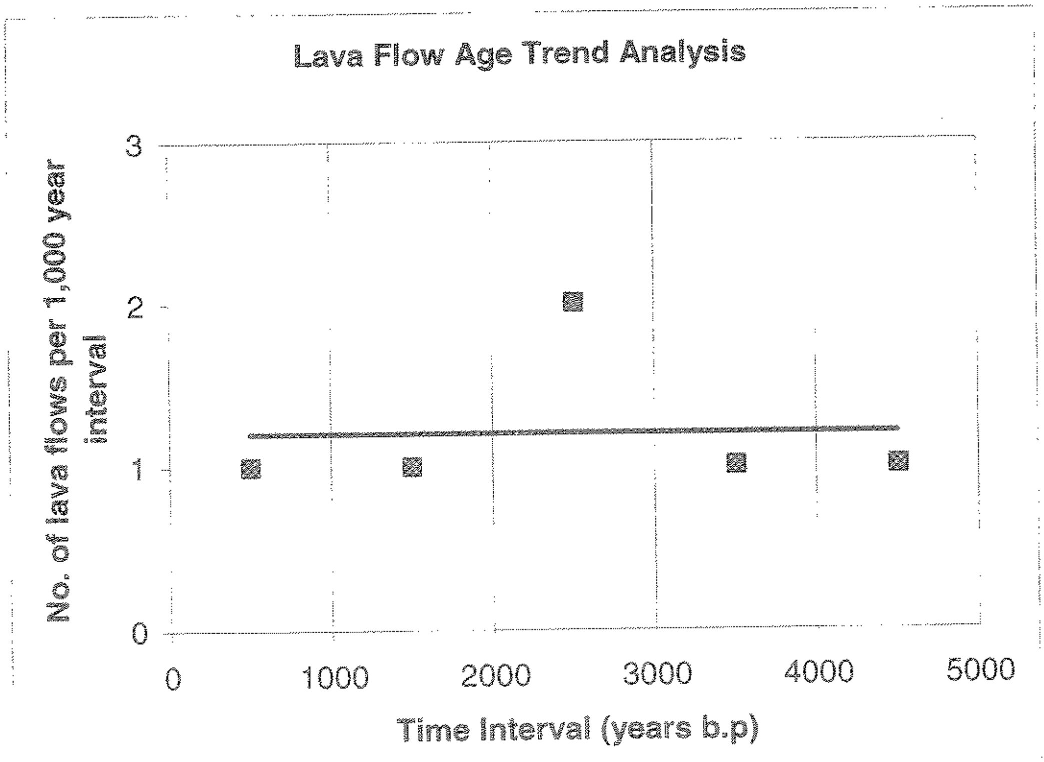

Figure A-1.Trend analysis for ages of lava flows that have entered the Study Area over the past 5,000 radiocarbon-years before the present (b.p.), showing the number of flows that entered the Study Area within each of five 1,000 year time intervals. The horizontal slope of the least squares regression line (dark) shows that there has been no increase or decrease in lava flow activity over this time period.

To evaluate the possibility that a serial correlation might exist in the data, the time between lava flows might depend on the time between the previous lava flows (i.e. that a short time between two flows would be followed by a short time till the next flow, or that a long time interval between flows would be followed by a long time until the next flow), a scatter plot was constructed for the four time intervals that were both preceded by, and followed by eruptions (Figure A-2). This plot shows both large dispersion and a concentration of points near the axes, typical of a random series of events (Davis 1973), and although sparse, the data show no connection between the lengths of repose before and after lava flows entered the Study Area.

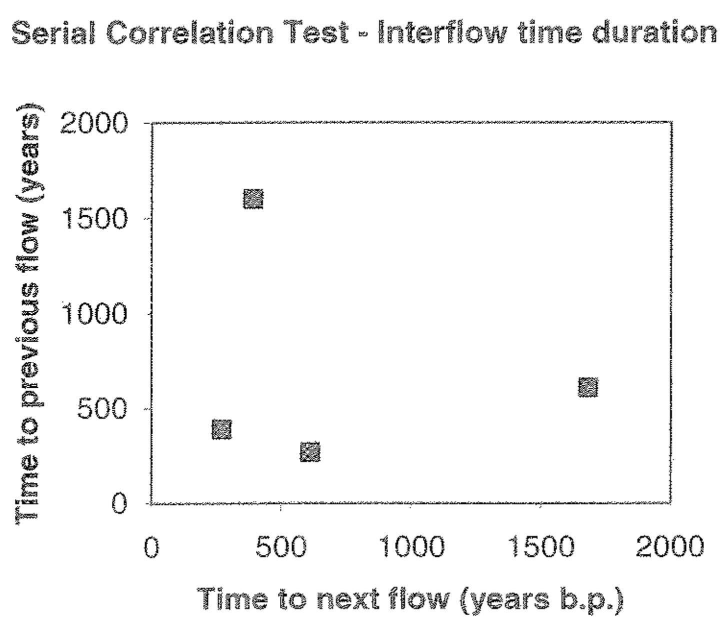

Figure A-2. Duration of time between successive lava flows that have entered the Study Area, showing intervals before and after individual flows. Repose intervals before individual lava flows show no relationship to length of time to next lava flow.

These tests demonstrate that the timing of lava flow entry into the KGS Study Area has indeed been random over the past 5,000 years, and that the flows that have entered the area are mutually independent events. The probability of future lava flow impact on the Study Area can thus be analyzed by Poisson probability statistics.

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Hawaii Electric Light Company, Inc. • PO Box 1027 • Hilo, HI 96721-10

Warren H. W. Lee, P.E.
President

September 1, 1998

FILED
1998 SEP -1 P 3: 36
PUBLIC UTILITIES COMMISSION

The Honorable Chairman and Members of
the Hawaii Public Utilities Commission
Kekuanaoa Building
465 South King Street, 1st Floor
Honolulu, Hawaii 96813

Dear Commissioners:

Subject: Docket No. 97-0349
<u>HELCO 1998 Integrated Resource Planning</u>

In accordance with Order No. 15977 dated September 26, 1997, attached is HELCO's 1998 IRP Plan for the 20-year planning horizon of 1999 - 2018. Volume 1 contains the 1998 IRP Plan, and Volume 2 contains supporting appendices.

HELCO has scheduled the following for publication of a Notice of Integrated Resource Plan Filing:

1) The Honolulu Advertiser September 13, 1998
2) Hawaii Tribune Herald September 14, 1998
3) West Hawaii Today September 15, 1998.

Sincerely,

Warren H W Lee

Attachments

cc: Division of Consumer Advocacy

W. Lee
T. Goya
S. Burns
G. Hashiro
C. Chang
C. Nihei
A. Seki
B. Nakamoto
J. Dizon
N. Creveston
G. Willoughby
E. Ifuku
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D. Brown
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NP File

Hawaii Electric Light Company, Inc.
Integrated Resource Plan
1999 - 2018

Docket No. 97-0349

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EXECUTIVE SUMMARY

BACKGROUND

HELCO submits this major review of its IRP in compliance with the Commission's Framework for Integrated Resource Planning (Framework), as revised May 22, 1992, in Decision and Order No. 11630, Docket No. 6617.

Section VII.A of the Decision and Order established July 1, 1997, as the date by which HELCO must conduct a major review of its IRP. By letter dated July 5, 1996, HELCO requested Commission approval of an extension of the submission date of HELCO's revised IRP from July 1, 1997, to September 1, 1998. By Order No. 14866, dated August 8, 1996, the Commission approved HELCO's request to extend the submission date. On September 26, 1997, the Commission issued Order No. 15977, opening Docket No. 97-0349, regarding HELCO's 1998 IRP filing (IRP-98).

IRP-98 PREFERRED PLAN

The IRP Framework states that the overall objective of the IRP process is to identify "the resources or mix of resources for meeting the near and long-term consumer energy needs in an efficient and reliable manner at the lowest reasonable cost"[1] and that the "ultimate objective of utility's integrated resource plan is meeting the energy needs of the utility's customers over the ensuing 20 years."[2] It is with this primary intent that HELCO has selected its preferred integrated resource plan. In the plan selection process, the Company also gave substantial consideration, and incorporated where possible, those resources that provide non-monetary benefits to both utility customers and society in general.

Figure ES-1 illustrates the preferred plan for IRP-98. Table ES-1 summarizes the system peak forecast and the firm capability of the system assuming the resources in the preferred plan are installed.

The demand-side features of the preferred plan include:

- Four energy efficiency DSM programs implemented over the 20-year period, 1999-2018. The programs include: Residential Water Heating, Commercial & Industrial Energy Efficiency, Commercial & Industrial New Construction and Commercial & Industrial Custom Rebate programs.
- A forecasted maximum energy efficiency DSM peak impact of about 15.2 MW, reducing the forecasted net peak load in 2018 from 263.6 to 248.4 MW.
- A forecasted total energy savings of roughly 1300 GWh, or a savings of about 3 million barrels of oil from energy efficiency DSM over the 20-year planning period.
- Continuation of existing load management rates and rider contracts, estimated to reduce the system peak demand by more than 6.7 MW.

The supply-side features of the preferred plan include:

- Retire Keahole D18-20 (total of 8.25 MW) with the addition of CT-4 and CT-5 in December 1998
- Retire Shipman 1, Waimea D8-10 and D12-14 (total of 14.3 MW) upon completion of Encogen Phase 1[3], currently estimated to be in April 1999
- Retire Kanoelehua D11 and D15-17, Keahole D21-23 and CT-1 (total of 30 MW) upon completion of Phase 2 of the Encogen combined cycle[4], currently estimated to be in August 1999

[1] IRP Framework, Section II.A, page 3.

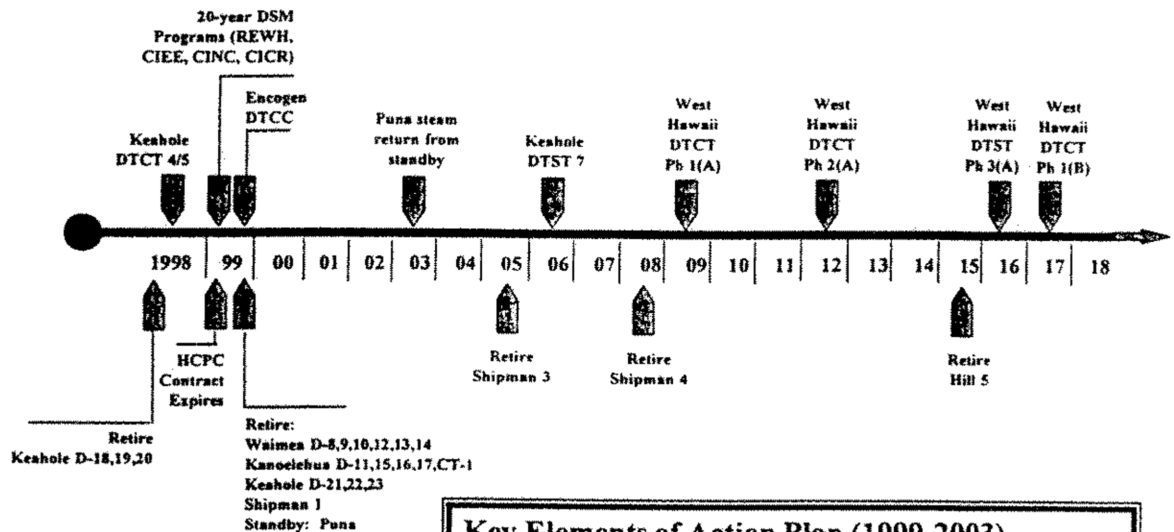
[2] IRP Framework, Section IV.B.1, page 20.

[3] Consistent with HELCO Rate Case, Docket No. 97-0420 (HELCO T-4, p. 43)

[4] Ibid.

Figure ES-1. IRP-98 Preferred Plan

HELCO IRP-98 PREFERRED INTEGRATED RESOURCE PLAN (1999-2018)



Key Elements of Action Plan (1999-2003)

- Pursue installation of a wind project and/or photovoltaic facility
- Conduct a more refined analysis of distributed generation resources, to determine whether or not they should be implemented
- Permitting and engineering activities for Keahole ST-7
- Acquire new West Hawaii site (to support 2009 DTCT)

DTCC - Dual-train Combined Cycle	REWH - Residential Efficient Water Heating
DTCT - Combustion Turbine	CIEE - Commercial & Industrial Energy Efficiency
DTST - Steam Turbine with conversion of DTCTs to Combined Cycle	CINC - Commercial & Industrial New Construction
	CICR - Commercial & Industrial Custom Rebate

- Place the Puna steam unit on cold standby upon completion of Phase 2 of the Encogen combined cycle[5], currently estimated to be in August 1999
- Expiration of the contract between HELCO and HCPC for the purchase of 22 MW of firm capacity on December 31, 1999
- Return the Puna steam unit to service from cold stand-by for cycling operation in 2003
- Install Keahole ST-7 in 2006, converting CT-4 and CT-5 to dual train combined cycle
- Install a 60.7 MW dual train combined cycle at a new West Hawaii site in phases, with the first phase combustion turbine added in 2009. The second combustion turbine and steam turbine would be installed in 2012 and 2016, respectively.
- Install the first combustion turbine of a second 60.7 MW dual train combined cycle at the new West Hawaii site in 2017.

The IRP analyses, and consideration of Advisory Group input, suggested pursuing various means of acquiring additional wind and PV resources and performing site-

[5] Ibid.

Table ES-1. Summary of Preferred Plan System Peaks and Capacity

	Base Peak Forecast, Without Peak Reduction Benefits of DSM		Energy Efficiency DSM Peak Reduction Benefit		Base Peak Forecast, With Peak Reduction Benefits of DSM		Total System Capability for Preferred Plan	
Year	Gross MW	Net MW	Gross MW	Net MW	Gross MW	Net MW	Gross MW	Net MW
1999	172.7	166.8	0.8	0.8	171.9	166.1	239	235
2000	174.4	168.5	1.5	1.5	172.8	167.0	217	213
2001	177.2	171.2	2.3	2.2	174.8	168.9	217	213
2002	180.9	174.7	3.0	2.9	177.9	171.8	217	213
2003	184.9	178.6	3.8	3.7	181.1	174.9	232	228
2004	188.9	182.5	4.6	4.4	184.3	178.0	232	228
2005	193.1	186.5	5.4	5.2	187.7	181.3	232	228
2006	198.8	192.1	6.3	6.1	192.5	186.0	243	238
2007	204.2	197.3	7.2	6.9	197.0	190.4	243	238
2008	209.5	202.4	8.1	7.8	201.4	194.6	243	238
2009	214.7	207.5	9.0	8.7	205.7	198.7	256	251
2010	220.0	212.6	10.0	9.7	210.0	202.9	256	251
2011	226.0	218.4	11.0	10.6	215.0	207.8	256	251
2012	232.3	224.5	11.9	11.5	220.4	213.0	278	272
2013	239.0	230.9	12.9	12.5	226.0	218.4	278	272
2014	245.3	237.0	13.4	13.0	231.8	224.0	278	272
2015	251.7	243.2	14.0	13.5	237.6	229.7	278	272
2016	258.5	249.8	14.6	14.1	243.9	235.7	284	278
2017	265.5	256.6	15.1	14.6	250.4	242.0	305	299
2018	272.8	263.6	15.7	15.2	257.1	248.4	305	299

specific studies on distributed generation resources. Details on how these resources may be incorporated into HELCO's long-term strategy are provided in the IRP-98 Action Plan.

DEVELOPMENT OF THE CURRENT INTEGRATED RESOURCE PLAN

Scenarios for the future electricity business environment vary widely, with many risks and much uncertainty. The goal of the planning process was to develop a plan or plans which would be responsive to an array of reasonable scenarios for the future. Flexibility and resilience are essential attributes of a long-term integrated resource plan.

The planning context for IRP-98 was similar to that of IRP-93 in terms of risk, uncertainties and conflicting objectives. One major difference is a clear change toward increased competition in the electric utility industry. Other differences are summarized in Table ES-2. All of these differences were considered in the plan development process of IRP-98. As in IRP-93, HELCO made every reasonable effort to comply with the requirements of the IRP Framework.

PUBLIC PARTICIPATION

An IRP Advisory Group, comprised of representatives from state and county agencies, environmental, cultural, business and community interest groups, as well as other interested individuals, served to provide HELCO with a diverse set of opinions and perspectives for consideration in the development of its IRP plan. HELCO made extensive effort to keep its IRP Advisory Group educated, informed and involved, by scheduling meetings at major

Table ES-2: Major differences between IRP-93 Reassessment and IRP-98

IRP-93 (reassessment)	IRP-98
• March 1994 Sales & Peak Forecast	• September 1997 Sales & Peak Forecast (lower than March 1994 forecast)
• August 1992 Fuel Price Forecast	• May 1995 Fuel Price Forecast (lower than August 1992 forecast)
• Forecast of DSM impacts as of June 1994	• Forecast of DSM impacts as of November 1997 (lower than June 1994 estimates)
• Supply-side resource data as of July 1993	• Supply-side resource data as of October 1997
• Planned addition of CT-4 and CT-5 at Keahole in 1995, ST-7 in 1997	• Planned addition of CT-4 and CT-5 at Keahole in 1998, ST-7 in 2006
	• Addition of Encogen's proposed 62 MW dual-train combined cycle in 1999
	• Deferral of planned unit retirements (Waimea D8-10, 12-14; Kanoelehua D11, 15-17, CT-1 and Shipman 1) until sufficient capacity is installed. Retire Shipman 1, Waimea D8-10 and D12-14 after Encogen Phase 1; retire Kanoelehua D11, D15-17, CT-1 (and Keahole D21-23) upon completion of Phase 2 of the Encogen combined cycle
• HCPC assumed to continue to provide 18 MW of firm capacity through the IRP-93 planning period (2013)	• HCPC contract for 22 MW of firm capacity terminates on December 31, 1999
	• Commission opened Docket No. 96-0493, Order No. 15285, instituting a proceeding on electric competition, including an investigation of the electric utility infrastructure in the State of Hawaii

points throughout the IRP process, as well as through written correspondence and informal discussions with HELCO staff. While HELCO welcomed the feedback it received from the Advisory Group members, it was not possible to incorporate all suggestions into the preferred plan due to competing objectives and other constraints.

IRP OBJECTIVES AND PLAN ATTRIBUTES

As stated in the IRP Framework, the goal of integrated resource planning is "the identification of the resources or mix of resources for meeting near and long term consumer energy needs in an efficient and reliable manner at the lowest reasonable cost."[6] With input from its IRP Advisory Group, HELCO prepared a list of objectives and plan attributes to assist in evaluating plans supportive of the IRP goals. The nine IRP objectives were:

- Meet Customer Electrical Needs at the Lowest Reasonable Cost
- Improve the Quality of Electrical Products and Services
- Maintain Corporate Financial Integrity
- Maintain Corporate Competitiveness
- Increase Fuel Diversity for the Electrical System
- Support the State of Hawaii Energy Objectives
- Protect the Environment
- Mitigate Potential Negative Societal and Cultural Impacts of the IRP Plan
- Increase Plan Flexibility

SALES, PEAK DEMAND AND FUEL FORECASTS

The IRP-98 analyses were based on the following forecasts:

- Long-term sales and peak forecast, dated September 11, 1997
- Fuel Price Forecast, dated May 22, 1995

On May 22, 1998, HECO adopted an updated fuel price forecast, which forecasts fuel prices for HECO, HELCO and MECO. The 1998 fuel price forecasts for diesel and MSFO are lower than the 1995 forecast used in the IRP-98 analysis. The 1998 forecast for coal is higher in the near term, but lower in the long term. By the time the 1998 fuel forecast was issued, the IRP-98 analysis was near completion. Therefore, the 1998 forecast was not used in the development of the IRP preferred plan. However, the 1998 fuel forecast does not affect the selection of the preferred plan for the following reasons:

- The supply-side resources in the 20-year IRP preferred plan were determined to be all oil-fired units using the 1995 fuel forecast. Lower oil prices and a smaller differential between coal and oil prices in the 1998 forecast will increase the cost premium for renewable energy and coal.

- HELCO performed an analysis which indicated that all four 20-year energy efficiency DSM programs remain cost-effective with the 1998 forecast.

- Lower fuel prices in the 1998 fuel forecast would reduce the cost of transmission energy losses, but would not change HELCO's preference to install efficient generation closer to the load in West Hawaii.

[6] IRP Framework, Section II.A.

Assessment of Demand-Side Resources

Four energy efficiency DSM programs were evaluated in IRP-98. These programs represent continuation of the DSM programs approved by the Commission for the 5-year period 1995-2000:

- *Residential Efficient Water Heating Program (REWH), Docket No. 95-0173.* Incentives encourage homeowners to install solar water heaters, electric heat pumps or high efficiency resistance water heaters.
- *Commercial and Industrial Energy Efficiency Program (CIEE), Docket No. 95-0174.* Incentives encourage commercial and industrial customers to replace existing air conditioning, refrigeration, electric motors and lighting with more energy efficient equipment.
- *Commercial and Industrial New Construction Program (CINC), Docket No. 95-0175.* Technical assistance is provided to the engineering community to design energy efficient buildings and facilities.
- *Commercial and Industrial Customized Rebate Program (CICR), Docket No. 95-0176.* Incentives encourage commercial and industrial customers to identify opportunities to increase the efficiency of electrical energy use in their businesses or facilities and implement them.

The DSM programs reduce both energy consumption and peak demands on the system. They were evaluated as both 2-year programs (1999-2000), completing the five-year period currently approved by the PUC) and 20-year programs (1999-2018, through the IRP planning period) in the integration analysis.

A pilot Capacity Buy-back DSM program was approved by the PUC in Decision and Order 15457, Docket No. 96-0421 on March 24, 1997. Given the positive customer response to HELCO's rate rider contracts, HELCO is not pursuing implementation of the Capacity Buy-back program at this time. As part of its Contingency Generation Resource Plan, HELCO has made an aggressive effort to acquire 28 contracts, or about 6.7 MW of potential peak-shaving capacity through its existing load management rates and rate riders (Schedule U, Rider M and Rider T). These rider contracts give incentives to customers to curtail load during system peak periods. However, compliance on any given night is not assured and long-term participation by customers has not been demonstrated. Therefore, for long-term planning purposes, HELCO has assumed 5.5 MW is curtailed at the daily peak.

ASSESSMENT OF SUPPLY-SIDE RESOURCES

For the purposes of integrated resource planning, HELCO evaluated commercial supply-side technologies that could be developed by either the utility or by Non-Utility Generators.

The cost and performance characteristics of existing HELCO-owned generating units were updated in IRP-98 based on actual performance data. Cost and performance characteristics of future supply-side resource options were also updated from IRP-93 to reflect current performance and cost estimates.

A broad range of fossil-fired supply-side resource options was screened down to a shorter list of the most cost-effective alternatives. A number of renewable technologies were also considered in the supply-side resource option portfolio. The short-list of fossil fueled and renewable resource alternatives is shown in Table ES-3.

Table ES-3. Supply-side Resources considered in the Integration Analysis

Simple Cycle Combustion Turbines	MW
GE LM-2500 Simple Cycle	20.9
GE LM-2500 STIG	22.7
GE LM6000 Simple Cycle	43.5
Single Train Combined Cycle Resources	MW
GE LM-2500 1 on 1 Combined Cycle	29.7
Dual Train Combined Cycle Resources	MW
GE LM-2500 2 on 1 Combined Cycle	60.7
Steam Units	MW
Atmospheric Fluidized Bed	26.7
Repower Resource Options	MW
Hill 5 Repowering	58.3
Puna Steam Turbine Repowering	57.3
Hill 6 Repowering	58.1
Diesel Engine Resources	MW
Diesel Engine	10.4
Diesel Engine	1.0
Phosphoric Acid Fuel Cell	0.19
Renewables	
10MW (rated maximum) Wind energy (Lalamilo)	
5MW (rated maximum) Wind energy (Lalamilo)	
10MW (rated maximum) Wind energy (N. Hawaii)	
5MW (rated maximum) Wind energy (N. Hawaii)	
10MW (rated maximum) Wind energy (N. Hawaii)	
5MW (rated maximum) Wind energy (N. Hawaii)	
Battery Energy Storage: 3 hrs @ 5MW or 1.5 hrs @ 10MW	
Battery Energy Storage Spinning Reserve: 20 min @ 10MW	
0.9 kW (rated maximum) PV Energy-Distributed	
4MW (rated maximum) PV Energy	
Pumped Storage Hydro: 5 hrs @ 30MW (S. Hawaii)	
Pumped Storage Hydro: 5 hrs @ 30MW (Kona)	
13.8MW Run of River Hydro (E. Hawaii)	
25MW Geothermal	
25MW Biomass	

*Capacity of fossil fired units represent net MW at average conditions

RESOURCE INTEGRATION ASSUMPTIONS

The PROSCREEN II model was used to develop a multitude of plans which varied in demand-side and supply-side resource combinations, sequence of installation and timing of resource additions. The HELCO generation planning criteria was applied to determine the timing of firm resource additions.

Table ES-4 highlights the significant assumptions used in the IRP-98 analyses.

INTEGRATION ANALYSIS AND CANDIDATE AND FINALIST PLAN SELECTION

Resource integration is the process by which demand-side and supply-side alternatives are combined into resource plans capable of meeting the forecasted electrical energy needs of the Big Island.

Table ES-4. Summary of IRP-98 analysis assumptions

ITEM	ASSUMPTION
Analysis Period	1999-2018 (specified by IRP Framework)
Transmission & Distribution Losses and Company Use	8.64% of net generation
Sales & Peak Load Forecast	September 1997 HELCO Sales & Peak Forecast (Appendix E)
Fuel Price Forecast	May 22, 1995 Fuel Price Forecast (Appendix F)
DSM Cost and Performance Data	Data shown in Section 6
Future Supply-side Resource Cost and Performance Data	Data shown in Table 4-7 and Appendix G
Existing generating unit data	Data shown in Section 4.3
Existing unit retirements	Data shown in Section 4.3
Purchase Power Agreements	Data shown in Section 4.3
Cost of Capital (for long-term planning)	Weight / Rate Short-term debt: 5% / 6.5% Long-term debt: 40% / 6.5% Preferred stock: 7% / 9% Common equity: 48% / 12% Composite Weighted Ave.: 9.315% After-tax Weighted Ave.: 8.177%
Inflation Rate (source: May 1995 Fuel price forecast)	1999-2000 2.64% 2001-2005 3.31% 2006-2018 3.40%
Composite Income Tax Rate	38.91%
Revenue Taxes	8.885%
Externality Costs	Data shown in Table 5-3

Integration analysis involves the application of quantitative analytical techniques and experienced planning judgment to screen possible plans down to progressively smaller pools and to ultimately select the final preferred plan.

The integration process entailed the following steps:

Step 1: Development of base case IRP assumptions, including the Sales & Peak Forecast, Fuel Forecast, and existing unit data.

Step 2: Identification and screening of DSM options and supply-side alternatives

Step 3: Development of Candidate Plans, representing a broad array of objectives and including various combinations of DSM and supply-side resources

Step 4: Elimination of redundancies within the Candidate Plan set, to arrive at a set of Finalist Plans

Step 5: Detailed attribute and sensitivity analysis on the Finalist Plans; and analysis of the impact of other "special considerations" to the Finalist Plans

Step 6: Selection of the IRP Preferred Plan

The intent of Step 3, development of Candidate Plans, was to generate a diverse set of plans with various supply and DSM resource combinations from different perspectives (Utility, Customer and Societal). In addition to Candidate Plans HELCO developed according to suggestions from the Advisory Group, a number of PROSCREEN II optimization runs were made to develop plans with the following objectives:

- Plans with 2-year and 20-year DSM bundles
- Plan with no future DSM (from 1999)
- Plans with a coal unit
- Plans with repowering
- Plans with indigenous and renewable resources
- Plans with and without Keahole ST-7 as the next unit addition
- Plans optimized by either 20-year (planning period) or 50-year (study period including 30-year end effects) cost perspectives

The Candidate Plans were further narrowed to 14 Finalist plans in Step 4. Each candidate plan retained as a finalist plan had some distinguishing trait that HELCO and/or its Advisory Group (AG) felt deserved further consideration. All AG-suggested Candidate Plans were retained as Finalist Plans. While the AG generally concurred with the types of plans in HELCO's proposed finalist plan list, the AG requested that renewable resources be added earlier in the plans, ideally within the five-year Action Plan period. HELCO complied with this request, and the Finalist Plans reflect this change. Since there is a necessity to add baseloaded generation at the load center in West Hawaii, and inclusion of transmission costs associated with East and West Hawaii generation determined that ST-7 on the West side is the least cost next unit addition, the majority of the Finalist Plans have ST-7 in 2006.

Selection of a reasonable number of Finalist Plans allowed for more in-depth analyses to be performed. An attribute analysis was conducted to identify significant differences between the Finalist Plans in achieving the IRP objectives. A sensitivity analysis determined how resource selection could change with deviation of actual sales or fuel prices away from the current base forecasts. In addition, other special considerations that could affect the selection of a preferred plan were taken into account at this stage of the IRP process. This included:

- the Hawaii Energy Strategy,
- climate change and
- an updated fuel price forecast.

In its review of the finalist plans, HELCO identified four major distinguishing characteristics among the plans:

1. Length of commitment to energy efficiency DSM programs
2. Location of future generation additions
3. Future renewable energy development
4. Distributed generation to defer large scale, central station generation

Thorough examination of each of the four differentiating factors consequently led to the selection of the IRP-98 Preferred Plan. Selection of the preferred IRP plan was made in consideration of the requirements of the IRP Framework, the planning context, forecasts, IRP objectives and their relative importance, premises for the analyses, results of the analyses and Advisory Group input. The four major issues are discussed below.

1. DSM

All four 20-year energy efficiency programs continue to be cost effective from the utility, total resource cost (TRC) and societal perspectives even with a reduced level of penetration from what was expected at the time of the program applications. The fact that the programs are cost-effective from the TRC perspective is especially important, since this indicates that customer costs, as a whole, will be reduced relative to a no DSM case. Aside from economic benefits, there are also reductions in air emissions and fuel usage associated with implementation of energy efficiency programs. Solar water heating in the residential water heating program will support HELCO's participation in the federal Million Solar

Roofs Program. DSM can provide HELCO flexibility in the timing of generating unit additions, to the extent that program ramp rates can be modified. At the same time, though, energy efficiency DSM does increase the per unit cost of electricity, seen by the consumer as higher electric rates.

HELCO believes that the advantages of continuing energy efficiency DSM programs outweigh the drawback of increased rate impacts at this time, and therefore is including all four 20-year DSM programs in its preferred plan. The Advisory Group has also demonstrated support for 20-year DSM, assigning the IRP attribute of "increase DSM penetration" the highest weight in their rank-and-weight attribute analysis. Having the 20-year DSM programs in the IRP plan will give HELCO the flexibility to continue with these programs over the long term, provided they are justified in applications and approved by the Commission beyond the currently approved 5-year period. Future changes in the nature of the electric utility business environment may justify an increased weight placed on mitigating rate impacts to the point where it may be high enough to offset the favorable attributes of DSM. In that case, HELCO would need to be able to scale back or phase out the DSM programs in order to reduce rate impacts.

2. Preferred Location of Future Generation

In the year 2000, HELCO forecasts approximately 56 percent of the total system load to be situated on the West side of the Big Island. However, only about 26 percent of total generation, comprised of three relatively inefficient combustion turbines, will be located in West Hawaii at Keahole. Thus, a large proportion of the energy needs on the West side must be exported across the island, incurring high losses across transmission lines. Or, if the West side CTs need to be run for voltage support, then losses will be reduced, but operating fuel costs will increase. This obvious mismatch between the location of generation and load will continue to grow if future generation is not sited in West Hawaii, as more than half of future load growth is projected to be on the West side of the island.

Completion of the Keahole dual-train combined cycle with the addition of ST-7 will contribute an additional 18 MW (gross) of capacity as well as significant gains in efficiency to West Hawaii. This capacity addition and efficiency improvement will be achieved without burning more fuel or generating additional emissions. Moreover, the conversion of CT-4 and CT-5 at Keahole to combined cycle will provide voltage support from efficient generation on the West side. However, even with ST-7, total generation on the West side will only amount to about 30 percent.

Future generation additions beyond ST-7 at a new West Hawaii site will bring a closer balance between generation and load to the west side of the island. This will not only serve to reduce transmission losses, but will increase the chances that the system will remain stable in case a transmission line or lines are out of service and system separation should occur. The closer generation is to the load, energy delivery becomes less dependent on the transmission system, thereby increasing system reliability.

HCPC and PGV, independent power producers currently providing firm power to the HELCO system, have expressed interest to expand their power generation operations on the Big Island. Since these existing facilities are located in East Hawaii, and contracts could be negotiated with these parties in the future through PURPA, there is even more reason for HELCO to pursue efficient generation on the west side to serve that local load.

When transmission costs are accounted for, it is lower in cost to add ST-7 at Keahole as the next unit in 2006 than repowering Hill 5. In consideration of the cost and non-cost aspects of siting future generation noted above, HELCO's preference is that the next unit after ST-7 be sited in West Hawaii near the load center.

3. Future renewable energy development

In 1997, about 30 percent of total generation on the HELCO system came from renewable sources, ranking HELCO among the top utilities in the nation in terms of renewable energy as a percent of total generation. HELCO's existing grid-connected renewable sources include geothermal, run-of-the-river hydro and wind. Assuming continued operation of all existing renewable facilities through 2018, HELCO would surpass the federal Comprehensive Electricity Competition Plan proposal of a 5.5 percent minimum energy from renewable sources by more than four times over the 20-year period.

The integration analysis determined that plans with future addition of renewable resources are more expensive than a comparable all-fossil plan within the 20-year IRP planning horizon. This is true even under a high fuel price sensitivity analysis or including the highest value externality adders. In the 50-year study period horizon, the plan that adds wind generation has a slightly lower present value of revenue requirements than a comparable all-fossil plan (estimated difference of about $800,000 over a 50-year period, using the base case fuel forecast). It should be noted that the PROSCREEN II model is not capable of modeling the curtailment of supplemental energy sources; therefore, the integration analysis overstates the energy from wind during the minimum load periods. Only if the low capital cost estimate is assumed for geothermal is the plan with geothermal and wind lower in estimated cost than the all-fossil plan in the 50-year study period. All other renewable plans considered are more expensive than a comparable all-fossil plan even when considering the longer term study period and including the highest value externality adders.

a. Supplemental energy sources (Run-of-river hydropower units, Wind turbines, Photovoltaic panel generating systems)

Since each of these resources depends either directly or indirectly on the weather, they are non-firm generation sources. HELCO utilizes supplemental resources to reduce fuel oil consumption. Fuel savings also has the effect of reducing air emissions. Supplemental renewable resources will increase the fuel diversity of the system and support the State of Hawaii energy objective to increase the proportion of energy from indigenous and renewable resources.

However, there are limitations to the amount of supplemental generation that can be incorporated into the utility system. Due to a relatively small margin between the minimum capability of its baseload units and its minimum load, HELCO has recently experienced instances where it had to curtail generation from existing hydro and wind resources. HELCO is also incurring increased production costs with existing wind resources because of operating reserve that must be carried by oil-fired units capable of regulating system frequency. The operating reserve is necessary to counter excursions of the system frequency away from 60 Hz, such that power quality will not be compromised and load shedding will not occur.

HELCO is aware of the growing development of the wind industry and the gains that have been made with new technology. These new technologies, however, need to withstand field testing and performance verification. The various advanced wind turbines are currently being field tested at various locations on the mainland. These new advanced wind turbines do not have any significant track record to measure their performance over a long period.

In consideration of the result of the Advisory Group rank-and-weight analysis which indicated a preference for wind and PV, and the positive aspects of these resources such as fuel savings and reduced emissions, HELCO is proceeding to concentrate its renewable energy efforts on acquiring additional wind and PV resources as listed below.

HELCO is currently negotiating with Zond Pacific, Inc. ("Zond") for purchase of as-available energy from a 10 MW windfarm which would be located at Kahua Ranch. HELCO has also received a proposal from Amoco/Enron Solar Power Development ("Amoco/Enron") for purchase of as-available energy from a 4 MW PV resource. As part of its IRP Action Plan, HELCO will continue to negotiate with Zond and Amoco/Enron for wind and PV resources, respectively. However, in the case that either or both projects do not materialize, HELCO will consider the purchase of wind and/or PV resources through one of the following avenues:

a. Renewable Resource Request for Proposal (RFP) — HELCO will develop a Renewable RFP to invite renewable developer(s) to submit a proposal to provide energy to the HELCO system in return for payments at or below HELCO's avoided energy cost;
b. Green Pricing Expansion — HELCO will expand and extend the current Green Pricing program filed with the PUC to include a wind and/or photovoltaic projects. HELCO customers will be given the choice to pay a premium for these renewable resources; or
c. Utility Installation — HELCO will consider installing a wind and/or a photovoltaic project as part of its utility-owned electrical generating system.

In addition to these utility scale projects, HELCO and the Big Island community are participating in the federal Million Solar Roofs Program, with a vision to have 20,000 solar systems in place on the Big Island by the year 2010. The types of solar systems include both water heating and photovoltaics. The solar water heating system portion of the vision is reflected in HELCO's Residential Water Heating DSM program and therefore is reflected in HELCO's IRP plan. The photovoltiac systems may involve a number of different types of applications such as remote homes, solar communities, remote water pumping and PV lighting, commercial building rooftop grid-connected systems and residential grid-connected systems. While HELCO envisions having a role in this new PV energy development activity, the precise nature of that role is presently undetermined. Other possible partners in the realization of this vision for the Big Island include the solar industry, government, educational institutions, and related professional groups like architects, realtors, and engineers. As the estimated PV installations in the federal Million Solar Roofs Program is a vision and is still in the conceptual stage, it was not possible to reflect it in HELCO's IRP plan.

b. Geothermal

Due to potential minimum load constraints and uncertainties in the forecasts, geothermal was allowed in candidate plans where sufficient margin was forecasted between the system minimum load and minimum baseload capability. Geothermal power is normally designed and operated as a baseload resource because it has a high capital cost but essentially no fuel costs. Minimum load conflicts could require future geothermal plants to be designed to be dispatchable and for cycling duty.

HELCO recognizes that, if successfully developed and operated, and if it can be integrated with existing resources on the system, geothermal can be a highly beneficial source of firm power. Geothermal does not consume fuel oil. Under normal operations, it releases relatively insignificant amounts of the criteria pollutants into the atmosphere as compared to fossil fired generation.[7] It would increase the ratio of energy from indigenous and renewable resources in support of the State of Hawaii energy objectives, and improve fuel diversity.

However, geothermal is only cost-effective if considering a long-term, 50-year study period horizon and if geothermal can be acquired at the low capital cost estimate of about $3,700 per kW. Realization of this installed cost would depend on the number of wells that would have to be drilled to find an adequate geothermal resource to provide 25 MW of firm power, and the cost to drill each well. Enhancing load following capability would probably require more wells at a greater capital cost.

Aside from this uncertainty in initial development cost, geothermal faces a number of uncertainties and risks throughout the period in which it is operational. Geothermal facilities are limited to certain areas of the Big Island where there is some risk of either lava flow or earthquake, which could cause long-term damage to the generation facility. Since HELCO would depend on geothermal to provide firm capacity to the system, additional geothermal on the system may require HELCO to increase its reserve margin requirement. There is also uncertainty in the long term reliability of geothermal.

There are also members of the Big Island community that are strongly opposed to geothermal development.

In consideration of these factors, geothermal was not included in the preferred IRP plan.

c. Biomass

HELCO recognizes that biomass resources have a number of environmental and societal benefits, including: promotion of fuel diversity with the use of banagrass as feedstock, increasing energy from indigenous and renewable resources, consistent with the State of Hawaii energy objectives, reducing total fuel oil consumption, and reducing PM and SOx emissions. While biomass has these favorable attributes, HELCO does not believe that it supports the IRP objective of meeting consumer energy needs in a "reliable manner at the lowest reasonable cost" for the following reasons:

- Biomass resources are still not cost-competitive when compared to conventional technologies, and would thus add a cost-premium to utility ratepayers if implemented.
- Biomass plants carry substantial risks. The dependability as well as the cost of the feedstock may be subject to much variability, as the result of inclement weather or crop damage due to pests, brush fire or disease.
- Opportunities already exist at former sugar plantations to grow and utilize a biomass feedstock. However, none of the former plantations are currently pursuing this, indicating that it may not be economically attractive to do so.
- According to the Electric Power Research Institute (EPRI), at this time there are no commercial biomass-to-electricity facilities utilizing a crop

[7] see Unit Information Form for 25 MW geothermal in Appendix G, "IRP-98 Supply-Side Resource Option Portfolio Development" (Black & Veatch)

grown solely for electricity generation in the United States.

- Biomass resources require significantly more land area than an equivalent sized oil-fired generating unit for cultivation of the banagrass crop.

Due to these factors, biomass was not included in the IRP preferred plan.

d. Pumped Storage Hydro

The Advisory Group suggested a plan that paired a 10 MW wind resource with pumped storage hydro (PSH) in 2009 after the addition of ST-7. The idea behind the concurrent installation of wind and PSH was that the negative effects on system frequency of wind fluctuations could be avoided by having wind energy directly provide pumping power for the PSH resource. However, the physical location of wind (Lalamilo) and PSH would not be able to accommodate such a configuration. There are also uncertainties as to whether or not the PSH resource can actually withstand the volatility in power input, as would be realized with wind.

Pumped storage can provide system benefits by pumping at, and thereby increasing, the system minimum load. This would serve to reduce the probability that the minimum baseload capability of the system would exceed the minimum load. Storage technologies such as PSH are designed to take advantage of the differential in system production costs between the peak and off-peak periods. The differential in on-peak and off-peak costs is not wide enough to make PSH cost effective at HELCO.

For IRP analysis purposes, PSH was given partial firm capacity due to its limited availability over a 24 hour period. Even with this assumption, PSH was not cost-effective. With these cost and operational considerations in mind, PSH was not selected as a resource in the preferred plan.

4. Distributed Generation

In the integration analysis, HELCO found that the installation of multiple 1 MW diesels in 2009 may be cost-competitive with large-scale generation resources over the 20-year planning period. Over the 50-year study period, however, the plan with multiple 1 MW diesels in 2009 had a higher estimated present value of revenue requirements than a comparable plan comprised of dual-train combined cycles. In the plan with 1 MW diesels, generation is added in small increments commensurate with the growth in system load, thus having the potential to defer large-scale generation additions. Distributed generation could also provide system cost savings if it is sited to defer the need for transmission or distribution lines. Operationally, the 1 MW diesels would provide quick-start capability to the system in times of system emergency.

The costs and benefits of distributed generation, however, are highly sensitive to the site and case under consideration. The IRP analysis has assumed planning level cost estimates, and the specific location of each 1 MW unit has not yet been identified. As a component of its Action Plan, HELCO will evaluate distributed generation in further detail on a site-specific basis. If siting and permitting issues can be resolved, the refined cost of distributed generation is determined to be less than or equal to the costs assumed in this IRP planning analysis, and if system benefits can be achieved, then HELCO will pursue installation of distributed resources.

ACTION PLANS

Demand-Side Action Plan

In order to implement the DSM Action Plan, a number of activities must continue to be accomplished.

- HELCO will continue to monitor the DSM programs for their effectiveness and will continue to identify methods by which the programs can be better targeted, implemented and administered.
- Programs will continue to be adjusted as the implementation process moves forward. The DSM plans must be flexible and allowed to change over the IRP cycle as experience with the DSM programs is developed.
- The pilot Residential Direct-Install Effort (referred to as the Residential Retrofit Program in the 1996 and 1997 M&E Reports and A&S Reports) will make free energy efficiency measures available to qualified customers. HELCO is working with community organizations, government and the company's credit division to identify participating customers for this pilot effort.
- Budget flexibility shall continue to be required as some programs will exceed their goals and others will fall short due to customer interest and market conditions.
- Baseline data collection efforts shall be implemented to strengthen the basis for DSM planning in the next IRP cycle.

The implementation steps now under way that will continue include:

1. Ongoing Staffing, Training, and Program Procedures
2. Ongoing Measurement and Evaluation Activities
3. Preparation of Annual Reports - The Annual Program Modification and Evaluation Report and the Annual Program Accomplishments and Surcharge Report are intended to be filed in the Fall and Spring of each year, respectively
4. Preparing for the next IRP Plan.

In order to mitigate risks associated with the DSM programs, HELCO has undertaken, and will continue to undertake, the following efforts:

- *Baseline Data Collection* - to 1) prepare information for the next IRP cycle, 2) support program planning as information becomes available, and 3) support market assessment and demand forecasting efforts.
- *Measurement and Evaluation* - to not only measure the impacts of the programs, but also to diagnose what aspects of the programs are working well and which parts can be improved.
- *Work with Vendors and Contractors* - to be able to monitor problems that can occur and identify actions HELCO can take to assure performance from the trade allies.
- *Research and Development* - to initiate, where appropriate, pilot programs or exploratory research to determine the viability of DSM options and identify appropriate design options for Hawaii.
- *Annual Program Plans* - to continue to update program plans on an annual basis, incorporating modifications in order to best acquire the DSM resource based on lessons learned from program implementation.

Supply-Side Action Plan

The major elements of the IRP-98 supply-side action plan, which include activities between 1999 and 2003, are:

- Permitting and preliminary engineering activities for Keahole ST-7
- Continue efforts to acquire a new West Hawaii site to support the 2009 addition of the first phase simple cycle combustion turbine of a dual train combined cycle
- Conduct site-specific studies to validate the generic data used in the IRP-98

analysis for distributed generation resources

- Continue to pursue installation of a wind farm and/or photovoltaic facility. In the event that current negotiations with renewable energy developers for a wind farm and photovoltaic facility do not result in a power purchase agreement, HELCO will consider the purchase of a wind project and/or a photovoltaic project from other renewable energy developers and manufacturers through the following options:
  a. Renewable Resource Request for Proposal (RFP) — HELCO will develop a Renewable RFP to invite renewable developer(s) to submit a proposal to provide energy to the HELCO system in return for payments at or below HELCO's avoided energy cost;
  b. Green Pricing Expansion — HELCO will expand and extend the current Green Pricing program filed with the PUC to include a wind and/or photovoltaic projects. HELCO customers will be given the choice to pay a premium for these renewable resources; or
  c. Utility Installation — HELCO will consider installing a wind and/or a photovoltaic project as part of its utility-owned electrical generating system.
- Continue other renewable energy activities, including:
  - continue commitment to assist in renewable energy development as presented in PUC Renewable Energy Resource Investigation, Docket No. 94-0226.
  - increase commitment to educate customers on renewable energy technologies
  - continue to evaluate and assess renewable energy resources and technologies
  - continue to examine and, if prudent, develop renewable energy technologies through small-scale demonstration and pilot projects, or expand existing demonstration or pilot projects in situations where knowledge can be gained through hands-on experience.

1. INTRODUCTION

1.1 BACKGROUND

By Decision and Order No. 11523, filed March 12, 1992, in Docket No. 6617, the Hawaii Public Utilities Commission (Commission) established a framework for integrated resource planning (IRP Framework) by the electric and gas utility companies, and ordered them to develop an Integrated Resource Plan (IRP) in accordance with the IRP Framework. The IRP Framework was subsequently revised by Decision and Order No. 11630, dated May 22, 1992, in Docket No. 6617. A copy of the IRP Framework is provided in Appendix A.

On October 15, 1993, Hawaii Electric Light Company, Inc. (HELCO) filed its initial IRP. By letter dated March 28, 1994, HELCO notified the Commission of its intent to assess the impact of its new March 1994 sales and peak forecast. The primary purpose of this assessment was to reschedule the timing of the planned supply-side additions and to validate the continued cost-effectiveness of the previously proposed DSM programs. Hence, on June 6, 1994, HELCO filed an IRP Plan Reassessment.

On May 29, 1996, the Commission issued Decision and Order No. 14708 in Docket No. 7259 stating that HELCO's proposed IRP and action plans complied with the IRP Framework and were approved, subject to the conditions within the Decision and Order. Section VII.A of the Decision and Order established July 1, 1997, as the date by which HELCO must conduct a major review of its IRP.

By letter dated July 5, 1996, HELCO requested Commission approval of an extension of the submission date of HELCO's revised IRP from July 1, 1997, to September 1, 1998. By Order No. 14866, dated August 8, 1996, the Commission approved HELCO's request to extend the submission date.

On September 26, 1997, the Commission issued Order No. 15977, opening Docket No. 97-0349. Among other things, this docket directed HELCO to submit a revised IRP for Commission review and approval no later than September 1, 1998.

1.2 PREVIOUS INTEGRATED RESOURCE PLAN

1.2.1 Original IRP-93 (October 1993)

On October 15, 1993, HELCO filed its initial integrated resource plan. This plan consisted of both demand-side and supply-side resources and was developed using a March 1993 forecast of long-term sales and peak loads. The demand-side resources consisted of demand-side programs intended to increase the efficiency of customers' use of electricity. The supply-side resources included resources that would produce additional amounts of power and energy to meet the forecasted increase in demand. Figure 1-1 illustrates HELCO's original IRP plan filed on October 15, 1993.

1.2.2 Modified IRP-93 (June 1994 Reassessment)

On June 6, 1994, HELCO filed an IRP Plan Reassessment. The primary purpose of this reassessment was to incorporate HELCO's most recent sales and peak forecast, the March 1994 Forecast, and to reschedule the timing of the planned supply-side additions. The reassessment also modified HELCO's October 1993 DSM Action Plan by re-bundling the DSM technology options into four DSM programs (three commercial and industrial market programs and one residential market program). Figure 1-2 illustrates the modified HELCO IRP plan.

Figure 1-1. Original HELCO IRP-93

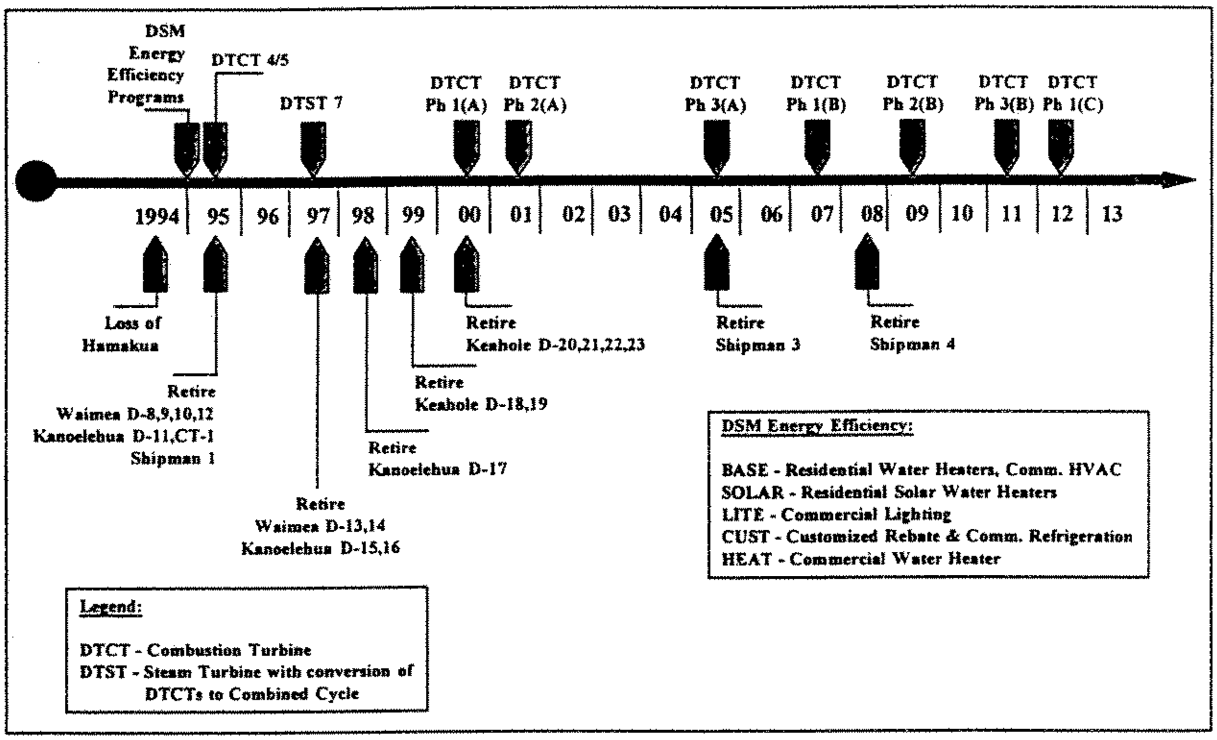
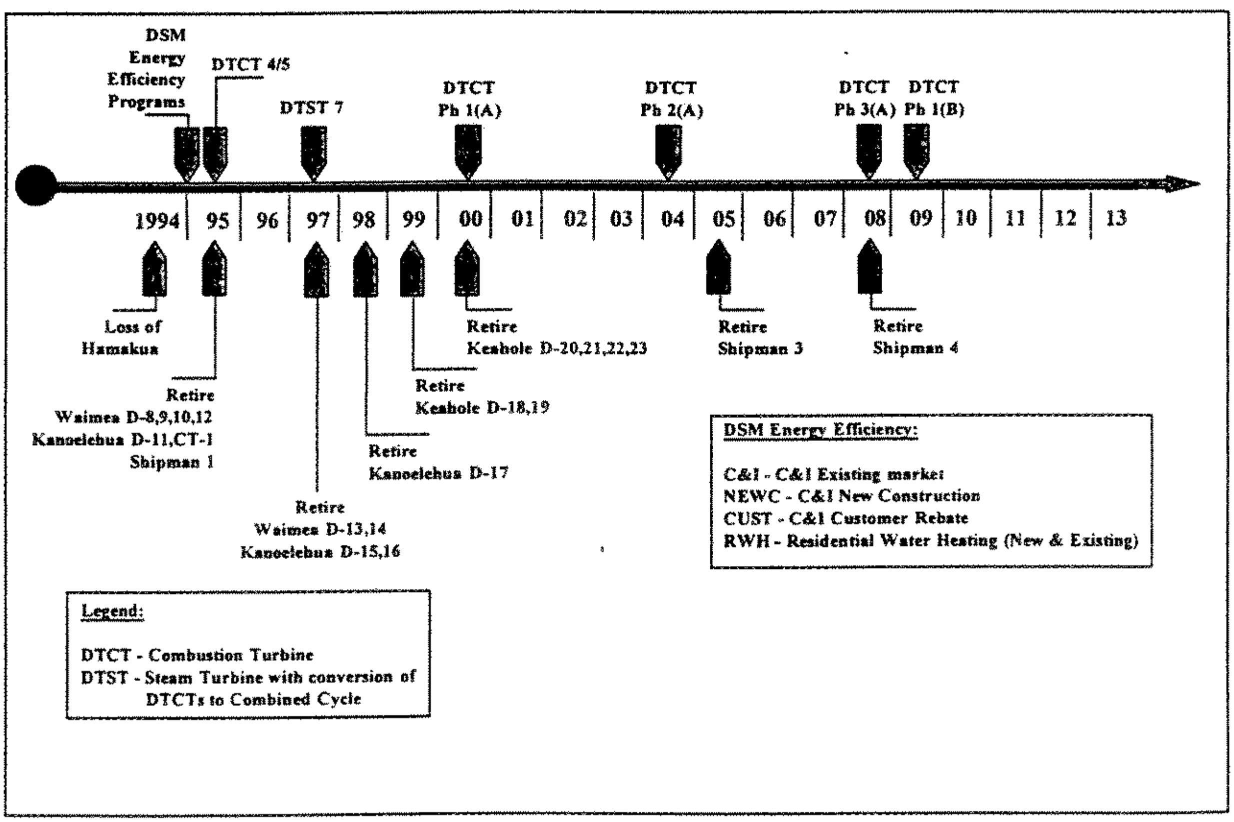


Figure 1-2. Modified IRP-93 (June '94 Reassessment)



The results of the June 1994 reassessment confirmed the continued need for the Keahole Combined Cycle project (DTCT 4/5, DTST 7) despite the slightly lower March 1994 short-term forecast (by 1996, the March 1994 Forecast was about 2 MW lower than previously forecasted). Other unit in-service dates, however, were revised to meet the decreased long-term load growth, and approximately 65 MW of supply-side capacity additions were deferred beyond the 20-year planning period. A comparison of the original IRP and the IRP reassessment is shown in Table 1-1.

Table 1-1. HELCO's IRP Plan Comparison

Original IRP (October 1993)					IRP Reassessment (June 1994)				
Year	Frcst Peak	DSM Peak	System Capability	Resource Description	Year	Frcst Peak	DSM Peak	System Capability	Resource Description
1994	165	164	198	Loss of Hamakua (1)	1994	161	161	198	Loss of Hamakua (1)
1995	171	170	218	CT-4 (2)	1995	168	166	218	CT-4 (2)
			238	CT-5 (3)				238	CT-5 (3)
			235	Retire Waimea D-8, 9, 10				235	Retire Waimea D-8, 9, 10
			233	Retire Kanoelehua D-11				233	Retire Kanoelehua D-11
			230	Retire Shipman 1				230	Retire Shipman 1
			221	Retire Kanoelehua CT-1				221	Retire Kanoelehua CT-1
			218	Retire Waimea D-12				218	Retire Waimea D-12
1996	177	174	218		1996	175	172	218	
1997	184	179	236	ST-7 (CT-4 & CT-5 to DTCC #1)	1997	179	174	236	ST-7 (CT-4 & CT-5 to DTCC #1)
			225	Retire Waimea D-13 & 14				225	Retire Waimea D-13 & 14
				Retire Kanoelehua D-15 & 16					Retire Kanoelehua D-15 & 16
1998	191	183	222	Retire Kanoelehua D-17	1998	184	177	222	Retire Kanoelehua D-17
Long-Term Resource Plan									
1999	199	189	222		1999	190	181	222	
			217	Retire Keahole D-18, 19				217	Retire Keahole D-18, 19
2000	207	194	239	DTCT-PH1 (A)	2000	196	185	239	DTCT-PH1 (A)
			228	Retire Keahole D-20,21,22,23				228	Retire Keahole D-20,21,22,23
2001	215	200	251	DTCT-PH2 (A)	2001	202	189	228	
2002	224	207	251		2002	207	192	228	
2003	233	213	251		2003	212	194	228	
2004	242	219	251		2004	217	197	251	DTCT-PH2 (A)
2005	251	225	270	DTST-PH3 (A) (DTCT-PH1 (A) & DTCT-PH2 (A) to DTCC #2)	2005	223	202	243	Retire Shipman 3
			262	Retire Shipman 3					
2006	261	233	262		2006	229	206	243	
2007	271	242	285	DTCT-PH1 (B)	2007	235	210	243	
2008	283	252	277	Retire Shipman 4	2008	241	215	262	DTST-PH3 (A) (DTCT-PH1 (A) & DTCT-PH2 (A) to DTCC #2)
								255	Retire Shipman 4
2009	295	263	300	DTCT-PH2 (B)	2009	247	220	277	DTCT-PH1 (B)
2010	306	273	300		2010	253	225	277	
2011	321	285	319	DTST-PH3 (B) (DTCT-PH1 (B) & DTCT-PH2 (B) to DTCC #3)	2011	259	230	277	
2012	334	296	342	DTCT-PH1 (C)	2012	266	236	277	
2013	348	309	342		2013	273	242	277	
			342	TOTAL SYSTEM CAPABILITY (MW)				277	

Notes:

(1) Hamakua contract revised from 10 to 8 MW for final Harvest.

(2) Scheduled install date. (3) Scheduled install date. Required date 4/1/96.

CT=combustion turbine; DTCT-PH# = dual-train combustion turbine, phase #

DTST-PH# = dual-train steam turbine, phase #, DTCC=dual-train combined cycle

Peaks per FPC 3/01/93

Peaks per FPC 3/01/94

Resource plan based on GEPPS run

HL0008 / HU0008 / HY0008

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1.2.3 Commission's Findings

On May 29, 1996, the Commission issued Decision and Order No. 14708 in Docket No. 7259 stating that HELCO's proposed IRP and action plans, as submitted in the original filing and subsequently modified in the June 1994 Reassessment, were approved. This approved plan is hereon referred to as IRP-93.

In this major review of its IRP, HELCO has produced a revised IRP, hereon referred to as IRP-98. In its development, HELCO drew upon much of the work done in IRP-93 in order to contain costs while still maintaining the integrity of the process and work products. Examples of this are in the areas of the demand-side resource assessment, where the current effort drew from the IRP-93 effort (See Section 6) and the State of Hawaii Department of Business, Economic Development, and Tourism's Hawaii Demand-Side Management Opportunity Report; and the supply-side resource assessment, where results of the previous supply-side resource identification and evaluation effort was used as a starting point for IRP-98 (see Section 7). Furthermore, in order to make this a quality and meaningful effort, HELCO continued with those processes which the Commission found to be satisfactory in IRP-93 and improved upon those areas which the Commission found needing some development. Following is a summary of the areas which the Commission found to be satisfactory and those areas where improvement was expected.

- <u>IRP Framework</u> - The Commission noted in its D&O that "HELCO made a good faith effort to comply with each requirement set forth in the framework for its initial IRP."[8] The Commission also stated that "HELCO's IRP is in the public interest, is consistent with the goals and objectives of integrated resource planning, and represents a reasonable course for meeting the energy needs of its customers."[9] In this major review of its IRP, HELCO again made every effort to comply with all of the Framework requirements.
- <u>Public participation</u> - The Commission noted that they were "generally satisfied with HELCO's efforts to involve the public in its planning process, ... [and that] all in all, HELCO provided sufficient opportunity for the Advisory Group to participate in and contribute to the development of its IRP."[10] HELCO continued to work with its Advisory Group in a similar manner in developing IRP-98. Details are given in Section 3.3, Public Participation.
- <u>Supply-side resource options</u> - The Commission noted that "HELCO's selection of supply-side resource options is reasonable, [and] that HELCO's initial IRP, as modified, considered and analyzed the cost-effectiveness and benefits of all appropriate, available, and feasible supply-side options."[11] In this major review of its IRP, HELCO built upon the supply-side resource assessment work of IRP-93 and applied a similar screening and evaluation process.
- <u>Demand-side management (DSM) resource options</u> - While the Commission concluded that "HELCO considered and analyzed the cost-effectiveness and benefits of all appropriate, available, and feasible DSM options,"[12] it also directed HELCO to "include a methodical determination of the achievable DSM potential for its service territory in its program implementation schedule for the next integrated resource planning

[8] Docket No. 7259, D&O No. 14708, filed May 29, 1996, page 7.

[9] Ibid., page 45.

[10] Ibid., page 6.

[11] Ibid., page 16.

[12] Ibid., page 22.

cycle."[13] HELCO has addressed this using the DBEDT assessment of DSM potential in lieu of duplicating the study. (See Sections 6.1 and 6.4).

- Externalities - While the Commission found HELCO's qualitative approach to consider externalities reasonable in its initial integrated resource planning cycle, the Commission noted, "We expect HELCO to quantify externalities in subsequent integrated resource planning cycles."[14] To the extent feasible, HELCO did quantify externalities through its participation in a separate Externalities Project that was led by HECO. The details and results of that project are documented in the *Hawaii Externalities Workbook*, which was submitted to the Commission on July 22, 1997. The Executive Summary of the *Hawaii Externalities Workbook* is included as Appendix I, and the entire report can be reviewed at the HELCO Customer Service office. The Commission also stated that "No values derived for externalities shall be used without prior Commission approval."[15] However, by Order No. 14862, filed August 8, 1996, of Docket No. 95-0347, the Commission approved the Companies' request to use the externality values in sensitivity analyses in the second cycle of its integrated planning process prior to receiving Commission approval of the externalities study. The externality values were used to evaluate possible, relative impacts on a societal level. This was done to comply with Section II.B.4 of the IRP Framework, which requires HELCO to give consideration to the plans' impacts upon the utility's consumers, the environment, culture, community lifestyles, the State's economy, and society.
- Supply-side action plan - While the Commission found HELCO's supply-side action plan to be consistent with section III.D.2.a of the Framework, the Commission also directed HELCO to "conduct an updated study to determine the cost-effectiveness of establishing spinning reserve criteria."[16] The Commission requested that HELCO's analysis include a determination of whether the tangible and intangible costs of establishing spinning reserve criteria would exceed the benefits and that this study be submitted to the Commission with HELCO's next IRP or with its next application to commit generation capacity funds. A spinning reserve assessment is included as Section 5.3 of this report.
- Multi-attribute analysis (MAA) - The Commission noted that "Although the MAA is not perfect, we find that the MAA is an acceptable method to review the competing objectives. We expect that HELCO will review the MAA process and refine the system in future integrated resource planning cycles." In IRP-98, HELCO did review the MAA process used in IRP-93 but found that the process could not be refined to avoid the criticisms received during the IRP-93 hearings. HELCO, therefore, has chosen to evaluate the various attributes using a direct-comparison approach. This method is similar to that which was used in HECO's IRP-97. HELCO explained the direct-comparison analysis to the Advisory Group, including reasons for using this method. The Advisory Group, however, requested the use of a rank-and-weight tool, similar to that used in IRP-93, to assist in their understanding of the attribute trade-offs. HELCO informed the Advisory Group that it would not endorse the rank-and-weight exercise as the preferred multi-attribute analysis

[13] Ibid., page 21.
[14] Ibid., page 24.
[15] Ibid., page 49.
[16] Ibid., page 33.

method, and would continue with its plans to use the direct-comparison approach. Nevertheless, HELCO recognized the desire of the Advisory Group and agreed to facilitate the development and application of an Advisory Group rank-and-weight tool at scheduled meetings. Details are given in Section 3.4.2, Attribute Analysis Methods.

1.3 MAJOR CHANGES SINCE IRP-1

1.3.1 Contingency Plans

As shown in Section 1.2.2, HELCO's IRP-93 Preferred Plan included the installation of Keahole CT-4 and CT-5 in 1995 and the conversion of those units to a dual-train combined cycle unit in 1997. The planned in-service dates were based on an accelerated schedule for CT-4 and the receipt of necessary approvals for the Keahole site by December 1994. Due to delays and significant uncertainty in adding a large increment of firm capacity (whether at Keahole, at Kawaihae, at Hamakua or by other developers), HELCO developed a contingency plan and continues to re-evaluate, re-assess and update the plan to reflect changes in circumstances.

On June 9, 1995, HELCO filed its first Generation Resource Contingency Plan with the Commission. The purpose of this contingency plan was to address the possibility of delays at Keahole or the possibility that the Conservation District Use Permit (CDUP) or the covered source air permit would be denied. The contingency plan focused on the following areas: 1) maximizing available generation; 2) accelerating the installation of additional generation; 3) minimizing load demand through DSM; and 4) evaluating other mitigation measures.

Delays in permitting of the Keahole project occurred, and HELCO filed subsequent Contingency Plan Updates in March and October 1996, April 1997, and June 1998. As a result of its contingency planning efforts, HELCO was able to reach an agreement with HCPC for the continued operation of the facility through 1999, and to increase the capacity provided from 18 to 22 MW. HELCO began receiving 22 MW from HCPC on June 1, 1995. In December 1994, PGV began providing 3 to 3.5 MW above the 25 MW of the firm power contract amount, which later was increased to 3 to 5 MW. On February 12, 1996, HELCO and PGV executed an amendment to the PGV PPA increasing the capacity provided from 25 to 30 MW and on September 23, 1996 PGV began supplying HELCO with 30 MW of firm capacity.

In its most recent Contingency Plan Update (June 1998), HELCO reported substantial progress with respect to its contingency plan efforts. For instance, a significant milestone had been reached in negotiating a power purchase agreement (PPA) with Encogen, a Non-Utility Generator (NUG) affiliated with Enserch Development Corporation (EDC). The June 1998 Update reported that on January 16, 1998, HELCO filed an application requesting Commission approval of a PPA and an Interconnection Agreement with Encogen dated October 22, 1997. The June 1998 Update also addressed uncertainties associated with the next increment of generation additions. With regard to HELCO's Keahole project, the update reported that much of the uncertainty regarding the permitting for HELCO's Keahole dual-train combined cycle unit has been resolved and that HELCO expects to be able to install both CT-4 and CT-5 in the December 1998 timeframe. On the other hand, the Encogen project has not yet received its final air permit nor a "non-appealable" PUC order approving the PPA. As such, the Encogen project could be installed as early as 1999, but could also be delayed pending resolution of any appeal of a PUC decision or appeal to the Environmental Appeals Board (EAB) of the air permit. More details about the Encogen project are given in Section 1.3.3.

The June 1998 Contingency Plan Update concluded that in order to address delays in and uncertainties associated with the addition of needed generation, HELCO would maximize its generation options by proceeding with Keahole CT-4 and CT-5 in parallel with Encogen. This strategy increases the likelihood of providing reliable power to HELCO's customers. See Appendix P for the Executive Summary of the June 1998 Contingency Plan Update.

1.3.2 Annual Evaluation Report

On June 30, 1997, in Docket No. 7259, HELCO filed its Annual Evaluation Report with the Commission. The primary purpose of this report was to assess the continuing validity of the forecasts and assumptions upon which the approved IRP Plan and Action Plans were based and to assess the impact of changes in forecasts, assumptions, and conditions on these plans. Some of the key findings and conclusions of the evaluation were as follows:

- Uncertainty of the timing and regulatory approvals remained an issue for both the Keahole and Encogen projects.
- Unit retirements scheduled in 1995 and 1997 in HELCO's approved IRP Plan would be deferred until a large new increment of capacity is added to the system.
- Encogen's proposed 60 MW (net) dual train combined cycle at Hamakua was added to HELCO's updated plan.
- Lower diesel fuel prices in the May 1995 fuel forecast as compared to the August 1992 fuel forecast used in IRP-93 made the dual-train combined cycle resource more cost effective.
- HELCO's planned addition of a 58 MW phased combined cycle unit at its Keahole power plant site in West Hawaii continued to be a necessary and cost-effective component of its plan to meet both near-term and long-term customer needs.

1.3.3 Encogen Power Purchase Agreement (PPA)

HELCO negotiated a finalized PPA with Encogen, and on June 2, 1997, in Docket No. 94-0079, filed with the Commission a Motion for Approval of Settlement Agreement. On August 7, 1997, the Commission issued Order No. 15745, in which it 1) approved the Settlement Agreement, insofar as it settled the issues concerning the terms and conditions of a PPA and interconnection agreement between HELCO and Encogen; and 2) ordered HELCO and Encogen to submit to the Commission for review and approval executed copies of the PPA and interconnection agreement. On January 16, 1998, HELCO filed an application for approval of a PPA and an Interconnection Agreement dated October 22, 1997.

Encogen's proposal consists of a 60 MW (net) oil-fired combined cycle Qualifying Facility ("QF") at Hamakua. The project is to be installed in two phases. The Phase 1 and Phase 2 in-service dates are generally tied to the Commission approval date ("PUC Approval Date") for the PPA. If the Commission order approving the PPA is appealed, the PUC Approval Date will be the earlier of the date upon which it becomes non-appealable (i.e., after successful resolution of an appeal) or two years after January 16, 1998 (with Encogen having the right to terminate the agreement if the appeal is not resolved within two years). The Encogen in-service dates for Phase 1 and 2 generally are set at 8 months and 12 months, respectively, after the PUC Approval Date, subject to extension for force majeure (such as further delays in the issuance of Encogen's air permit). As a result, Encogen Phases 1 and 2 could be installed as early as April and August of 1999, but could also be delayed to 2001 or 2002. For example, an appeal of a PUC decision could go to the Hawaii Supreme Court. Two previous electric utility cases at the Hawaii Supreme Court took 25 months and 40 months to resolve.[17]

1.3.4 Change in the Planning Context

One significant difference in the planning context between IRP-93 and IRP-98 is a clear change toward increased competition in the electric utility industry. New federal rules have opened wholesale power markets to competition on the mainland.[18] The new federal rules are aimed at encouraging economic efficiency and lower electricity prices in wholesale power markets. Among other things, the rules will facilitate the development of competitive generation markets and consumer-oriented energy services.[19] Competition has also moved to the retail level in a number of states through retail wheeling pilot programs and increased legislative, regulatory or utility support of retail competition initiatives.

In Hawaii, which is among the remaining states which have legislative, regulatory or end-use activity in progress, the PUC opened Docket No. 96-0493, Electricity Infrastructure Investigation, Order No. 15285, filed December 30, 1996, to "examine the issues related to the introduction of competition in the electric utility industry and to identify the infrastructure necessary to support the transition to a competitive electric industry marketplace in Hawaii."[20] A complete copy of the Order is included as Appendix B.

[17] See June 1998 HELCO Generation Resource Contingency Plan Update #4, Section 6.3

[18] The Federal Energy Regulatory Commission (FERC) issued the final rules in FERC Order No. 888, Promoting Wholesale Competition Through Nondiscriminatory Transmission Services by Public Utilities; Recovery of Stranded Costs by Public Utilities and Transmitting Utilities. See 18 C.F.R. Parts 35 and 385 (1996).

[19] PUC Order No. 15285, Docket No. 96-0493, filed December 30, 1996, page 2.

[20] Section III.B, page 6, of Order No. 15285, Docket No. 96-0493.

2. IRP OBJECTIVES

2.1 IRP OBJECTIVES

As stated in the IRP Framework, the goal of integrated resource planning is "the identification of the resources or mix of resources for meeting near and long term consumer energy needs in an efficient and reliable manner at the lowest reasonable cost."[21] With input from its IRP Advisory Group, HELCO prepared a list of objectives and plan attributes to assist in evaluating plans supportive of the IRP goals.

This section provides an explanation of the nine IRP objectives used to evaluate plans from various perspectives. The objectives encompass a wide range of considerations, such as uncertainties, risk, and other issues that are technical, social, and economic in nature.

Objective 1: Meet Customer Electrical Needs at the Lowest Reasonable Cost

One of the goals of integrated resource planning is to meet near and long term energy needs at the lowest reasonable cost.

Objective 2: Improve the Quality of Electrical Products and Services

The primary measure of the quality of electric utility service from the customer perspective is the level of service reliability. Although improvements in reliability often mean increases in costs, HELCO finds it necessary to maintain reasonable levels of reliability for the safety and satisfaction of its customers.

Objective 3: Maintain Corporate Financial Integrity

Section II.B.5 of the IRP Framework states that the IRP shall take into account the utility's financial integrity. As an investor-owned utility, a financially stable standing is critical to the company's ability to acquire relatively low-cost capital from investors and financial institutions. This, in turn, determines the utility's ability to make capital additions and improvements that are necessary to provide reliable energy services at the lowest reasonable cost. Lower financing costs for the Company result in lower rates for its customers.

Objective 4: Maintain Corporate Competitiveness

The electric utility industry has been going through many changes recently that stress the importance of a good competitive position. This objective seeks to minimize investment risks and allow the Company to provide energy services at a competitive cost.

Objective 5: Increase Fuel Diversity for the Electrical System

Fuel prices are subject to worldwide influences and are sometimes volatile. Therefore, it is important to reduce the risks of both large fuel price increases and potential limitations in the availability of certain fuel types. Risk reduction can be achieved by selecting resources that add fuel flexibility and diversity.

Objective 6: Support the State of Hawaii Energy Objectives

The State of Hawaii's statutory energy objectives given in Section 226-18(a) of the Hawaii Revised Statutes, as amended by Act 96, Session Laws of Hawaii, 1994 are to achieve:

1. dependable, efficient, and economical state-wide energy systems capable of supporting the needs of the people;
2. increased energy self-sufficiency where the ratio of indigenous to imported energy use is increased; and
3. greater energy security in the face of threats to Hawaii's energy supplies and systems.

[21] IRP Framework, Section II.A.

The plans seek to achieve these statutory objectives along with consideration of all other planning objectives.

Objective 7: Protect the Environment
All plans must be in compliance with all environmental regulations with respect to air quality, water quality, and land use. In terms of air emissions, all plans must fall within the maximum allowable levels set by state and federal standards.

Objective 8: Mitigate Potential Negative Societal and Cultural Impacts of the IRP Plan
Depending on the nature of the plan or the location of the resources in the plan, there may be negative societal or cultural impacts, such as increased development where none is desired by the local community. An important consideration in the development of the plan is mitigating any negative impacts on the local culture or society.

Objective 9: Increase Plan Flexibility
Deviations from forecasted fuel prices or the peak demand for electricity, the ability to achieve estimated DSM penetration, changes in regulation, and other unforeseeable and uncontrollable circumstances pose investment risks to the utility and its customers. For this reason, flexibility of a resource plan is very important.

2.2 IRP PLAN ATTRIBUTES

For each of the nine objectives above, attributes were selected that could be used to measure the level of attainment of each objective. Attributes were quantitatively measured where possible, and otherwise qualitatively evaluated. Certain attributes were assumed equal among plans, but were stated because of their importance. The list of attributes, including unit of measure and the formula used to calculate the attribute, is provided in Table 2-1 at the end of this section.

Objective 1: Meet Customer Electrical Needs at the Lowest Reasonable Cost

Attributes for Objective 1:

a) *Reduce the accumulated present worth of revenue requirements (APWRR) of the plan over the 20-year planning period* - Total revenue requirements for generation include capital, fuel, operation and maintenance, and DSM program costs.
b) *Reduce the average "rate" impact over the 20-year planning period* - Rate increases affect customers' ability to pay for necessary electric energy services. Rate increases not only affect residential customers, but may adversely impact the business sector as well. Avoidance of non-cost effective and/or capital intensive resources will mitigate the need for rate increases. This attribute was measured by comparing average annual "rates" over the 20-year planning horizon.
The annual "rate" for each plan was calculated by dividing annual revenue requirements by annual system kWh sales. It should be noted that the annual "rate" is a simplified projection of future rates. For example, these "rates" do not consider allocation of costs by class of service and timing of actual rate cases. The attribute also assumes that the decrease in revenue requirements due to the depreciation of existing assets is offset by the escalation in non-generation O&M costs, non-generation capital additions, and capital improvements. For IRP purposes, the differential between calculated "rates" for each plan served as an indicator of the rate impact plans would have relative to each other.
c) *Reduce "Rate Shock"* - Large step increases in revenue requirements result in relatively substantial rate increases,

here referred to as "rate shock". "Rate shock" can be reduced by evaluating supply-side resources not only by total life-cycle costs, but on an annual revenue requirements basis. Matching the size of capacity additions closer to the rate of load growth can also aid in the reduction of "rate shock".

"Rate shock" was measured by determining the annual percentage change in "rates" for all finalist plans. The annual percentage change is the difference in "rates" between the previous year and the current year divided by the "rate" for the previous year.

d) *Reduce total customer cost over 20-years* - Total customer energy costs should be considered when evaluating resources from the customer perspective. In the integration process, use of the total resource cost (TRC) objective function minimizes the sum of customer bills plus DSM participant out-of-pocket expenses.

Objective 2: Improve the Quality of Electrical Products and Services

Attributes for Objective 2:

a) *Maintain generating system reliability* - As an isolated island utility, HELCO does not have interties to alternative generation resources to draw from in times of system emergency. HELCO's capacity planning criteria takes this unique situation into account by ensuring that an adequate level of reserve margin is maintained to reduce the likelihood and duration of customer outages. All resource plans were required to satisfy the HELCO capacity planning criteria, which addresses this minimum level of reliability.

In addition to reserve margin, fuel security also relates to system reliability. HELCO does not have interties to alternative generation resources if the fuel for a resource is not available.

b) *Maintain an appropriate mix of baseload, cycling, and peaking generating capacity based on system needs* - As a general guideline, HELCO seeks to keep a mix of 65% baseload capacity, 25% cycling capacity, and 10% peaking capacity. These tend to be the optimal points for cost-effectiveness and operational efficiency.

Problems may arise if the sum of the minimum capacity of baseload units exceeds the system minimum load. Baseload units, which are designed to operate continuously, may be forced to cycle off and on in such a situation. Stresses induced by repeated thermal cycles can cause critical metal parts of these baseload units to develop cracks, thus jeopardizing the reliability of the unit or units.

This minimum load constraint was measured by "dumped energy" in MWh. "Dumped energy" is a measure of the amount of generation in excess of the system minimum load, if baseload units are operating at their minimum capacities.

c) *Generation resources support transmission efficiency* - Due to the size of HELCO's service territory, it is important that the selection of generation resources supports the efficiency of the transmission system. Transmission capital costs and losses should not outweigh the benefit of the resource selection.

d) *Generation resources support transmission reliability* - In addition to supporting transmission efficiency, it is important that the selection of generation resources supports the reliability of the transmission system.

Objective 3: Maintain Corporate Financial Integrity

Attributes for Objective 3:

a) *Maintain allowed rate of return* - For planning purposes, a 12% allowed rate of return on equity was used to represent a long-term outlook. The rate was kept constant throughout the 20-year planning horizon for all plans and for all planning perspectives. Although this factor was not a differentiating characteristic between plans, it is a vital consideration in determining financial viability and was included in the list of attributes to highlight its importance.

b) *Maintain prudent capitalization ratios* - For all plans for all planning perspectives, the target capitalization ratios were based on the Company's current long-term cost of capital forecast. Although not necessarily a differentiating characteristic between plans, it is another vital consideration in determining financial viability and was also included in the list of attributes to highlight its importance.

c) *Reduce capital expenditures* - Reducing capital expenditures would mitigate the need to incur additional debt and fixed obligations, which could lower financial integrity. Reducing capital expenditures would also minimize exposure to stranded investment and would contain the need for increases in rates.

d) *Maintain low technological and financial risk* - Maintaining low risk - both technological and financial - is conducive to maintaining financial integrity without jeopardizing system reliability.

Objective 4: Maintain Corporate Competitiveness

Attibutes for Objective 4:

a) *Increase deferral of capital expenditures* - Pending changes in utility regulation and the increasing uncertainty as to the recovery of the cost of major investments make it prudent for HELCO to defer major generating unit additions until the future utility environment is more certain. The deferral of capital expenditures should not jeopardize system reliability.

b) *Reduce annual revenue requirements in the first 12 years of the plan* - Total revenue requirements for generation include capital, fuel, operation and maintenance and DSM program costs. Although this IRP considers a planning period of 20 years, a 12-year timeframe was used here to highlight the utility's focus on the impact to annual revenue requirements of near- term unit additions. Reducing annual revenue requirements is important because it will contain the need to increase rates.

c) *Reduce rate impact over the first 12 years of the plan* - The Company's focus is on the rate impact to customers as a result of unit additions early in the plan and/or due to the cost of DSM programs. In a competitive environment, the magnitude of rate increases will weigh heavily on the Company's ability to retain customers and sales.

Objective 5: Increase Fuel Diversity for the Electrical System

Attributes for Objective 5:

a) *Increase ability to utilize different types of fuel* - Fuel costs account for roughly 40 percent of total generation costs; therefore, the long-term fuel price forecast has a significant influence on the selection of the least cost resource plan at any given point in time. Fuel price forecasts are developed using the best available data and established methodologies; however, it is reasonable that fuel prices and availability during the 20-year IRP planning horizon will vary from the current forecast. Therefore, it is advantageous to revisit the selection of fuel type when firm commitments for purchase of the unit must be made. Selection of certain combustion turbines and combined cycles brings fuel flexibility to the plan through their ability to utilize different fuels - from light to heavy liquid petroleum products to gasified products from solid, liquid, or emulsified fossil-fuel products. Selection of these types of units also gives HELCO the flexibility to modify the unit during its 30-year service life if burning another fuel type should become more economical. A small variation in a fuel characteristic could result in the fuel being classified as a different type, resulting in the potential for a very large number of fuel types to be considered. As a result, this attribute was evaluated qualitatively. Renewable resources also contribute to increasing the fuel diversity of the electrical system.

Objective 6: Support the State of Hawaii Energy Objectives

Attributes for Objective 6:

a) *Increase system fuel heat rate efficiency* - It is desirable to decrease overall fuel consumption through the addition of supply resources that consume less fuel per kWh generated (have a low heat rate) relative to other units.
b) *Increase system fuel cost efficiency* - Heat rate efficiencies in Btu/kWh can sometimes be deceiving since certain supply-side units may utilize expensive fuels. Therefore, the system fuel cost efficiency in dollars/kWh was also examined.
c) *Increase DSM penetration* - Increased DSM penetration would have the beneficial effect of reducing fuel consumption, reducing overall emissions and deferring the need for additional generating capacity.
d) *Increase the ratio of energy produced by commercially viable indigenous and renewable resources as a proportion of total energy produced* - This would reduce the dependence on oil and reduce cashflow out of the state.
e) *Reduce use of fuel oil as an energy resource* - This would mitigate exposure to potential disruptions in oil supplies. The selection of coal or renewable supply-side resources and an increased amount of DSM would help to achieve this objective.

Objective 7: Protect the Environment

While all plans must meet State and Federal environmental regulations, certain plans may have lower total emissions than others. The following attributes were used to assess the potential air quality impacts of the various resource plans.

a) *Total VOC (volatile organic compounds) emissions of the plan*
b) *Total CO (carbon monoxide) emissions of the plan*
c) *Total PM emissions of the plan* - Includes PM_{10} which is particulate matter 10 microns or less in diameter.
d) *Total NO_X (oxides of nitrogen) emissions of the plan*
e) *Total SO_X (oxides of sulfur) emissions of the plan*
f) *Total CO_2 (carbon dioxide) emissions of the plan* - This parameter was selected because of concerns over the potential gradual rise in the atmospheric concentration of CO_2 and the impact this may have on global climate change.

VOC, CO, PM_{10}, NO_X and SO_X were selected to assess potential air quality impacts because they are classified as "criteria" pollutants and are regulated under National Ambient Air Quality Standards. Details of the impacts of these pollutants are given in Chapter 5.0 of the Externalities Workbook filed with the Commission on July 22, 1997. Monetized externality values for NO_X, SO_X, and PM[22] were included in the societal perspective screening. Total quantities were also accumulated in each resource plan and evaluated across all plans.

With respect to water quality impacts, various attributes such as quantities of equipment cleaning wash water, facility wash water, sanitary wastewater, water treatment reject, boiler blowdown, and cooling tower blowdown were considered. However, water quality was omitted as an attribute because it was not expected to differ between plans based on the Externalities Workbook finding that water-related externality values ranged from zero to negligible. In addition, the following considerations made it difficult to consider water-related quantities as attributes:

a) Water quality issues are very site-specific and plant design-specific. Different issues are raised depending on whether a plant uses brackish, potable, or salt water.
b) Many water quality issues can be addressed by engineering design. All plants would have to comply with local water permit requirements.
c) Water quality issues are important and are more appropriately addressed in the Environmental Impact Statement (EIS) for a proposed site rather than in the IRP.

With respect to land use impacts, attributes such as competing land use and hazardous waste were considered. However, other than land quantity (see attribute 8d), land use impacts were omitted as attributes because of the Externalities Workbook finding that land-related externality values ranged from zero to negligible. Similar to water-related issues, land-related issues are very site and plant design specific and would be addressed in the plant engineering design process. Land use issues are more appropriately evaluated in the EIS and not in the IRP.

[22] Monetization of particulate matter not only included PM_{10}, but also particulate matter greater than 10 microns in diameter.

Objective 8: Mitigate Potential Negative Societal and Cultural Impacts of the IRP Plan

Attributes for Objective 8:

a) *Meet all applicable federal, state, and county regulations* - All plans will comply with all applicable federal, state, and county regulations. While this attribute does not differ between resource plans, it is an important aspect of societal impact.
b) *Mitigate potential negative impacts on social practices within various cultures* - This attribute is dependent on the specific location of the resource and could not be evaluated between plans at this time. It will need to be assessed at the time of actual implementation of the plan. While the resource plans were based on assumptions using prototypical sites, their exact locations were not determined and variability in the sequence of generating unit additions made it difficult to assess the impact on social practices within various cultures. Therefore, for purposes of long-term planning, it was assumed that the impacts among plans were equal.
c) *Increase compatibility with community lifestyle* - This attribute is also dependent on the specific location of the resource and could not be evaluated between plans at this time. Therefore, for purposes of long-term planning, it was assumed that the impacts among plans were equal.
d) *Reduce land use* - The amount of land required for the various supply-side technologies was used as a measure of potential cultural and societal impact since competition for the "highest and best use" of land could have cultural and societal consequences. For

example, the Advisory Group believed that "there could be aesthetic value to biomass cultivation over lands which otherwise might remain fallow".[23]

Objective 9: Increase Plan Flexibility

Attributes for Objective 9:

a) *Increase resilience under sensitivity analysis* - A plan's ability to remain least-cost or near least-cost under a variety of sensitivities was considered highly desirable, given the uncertainties inherent in long-term forecasts. A plan's resilience under sensitivities is an indication of its ability to remain cost-effective under several future scenarios.

b) *Increase flexibility of project configurations* - Flexibility can be evaluated in terms of the configuration of the plant (as in combined cycle units, for instance) for particular resources, scheduling, fuel types and sequencing.

[23] August 7, 1998 letter from DBEDT to W. Lee, p. 6.

Table 2-1: IRP Plan Attributes and Method of Calculation

	OBJECTIVE	ATTRIBUTE	MEASURE	FORMULA	COMMENTS
1 a	Reduce accumulated present worth of revenue requirements (APWRR) of plan over 20-year planning period	APWRR	Dollars (000)	$=\sum(\text{present worth of revenue req})\ \text{annual}$	In $1999, using discount rate 8.177%
1 b	Reduce average rate impact over 20-year planning period	System Average Rate Impact	cents / kWh	$=\dfrac{\text{annual revenue requirements}}{\text{annual system kWh sales}}$	
1 c	Reduce rate "shock"	Largest annual % change in rates	Annual % change	$=\left[\dfrac{\text{rate for current year}}{\text{rate for previous year}}-1\right]*100\%\ \text{annual}$	
1 d	Reduce total customer cost over 20-year planning period	APWRR + DSM participant cost	Dollars (000)	$=\sum(\text{present worth of total resource cost from 1999 - 2018})$	In $1999, using discount rate 8.177%
2 a	Maintain generating system reliability	Average Reserve Margin	Reserve margin percent	= annual reserve margin	K10 (no DSM plan) as reference
2 a	Maintain generating system reliability	Fuel Security	+ / reference / -	Qualitative	
2 b	Maintain an appropriate mix of baseload, cycling, and peaking generating capacity based on system needs	System Mix	+ / reference / -	Qualitative	
2 c	Generation resources support transmission efficiency	Transmission capital cost & losses	+ / reference / -	Qualitative	
2 d	Generation resources support transmission reliability	System Stability & Voltage Support	+ / reference / -	Qualitative	
3 a	Maintain allowed rate of return	Rate of Return	Percent	12%	Constant throughout 20-yr planning horizon for all plans and for all planning perspectives
3 b	Maintain prudent capitalization ratios	Capitalization	Percent	See table 4-8 under Cost of Capital	Constant throughout 20-yr planning horizon for all plans and for all planning perspectives
3 c	Reduce capital expenditures	Capital Expenditures	$million	$=\sum(\text{generation capital expenditures w / o AFUDC})$	Escalated at 3.4% annually to year of installation, and present valued to $1999 using discount rate of 8.177%
3 d	Maintain low technological and financial risk	Technological & Financial Risk	+ / reference / -	Qualitative	
4 a	Increase deferral of capital expenditures	Capital Expenditure Deferral	Years (for 1st unit)		First required generation capacity unit addition is needed in 2006 and is constant in all plans
4 b	Reduce annual revenue requirements in first 12 years of plan	Revenue Req profile first 12 years	Dollars (000)	= revenue requirements by year	
4 c	Reduce rate impact over first 12 years of plan	System Avg Rate Impact 12 years	cents / kWh	$=\dfrac{\text{annual revenue requirements}}{\text{annual system kWh sales}}$	
5 a	Increase ability to utilize different types of fuel	Fuel Flexibility	+ / reference / -	Qualitative	

Table 2-1: IRP Plan Attributes and Method of Calculation

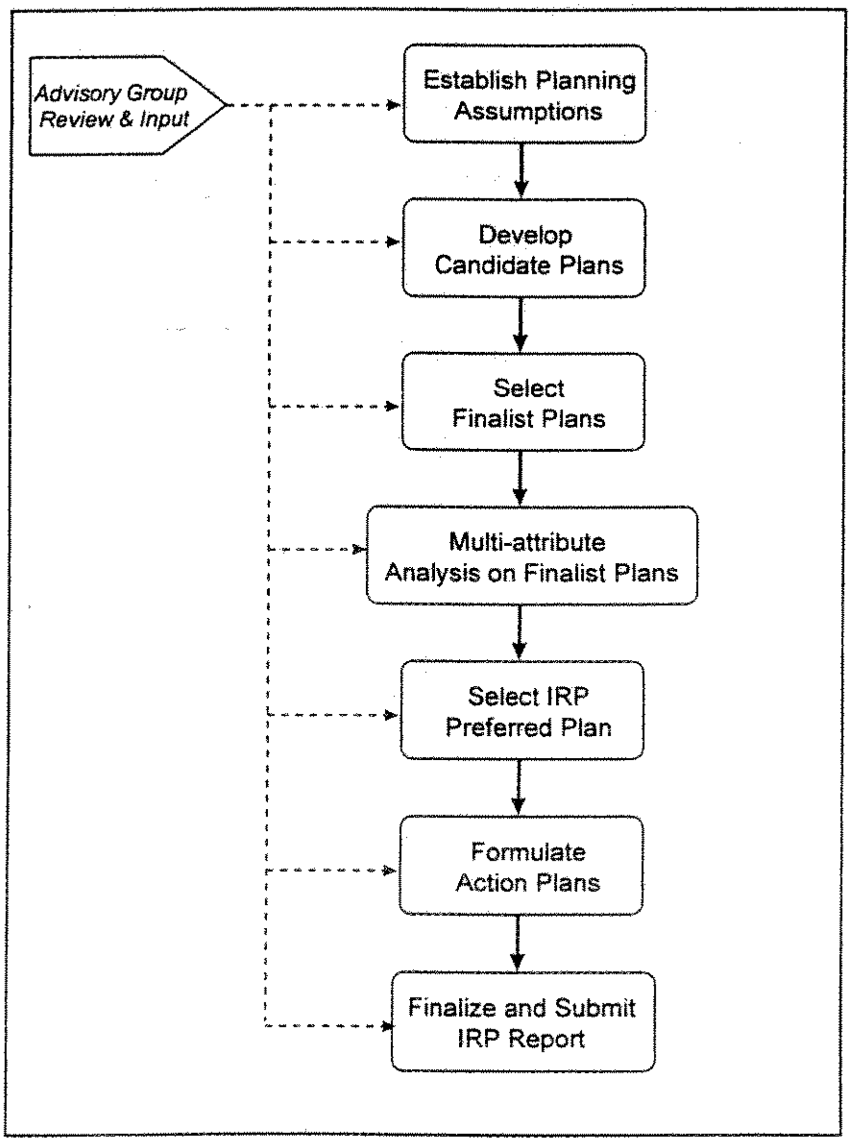
	OBJECTIVE	ATTRIBUTE	MEASURE	FORMULA	COMMENTS
6 a	Increase system fuel heat rate efficiency	Fuel Heat Rate Efficiency	BTU / kWh	$= \frac{\text{total MBtu consumed}}{\text{total system energy generated}}$	Total system energy generated at net generation level
6 b	Increase system fuel cost efficiency	Fuel Cost Efficiency	cents / kWh	$= \frac{\text{total fuel cost for MBtu consumed}}{\text{total system energy generated}}$	Total system energy generated at net generation level
6 c	Increase DSM penetration	DSM penetration	Maximum Peak Impact (MW)		Maximum DSM impact at the annual system peak hour in the 1999 - 2018 time period
6 d	Increase the ratio of energy produced by commercially viable indigenous and renewable resources as a proportion of total energy produced	Indigenous and Renewable Resources	Percent of total energy produced	$= \frac{\sum \text{(kWh from Wind, Geothermal, Hydro, Biomass, PV)}}{\text{Total system energy generated}}$	All generated kWh at net generation level
6 e	Reduce use of fuel oil as an energy resource	Fuel Oil Use	MBTU (000)	$= \sum$ (MBTU from Diesel & MSFO)	
7 a	Total VOC emissions of plan	VOC	Tons	$= \sum$ (annual emission from 1999 - 2018)	
7 b	Total CO emissions of plan	CO	Tons	$= \sum$ (annual emission from 1999 - 2018)	
7 c	Total PM emissions of plan	PM	Tons	$= \sum$ (annual emission from 1999 - 2018)	
7 d	Total NO_x emissions of plan	NO_x	Tons	$= \sum$ (annual emission from 1999 - 2018)	
7 e	Total SO_x emissions of plan	SO_x	Tons	$= \sum$ (annual emission from 1999 - 2018)	
7 f	Total CO_2 emissions of plan	CO_2	Tons	$= \sum$ (annual emission from 1999 - 2018)	
8 a	Meet all applicable federal, state, and county regulations	Compliance with Regulations	Yes / No		All plans meet all regulations
8 b	Mitigate potential negative impacts on social practices within various cultures	Impact on Social Practices	+ / reference / -	Qualitative	Location specific
8 c	Increase compatibility with community lifestyle	Compatibility with Community Lifestyle	+ / reference / -	Qualitative	Location specific
8 d	Reduce Land use	Land Use	Acres	$= \sum$ (land requirements for all plan resources from 1999 - 2018)	
9 a	Increase resilience under sensitivity analysis	Performance Under Sensitivities	+ / reference / -	Qualitative	
9 b	Increase flexibility of project configurations	Configuration Flexibility	+ / reference / -	Qualitative	

3. IRP PROCESS, METHODS AND MODELS

3.1 IRP-98 PROCESS

The flowchart shown in Figure 3-1 illustrates the process for HELCO's IRP-98. Along each step of the process, the HELCO Advisory Group provided valuable review and input.

Figure 3-1. HELCO IRP-98 Process



3.2 HELCO IRP-98 ORGANIZATION

Figure 3-2 illustrates the corporate organizational structure for the HELCO IRP-98 process. It also indicates the relationship of the IRP Advisory Group to the overall organization.

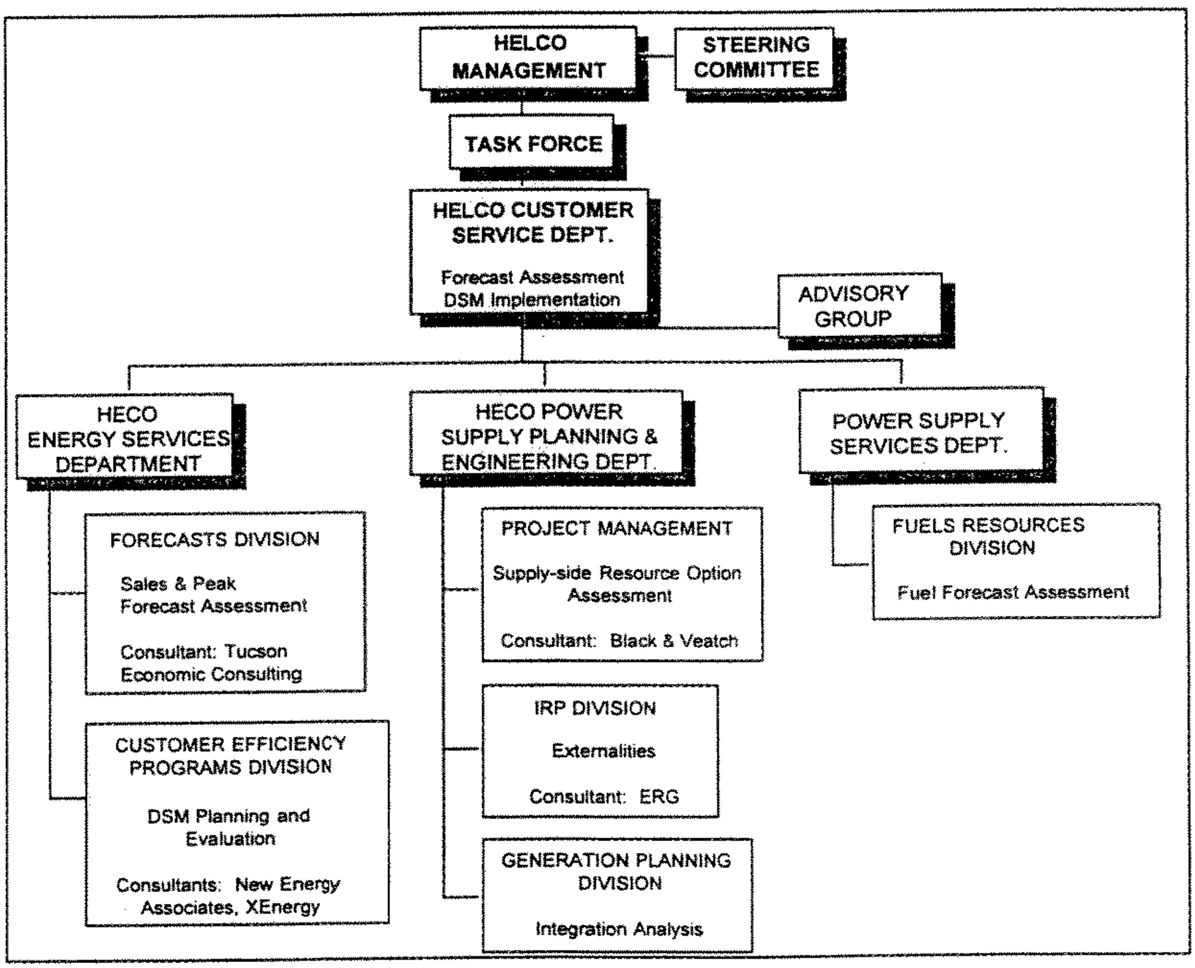
3.3 PUBLIC PARTICIPATION

3.3.1 IRP Advisory Group

An IRP Advisory Group, comprised of representatives from state and county agencies, environmental, cultural, business and community interest groups, as well as other interested individuals, served to provide HELCO with a diverse set of opinions and perspectives for consideration in the development of its IRP plan. HELCO made extensive effort to keep its IRP Advisory Group educated, informed and involved, by scheduling meetings at major points throughout the IRP process, as well as through written correspondence and informal discussions with HELCO staff. The subject matter discussed at the meetings covered all aspects of the IRP process, including: forecasting, development and screening of demand-side and supply-side options, renewables and the integration analysis.

While HELCO welcomed the feedback it received from the Advisory Group

Figure 3-2: Corporate Organizational Structure for HELCO IRP-98



members, and took their input into consideration in the process and analyses, it was not always possible to incorporate all suggestions due to competing objectives and other constraints.[24]

Copies of the Advisory Group roster, meeting agendas, and all written correspondence are included in Appendices C and D. Transcripts of the meetings were taken and are available for review upon request.

3.3.2 Public Meeting

HELCO will hold a public meeting upon selection of the IRP preferred plan, to inform the public of the IRP preferred plan and receive feedback. Significant feedback will be provided to the Commission.

3.4 INTEGRATION METHODS AND MODELS

3.4.1 PROSCREEN II Corporate Strategic Planning System

The PROSCREEN II model was used to evaluate DSM and supply-side options, generate resource plans, determine the timing of generating unit additions, calculate plan generation and DSM costs and quantify other plan attributes. Documentation for the PROSCREEN II model was included in the IRP-93 Integration Report[25]. New Energy Associates, the vendor of PROSCREEN II, has made significant improvements to the model subsequent to IRP-93, including:

- Capability to model HELCO's generation capacity addition criteria - In the IRP-93 integration analysis, PROSCREEN II added generating units to meet a minimum reserve margin of 27%. Timing of unit additions according to the HELCO capacity addition criteria was later determined for the IRP-93 preferred plan outside of the PROSCREEN II model.
- Capability to model four load points for thermal generating units, and a corresponding four-segment approximation of the unit heat rate curve - Previously, PROSCREEN II could only model two segments (minimum/maximum load points) for thermal units.

HELCO has made several changes in modeling its generating system in PROSCREEN II between IRP-93 and IRP-98:

- Generating unit capacities were changed from gross MW to capacities net of generating unit auxiliaries. This is an improvement from IRP-93, where gross unit capacities were adjusted to account for differences in auxiliary loads between different types of units.
- Forecasted system peaks were similarly changed from gross values to values net of generation auxiliary loads
- As discussed further in Section 6, the DSView module of PROSCREEN II, rather than the COMPASS model used in IRP-93, was used in the development of DSM cost and impact data
- In IRP-93, PROSCREEN II study period costs included an infinite end-effects period following the 20-year IRP planning period. The end-effects logic in the Proview module of PROSCREEN II calculates capacity and production costs for a specified number of years following the 20-year planning period. By extending the period over which unit additions are evaluated, the production cost benefits over the lifetime of highly efficient, yet capital intensive units will be accounted for. It should be realized,

[24] Section III.E.1.c of the IRP Framework states that "The utility shall consider the input of each advisory group; but the utility is not bound to follow the advice of any advisory group."

[25] October 1993 HELCO IRP Integration Report, Appendix B, pp. B-5 to B-9.

however, that evaluating plans over such an extended period tends to dilute differences in sometimes significant near-term costs. Moreover, the end-effects calculation and resulting study period optimization are highly sensitive to the assumptions made for the escalation of costs. This is especially true with regard to fuel costs, which typically comprise about 40 percent of PROSCREEN II plan costs. Historically, fuel costs fluctuate with no discernable pattern. This makes it difficult to accurately forecast what fuel prices will be even in the next few years, and any attempt at a forecast more than 20 years into the future is highly speculative.

In the end-effects period calculations:

- System load and sales (and DSM peak and energy impacts) are held constant at the 20th year values.
- No unit retirements occur during the end-effects period.
- New units added during the planning period are assumed replaced in kind at the end of their service lives. Capital costs are escalated at an annual rate of 3.4% (same as the capital escalation rate during the planning period).
- All fuel costs, fixed and variable O&M costs, purchased power costs and externality costs are escalated at 3.4% per year (same as the escalation assumed in the last year of the planning period). The present value of the escalated production costs over the end-effects period are then levelized. The levelized costs are then used to perform a single economic dispatch of the generating units to meet the system load in the last year of the planning period.
- Utility DSM expenses and DSM customer costs, which typically vary by year, are escalated at 3.4% from the costs in the last year of the planning period.

The infinite end-effects period modeled in IRP-93 was reduced to a 30-year end-effects period in IRP-98. The 30-year period was considered reasonable as it equals the expected service life of a supply-side unit added in the last year of the planning period. This change was made such that end-effects costs do not comprise an unreasonable proportion of the total present value of study period plan costs.

3.4.2 Attribute Analysis Methods

In IRP-93, HELCO used a multi-attribute method (MAA) in the process of selecting its preferred IRP plan. The IRP-93 method, used by HECO and MECO in their first IRPs as well, involved weighting various plan attributes by relative level of importance from different perspectives (utility, customer, societal). The resulting weights were then multiplied by the quantified plan attributes and summed to produce a plan score. HECO and HELCO received a number of criticisms in IRP-93 regarding this multi-attribute method:

- GASCO's position was that: *"The multi-attribute analysis, as applied by HELCO, 'does not provide a logical nor a transparent framework for the comparison of alternative resource plans.' Without substantial revision it cannot be deemed truly useful and should be abandoned. Any revisions must address existing problems of overlapping attribute categories, double counting, attribute definition and scaling."*[26]
- The CA summarized the shortcomings of the method identified by both GASCO and the CA as: *"(1) the assignment of weights to the attribute categories is not based upon sound*

[26] (Docket No. 7259, GASCO OB, p. 22)

> *evidence or analysis; (2) HELCO uses a scoring method that is not appropriate; and (3) several non-quantified external costs and benefits are not taken into consideration.*"[27]

In the development of its second IRP, HECO attempted to refine the IRP-93 MAA method in consideration of the deficiencies identified above. However, HECO found that the problems of double-counting and scaling could not be rectified within a similar ranking and weighting type of methodology. HECO also found it infeasible to pursue an alternative method suggested by GASCO which involved direct monetization of externalities because (1) it would require intensive effort, time and expenses to determine the monetary value of certain attributes and (2) it is simply not possible to assign dollar values to certain societal and cultural attributes. HECO also explored other alternative methods, but found that each had its own inherent problems.

HECO finally arrived at a method which directly compared individual attributes across the finalist plans. This method provides a clearer understanding of how well a resource plan satisfies IRP objectives relative to other alternatives. HELCO chose to adopt HECO's direct-comparison method which:

- Quantifies attributes to the extent possible
- Evaluates all other attributes on a qualitative basis
- Compares attribute values across finalist plans, noting similarities and examining the cause for significant differences
- Determines specific trade-offs between attributes that are made in the selection of one resource plan over another

When HELCO presented its proposal for attribute analysis (i.e., the direct-comparison method) at the December 16, 1997 Advisory Group meeting, members were given an opportunity to present alternate methods. One member, representing the Division of Consumer Advocacy, presented a method similar to that used in IRP-93 but which used a comparison matrix for determining weights. Another member, representing the Department of Business, Economic Development, and Tourism (DBEDT), presented a method for scaling the attribute data. Upon review and discussion of the various methods, the Advisory Group voted to utilize a rank-and-weight method in addition to HELCO's proposed direct-comparison method, to assist in their understanding of the attribute trade-offs. This rank-and-weight method was similar to that used in IRP-93 but incorporated the suggestions proposed by the two Advisory Group members regarding weight-determination and scaling. HELCO informed the Advisory Group that it could not endorse the rank-and-weight method as the preferred method for multi-attribute analysis. The rank-and-weight method proposed by the Advisory Group improved upon the method used in IRP-93; however, it did not rectify the problems of double-counting and scaling. HELCO's position was that it believed that the direct-comparison method was a better approach for analyzing both quantitative and qualitative attributes simultaneously. In addition, the direct-comparison method allowed one to focus on the attributes themselves rather than the numerical complexities of the rank-and-weight method - i.e., scaling, double-counting and implicit monetization.

Nevertheless, HELCO recognized the desire of the Advisory Group to utilize the rank-and-weight method and agreed to help facilitate the development and application of an Advisory Group rank-and-weight method. At a March 1997 Advisory Group meeting, two exercises were conducted --

[27] (Docket No. 7259, CA OB, p. 63)

one to select attributes and the other to determine the corresponding weights for the selected attributes. First, members were given a list of attributes from which to choose from. This list of attributes had been explained and established at a previous Advisory Group meeting. Four of the 37 attributes were marked with a "C," meaning that those attributes did not change, or remained constant, between plans. Ten of the 37 attributes were marked with a "Q." These attributes contained qualitative measures and therefore did not lend themselves to a quantitative analysis. However, in the next Advisory Group meeting, members would be presented with the results of their rank-and-weight exercise and would then be given a chance to speak to each of the qualitative attributes. Advisory Group members then used the form shown in Table 3-1 as a ballot to select eight attributes, not including those marked with a "C" or a "Q." Since there was a tie in the number of votes received for certain attributes, ten attributes were ultimately retained for use in the rank-and-weight tool. The attributes which were selected are shown in italics.

Next, Advisory Group members were provided with matrices, as shown in Figure 3-3, to determine weighting factors. As mentioned earlier, this method of determining weights had been proposed by a member of the Advisory Group. The members' individual weight sets were then combined to arrive at an "Advisory Group weight set." Members reviewed this "Advisory Group weight set" and agreed that it was acceptable. The Advisory Group weight set is shown in Table 3-2.

The appropriate attribute data was compiled for the Finalist Plans, then scaled according to the method proposed by DBEDT. Although some of the plan scores that resulted from application of the AG's MAA were very close, the Finalist Plans were ranked from one to thirteen, with the number-one ranked plan (Plan K3) being the most desirable according to the Advisory Group's selected weights. The attribute data, as well as the results of the Advisory Group's rank-and-weight exercise, are shown in Table 3-3. Note that Plans K3 and K5 assumed the low capital cost estimates for PV and geothermal. An analysis was also done using the high capital cost estimates for PV and geothermal. The results of this analysis, as shown in the shaded columns of Table 3-3, moved the geothermal plan, K5, from rank 4 to rank 7.

Table 3-1. IRP-98 Attributes
(Q=qualitative, C=constant between plans; attributes in italics selected for AG multi-attribute tool)

			ATTRIBUTE	MEASURE
	Meet Customer Electrical Energy Needs at the Lowest Reasonable Cost			
	a.	Reduce accumulated present worth revenue requirements (APWRR) of plan over 20-year planning period	APWRR	Dollars
	b.	Reduce average rate impact over 20-year planning period	Average Rate Impact	¢/kWh
	c.	*Reduce rate "shock"*	*Largest annual %change in rates*	*Largest annual % change in (revenue req./energy sales)*
	d.	*Reduce total customer cost over 20-year planning period*	*APWRR + DSM Participant Costs*	*Dollars*
	Improve the Quality of Electrical Products and Services			
	a.	Maintain generating system reliability	Average Reserve Margin	Reserve Margin Percent
Q			Fuel Security	High/Medium/Low
Q	b.	Maintain an appropriate mix of baseload, cycling and peaking generating capacity based on system needs.	System Mix	Good/Fair/Poor
C			Minimum load constraint	Dumped energy (MWH)
Q	c.	Generation resources support transmission efficiency	Transmission capital costs & losses	High/Medium/Low
Q	d.	Generation resources support transmission reliability	System Stability and Voltage support	Good/Fair/Poor
	Maintain Corporate Financial Integrity			
C	a.	Maintain allowed rate of return	Rate of Return	Percent
C	b.	Maintain prudent capitalization ratios	Capitalization	Percent
	c.	Reduce capital expenditures	Capital Expenditures	Dollars (PV$1999)
Q	d.	Maintain low technology and financial risk	Technology & financial risk	High/Medium/Low
	Maintain Corporate Competitiveness			
	a.	Increase deferral of capital expenditures	Capital Expenditure Deferral	Years (for 1st unit)
	b.	Reduce annual revenue requirements in first 12 years of plan	APWRR of first 12 yrs	Dollars
	c.	Reduce rate impact over first 12 years of plan	Average Rate Impact of first 12 yrs	cents/kWh
	Increase Fuel Diversity for the Electrical System			
Q	a.	Increase ability to utilize different types of fuel	Types of Fuel	Good/Fair/Poor
	Support the State of Hawaii Energy Objectives			
	a.	Increase system fuel heat rate efficiency	Fuel Heat Rate Efficiency	Btu/kWh
	b.	Increase system fuel cost efficiency	Fuel Cost Efficiency	cents/kWh
	c.	*Increase DSM penetration*	*DSM penetration*	*MWh*
	d.	*Increase the ratio of energy produced by commercially viable indigenous and renewable resources as a proportion of total energy produced*	*Energy from Indigenous and Renewable Resources*	*Percent of Total Energy Produced*
	e.	Reduce use of fuel oil as an energy resource	Fuel Oil Use	Btu
	Comply with Environmental Regulations			
	a.	*Total VOC emissions of plan*	*VOC*	*Tons*
	b.	*Total CO emissions of plan*	*CO*	*Tons*
	c.	*Total PM_{10} emissions of plan*	*PM_{10}*	*Tons*
	d.	*Total NOx emissions of plan*	*NOx*	*Tons*
	e.	*Total SO_X emissions of plan*	*SOx*	*Tons*
	f.	*Total CO_2 emissions of plan*	*CO_2*	*Tons*
	Mitigate Potential Negative Societal and Cultural Impacts of the IRP Plan			
C	a.	Meet all applicable federal, state and county regulations	Compliance with regulations	Yes/No
Q	b.	Mitigate potential negative impacts on social practices within various cultures	Impact on Social Practices	High/Medium/Low
Q	c.	Increase compatibility with community lifestyle	Compatibility with Community Lifestyle	High/Medium/Low
	d.	Reduce land use	Land Use	Acres
	Increase Plan Flexibility			
Q	a.	Increase resilience under sensitivity analysis	Performance Under Sensitivities	Good/Fair/Poor
Q	b.	Increase flexibility of project configurations	Configuration Flexibility	Good/Fair/Poor
Notes:		Q = attribute contains a qualitative measure		
		C = attribute remains constant across plans		

Figure 3-3. Matrix used to determine weighting factors for Advisory Group multi-attribute tool

Attribute A \ Attribute B	Increase Energy from Indigenous & Renewable Resources	Reduce total CO2 emissions	Reduce rate "shock"	Reduce total customer cost over 20-year planning period	Increase DSM penetration	Reduce total VOC emissions	Reduce total CO emissions	Reduce total PM10 emissions	Reduce total NOx emissions	Reduce total SOx emissions
Increase Energy from Indigenous & Renewable Resources										
Reduce total CO_2 emissions										
Reduce rate "shock"										
Reduce total customer cost over 20-year planning period										
Increase DSM penetration										
Reduce total VOC emissions										
Reduce total CO emissions										
Reduce total PM_{10} emissions										
Reduce total NOx emissions										
Reduce total SOx emissions										

Is attribute A the same, more, or less important than attribute B in selecting an integrated resource plan?

Much less =	1/10
Less =	1/5
Same =	1
More =	5
Much more =	10

Table 3-2. Advisory Group's weighting factors for use in the multi-attribute tool

Attribute	Weight
Increase DSM penetration	19.4
Increase energy from indigenous and renewable resources	19.0
Reduce total resource cost	14.4
Reduce rate shock	13.5
Reduce total PM emissions of plan	6.2
Reduce total NOx emissions of plan	5.9
Reduce total CO emissions of plan	5.5
Reduce total SOx emissions of plan	5.5
Reduce total CO2 emissions of plan	5.4
Reduce total VOC emissions of plan	5.1

Table 3-3. Advisory Group Weight-and-Rank Results

Advisory Group
Multi-Attribute Analysis

This analysis ranks attributes with the most desireable value equal to 1

	1	2	3		4	5		6	7	8	9	10	11	12	13		
	K1	K2	K3	K3C-3	K4	K5	K5C-3	K6	K7	K8	K9	K10	K11	K12	K13		
YEAR	No 1-MW diesels	AG Plan F, 20-yr DSM, wind only	PV(low cost) +wind	PV(high cost) +wind	hydro+wind	AG Plan E, geo (low cost)+wind	AG Plan E, geo (high cost)+wind	AG Plan H, ps+wind	all west side	coal plan	2-yr DSM	No DSM	AG Plan O: biomass first	AG Plan B, L Minimize oil	AG Plan J: 1-MW Diesels until 2010	Difference (Max - Min)	Percent Difference [(Max-Min)/Max]
1999	Encogen (60 MW) 20-yr REWH 20-yr CIEE 20-yr CINC 20-yr CICR	Encogen (60 MW) 20-yr REWH 20-yr CIEE 20-yr CINC 20-yr CICR	Encogen (60 MW) 20-yr REWH 20-yr CIEE 20-yr CINC 20-yr CICR	Encogen (60 MW) 20-yr REWH 20-yr CIEE 20-yr CINC 20-yr CICR	Encogen (60 MW) 20-yr REWH 20-yr CIEE 20-yr CINC 20-yr CICR	Encogen (60 MW) 20-yr REWH 20-yr CIEE 20-yr CINC 20-yr CICR	Encogen (60 MW) 20-yr REWH 20-yr CIEE 20-yr CINC 20-yr CICR	Encogen (60 MW) 20-yr REWH 20-yr CIEE 20-yr CINC 20-yr CICR	Encogen (60 MW) 20-yr REWH 20-yr CIEE 20-yr CINC 20-yr CICR	Encogen (60 MW) 20-yr REWH 20-yr CIEE 20-yr CINC 20-yr CICR	Encogen (60 MW) 2-yr REWH 2-yr CIEE 2-yr CINC 2-yr CICR	Encogen (60 MW)	Encogen (60 MW) 20-yr REWH 20-yr CIEE 20-yr CINC 20-yr CICR	Encogen (60 MW) 20-yr REWH 20-yr CIEE 20-yr CINC 20-yr CICR	Encogen (60 MW) 20-yr REWH 20-yr CIEE 20-yr CINC 20-yr CICR		
//	//	//	//	//	//	//	//	//	//	//	//	//	//	//	//		
2002		10MW Wind-Lalamilo	10MW Wind-Lalamilo 4MW PV (low cost)	10MW Wind-Lalamilo 4MW PV (high cost)	10MW Wind-Lalamilo	10MW Wind-Lalamilo	10MW Wind-Lalamilo				Puna return from Standby (15MW)	Puna return from Standby (15MW)	10MW Wind-Lalamilo	10MW Wind-Lalamilo			
2003	Puna return from Standby (15MW)	Puna return from Standby (15MW)	Puna return from Standby (15MW)	Puna return from Standby (15MW)	Puna return from Standby (15MW) Hydro (12.5MW)	Puna return from Standby (15MW)	Puna return from Standby (15MW)	Puna return from Standby (15MW)	Puna return from Standby (15MW)	Puna return from Standby (15MW)			Puna return from Standby (15MW)	Puna return from Standby (15MW)	Puna return from Standby (15MW)		
2004																	
2005																	
2006	Keahole ST7 (17MW)	Keahole ST7 (17MW)	Keahole ST7 (17MW)	Keahole ST7 (17MW)	Keahole ST7 (17MW)	Keahole ST7 (17MW)	Keahole ST7 (17MW)	Keahole ST7 (17MW)	Keahole ST7 (17MW)	Keahole ST7 (17MW)	Keahole ST7 (17MW)	Keahole ST7 (17MW)	Keahole ST7 (17MW)	Keahole ST7 (17MW)	Keahole ST7 (17MW)		
2007											Hill 5 Repower, 1st CT (21.6 MW)	Hill 5 Repower, 1st CT (21.6 MW)					
2008																	
2009	Hill 5 Repower, 1st CT (21.6 MW)	Hill 5 Repower, 1st CT (21.6 MW)	Hill 5 Repower, 1st CT (21.6 MW)	Hill 5 Repower, 1st CT (21.6 MW)	Hill 5 Repower, 1st CT (21.6 MW)	Hill 5 Repower, 1st CT (21.6 MW)	Hill 5 Repower, 1st CT (21.6 MW)	Pumped storage Hydro (Puu Enuhe, 30MW) 10MW Wind-Lalamilo	W. HI DTCC, 1st CT (20.9 MW)	Coal (26.7MW)			Biomass (25MW)	Biomass (25MW)	1 MW Diesel (7 units)		
2010								Hill 5 Repower, 1st CT (21.6 MW)							Hill 5 Repower, 1st CT (21.6 MW)		
2011											Hill 5 Repower, 2nd CT (21.6 MW)	Hill 5 Repower, 2nd CT (21.6 MW)					
2012	Hill 5 Repower, 2nd CT (21.6 MW)	Hill 5 Repower, 2nd CT (21.6 MW)	Hill 5 Repower, 2nd CT (21.6 MW)	Hill 5 Repower, 2nd CT (21.6 MW)	Hill 5 Repower, 2nd CT (21.6 MW)	Hill 5 Repower, 2nd CT (21.6 MW)	Hill 5 Repower, 2nd CT (21.6 MW)		W. HI DTCC, 2nd CT (20.9 MW)				Hill 5 Repower, 1st CT (21.6 MW)	Biomass (25MW)			
2013										Hill 5 Repower, 1st CT (21.6 MW)							
2014											Hill 5 Repower conversion to DTCC (58.3 MW) Hill 6 Repower, 1st CT (21.6MW)	Hill 5 Repower conversion to DTCC (58.3 MW) Hill 6 Repower, 1st CT (21.6MW)			Hill 5 Repower, 2nd CT (21.6 MW)		
2015	Hill 5 Repower conversion to DTCC (58.3 MW)	Hill 5 Repower conversion to DTCC (58.3 MW)	Hill 5 Repower conversion to DTCC (58.3 MW)	Hill 5 Repower conversion to DTCC (58.3 MW)	Hill 5 Repower conversion to DTCC (58.3 MW)	Hill 5 Repower conversion to DTCC (58.3 MW)	Hill 5 Repower conversion to DTCC (58.3 MW)	Hill 5 Repower, 2nd CT (21.6 MW) Hill 5 Repower conversion to DTCC (58.3 MW)		Conversion of Hill 5 Repower 1st CT to 1/2DTCC (29.3 MW)			Conversion of Hill 5 Repower 1st CT to 1/2DTCC (29.3 MW)		Hill 5 Repower conversion to DTCC (58.3 MW)		
2016	LM2500 SCCT (20.9MW)	LM2500 SCCT (20.9MW)	LM2500 SCCT (20.9MW)	LM2500 SCCT (20.9MW)	LM2500 SCCT (20.9MW)	Geothermal (25MW low cost)	Geothermal (25MW high cost)		W. HI DTCC - conversion to DTCC (60.7MW)	Hill 5 Repower, 2nd CT (21.6 MW) Conversion of Hill 5 Repower 2nd CT to 1/2DTCC (29 MW)			Hill 5 Repower, 2nd CT (21.6 MW)	LM2500 STIG (22.7 MW)			
2017									W. HI DTCC, 1st CT (20.9 MW)		Hill 6 Repower, 2nd CT (21.6MW)	Hill 6 Repower, 2nd CT (21.6MW)					
2018		5MW wind - N. Kohala						LM2500 SCCT (20.9MW)							LM2500 SCCT (20.9MW)		
Attribute Data																	
DSM Penetration (MW)	15.19	15.19	15.19	15.19	15.19	15.19	15.19	15.19	15.19	15.19	3.92	2.43	15.19	15.19	15.19	12.76	84.00%
Energy from Indigenous and Renew Resources (%)	27.14	25.85	26.33	26.37	25.78	28.42	28.42	24.89	23.15	23.14	22.22	22.08	28.12	29.5	23.14	7.42	25.15%
TRC Planning Period Cost ($000)	1,323,353.0	1,325,867.5	1,349,745.1	1,367,874.0	1,357,468.8	1,328,122.6	1,328,091.0	1,367,525.8	1,527,694.0	1,390,065.8	1,341,155.8	1,347,122.9	1,387,728.3	1,429,504.0	1,319,613.3	106,891	7.48%
Rate Shock (largest annual % change)	4.45	4.47	4.35	4.33	4.33	5.73	10.30	8.05	4.46	12.22	4.52	4.66	10.81	10.81	4.52	7.86	64.57%
PM (Tons)	7,081	6,901	6,874	6,874	6,905	6,762	6,762	6,977	7,124	6,757	7,364	7,450	6,787	6,763	7,015	687	9.22%
NOX (Tons)	25,980	24,348	24,224	24,224	24,385	23,781	23,781	24,637	25,388	24,590	25,008	25,231	25,024	25,569	24,886	2,450	9.94%
CO (Tons)	7,527	7,219	7,185	7,185	7,247	6,986	6,986	7,366	7,554	6,630	7,949	8,524	8,519	10,003	7,496	3,373	33.72%
SOX (Tons)	68,971	68,577	68,385	68,385	68,502	67,572	67,572	69,146	70,817	66,989	71,611	72,121	65,061	66,101	69,411	5,535	7.67%
CO2 (Tons)	14,016,457	13,817,624	13,543,321	13,543,321	13,624,123	13,206,877	13,206,877	13,759,402	13,999,876	15,444,191	14,571,354	14,064,012	14,480,516	15,100,559	13,981,810	2,237,304	14.49%
VOC (Tons)	894	860	853	853	861	831	831	874	914	791	935	943	974	1,068	892.0	277	25.94%
Multi-Attribute Analysis																	
Increase DSM penetration (19.4)	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	0.258	0.160	1.000	1.000	1.000	0.840	84.00%
Increase energy from indigenous & renew (19.0)	0.764	0.876	0.893	0.893	0.874	0.963	0.963	0.837	0.785	0.784	0.753	0.748	0.953	1.000	0.784	0.252	25.15%
Reduce total resource cost (24.4)	0.997	0.995	0.978	0.965	0.972	0.994	0.986	0.965	0.864	0.949	0.984	0.980	0.951	0.923	1.000	0.078	6.29%
Reduce rate shock (13.5)	0.964	0.969	0.979	1.000	1.000	0.756	0.418	0.538	0.971	0.354	0.958	0.929	0.401	0.401	0.958	0.646	64.57%
Reduce total PM emissions of plan (6.2)	0.955	0.980	0.984	0.984	0.979	1.000	1.000	0.969	0.949	0.998	0.915	0.908	0.995	1.000	0.964	0.092	9.22%
Reduce total NOx emissions of plan (5.9)	0.949	0.971	0.982	0.982	0.976	1.000	1.000	0.965	0.937	0.963	0.954	0.947	0.950	0.926	0.956	0.093	9.94%
Reduce total CO emissions of plan (5.5)	0.881	0.918	0.922	0.923	0.915	0.949	0.948	0.901	0.878	1.000	0.834	0.827	0.759	0.663	0.884	0.337	33.72%
Reduce total SOx emissions of plan (5.6)	0.957	0.971	0.974	0.974	0.971	0.985	0.985	0.963	0.946	1.000	0.930	0.922	0.978	0.928	0.959	0.077	7.67%
Reduce total CO2 emissions of plan (5.4)	0.942	0.970	0.975	0.978	0.969	1.000	1.000	0.959	0.940	0.855	0.906	0.901	0.912	0.875	0.944	0.145	14.49%
Reduce total VOC emissions of plan (5.1)	0.885	0.920	0.927	0.927	0.915	0.952	0.952	0.905	0.865	1.000	0.846	0.835	0.812	0.741	0.887	0.259	25.94%
TOTAL MAA SCORE	0.9289	0.9561	0.9610	0.9607	0.9582	0.9521	0.9054	0.8821	0.8265	0.8534	0.7640	0.7377	0.8707	0.8632	0.8381	0.223	23.24%
MAA Rank	6	3	1	1	2	4	7	8	7	11	12	13	9	10	5		

4. PLANNING ASSUMPTIONS

4.1 SALES AND PEAK FORECAST

4.1.1 Existing Customer Base

In 1997, HELCO had total energy sales of approximately 894 GWh and 59,744 customer accounts. HELCO's six major customer classes include:

- residential service,
- large power,
- commercial cooking, heating, air conditioning and refrigeration,
- general service - demand,
- general service and
- street lighting.

4.1.2 Base Forecast

4.1.2.1 Background

HELCO prepared the 1997-2002 short-term forecast as scheduled in late 1996. This short-term forecast was adopted by the Forecast Planning Committee (FPC) on January 17, 1997. A long-term forecast covering the period 1997-2017 was scheduled to be completed in late 1997 and used as the basis for the IRP filing in late 1998. Because the January 1997 forecast was still reasonable, HELCO extended the short-term forecast process into a long-term forecast covering the period 1997-2017. This forecast, adopted on September 11, 1997, serves as the base forecast for IRP-98. A copy of the Executive Summary of the September 11, 1997 forecast report is provided in Appendix E.

HELCO's long-term sales and peaks (excluding future DSM programs and including 1996 acquired DSM and Hawaii Model Energy Code impacts) are expected to increase at an average of 2.2 percent per year between 1996 and 2017.

4.1.2.2 Economic Outlook for Base Forecast

The forecast, shown in Appendix E, is based on the results of HECO's economic model for the County of Hawaii. The forecast projects the Hawaii County visitor census to grow an average of 4.1 percent annually as the length of stay decreases from 6.4 days in 1995 to 6.3 days in 2017. Projected visitor census growth over the period 1997-2017 is 98%. Real personal income increases 2.7 percent per year on average. Projected real personal income increases 72% over the period 1997-2017. Furthermore, the county's resident population is expected to increase at an average annual rate of 1.4 percent. Resident population is projected to increase a total of 33% over the period 1997-2017.

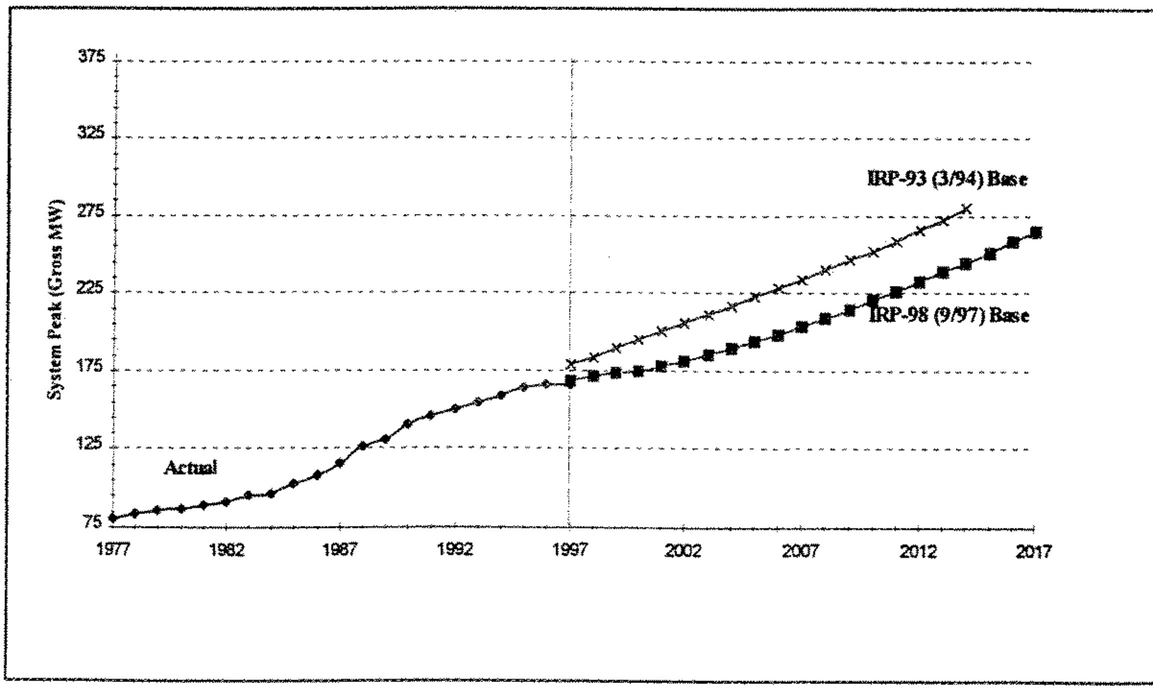
The economic forecast includes the impact of the direct flights from Japan to Kona. These flights began in June 1996. The closure of the Ka'u Sugar Plantation in March 1996 marked the end of sugar's long history with Hawaii County. However, the employment and personal income impact on the island is assumed to be offset somewhat by growth in diversified agriculture over the long term.

As illustrated in Figure 4-1, the September 1997 peak forecast is lower than the March 1994 forecast which was the basis for HELCO's IRP-93 Re-assessment. The March 1994 forecast does not include full-scale DSM, Hawaii Model Energy Code (HMEC) or rate rider impacts. The September 1997 forecast includes HMEC, DSM acquired through 1996 and rate rider impacts. Table 4-1 provides details of the peak forecast comparison. The primary reason for the difference in the 1994 and 1997 peak forecasts is the lower economic outlook for the County.

Table 4-1. Peak Load Forecast Comparison (Gross MW) - September 1997 vs March 1994

Year	Sept 1997 Forecast High Case (Gross MW) (A)	Sept 1997 Forecast Low Case (Gross MW) (B)	Sept 1997 Forecast Base Case (Gross MW) (C)	March 1994 Forecast Base Case (Gross MW) (D)	Peak Load Difference (E)=(C)-(D)
1997	172.9	165.9	168.9	179.0	-10.1
1998	177.7	167.3	171.6	184.0	-12.4
1999	181.6	167.9	173.4	190.0	-16.6
2000	187.5	168.3	175.1	196.0	-20.9
2001	193.4	168.9	177.9	202.0	-24.1
2002	200.2	170.3	181.6	207.0	-25.4
2003	208.1	172.1	185.6	212.0	-26.4
2004	216.3	173.9	189.6	217.0	-27.4
2005	224.8	175.7	193.8	223.0	-29.2
2006	233.7	178.5	198.7	229.0	-30.3
2007	242.9	181.3	203.7	235.0	-31.3
2008	252.4	184.1	208.9	241.0	-32.1
2009	262.4	187.0	214.1	247.0	-32.9
2010	274.1	191.4	220.9	253.0	-32.1
2011	284.9	195.2	226.8	259.0	-32.2
2012	296.1	199.0	232.7	266.0	-33.3
2013	307.6	202.8	238.9	273.0	-34.1
2014	319.6	206.8	245.2	280.0	-34.8
2015	332.0	210.7	251.6	-	-
2016	343.8	214.5	258.4	-	-
2017	355.9	218.3	265.4	-	-

Figure 4-1: Comparison of 1994 and 1997 Base Peak Forecasts



4.1.2.3 Demand Side Management

Both the March 1994 and September 1997 forecasts include the impact of pilot DSM programs. The September 1997 forecast is the basis for this IRP and includes HMEC impacts and 1996 acquired DSM impacts, but excludes future DSM. DSM impacts assumed in IRP-98 are provided in Section 6.

4.1.2.4 Historical Data and Forecast Methods

Adjustments were made to the historical sales data for Schedules G and P. These adjustments account for the transfers of customers between Schedules G and P and the sales impact of large customer additions as they came on line. Adjustments were then made to the forecasted sales derived from the econometric and trended models by rate schedule in order to appropriately reflect the customers actually expected to be on line in each rate schedule.

The data used in the short-term statistical trending models were not adjusted for weather as it is assumed that, for the long period of data being used, average weather patterns resemble normal weather.

This forecast continues the use of econometric models for each of the major commercial rate schedules.

The Residential End Use Energy Planning System (REEPS) and Commercial End-Use Forecasting Model (COMMEND) are employed in determining the residential sales forecast and the Hawaii Model Energy Code impacts for the commercial sales forecast. End-use models basically use market share (appliance/equipment saturations), technology characteristics and energy use to calculate energy consumed. Exogenous variables drive the forecast to project energy that will be consumed in future years.

HELCO's Customer Service and Marketing staff also provide base scenario short-term forecasts. In general, because of the experience and breadth of local knowledge possessed by HELCO staff, the adopted forecast relies upon their estimates for short-term sales. With the exception of the Schedule R forecast, which is entirely derived from the REEPS model, the long term forecast is derived by applying econometric projections for growth to the last year of Customer Service or Marketing estimates. This combination of the short-term detailed studies and the long-term perspective is a reasonable method for projecting sales over the twenty-year horizon.

4.1.2.5 Residential Sales Forecast

The REEPS model was initially implemented in HELCO's March 1994 forecast. REEPS is an end use model which examines residential energy consumption at the appliance, or end use level.

The REEPS model requires a large amount of end use data. A significant portion of the required information was derived from the results of the 1994 residential survey and Conditional Demand Analysis (CDA). This survey provided the base year (1994) appliance saturation and marginal saturation data. The survey was also used to determine household size and lighting technology profiles. HELCO conducted a residential appliance survey in 1996; however, the results were not available in time for this latest forecast.

HELCO's appliance energy usage information, or unit energy consumption (UEC), was derived from the 1994 CDA. These UEC's were developed through an extensive analysis of customer appliance saturations and the associated billing data. These appliance usage rates were based on HELCO's specific household income, household size, and electricity price levels.

The water heater provisions of the proposed HMEC are equivalent to the Federal residential appliance efficiency standards. The additional impact of the proposed HMEC above the REEPS model results is minimal.

4.1.2.6 Commercial Rate Schedules

For its long term forecast of commercial sector sales, HELCO relied upon an econometric equation that combines Schedules G, H and P. Combining the rate schedules in this manner removes the impact of transfers of customers among the three commercial rate schedules. Since a projection by rate schedules is still necessary for revenue estimates, the following procedure was used to allocate the commercial sales forecast into the individual rates:

1. HELCO's Customer Service and Marketing Department developed the Schedule H forecast (see discussion below), which was subtracted from the total commercial sales projection.

2. The forecasted Schedule P sales (developed by HELCO's Customer Service and Marketing Department and extended by the econometric model for rate Schedule P) were subtracted from the total commercial sales projection.

3. The remaining portion represents the Schedule G econometric forecast.

Schedule H - Commercial Cooking and Heating Service: The short-term Customer Service forecast for Schedule H was adopted because it takes into account a more detailed look at customers and their electricity usage than the alternative methods. Due to the rate restructuring of Schedule J (combined with Schedule G for forecast purposes), new customers are finding that it is more advantageous to initiate service as a Schedule J customer than as a Schedule H customer. Future schedule H sales are held constant to reflect expected stabilization in sales.

Schedule F - Street Light Service: Street lighting sales have been growing at a rate of 1.8 percent over the past three years. This growth in Schedule F sales is consistent with the additions of newer residential subdivisions and roads in the County. The 1.8 percent growth is extended into the future to forecast Schedule F Sales.

4.1.2.7 System Peaks

HELCO's peak forecast for the 1997 to 2017 period was prepared using the Hourly Electric Load Model (HELM) program. HELM produces a system load profile by summing the estimated aggregate load profiles of customers in each of HELCO's five rate schedules: R, G, H, P and F. The rate schedule aggregate load profiles were derived using customer load data from HELCO's 1993-94 Class Load Study. HELM then uses the energy forecast for each rate schedule to adjust the reference load profiles for each year of the forecast. HELCO's system load profile is equal to the sum of the adjusted class load profiles, and the system peak is the maximum point on the system profile.

Adjustments were applied to the sales and peak forecasts to accommodate the effects of load management riders (Rider M impacts), 1996 acquired DSM efficiency programs, and the Hawaii Model Energy Code.

Table 4-2. Comparison of Base, Low and High Net Peak Forecasts

Year	Sept 1997 Forecast Base Case (Net MW)	Sept 1997 Forecast Low Case (Net MW)	Sept 1997 Forecast High Case (Net MW)
1997	163.3	160.4	167.2
1998	166.0	161.8	171.9
1999	167.7	162.4	175.6
2000	169.3	162.8	181.3
2001	172.1	163.3	187.0
2002	175.6	164.7	193.6
2003	179.5	166.5	201.3
2004	183.4	168.2	209.2
2005	187.4	169.9	217.4
2006	192.2	172.6	226.0
2007	197.0	175.3	234.9
2008	202.0	178.1	244.1
2009	207.0	180.8	253.8
2010	213.6	185.1	265.1
2011	219.4	188.8	275.5
2012	225.1	192.5	286.4
2013	231.0	196.2	297.5
2014	237.1	200.0	309.1
2015	243.3	203.8	321.1
2016	249.9	207.5	332.5
2017	256.7	211.1	344.2

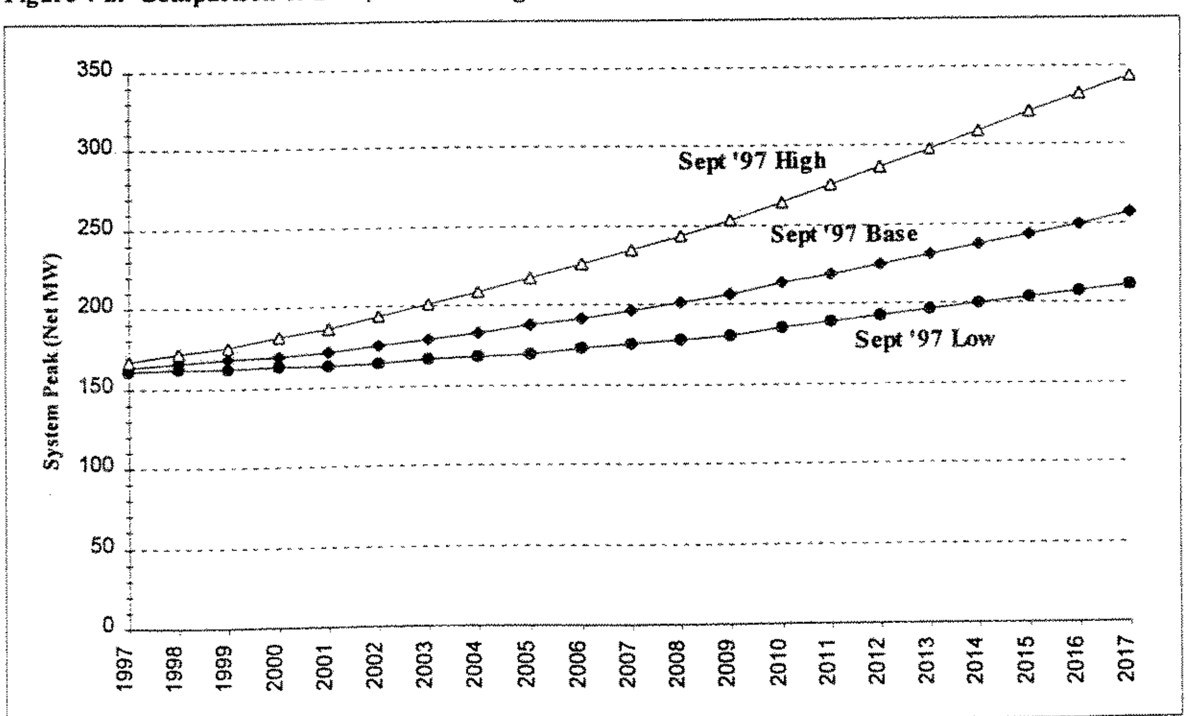
4.1.3 High and Low Forecasts

For IRP sensitivity analyses, HELCO developed two scenarios in addition to the base scenario adopted by the Forecast Planning Committee (FPC). The FPC adopted the low and high scenarios on September 26, 1997. In the low scenario, sales grow at an average rate of 1.4% to 1,119.2 GWh in 2017. The peaks in this scenario grow at an average rate of 1.3% to 211.1 MW in 2017. In the high scenario, sales grow at an average rate of 3.6% to 1,816.1 GWh in 2017, and peaks grow at an average rate of 3.6% to 344.2 MW in 2017. In the base scenario sales grow at an average rate of 2.2% to 1,371.1 GWh in 2017, and peaks grow 2.2% annually to 256.7 MW. The September 1997 high and low peak forecasts are shown in Figure 4-2, with details provided in Table 4-2.

4.1.3.1 Economic Assumptions for High and Low Forecasts

The low scenario projects the Hawaii County visitor census to grow an average of

Figure 4-2. Comparison of Base, Low and High Net Peak Forecasts



3.3% percent annually as the length of stay decreases from 6.34 days in 1995 to 5.94 days in 2017. Projected visitor census growth over the period 1997-2017 is 62%. Real personal income increases 1.7% per year on average. From 1997 to 2017, projected real personal income growth is 41%. Furthermore, the county's resident population is expected to increase at an average annual rate of 0.9%. Over the twenty year period 1997-2017, resident population growth averages 21%.

The high scenario projects the Hawaii County visitor census to grow an average of 4.5% percent annually as the length of stay increases from 6.34 days in 1995 to 6.65 days in 2017. Visitor census growth over the period 1997-2017 is 140%. Real personal income increases 4.1% per year on average. From 1997 to 2017, projected real personal income growth is 122%. Furthermore, the county's resident population is expected to increase at an average annual rate of 2.3%. Over the twenty year period 1997-2017, resident population growth averages 59%.

4.1.3.2 Other Electricity Price Assumptions for High and Low Forecasts

Electricity Price: HELCO also evaluated the effect of changes in the price of electricity on the forecast. For the low scenario, electricity prices were assumed higher due to higher fuel prices. The high scenario assumed lower fuel prices. In addition, the price elasticity in the commercial sales econometric model was doubled in the low scenario and halved in the high scenario to reflect the uncertainty inherent in the estimates of price-based consumer behavior.

Hawaii Model Energy Code (HMEC): Impacts of the HMEC are forecasted to begin in 1998. Compliance with prescribed energy efficient measures of the HMEC lowers forecasted sales and peaks. The uncertainty associated with HMEC impacts is incorporated by doubling the base level impact for the low scenario, and halving the base level impact in the high scenario.

Residential Appliance Efficiency Standards: In the residential low scenario forecast, certain appliance efficiency improvements in the REEPS model were accelerated. Higher efficiencies result in a lower sales forecast. These appliances include freezers, central air conditioners, room air conditioners, water heaters and dishwashers. Additionally, the low scenario assumes that an efficient refrigerator is available on the market with an efficiency rating of ER18.

There were no adjustments made to the appliance efficiencies for the residential high scenario. Thus, the appliance efficiencies in the high scenario are the same as the base scenario.

Residential Air Conditioning Saturations: The high scenario assumes that more new homes own air conditioners.

Electric Vehicles (EV): In the commercial sector, the high scenario assumes 3300 EVs in the year 2017. The estimated GWh impact is assumed to be an addition to Schedule P for the years 2000-2017.

4.1.4 June 1998 Short-term Forecast

A short-term HELCO sales and peak forecast was issued on June 9, 1998. The forecast covers the period 1999-2003. Sales by rate schedule was adjusted in the June 1998 forecast, but total system sales and peak remained the same as forecast in the September 1997 20-year forecast used as the basis for the IRP-98 analyses.

4.1.5 Forecast Sensitivities

A summary of the differences between the scenarios broken down by exogenous variables and sector (residential or commercial) is presented in Table 4-3. The sales impact was derived by varying each variable separately between its high and low scenario values and re-running the econometric and end use models. Each resulting sales forecast was compared to the base sales forecast for 2015. The difference represents the impact of that variable on the sales forecast.

For example, in the high scenario, higher economic variables were input into the residential and commercial models. These included higher population and higher income. Residential sales increased by 109.6 GWh due to the higher economic variables used. Commercial sales increased by 218.6 GWh due to the higher economic variables used. For the electricity price impact, lower prices (which result in higher sales) were input into the residential and commercial models. The impact was 4.9 GWh and 2.7 GWh on residential and commercial sales forecasts, respectively.

The sum of all impacts from changes in these variables explains a majority of the differences between the alternative scenarios and the base scenario. This analysis helps to determine the magnitude of the impact that each variable has on the forecast.

As shown by Table 4-3, the forecast is particularly sensitive to the economic assumptions underlying the forecast. The combination of resident population, visitor census and personal income growth rates are the primary drivers of electricity consumption and demand. The forecast is more than ten times less sensitive to electricity prices - the second key assumption.

Table 4-3. Sales Sensitivity

2015 - High Scenario	Res	Comm	Total
Economy	109.6	218.6	328.2
Electricity Prices	4.9	2.7	7.6
HMEC		5.3	5.3
Res Efficiencies			0.0
Res A/C	3.2		3.2
Elec Vehicles		6.8	6.8
Price Elasticity		1.2	1.2
Total	117.7	234.6	352.3
Actual Difference	143.9	251.5	395.4

2015 - Low Scenario	Res	Comm	Total
Economy	-50.9	-124.6	-175.5
Electricity Prices	-8.1	-5.2	-13.3
HMEC		-10.6	-10.6
Res Efficiencies			0.0
Res A/C	-8.2		-8.2
Elec Vehicles			0.0
Price Elasticity		-0.6	-0.6
Total	-67.2	-141	-208.2
Actual Difference	-83	-115.8	-198.8

4.2 FUEL PRICE FORECAST

The IRP-98 analysis is based on the May 22, 1995 Fuel Price Forecast, which projects medium sulfur fuel oil (MSFO), No. 2 diesel and coal prices for the period 1995-2020 (1995-2015 for coal). The escalation in the fuel price forecast is based on the U.S. Department of Energy's forecast of inflation (Gross Domestic Product Implicit Price Deflator (GDPIPD)) and on a forecast for real fuel price changes over and above that of the GDPIPD. Fuel prices for HELCO include barge freight from Oahu, terminalling fees and trucking to the power plants. Development of forecasts for MSFO, diesel and coal prices are discussed below. High, low and reference case forecasts are provided in Appendix F.

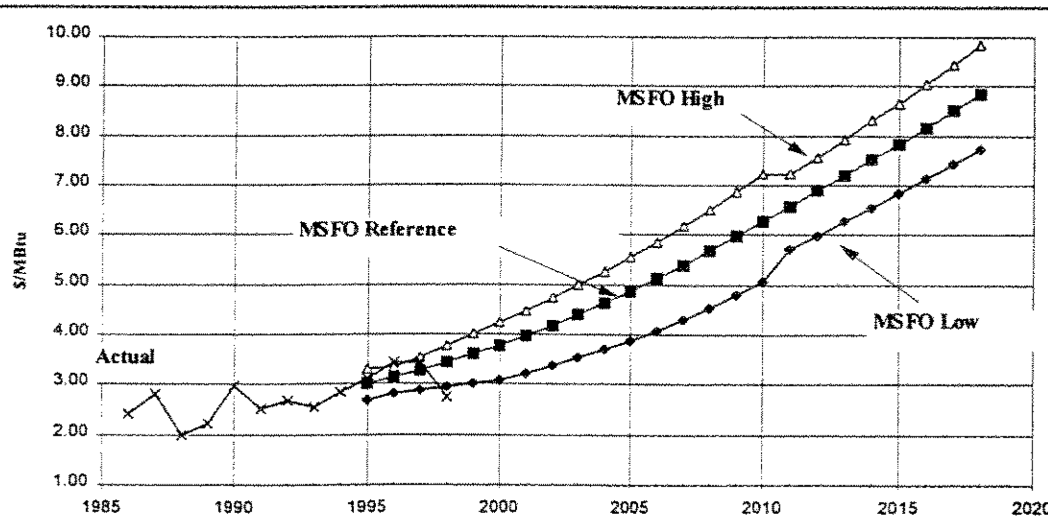
MSFO - The medium (2%) sulfur fuel oil (MSFO) forecast for 1995 was based on Los Angeles Bunker C Fuel Oil prices. This 1995 forecasted price was then escalated by the average annual escalation of long-term price forecasts produced by other organizations:

- U.S. Department of Energy
- California Energy Commission
- DRI/Electric Power Research Institute (EPRI)
- American Gas Association
- Gas Research Institute
- WEFA

DRI/EPRI and the U.S. Department of Energy also publish low and high forecasts in addition to reference price forecasts. For the period 1995-2010, these two forecasts were used as the basis for the development of the low and high case MSFO price forecasts in relation to the reference case. After 2010, when the U.S. Department of Energy forecast ends, the low and high MSFO prices are based on the DRI/EPRI forecast only. This is the reason for the slight discontinuity in the high and low forecasts in 2010. The May 1995 reference, low and high MSFO price forecasts are shown in Figure 4-3, along with historical averages from 1986.

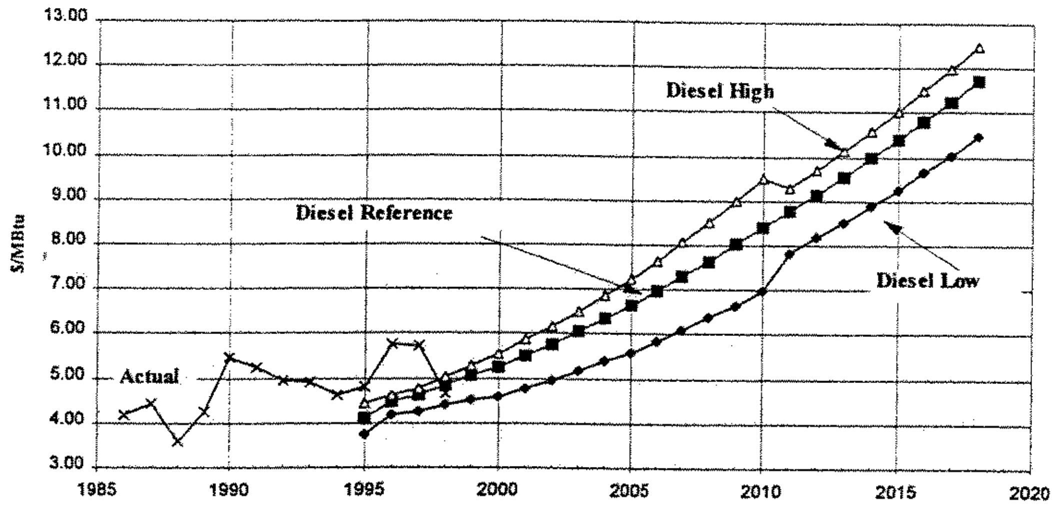
Diesel - The No. 2 diesel price forecast for 1995 was based on historical Pacific Northwest No. 2 diesel prices. Similar to development of the long-term MSFO forecast, the 1995 forecasted diesel price was escalated by the average annual

Figure 4-3. May 1995 MSFO Price Forecast vs. Actual



Actual system average MSFO prices (through June 1998) vs May 1995 MSFO forecast, delivered to Hill

Figure 4-4: May 1995 Diesel Price Forecast vs. Actual



Actual system average diesel prices (through June 1998) vs May 1995 diesel forecast, delivered to Hill

increase of other long-term diesel price forecasts. The low and high diesel price forecasts were developed through an identical process as described above for MSFO. The May 1995 reference, low and high diesel price forecasts, as well as historical average prices from 1986, are illustrated in Figure 4-4.

Coal - The coal price forecast is based on Indonesian low sulfur coal, or coal of similar quality. The forecasted prices are based on the 1988 coal supply contract price between AES and PT Kaltim Prima Coal, a mining consortium operating the source mine in Indonesia. The 1988 AES coal price was escalated to a 1993 market price by using historical import values of coal obtained from Australia, the dominant regional producer of low sulfur coals. This surrogate for the 1993 market price for low sulfur coal imported to Hawaii was then escalated to produce a forecast for the period 1995-2015 using the annual percentage change of Japan import coal prices forecast by the International Energy Agency.

4.2.1.1 Comparison of May 1995 Forecast to August 1992 Forecast

Figure 4-5 compares the August 1992 base MSFO, diesel and coal price forecasts used in IRP-93 against the May 1995 base forecasts used in the current IRP. Actual annual average fuel prices from 1986 through June 1998 are also provided as a basis for comparison. Several observations to note:

- a dramatic decline in the forecasted prices of all three fuel types between August 1992 and May 1995
- a significant reduction in the price differential between oil and coal
- deviation of actual MSFO and diesel prices from the current (May 1995) forecast in the period 1995-1997 (discussed in section 4.2.1.2 below)

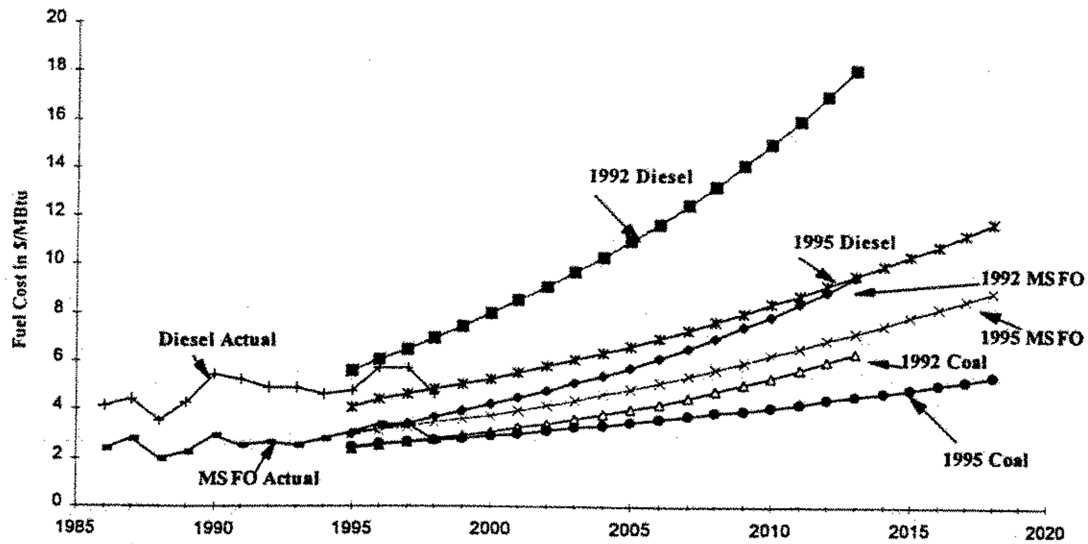
Table 4-4 provides the details of the forecasted price comparison.

Table 4-4: Comparison of May 1995, August 1992 and Actual Fuel Prices

Year	May 1995 Forecast			August 1992 Forecast			Difference 1992-1995 Forecast			Actual	
	MSFO	Diesel	Coal	MSFO	Diesel	Coal	MSFO	Diesel	Coal	MSFO	Diesel
1986	-	-	-	-	-	-	-	-	-	2.42	4.19
1987	-	-	-	-	-	-	-	-	-	2.81	4.43
1988	-	-	-	-	-	-	-	-	-	1.97	3.57
1989	-	-	-	-	-	-	-	-	-	2.23	4.27
1990	-	-	-	-	-	-	-	-	-	2.97	5.46
1991	-	-	-	-	-	-	-	-	-	2.50	5.24
1992	-	-	-	-	-	-	-	-	-	2.67	4.94
1993	-	-	-	-	-	-	-	-	-	2.56	4.92
1994	-	-	-	-	-	-	-	-	-	2.83	4.63
1995	3.02	4.11	2.47	2.98	5.61	2.42	-0.04	1.50	-0.05	3.10	4.80
1996	3.15	4.47	2.57	3.20	6.05	2.54	0.05	1.58	-0.03	3.45	5.75
1997	3.28	4.63	2.65	3.43	6.49	2.67	0.15	1.86	0.02	3.44	5.74
1998	3.45	4.85	2.73	3.68	6.97	2.80	0.23	2.12	0.07	2.76	4.66
1999	3.62	5.06	2.81	3.94	7.46	2.94	0.32	2.40	0.13	-	-
2000	3.78	5.25	2.90	4.20	7.97	3.09	0.42	2.72	0.19	-	-
2001	3.97	5.51	3.01	4.49	8.50	3.25	0.52	2.99	0.24	-	-
2002	4.18	5.77	3.13	4.78	9.07	3.42	0.60	3.30	0.29	-	-
2003	4.39	6.04	3.24	5.09	9.67	3.60	0.70	3.63	0.36	-	-
2004	4.62	6.34	3.37	5.42	10.31	3.80	0.80	3.97	0.43	-	-
2005	4.86	6.64	3.50	5.76	10.98	4.00	0.90	4.34	0.50	-	-
2006	5.12	6.96	3.61	6.14	11.70	4.23	1.02	4.74	0.62	-	-
2007	5.39	7.30	3.73	6.53	12.46	4.49	1.14	5.16	0.76	-	-
2008	5.67	7.65	3.86	6.96	13.27	4.75	1.29	5.62	0.89	-	-
2009	5.97	8.02	3.99	7.41	14.12	5.03	1.44	6.10	1.04	-	-
2010	6.29	8.41	4.12	7.87	15.02	5.33	1.58	6.61	1.21	-	-
2011	6.58	8.77	4.26	8.37	15.97	5.64	1.79	7.20	1.38	-	-
2012	6.89	9.15	4.41	8.90	17.01	5.98	2.01	7.86	1.57	-	-
2013	7.20	9.56	4.56	9.46	18.09	6.33	2.26	8.53	1.77	-	-
2014	7.53	9.97	4.71	-	-	-	-	-	-	-	-
2015	7.84	10.38	4.87	-	-	-	-	-	-	-	-
2016	8.16	10.80	5.03	-	-	-	-	-	-	-	-
2017	8.50	11.25	5.20	-	-	-	-	-	-	-	-
2018	8.85	11.71	5.38	-	-	-	-	-	-	-	-

Forecasted prices delivered to Hill plant.
Actuals reflect HELCO average prices. Actual for 1998 through June 1998.

Figure 4-5: Historical and Forecasted Fuel Prices



Actuals for 1998 are June YTD averages

4.2.1.2 Validity of Fuel Price Forecast

As illustrated in Figures 4-3 and 4-4, the actual prices of MSFO and diesel fuel increased above the high price forecast for each respective fuel from the end of 1995 through Fall 1997. These higher prices can be attributed to a number of anomalous events, such as weather and the political situation between the United Nations and Iraq. The most influential factor, however, was the historically low levels of petroleum product stocks in the United States. These low levels were the result of:

- an extremely cold winter following several years of milder winters where inventory levels were reduced;
- a change in oil refineries' oil storage policies to a "just in time" policy to improve their competitive position; and,
- the supply from the Strategic Petroleum Reserve not being utilized to mitigate the upward price pressure.[28]

The high pricing level experienced is not believed to be indicative of long-term trends, and producing a new forecast from such a high base would not have been meaningful. This assessment has been confirmed in the approximately 30 percent decline in crude oil and other petroleum prices between the levels prevailing in the second half of 1996 and the first quarter of 1998. Based on these considerations, HELCO believes that its May 22, 1995 fuel price forecast is still valid for long-term planning purposes.

4.3 EXISTING SYSTEM

4.3.1 HELCO System

HELCO currently owns and operates a total of 25 firm generating units, totaling about 151 MW (net), at five generating stations. HELCO also purchases a total of 52 MW of firm power from two existing independent

[28] Presentation by Dr. Kenneth Haley, Manager of Energy Forecasting, Strategic Planning Department, Chevron Corporation, on July 1, 1997 at a HECO IRP Advisory Group Meeting.

power producers (IPPs), Hilo Coast Processing Company (HCPC) and Puna Geothermal Ventures (PGV). Table 4-5 summarizes the characteristics of the firm generating units presently on the HELCO system.

In 1997, about 30% of HELCO's total generation came from renewable sources, including wind, hydro and geothermal. These renewable sources include a HELCO-owned windfarm at Lalamilo, two HELCO-owned run-of-the-river hydro facilities at Waiau and Puueo, and a number of wind and hydro IPPs (see Table 4-6).

During the course of the IRP-98 analysis, the Hill 6 net continuous (or reserve) rating was reduced from 21.75MW to 19.6MW. The 19.6 MW net reserve rating is derived from testing, and is due to decreasing fuel efficiency over time.

4.3.2 HELCO Unit Retirements

For long-term planning purposes, HELCO has estimated a typical service life of 25 years for the diesels, 30 years for the combustion turbines and 50 years for the steam turbines. The actual retirement date of a unit will depend on the condition of the unit as it nears its proposed retirement. A unit may be retired sooner or replaced with another unit if this is determined to be more economical. The age and expected retirement date for each HELCO owned unit is indicated in Table 4-5. As can be seen in the table, a number of generating units have already exceeded their expected service lives.

Table 4-6. As-available (Non-firm) Resources

	As-Available Capacity (kW)	1997 Actual Generation (MWh_{net})
HELCO AS-AVAILABLE		
Puueo Hydro	2,250	12,161
Waiau Hydro	1,100	6,633
Lalamilo Wind Farm	2,280	4,030
AS-AVAILABLE IPPs		
Wailuku River Hydro	11,000	30,445
Apollo Energy	7,000	12,047
Other	399	1,446
TOTAL AS-AVAILABLE	24,029	66,762

HELCO originally contemplated placing CT-1 on standby status in 1991 upon the installation of PGV, and retiring diesels 8, 9 and 10 in 1993 when both PGV and CT-3 were installed. However, the delay in PGV caused HELCO to defer the retirement of CT-1. When CT-1 was operated in regular service longer than anticipated, it experienced a number of mechanical problems including failure of the starting engine, generator and turbine rotor. Extensive repairs were completed in 1992. In the October 1993 IRP-93 filing, with the next increment of capacity needed by January 1995, and the expectation at the time that CT-4 would be installed by July 1995, all plant retirements were postponed until after CT-4 was placed in service.

With the continued delay in the next large increment of capacity, HELCO has pursued various avenues to maximize the amount of generation available to the system, one of which is the deferral of planned unit retirements. While discussed in detail in the Contingency Plan[29], mitigation measures that have been taken are summarized below:

- HELCO has restored 2.5 MW of reserve and 4.5 MW of normal top load (NTL) generating capacity through overhauls and repair work.[30]

[29] Hawaii Electric Light Company, Inc. Generation Resource Contingency Plan Update #4 was filed with the Commission on June 12, 1998 in Docket No. 96-0029.

[30] Reserve rating is the maximum capacity of the unit. Normal Top Load (NTL) is the maximum capacity at which the unit is normally allowed to dispatch on a daily basis.

Table 4-5: Firm Generating Resources

Unit	Duty Cycle	Fuel Type	Unit Minimum Rating (MW) Gross	Unit Minimum Rating (MW) Net	Unit Reserve Rating (MW) Gross	Unit Reserve Rating (MW) Net	Initial Operation Date	Current Age in 9/98 (Years)	Service Review Date
HELCO UNITS									
Shipman 1	Cycling	MSFO	3.0	2.7	3.4	3.1	1943	55	1999 [7]
Shipman 3	Cycling	MSFO	5.0	4.6	7.5	7.1	1955	43	2005
Shipman 4	Cycling	MSFO	5.0	4.7	7.7	7.3	1958	40	2008
Hill 5 (Kanoelehua)	Baseload	MSFO	8.0	7.4	14.1	13.5	1965	33	2015
Hill 6 (Kanoelehua)	Baseload	MSFO	16.0	14.9	20.8	19.5	1974	24	2024
Puna	Baseload[1]	MSFO	8.0	7.1	15.5	15.0	1970	28	2020
Waimea Diesel 8	Peaking	Diesel	0.6	0.6	1.0	1.0	1954	44	1999 [7]
Waimea Diesel 9	Peaking	Diesel	0.6	0.6	1.0	1.0	1954	44	1999 [7]
Waimea Diesel 10	Peaking	Diesel	0.7	0.7	1.0	1.0	1954	44	1999 [7]
Kanoelehua Diesel 11	Peaking	Diesel	2.0	2.0	2.0	2.0	1962	36	1999 [8]
Waimea Diesel 12	Peaking	Diesel	2.5	2.5	2.75	2.75	1970	28	1999 [7]
Waimea Diesel 13	Peaking	Diesel	2.5	2.5	2.75	2.75	1972	26	1999 [7]
Waimea Diesel 14	Peaking	Diesel	2.5	2.5	2.75	2.75	1972	26	1999 [7]
Kanoelehua Diesel 15	Peaking	Diesel	2.5	2.5	2.75	2.75	1972	26	1999 [8]
Kanoelehua Diesel 16	Peaking	Diesel	2.5	2.5	2.75	2.75	1972	26	1999 [8]
Kanoelehua Diesel 17	Peaking	Diesel	2.5	2.5	2.75	2.75	1973	25	1999 [8]
Keahole Diesel 18	Peaking	Diesel	2.5	2.5	2.75	2.75	1974	24	1999 [6]
Keahole Diesel 19	Peaking	Diesel	2.5	2.5	2.75	2.75	1974	24	1999 [6]
Keahole Diesel 20	Peaking	Diesel	2.5	2.5	2.75	2.75	1966[2]	32	1999 [6]
Keahole Diesel 21	Peaking	Diesel	2.5	2.5	2.75	2.75	1967[2]	31	1999 [8]
Keahole Diesel 22	Peaking	Diesel	2.5	2.5	2.75	2.75	1967[2]	31	1999 [8]
Keahole Diesel 23	Peaking	Diesel	2.5	2.5	2.75	2.75	1970's[2]	28	1999 [8]
Kanoelehua CT1	Peaking	Diesel	6.0	6.0	11.5	11.5	1962	36	1999 [8]
Keahole CT2	Cycling	Diesel	11.5	11.3	15.9	15.6	1989	9	2019
Puna CT3	Cycling	Diesel	8.3	8.1	20.8	20.4	1992	6	2022
Keahole CT4	Cycling	Diesel	5.0	4.9	20.0	19.9	1998[3]	NA	2028
Keahole CT5	Cycling	Diesel	5.0	4.9	20.0	19.9	1998[3]	NA	2028
TOTAL HELCO			114.7	110.4	195.2	190.8			
FIRM PURCHASES[4]							Contract start		Contract expires
Puna Geothermal Ventures (PGV)	Baseload	N/A		22.0		30.0	1993		2027
Hilo Coast Processing Company (HCPC)	Baseload	Coal		4.0		22.0	1995		1999
Encogen	Cycling	Naphtha		14.0 [5]		60.0	1999[3]		2029
TOTAL PURCHASED				26.0		112.0			

Unit ratings are based on test data and are subject to change.

[1] Puna will be placed on standby upon commercial operation of Encogen Phase 2, and will return from standby as a cycling unit.

[2] Diesels 20 through 23 were purchased used from various sources.

[3] Expected in-service dates for CT-4, CT-5 and Encogen.

[4] Capacity for firm purchases reflect net to system.

[5] 14 MW (per CT) minimum used in IRP analysis is based on information from Encogen prior to the PPA. The contracted minimum is 16 MW with both CTs on in combined cycle mode.

[6] Keahole D18-20 scheduled to retire upon installation of Keahole CT-4 and CT-5.

[7] Shipman 1, Waimea D8-10, D12-14 scheduled to retire upon installation of Encogen Phase 1.

[8] Kanoelehua D11, D15-17, Keahole D21-23, and CT-1 are scheduled to retire when Encogen Phase 2 comes on-line.

- HELCO has deferred the planned retirement of 33.65 MW of capacity until a sufficient increment of new capacity can be installed. Shipman 1, CT-1, Waimea D8-10, D12-14 and Kanoelehua D11, 15-16, which were scheduled to retire between 1995-1997 in IRP-93, are now scheduled to retire when Encogen comes on -line. (Shipman 1, Waimea D8-10, D12-14 with Encogen Phase 1; Kanoelehua D11 and D15-17, Keahole D21-23 and CT-1 with Encogen Phase 2).
- HELCO has installed four 1 MW high-speed diesel generators at HELCO's Panaewa, Ouli, Kapua and Punaluu substations for stand-by operation. The four units, identified as D24-D27, were installed between November and December, 1997. These units are currently planned to be retired upon commercial operation of the Encogen DTCC.

4.3.3 Puna Standby

The Puna steam unit will be placed on cold standby reserve service upon commercial operation of the Encogen DTCC, currently planned for August 1999. It is expected that cold standby operation would entail: (1) the use of a nitrogen gas blanket for the feedwater heaters, (2) filling the boiler and condenser with water, which would be treated to prevent corrosion, (3) the installation of heat blankets on unit auxiliaries, and (4) periodic inspection and tests of the condition of the major unit components to insure their integrity. During the period when the unit is on cold standby, it will not be counted toward the total capability of the system. Placing Puna on standby will result in cost savings through reduced O&M, which will partially offset the increase in costs expected with the installation of new capacity in the 1998-99 timeframe. The Puna steam unit would be returned to service when additional generation is required (following Encogen and currently projected to be in 2003) to maintain compliance with HELCO's generation capacity planning criteria and to defer the installation of ST-7 at Keahole. The estimated time required to take the Puna steam unit out of cold standby and prepare it for service is several weeks.

4.3.4 Non-Utility Generating Resources

Between IRP-93 and IRP-98, several changes have occurred with regard to firm purchases:

- The contract with Hamakua Sugar Company for 8MW expired in 1994.
- The IRP-93 analysis assumed that HCPC would continue to supply HELCO with 18MW of firm capacity through 2013, the end of the IRP-93 planning period. On December 12, 1994 HCPC filed for Chapter 11 bankruptcy and notified HELCO of its intent to shutdown the power plant (default on its contract). HELCO and HCPC negotiated an amended PPA where HCPC would provide capacity at 20MW in January 1995 and 22MW from June 1995 through December 1999. HELCO in turn would increase its capacity payment to HCPC, to provide a $6 million loan to HCPC to pay for its employee benefits and severance pay obligations, to provide funds necessary for any capital improvements to HCPC's power plant, and to provide a $2 million revolving line of credit to HCPC for fuel purchases. HELCO is using 22MW for HCPC which terminates in December 1999.
- PGV increased their firm capacity from 25 MW to 30 MW on September 23, 1996.
- On October 22, 1997, HELCO signed a purchase power agreement (PPA) with Encogen for the purchase of 62 MW (gross) of firm capacity and energy. Encogen's dual train combined cycle is

planned to be on-line by April (Phase 1) and August (Phase 2) 1999. The status of this project is further discussed in Section 4.4.2.

There are also several independent power producers who furnish power to the HELCO grid on a non-firm, as-available basis, as summarized previously in Table 4-6. For IRP modeling purposes, the as-available suppliers were treated as a "transaction"; that is, they are modeled as if they supply a relatively constant supply of as-available energy throughout the year, with some seasonal variation based on a historical average of their actual generation.

4.4 COMMITTED SUPPLY SIDE AND DSM PROJECTS

4.4.1 Status of Keahole CT-4 and CT-5

HELCO's current supply-side resource plan includes the near term installation of two combustion turbine generators, CT-4 (20MW) and CT-5 (20MW) at its Keahole Generating Station. Much of the uncertainty regarding the permitting for HELCO's Keahole DTCC unit has been resolved. The three motions for stay on HELCO's Conservation District Use Permit (CDUP) Amendment were denied, and HELCO is now proceeding to put the Keahole site to use consistent with the CDUP Amendment. The prevention of significant deterioration (PSD)/covered source permit ("air permit") was issued by Hawaii Department of Health (DOH) letter dated October 28, 1997, although it will not be effective until appeals to the Environmental Appeals Board (EAB) of the U.S. Environmental Protection Agency (EPA) are resolved. Recent experience indicates that such appeals take 5½ to 7 months to resolve. In the meantime, HELCO has proceeded with pre-PSD grading and site work (which is expected to be completed by the end of May 1998), as previously approved by DOH with EPA's concurrence. As a result, HELCO expects to be able to install both CT-4 and CT-5 in the December 1998 timeframe. HELCO continues to provide the Commission with a monthly report on the status of these items (in accordance with Docket No. 7623, D&O No. 14284).

Future conversion of CT-4 and CT-5 to a dual train combined-cycle unit with the addition of ST-7 is addressed in this IRP.

4.4.2 Status of Encogen

On January 16, 1998, HELCO filed an application requesting Commission approval of a PPA and Interconnection Agreement with Encogen dated October 22, 1997. Encogen plans to install a 60 MW (net) dual-train combined cycle qualifying cogeneration facility near Haina, Hawaii. Assuming the PPA and Interconnection Agreement are approved by the Commission by August 1998 (and that the approvals are not appealed), and there are no delays due to an appeal of its air permit, the two phases of the Encogen facility can be installed by April 1999 and August 1999, respectively. (See Docket No. 98-0013.)

The June 1998 Contingency Plan Update concluded that in order to address delays in and uncertainties associated with the addition of needed generation, HELCO would maximize its generation options by proceeding with Keahole CT-4 and CT-5 in parallel with Encogen. This strategy increases the likelihood of providing reliable power to HELCO's customers. See Appendix P for the Executive Summary of the June 1998 Contingency Plan Update. See Section 1.3.1 for further information on HELCO's contingency plans.

4.4.3 Existing DSM

In mid-December 1995, HELCO "rolled out" its residential and commercial & industrial DSM programs. These programs include a Residential Efficient Water Heating Program, Commercial & Industrial Energy Efficiency Program, Commercial & Industrial New Construction Program, and a Commercial & Industrial Customized Rebate Program. Through 1997, the four programs had total system-level impacts of 2.365 MW peak reduction and 10,130 MWh annual energy savings. DSM Annual Accomplishments and Surcharge Reports were filed in June 1997 (with an Addendum filed in November 1997) and March 1998 to report on the detailed performance of these DSM programs. Also, HELCO's DSM Modifications and Evaluation Report, dated November 26, 1997, was filed with the Commission on November 28, 1997.

HELCO plans to continue development and implementation of selected measures of the Residential Retrofit Program (Docket No. 7692) within the existing Residential Efficient Water Heating Program. In 1996 and 1997, approximately 21,000 high-efficiency showerheads were distributed to residents on request. As it did in 1996, HELCO promoted compact fluorescent lamps to residential customers through the distribution of approximately 58,000 rebate coupons via a bill insert from October to December, 1997. An additional 5,000 coupons have been distributed to participating dealers and vendors. Coupons are also being distributed to customers via the HELCO customer service lobbies. Eleven vendors participated in the program (five in Hilo, four in Kona, and two in Waimea). A similar program, with one additional vendor, is currently planned for July-August of 1998.

HELCO has also continued with aggressive promotion of its load management rates and rate riders, including Rider M, Rider T and Schedule U. As of November 30, 1997, HELCO has 28 contracts with its Commercial and Industrial customers totaling approximately 6.7 MW of loads curtailed off the priority peak period, 5:00 PM to 9:00 PM, Monday through Friday. HELCO is negotiating additional contracts for approximately 1.0 MW of load curtailment to be added in 1998.

4.5 SUPPLY SIDE RESOURCE OPTIONS (SRO)

A detailed discussion of all supply-side resources considered in this IRP can be found in Section 7.0. An initial screening of commercially available fossil-fired alternatives was performed in order to limit consideration to those resources within each technology type that were most likely to prove cost-effective in the integration analysis. All renewable technologies were carried forward to the integration phase. Table 4-7 summarizes the principal characteristics of the short-list of supply-side alternatives considered in the integration analysis.

Table 4-7: IRP-98 Supply-side Resources included in Integration Analysis

Commercial Resource Options	Fuel Type	Gross Capacity (MW)	Auxiliary Power (MW)	Net Capacity (MW)	Net Heat Rate (Btu/kWh)	Duty Cycle	Service Life (Years)	Land Req'd (Acres)	Total Capital Cost (1997 $mil)	Fixed o&m (1997 $mil/yr)	Variable o&m (1997 $/MWh)
SIMPLE CYCLE											
LM2500 STIG	No. 2 FO	23.1	0.4	22.7	9,760	Baseload	30	3.5	41.66	0.515	5.96
GE LM2500	No. 2 FO	21.3	0.4	20.9	10,970	Peaking	30	2.3	31.39	0.507	21.78
LM6000	No. 2 FO	44.0	0.5	43.5	9,360	Peaking	30	2.4	37.91	0.512	13.21
DIESEL ENGINE											
Diesel Engine Generator	No. 2 FO	10.9	0.5	10.4	8,510	Peaking	30	1.7	23.17	1.212	19.13
Diesel Engine Generator	No. 2 FO	1.00	0.03	0.97	9,408	Peaking	15	N/A	1.07	0.013	10.47
COMBINED CYCLE											
1 on 1 GE LM2500-PE	No. 2 FO	30.6	0.9	29.7	7,960	Baseload	30	3.5	55.27	1.422	4.55
2 on 1 GE LM2500-PE	No. 2 FO	62.5	1.8	60.7	7,790	Baseload	30	4.0	85.06	1.530	4.58
2 on 1 GE LM2500-PE w/Hill 5 STG and BOP	No. 2 FO	60.0	1.7	58.3	8,130	Baseload	30	0.0	64.50	1.416	4.32
2 on 1 GE LM2500-PE w/Hill 6 STG and BOP	No. 2 FO	59.8	1.7	58.1	8,180	Baseload	30	0.0	68.09	1.419	4.37
2 on 1 GE LM2500-PE w/Puna STG	No. 2 FO	57.8	0.5	57.3	8,480	Baseload	30	0.0	43.00	1.402	4.49
OTHER											
Atmospheric Fluidized Bed Coal	Coal	30.0	3.3	26.7	11,130	Baseload	30	6	101.5	5.050	7.36
Phosphoric Acid Fuel Cell	Propane	0.2	0.01	0.19	10,000	Baseload	20	0.05	1.02	0.067	0.84
RENEWABLE											
Biomass Combustion	Banagrass	28.1	3.1	25.0	15,600	Baseload	30	7608*	66.32	3.816	5.52
Geothermal	N/A	29.0	4.0	25.0	N/A	Baseload	30	20-30	81.67(low) 127.76(high)	4.224	7.79
10MW Wind Energy @ Lalamilo	N/A	-	-	10MW (rated)	N/A	Supplemental	30	71	12.58	0.683	4.45
5 MW Wind Energy @ Lalamilo	N/A	-	-	5MW (rated)	N/A	Supplemental	30	35	7.06	0.423	4.39
10MW Wind Energy @ N. Kohala	N/A	-	-	10MW (rated)	N/A	Supplemental	30	71	20.08	0.683	4.98
5 MW Wind Energy @ N. Kohala	N/A	-	-	5MW (rated)	N/A	Supplemental	30	35	7.29	0.423	4.98
10MW Wind Energy @ Kahua Ranch	N/A	-	-	10MW (rated)	N/A	Supplemental	30	71	16.36	0.683	3.31
5 MW Wind Energy @ Kahua Ranch	N/A	-	-	5MW (rated)	N/A	Supplemental	30	35	6.91	0.423	3.27
Battery Energy Storage (3hrs @ 10MW)	N/A	5.3	0.3	5	N/A	Storage	20	0.7	13.53	0.154	258.00
Battery Energy Storage, Spinning Reserve (20min @ 10MW)	N/A	10.5	0.5	10	N/A	Spinning Reserve	20	0.7	14.14	0.154	0.00
0.9 kW PV Energy - Distributed	Solar	-	-	0.9kW (rated)	N/A	Supplemental	20	N/A	0.024	0.000	377.41
4 MW PV Energy-N. Kohala	Solar	-	-	4MW (rated)	N/A	Supplemental	20	20	29.37 (low) 49.59 (high)	0.227	2.10
Pumped Storage Hydro - Puu Anahulu	N/A	30.2	0.2	30	N/A	Storage	50	60	73.32	1.1	N/A
Pumped Storage Hydro - Puu Enuhe	N/A	30.2	0.2	30	N/A	Storage	50	40	64.55	1.1	N/A
Run of River Hydro-Umauma	N/A	14.5	0.7	13.8	N/A	Supplemental	50	N/A	25.33	0.133	1.87

Notes:
Gross Capacity, Auxiliary Power, Net Capacity and Net Heat Rate at Average Conditions
Includes cost of purchase or lease of land
Variable O&M for supplemental resources in $/Mwh$_{avg}$
*7600 acres for banagrass; 8 acres for plant

4.6 DEMAND-SIDE MANAGEMENT PROGRAM OPTIONS

4.6.1 Energy Efficiency DSM

HELCO is currently implementing four energy efficiency DSM programs, approved by the Commission for a five-year period ending in the year 2000:

- Residential Efficient Water Heating (REWH)
- Commercial & Industrial Energy Efficiency (CIEE)
- Commercial & Industrial New Construction (CINC)
- Commercial & Industrial Custom Rebate (CICR)

As discussed in detail in Section 6, forecasted costs and impacts of the four programs have been re-evaluated in this IRP, but the program structures and DSM technologies are basically the same as what is currently being implemented. Updated estimates of program costs and impacts were developed for all four programs for

- 2 years through the 5-year PUC approved period (1999-2000), and
- 20 years through the IRP planning period (1999-2018).

Tables 6-30 and 6-31 in the DSM assessment show the ratio of benefits to costs (B/C ratios) from various perspectives for each of the 2-year and 20-year programs. Except for the 2-year REWH program which is marginal, all programs have B/C>1.0 by the Utility cost, TRC, Societal and Participant tests. None of the programs pass the Rate Impact Measure test.

Although the DSM programs may have B/C ratios greater than 1.0 by the standard practice tests, it does not necessarily mean that the programs will be cost-effective when allowed to "compete" against supply-side resources in a dynamic optimization. The reason for this is that the B/C ratios are derived by measuring the cost of the DSM program against the capacity deferral value and avoided production (fuel and O&M) costs of a static, least-cost reference supply plan. Proview optimization runs, where the model was allowed to select the least cost mix of the four DSM programs given various supply-side alternatives, confirmed the cost-effectiveness of all four 20-year programs from the Utility, Societal and TRC perspectives. That is, the plan which included all four 20-year programs was the least cost plan from these perspectives.

Since this preliminary DSM analysis indicated all four 20-year programs were cost-effective, the integration analysis evaluated two DSM options:
Option 1: Continuation of all four DSM programs through the 5-year PUC approved period, ending in 2000, and
Option 2: Continuation of all four DSM programs through the 20-year IRP planning period

4.6.2 Capacity Buy-Back Pilot Program

A pilot Capacity Buy-back DSM program was approved by the PUC in Decision and Order 15457, Docket No. 96-0421 on March 24, 1997. Given the positive customer response to HELCO's rate rider contracts, HELCO is not pursuing implementation of the Capacity Buy-back program at this time.

As part of its Contingency Generation Resource Plan, HELCO has made an aggressive effort to acquire 28 contracts, or about 6.7 MW of potential peak-shaving capacity through its existing load management rates and rate riders (Schedule U, Rider M and Rider T). These rider contracts give incentives to customers to curtail load during system peak periods. However, compliance on any given night is not assured and long-term participation by customers has not been demonstrated. Therefore, for long-term planning purposes, HELCO has assumed 5.5 MW is curtailed at the daily peak.

4.7 SUMMARY OF FINANCIAL DATA AND OTHER ASSUMPTIONS

Table 4-8 summarizes the significant assumptions used in the IRP-98 integration analysis.

Table 4-8. Summary of IRP-98 Assumptions

ITEM	ASSUMPTION		
Analysis Period	1999-2018 (specified by IRP Framework)		
Transmission & Distribution Losses and Company Use	8.64% of net generation		
Sales & Peak Load Forecast	September 1997 HELCO Sales & Peak Forecast (Appendix E)		
Fuel Price Forecast	May 22, 1995 Fuel Price Forecast (Appendix F)		
DSM Cost and Performance Data	Data shown in Section 6		
Future Supply-side Resource Cost and Performance Data	Data shown in Table 4-7 and Appendix G		
Existing generating unit data	Data shown in Section 4.3		
Existing unit retirements	Data shown in Section 4.3		
Purchase Power Agreements	Data shown in Section 4.3		
Cost of Capital		Weight	Rate
(for long-term planning)	Short-term debt	5%	6.5%
	Long-term debt	40%	6.5%
	Preferred stock	7%	9%
	Common equity	48%	12%
	Composite Weighted Ave.		9.315%
	After-tax Weighted Ave.		8.177%
Inflation Rate	1999-2000	2.64%	
(source: May 1995 Fuel price forecast)	2001-2005	3.31%	
	2006-2018	3.40%	
Composite Income Tax Rate	38.91%		
Revenue Taxes	8.885%		
Externality Costs	Data shown in Table 5-3		

5. PLANNING CRITERIA AND CONSIDERATIONS

5.1 CAPACITY PLANNING CRITERIA

For long-term generation planning purposes, HELCO's Capacity Planning Criteria states that new generation will be added to satisfy the following Generation Addition Rule:
"The sum of the reserve ratings of all available units, with a unit on maintenance, less the reserve rating of the largest available unit must be equal or greater than the system peak load to be supplied."

The Capacity Planning Criteria also provides a reserve margin guideline:
"In addition, consideration will be given to maintaining a reserve margin of approximately 20 percent based on Reserve Ratings."

In the development of IRP-98 resource plans, PROSCREEN II added new firm capacity to prevent violation of the rule stated above.

It should be noted that the Generation Addition Rule is applicable to long-range generation expansion studies. HELCO does not determine the need for new generation based solely on the application of this Rule. As capacity needs become imminent, it is essential that HELCO broaden its consideration to ensure timely installation of generation capacity necessary to meet its customers' energy needs. As stated in the Capacity Planning Criteria:
"The actual commercial operation date for the next unit to be added shall be determined using these rules as guides, with due consideration given to short-term operating conditions, equipment procurement, construction, regulatory approvals, financial and other constraints, etc."

Other near-term considerations may include:

- the current condition and rated capacity of existing units
- the preferred mix of generation resources to meet varying daily and seasonal demand patterns at the lowest reasonable capital and operating cost
- the forecasted minimum demand
- required power purchase obligations and contract terminations
- the unpredictable output of supplemental resources
- the uncertainties surrounding Non-utility generation (NUG) resources
- transmission system considerations
- system stability considerations for HELCO's isolated system.

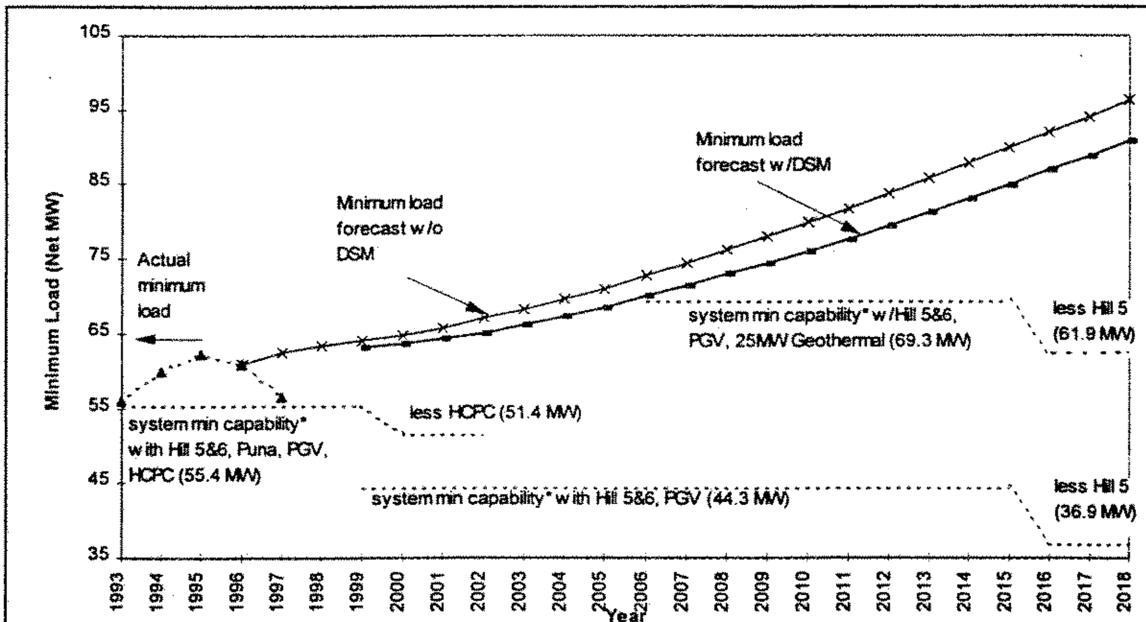
A complete copy of HELCO's current "Capacity Planning Criteria for Addition of Generation in HELCO Long-Range Expansion Studies" is included as Appendix H.

5.2 MINIMUM LOAD

Historical and forecasted minimum loads are graphed in Figure 5-1. The annual HELCO system minimum is typically about 40% of the annual system peak demand, and usually occurs between the hours of 2 and 4 A.M. Over the past five years, the system minimum load has not followed an increasing trend. In the five year period 1993-1997, the minimum load increased from 56 MW in 1993 to 62 MW in 1995, then decreased back to 56 MW in 1997. The minimum load forecast, however, projects a constantly increasing minimum load. As a result, in 1997, the actual minimum was about 6 MW below forecast.

Energy efficiency DSM programs target the on-peak hours for load reduction; however, the DSM programs also reduce load in the off-peak hours. The minimum load forecast adjusted for 20-year DSM impacts is shown in Figure 5-1. By 2018, the 20-year DSM programs are projected to reduce the minimum load by approximately 5 MW.

Figure 5-1: Forecasted Minimum Load and System Minimum Capability



*System minimum capability shown assumes that the Keahole DTCC cycles. It is likely that one CT of the Keahole DTCC would be baseloaded.

If the sum of the minimum capability ratings of baseload units exceeds the minimum demand, HELCO will be faced with an excess generation situation during these off-peak hours and will need to cycle units designed for baseload operation. Cycling baseload units off and on can result in severe damage to the units. Stresses induced by repeated thermal cycles can cause critical metal parts to develop cracks, resulting in increased operation and maintenance costs and forced outages. Therefore, in any given year, the sum of the minimum capability ratings of baseload units should always be less than the forecasted minimum load. Future baseload unit additions must not outpace the growth in system minimum demand. One way to avoid such conflicts is to plan generation additions with cycling capability. Similar considerations are necessary for other resource types or non-utility generators added to the HELCO system.

HELCO currently operates Hill 5, Hill 6 and the Puna steam unit in baseload mode. HELCO also purchases baseload power from Hilo Coast Processing Company (HCPC) and Puna Geothermal Venture (PGV). The dotted lines in Figure 5-1 indicate the sum of the minimum capability ratings of baseload units at different points in time within the 20-year planning period. As baseload units are added or retired, the minimum capability of the system will change.

The Keahole and future DTCC units are designed to enhance cycling and minimize adverse effects to the system (startup time and unit reliability) and to the unit (increased O&M and lower reliability). However, it is still desirable to only cycle the steam turbine as a last resort, since the stresses are much greater in the thermal cycle. Under the DTCC design, one CT can be cycled off-line allowing the remaining CT and steam turbine to operate at reduced load. The Keahole unit will initially be the only efficient unit on the West side that can be base loaded to provide area reliability, to maintain system frequency and voltage control under adverse conditions, and to reduce system transmission losses.

As-available resources such as wind and hydro could also provide energy during the off-peak hours which could raise the minimum capacity of the system. If the minimum capability of the system exceeds the minimum load, HELCO would have to curtail as-available generation. If excess capacity still exists, power from PGV would probably be curtailed.

If an additional 25 MW of geothermal generation is installed in the 2006 timeframe, excess capacity at the minimum could occur, resulting in the curtailment of one of the geothermal units. In addition to added O&M costs, the steam units at Hill would not be cycled since geothermal is unable to ramp up fast enough to regulate system frequency, a function necessary with the existing wind resources on the system. Consequently, additional geothermal resources were not considered until the latter part of the planning period.

5.3 SPINNING RESERVE

The purpose of maintaining spinning reserve is twofold:

(1) to prevent load shedding should a running unit or units suddenly trip, and
(2) to be able to respond to system transients, maintaining system frequency and voltage levels.

The units which provide the spinning reserve should be capable of ramping up quickly enough to restore system frequency to a normal operating level, and the source of power needs to be controllable by a system operator. As-available resources such as run-of-the-river hydro, wind and PV cannot be counted on for spinning reserve because there are times when the wind does not blow, the sun does not shine or water does not flow. The ramp rates of specific geothermal and pumped storage hydro units would need to be considered in determining whether or not these units would be capable of providing spinning reserve. Existing geothermal on the HELCO system is unable to contribute to frequency regulation due to its ramp rate.

5.3.1 Issues in IRP-93

In IRP-93, the Consumer Advocate presented an analysis demonstrating that: "Using reasonable spinning reserve margin assumptions significantly affects the selection of a preferred mix of resources."[31] The CA's analysis showed that HELCO's IRP-93 preferred plan comprised of all dual-train combined cycles was the least cost plan assuming a 5 MW spinning reserve. However, when the spinning reserve margin was increased to 20 MW, a plan with a 15 MW diesel unit as the next unit after Keahole ST-7 resulted in lower revenue requirements in the 20-year planning period.[32]

In IRP-93, HELCO had calculated an increase in fuel costs of about $32 million (1993$ NPV) if spinning reserve was maintained to cover the loss of the largest unit on the system.[33] The CA argued that this additional fuel cost could be reduced by adding a diesel engine and battery storage to the system.[34] However, HELCO pointed out that running diesels at low loads for spinning reserve would result in higher O&M costs. Along with higher overhaul costs, diesels tend to consume more lube oil at low loads, and at low loads, combustion is less complete resulting in a higher amount of unburned fuel and lube oil in the exhaust and carbon buildup in the turbocharger. HELCO also maintained that diesels have about twenty times the NOx emissions of a combined cycle across the full load range.[35]

[31] CA OB, Docket No. 7259, p. 17.
[32] CA OB, Docket No. 7259, p. 26.
[33] HELCO RT-5, Docket No. 7259, p. 13.
[34] CA-T-1, Docket No. 7259, pp. 126-7.
[35] HELCO RT-4, Docket No. 7259, p. 7.

In Decision and Order No. 14708 in Docket No. 7259, the Commission stated: "The Consumer Advocate and HELCO have raised valid points of contention with respect to spinning reserve margins, and we believe further study of the matter is warranted."[36] The Commission directed HELCO to conduct an updated study to determine the cost-effectiveness of establishing a spinning reserve criteria.

5.3.2 IRP-98 Spinning Reserve Analysis

The two objectives of HELCO's spinning reserve analysis in IRP-98 were:

(1) to determine if supply-side resource selection is affected by the spinning reserve assumption, and

(2) to calculate the cost of maintaining spinning reserve at different MW levels.

The spinning reserve analysis was performed using PROSCREEN, and did not include a quick load pickup criteria.

The findings of the IRP-98 analysis are:

(A) Spinning reserve does not change resource selection from dual train combined cycles to a plan with a diesel engine

The least cost supply-side resource plan[37], comprised of all dual train combined cycles, was compared against a plan with an 11 MW diesel engine after Keahole ST-7. The two plans are shown in Table 5-1. The cost of each plan was determined assuming 0, 10MW, 20MW and 30MW of spinning reserve for the 20-year IRP planning period, then graphed in Figure 5-2. The 30MW upper bound of the spinning reserve requirement is based on a typical guideline of having enough generation spinning to cover the loss of the largest operating unit, currently PGV. As illustrated, the plan with the 11 MW diesel engine is more expensive than the all dual train combined cycle plan at all levels of spinning reserve. This is contrary to the results of the CA's analysis in IRP-93.

Table 5-1. Plans compared in IRP-98 spinning reserve analysis

Year	All DTCC (K1)	Diesel after ST-7
1999	Encogen DTCC 20-yr DSM	Encogen DTCC 20-yr DSM
2000		
2001		
//		
2002		
2003	Puna return from standby	Puna return from standby
2004		
2005		
2006	Keahole ST-7	Keahole ST-7
2007		
2008		
2009	Hill 5 Repower, 1st CT	11 MW Diesel
2010		Hill 5 Repower, 1st CT
2011		
2012	Hill 5 Repower, 2nd CT	
2013		
2014		
2015	Hill 5 Repower, conversion to DTCC	Hill 5 Repower, 2nd CT & conversion to DTCC
2016	LM2500 SCCT	
2017		
2018		LM2500 SCCT

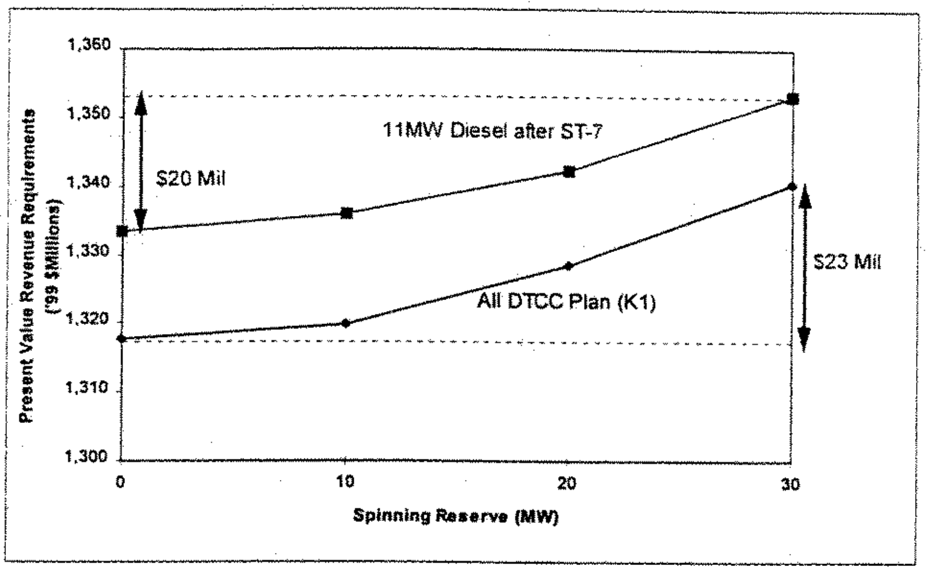
(B) Spinning reserve increases production costs

Since units will be committed earlier in order to meet the spinning reserve criteria in every hour, it is expected that production costs (fuel and variable O&M) would increase. Figure 5-2 shows that production costs increase exponentially with additional spinning reserve requirements. The reason for this is that there is an inherent level of spinning reserve on the system as units are brought on-line. Low levels of spinning reserve can be maintained without major changes to the system dispatch. As the spinning reserve requirement is increased,

[36] D&O No. 14708, Docket No. 7259, p. 33.

[37] The all DTCC plan was the lowest cost plan in the 20-year planning period, not including the plan with distributed diesels (discussed further in Section 8.6.4).

Figure 5-2. Comparison of plan costs: Diesel plan vs. all DTCC plan



additional units must be started and brought on-line.

Differences in 20-year plan costs with various levels of spinning reserve are compared against a no spinning reserve case in Table 5-2 for both the all DTCC and 11 MW diesel plans. While the incremental fuel and variable O&M costs due to spinning reserve are lower for the 11 MW diesel plan, the absolute cost of the 11 MW diesel plan is higher for all levels of spinning reserve. Note that this is a conservative estimate of the costs incurred with spinning reserve, as this does not include unit start-up costs[38], nor does the analysis account for the possibility that additional generation capacity may need to be installed in order to meet the spinning reserve criteria.

Conclusions

The HELCO system currently needs capacity in order to continue to provide reliable electric service to its customers. Adoption of a spinning reserve criteria at this time will not alleviate HELCO's contingency planning situation. HELCO is also reluctant to incur the additional costs of maintaining spinning reserve, realizing that this would simply mean a higher cost of electricity to its customers.

Table 5-2: Comparison of plan costs with and without spinning reserve

20-year Present Value of Revenue Requirements

Spin Reserve (MW)	Plan cost in $000		Increase in Fuel and Variable O&M with Spinning Reserve ($000)		Difference between Diesel & All DTCC Plans ($000)
	All DTCC (K1)	11mw diesel	All DTCC (K1)	11mw diesel	
0	1,317,816	1,334,519	-	-	16,703
10	1,319,765	1,335,890	1,949	1,371	16,125
20	1,328,517	1,342,266	10,701	7,747	13,749
30	1,340,391	1,353,158	22,575	18,639	12,767

[38] PROSCREEN II is a load duration curve model, not a chronological model, and thus does not simulate unit starts and stops.

The IRP-98 analysis showed that supply-side resource selection does not change from dual train combined cycles to diesel engines depending on the assumed level of spinning reserve. Therefore, it is not critical to the selection of a long-term IRP plan that HELCO establish future operating criteria now. HELCO's generation capacity planning criteria recognizes that over time changes may occur which make operational changes either prudent or necessary, and thus has a provision to incorporate such modifications.

While HELCO will not adopt a spinning reserve criteria now, it will continue to carry spinning reserve, at the system operator's discretion, during those periods when the system is most at risk. This includes spinning reserve carried to regulate system frequency when the output of existing wind resources is highly volatile.

5.4 TRANSMISSION CONSIDERATIONS

5.4.1 T&D Considerations in Generation Planning

A transmission study was performed to determine the benefits of adding West Hawaii generation versus East Hawaii generation from a transmission planning point of view. Load flow simulations were used to identify transmission capital projects that would be required and the magnitude of line losses that would be incurred with different combinations of East and West Hawaii generation. The study concluded that the addition of new baseload generating units at Keahole and West Hawaii is preferred from a transmission perspective on the basis of lower cost of transmission losses, lower cost of transmission capital additions, and an improvement in the reliability of supply by achieving a more equitable balance between load and generation on the HELCO system.

A complete copy of the transmission study can be found in Appendix N.

5.4.2 T&D Considerations for Supply-Side Options

For each of the supply-side resources evaluated, assumptions were made as to what T&D facilities would be required for interconnection into the HELCO grid. The assumptions included connecting the generator from the high-voltage side of the step-up transformer to the power plant switchyard, the configuration of the switchyard, and the transmission line connecting the switchyard to HELCO's transmission system. The assumed T&D interconnection costs were modeled as part of the capital cost of each supply-side resource and are included in the IRP-98 Supply-Side Resource Option Portfolio Development Report in Appendix G. It should be noted that actual T&D interconnection costs may deviate from those used in this IRP when site specific factors and cumulative T&D loads are evaluated in greater detail during the actual implementation of a project or subsequent analysis.

5.4.3 T&D Considerations for Demand-Side Options

DSM reduces demand at the customer level (at the meter). As such, it also reduces transmission and distribution line loadings, and has the potential to defer T&D projects related to load growth. However, actual deferral of distribution or transmission lines depends on the specific location of the demand reduction, as well as the coincidence of the demand reduction with the time of peak line loading.

In IRP-93, HELCO conducted a study to determine T&D costs that could possibly be avoided with DSM load reduction. In IRP-98, a similar study was not performed by HELCO since all four 20-year energy efficiency DSM programs were cost effective by the Utility, TRC and Societal tests even without a T&D credit.

5.5 CONSIDERATION OF NON-UTILITY GENERATION IN THE IRP

For purposes of integrated resource planning, HELCO evaluated commercial supply-side technologies that could be developed by either the utility or by Non-Utility Generators (NUGs). In Docket No. 7259, Decision and Order 14708, the Commission stated:

> "We acknowledge that there are no NUG-specific projects planned or programmed for implementation by HELCO in its 20-year planning horizon. However, this does not mean that there will be no NUG-operated facility during the period covered by the IRP. HELCO made its assessment of the supply-side resources without distinction as to the ownership of the resources. NUGs are free to submit proposals to HELCO for evaluation to implement, replace, or defer the resource options included in HELCO's IRP.
>
> The framework does not specifically address the role of NUGs in the development or acquisition of the resources deemed appropriate in the IRP. However, the framework, at section IV.D.2, provides that the utility, in the development of its IRP, shall consider supply-side and demand-side resource options that 'are or may be supplied by persons other than the utility.' This provision was deliberately intended to leave to the implementation phase the determination of who should build and operate the resources included in the IRP. NUG-supplied resources should be in conformance with the utility's IRP."[39]

5.6 EXTERNALITIES

The Commission's Decision and Order No. 11630, filed May 22, 1992, required Hawaii's electric utilities to consider external costs and benefits in the development of integrated resource plans. The Commission defined "external costs" as: *"external diseconomies; costs to or negative impacts on the activities of entities outside the utility and its ratepayers. External costs include environmental, cultural and general economic costs."* As a result of this Decision and Order, HECO engaged Energy Research Group, Inc. (ERG) to prepare the Externalities Workbook, applicable to HECO, HELCO and MECO.

By Order No. 14862, filed August 8, 1996, in Docket No. 95-0347, the Commission approved HECO's request to use the externality values derived in the Externalities Workbook in its second IRP process, prior to receiving Commission approval of the study. Based on this approval, HELCO has also used the results of the Externalities study in IRP-98. HELCO performed a sensitivity analysis to assess the impact of various resource plans to society as required by the IRP Framework. The "high" air externalities in Table 5-3 under the heading "ERG Results for HELCO" were used in the sensitivity analysis for all technologies except for the biomass unit, for which air emissions are shown separately.

The executive summary of the Externalities Workbook is provided in Appendix I. A complete copy of the Externalities Workbook is available for examination at the HELCO Customer Service office.

[39] Docket No. 7259, Decision and Order No. 14708, pp. 13-14.

Table 5-3. Summary of Externalities Workbook Results

Impact	ERG Results for HELCO[1]			IRP-1 [2]	Other Studies [3,4]		
	Low	High	Biomass		Low	Average	High
Air-Related ($/ton)							
NO_x	$ 0.69	$ 6.73	$ 4.98	$ 16,076	0	$2,562.0	$17,536.0
SO_x	$ 0.91	$ 10.84	$ 8.07	$ 8,241	0	$1,657.0	$ 8,990.0
PM_{10}	$ 34.47	$ 904.34	$ 670.00	$ 52,858	0	$4,065.0	$57,659.0
VOC				$ 451	0	$1,783.0	$ 9,676.0
CO				$ 10,401	0	$ 4.0	$ 8.0
CO_2				$ 7	0	$ 4.0	$ 45.0
Water-Related (¢/kWh) [5]					0.0010		0.0020
Equipment cleaning	0	negligible					
Facility Water Washing	0	negligible					
Sanitary Wastewater	0	negligible					
Water Treatment Reject	0	negligible					
Boiler Blowdown	0	negligible					
Cooling Tower Blowdown	0	negligible					
Land-Related (¢/kWh) [5]					0.0017		0.0032
Competing Land Use	0	negligible					
Hazardous Waste	0	0					
Oil Spill							
Ocean-related spill ($/barrel) [6]	n/a	0.1308					

Notes:

1. Results based on direct impact assessment method presented in July 1997 *Hawaii Externalities Workbook*, Table 5-18. Not reduced for emission fees paid by HELCO.
2. HECO/MECO/HELCO IRP-1 values based on California Energy Commission SCAQMD externalities costs.
3. Results based on Energy Research Group's database of direct impact monetization method.
4. Based on review of values provided in Department of Energy, Estimating Externalities of Coal Fuel Cycles, Report 3, September 1994 and New York State Environmental Externalities Cost Study, January 1995 (for a 200 MW AFBC unit.)
5. Values represent total water-and land-related impacts as presented in July 1997 Hawaii Externalities Workbook.
6. Based on 1992 Sea Grant report, Oil Spills at Sea and Externalities Associated with Ocean-Related Spills, Rose T. Pfund and Henry Marcus, 1996.

Shading indicates monetized cost data not available.

5.7 IMPACT ON THE STATE ECONOMY

The potential economic impacts of utility resource selection result from two main factors. The first is rate impacts, or rate increases which are required to pay for the construction and operation of new utility resources. To this extent, HELCO completed a rates and bills analysis, which can be found in Appendix L. The second factor is employment and other purchases due to the operation and maintenance of the resources that might add value to the economy. In addition, both factors are subject to multiplier effects.

For coal and oil-fired plants, the local labor pool could provide much of the construction and plant operation labor requirements. However, fuel payments would flow out of the State. Thus, in addition to the direct and indirect effects of the rate impact of the resources, the general impact on the State economy would be: 1) an outflow of payments for plant engineering and fabrication; 2) a temporary gain in construction jobs; 3) a permanent gain in plant operation, fuel handling, and fuel refining jobs; 4) a long-term increase in general excise tax (tax on fuel) and State income tax collection, and; 5) an outflow of fuel payments.

The general impact of renewable technologies on the State economy, other than the direct and indirect effects of rate impacts, would be: 1) an outflow of payments for plant engineering and fabrication; 2) a temporary gain in construction jobs; 3) a permanent gain in plant operation jobs; 4) a long-term increase in State income tax collection; and 5) a reduction in fuel payment outflow.

The sum of all of the effects of the various categories mentioned above comprise the net impact on the State economy of a utility's resource selection. Chapter ten of the Hawaii Externalities Workbook describes models that can be leased or purchased to estimate the detailed economic impacts of alternative utility resource plans on the state economy. The cost of the computer model and retaining the consulting economist to conduct the analyses is significant. Therefore, HELCO chose to address the impacts to the state economy primarily through its rates and bills analysis, drawing upon HECO's analysis of alternate energy plans, and an assessment of the impact of a biomass unit on the Big Island economy.

Regarding the impact to the State economy of a reduction in cash flow out of the state for fuel oil, HELCO drew upon the results of HECO's analyses of the impact of its resource plan selection on the State economy. HECO, as part of its second IRP for the island of Oahu, engaged National Economic Research Associates (NERA) consulting economists to perform a quantitative analysis of the impacts of alternative resource plans for HECO on the State economy. NERA utilized the computer model developed by Regional Economic Models, Inc. (REMI) to provide a detailed assessment of the impact to the State economy. From the results of the analysis, NERA concluded that the benefit of reducing the consumption of fuel oil through renewable energy technology or through alternate fuels, and the resulting reduction in cash flow out of the state for fuel oil, did not outweigh the negative effect of higher electricity rates on the State economy. The conclusion did not change even when the effects of a potential spike in oil prices was considered.

In NERA's analyses, they found that a biomass unit on Oahu would lead to a gain in employment. However, there would be an overall reduction in personal income reflecting the fact that the farm jobs gained are lower-paying. Since the Big Island economy has a larger agricultural sector than Oahu, this may not be the case on the Big Island. HELCO retained Dr. Youngki Hahn of the University of Hawaii - Hilo to examine the effect of a biomass unit versus higher electricity rates on the Big Island. Dr. Youngki Hahn's analysis is provided in Appendix O.

6. ASSESSMENT OF DEMAND-SIDE RESOURCES

6.1 BACKGROUND AND OVERVIEW

In IRP-93, Synergic Resources Corporation (SRC) performed a comprehensive screening of a wide range of DSM technologies. This screening produced a number of residential and commercial energy efficient technologies best suited for Hawaii. HELCO grouped these selected technologies into four energy efficiency[40] programs which targeted both retrofit of existing fixtures as well as installations in new developments for both the residential and commercial sectors. The IRP-93 (re-assessment) plan proposed the four DSM programs as 20-year concepts. On July 6, 1995, HELCO submitted applications for Commission approval of the first 5-year increment of the programs in the following dockets:

- Residential Efficient Water Heating Program ("REWH"), Docket No. 95-0173
- Commercial and Industrial Energy Efficiency Program ("CIEE"), Docket No. 95-0174
- Commercial and Industrial New Construction Program ("CINC"), Docket No. 95-0175
- Commercial and Industrial Customized Rebate Program ("CICR"), Docket No. 95-0176

As part of its contingency plan, HELCO requested expedited interim approval of the four energy efficiency programs. On October 26, 1995, the Commission approved HELCO's request in Order No. 14326. HELCO initiated implementation of the four full-scale DSM programs on December 26, 1995.

Since the filing of the DSM applications in 1994, HELCO has developed new sales and peak and fuel price forecasts, updated supply-side resource costs, collected Hawaii-specific DSM data, and acquired a more detailed DSM evaluation model. These events warranted re-evaluation of both the programs currently being implemented, as well as any future DSM plans.

As part of the IRP-98 DSM assessment, HELCO also reviewed the *Hawaii Demand-Side Management Opportunity Report*, issued by the Energy Division of the Hawaii State Department of Business, Economic Development, and Tourism (DBED&T) in August 1995. HELCO concluded that it was addressing all of the commercial and industrial measures identified in the study and most of the measures identified for the residential sector. HELCO had conducted a compact fluorescent lighting pilot program, which did not appear to be cost-effective. HELCO also examined horizontal axis washing machines, but found that the machines are not readily available in Hawaii and are very expensive.

As a result of this review, HELCO believes that the end-uses and DSM technologies identified by the IRP-93 SRC study continue to be the prime targets for realizing energy efficiency benefits in Hawaii. Accordingly, the IRP-98 assessment uses the existing framework for each of the four approved programs, focusing on updating projected participation and program costs and re-evaluating cost-effectiveness of the programs in light of updated data.

[40] Energy efficiency or conservation DSM programs are electric utility marketing programs designed to encourage the utility's customers to adopt energy efficient technologies that lower total electricity usage. The major goals of these programs are to defer the need for new capacity and reduce the total consumption of energy resources such as oil, coal or nuclear fuels.

Figure 6-1. DSM Forecast Update Methodology

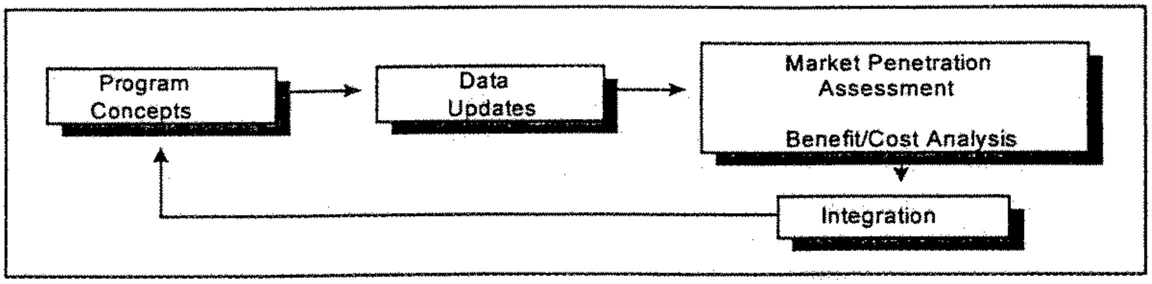


Figure 6-1 illustrates the workflow process employed to update the forecast of DSM impacts. All inputs to the process were revisited and updated and a new DSM screening tool, the PROSCREEN II® DSVIEW module, was used. Once preliminary information on current program results was available, meetings with the HELCO Advisory Group were held to inform interested parties of the structure of the new methodology and solicit input into the process.

Upon completion of this DSM assessment, HELCO compared the estimated DSM potential to projections in DBED&T's study, *Hawaii Demand-Side Management Opportunity Report.* The program data developed in this assessment was subsequently used to select the optimal level of DSM in the IRP-98 integration analysis.

6.2 OBJECTIVES

In IRP-98, the primary objectives of the DSM assessment remain the same as during the development of IRP-93. At that time, a strategic objective was developed by HELCO's Advisory Group to guide the process of assessing DSM resources. This objective, from the document entitled "*Integrated Resource Planning Demand-Side Management Report*" issued in October 1993, is described as follows:

"The DSM resource assessment activity is to develop aggressive and achievable DSM programs that:

- *Substitute for the need for new generation capacity*
- *Are evaluated in the context of IRP*
- *Reflect the operational and contractual characteristics of the system*
- *Provide services for all customer sectors*
- *Build the capabilities of HELCO and the market to support DSM programs*
- *Capture lost opportunity resources."*

In addition to the guiding objective stated above, there continue to be operational objectives for the development of DSM resources. These objectives include:

- Conduct a process to gather input and provide reviews from customers, energy professionals and interested parties
- Ensure that the DSM resources characterized as part of this effort can actually be acquired
- Continue to rely upon the basic framework of programs developed for IRP-93
- Obtain an updated forecast of technology penetrations which lie within the bounds of achievable program potential presented by the DBED&T study, *Hawaii Demand-Side Management Opportunity Report*
- Characterize the costs and benefits of acquiring DSM resources. Develop benefit-to-cost ratios both with and

without estimated shareholder incentives.

- Compile the DSM program data necessary to perform integration and optimization of demand-side and supply-side alternatives in resource plans. DSM data was developed for a 2-year period (1999-2000) and a 20-year period (1999-2018) in order to assess the optimal duration of the DSM programs.

6.3 UPDATED DSM PROGRAM IMPACTS AND COSTS

6.3.1 Comparison of 2-year and 20-year DSM Program Potential

Figures 6-2 and 6-3 compare updated DSM impacts for 2-year and 20-year representations of the four approved energy efficiency DSM programs. These graphs reflect the estimated maximum potential DSM impact if all four energy efficiency programs are pursued. The graphs show peak impacts and energy savings during program implementation as well as residual

Figure 6-2. Total Annual Energy Savings (GWh)

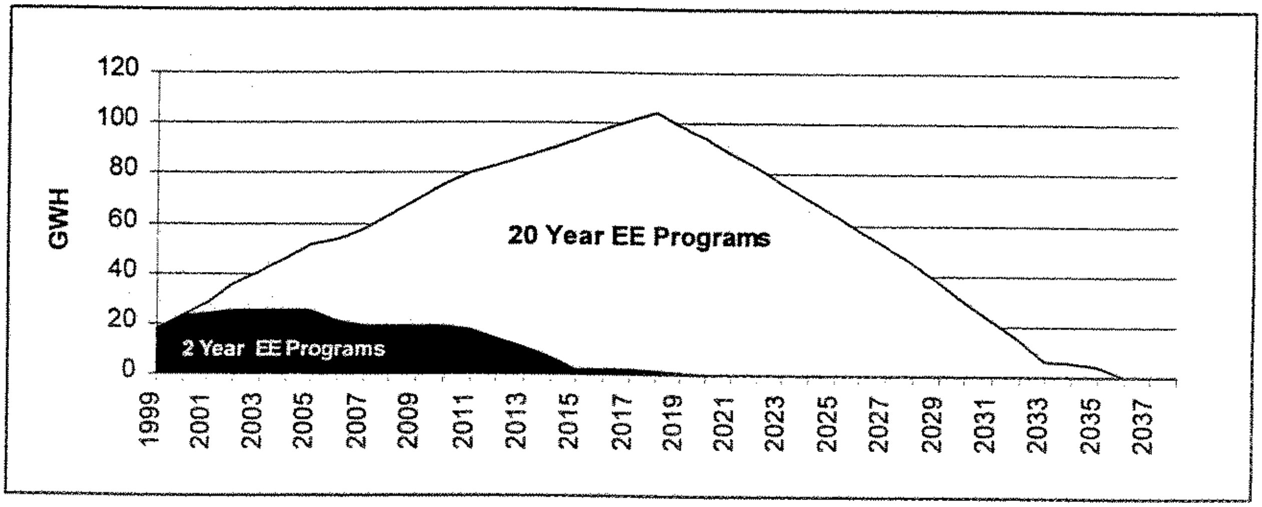


Figure 6-3. Total Peak Impact (MW)

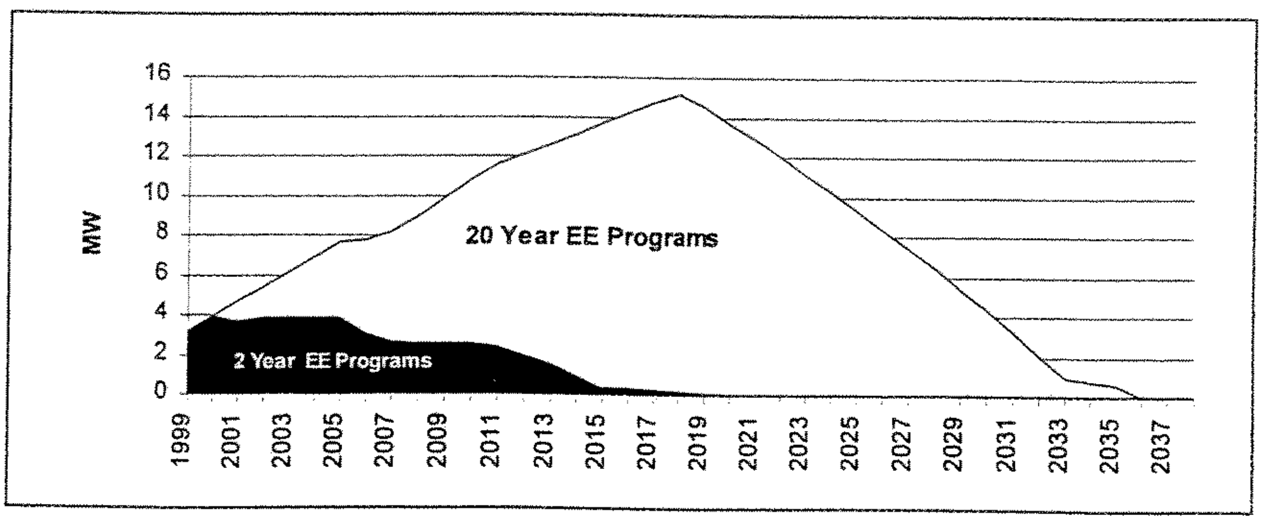
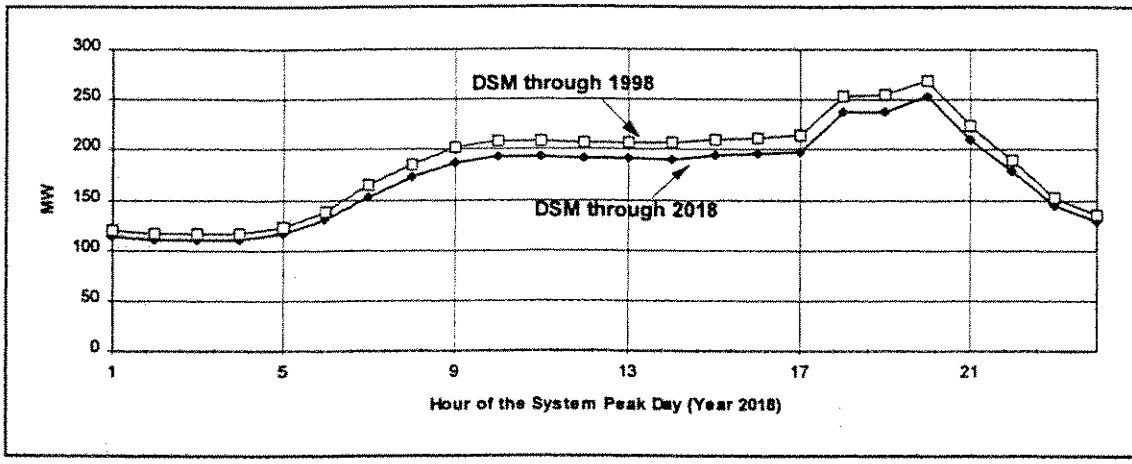


Figure 6-4. System Load Profile with DSM



effects over the lifetimes of the technologies installed.

DSM peak and energy impacts were determined using PROSCREEN II®'s DSVIEW module. For a given DSM program, DSVIEW figures out the differences between a base case scenario absent HELCO promotion and a DSM case scenario where HELCO actively promotes efficient technologies. DSVIEW estimates impacts by tracking the following variables:

- Market size
- New construction entries
- Saturation of technologies per unit of market size
- Energy and demand usage by technology
- Technology lifetimes and resultant stock turnover
- Diffusion of technologies into the marketplace
- Customer purchase and maintenance costs
- Incentives paid to customers
- DSM administration costs
- DSM evaluation costs

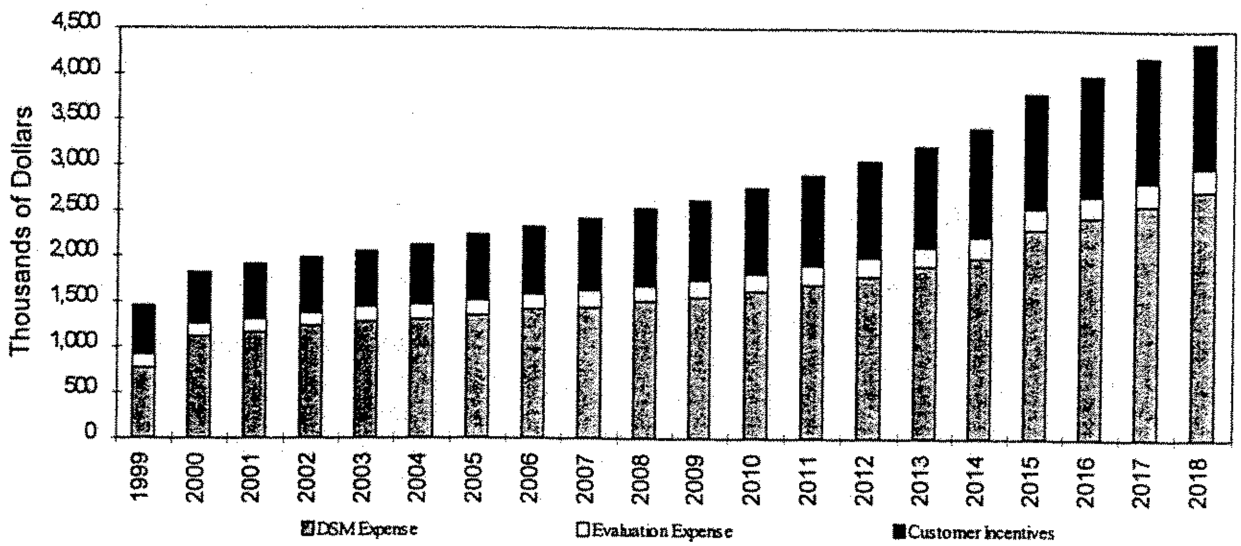
While DSM is expected to reduce system demand, Figure 6-4 illustrates that the system load shape will not be dramatically altered, even if all 20-year energy efficiency program impacts are fully realized.

A summary of future DSM expenses[41] for the 2-year representation (ending in 2000) and a 20-year period is shown in Figure 6-5. Detailed DSM impact and cost data and cost-effectiveness evaluations for each individual program are provided in the next section (6.3.2).

Note that the impacts associated with HELCO's rate riders are excluded from these summary graphs. Instead, rate riders are treated as adjustments to the base load forecast.

[41] DSM expenses include utility program costs, customer incentives and evaluation costs. (Shareholder incentives and lost margin are not included here). DSM expenses shown do not include the current 8.885% revenue tax.

Figure 6-5: Total DSM Expenditures



6.3.2 Individual DSM Programs - Updated Data

The following sections provide peak and energy impacts, costs, and benefit/cost (B/C) ratios for each of the four energy efficiency programs.

6.3.2.1 Residential Efficient Water Heating Program (New And Existing Customers)

Docket No. 94-0206 (Application filed on July 6, 1995; D&O No. 14326 (Interim Approval) issued on October 26, 1995, D&O No. 14984 (Final Approval) issued on September 12, 1996). The residential water heating market represents one of the largest segments of electrical energy and capacity on the Big Island of Hawaii.

The residential water heating program promotes the use of high efficiency water heating technologies such as solar water heating and heat pump water heaters. Since there are also customers who may not be capable of installing either a heat pump or a solar system, incentives for efficient resistance water heaters are also offered. To further reduce hot water consumption and conserve water, low flow showerheads have been offered to all residential customers.

Tables 6-1 through 6-6 contain program impact and cost data for the residential water heating program. Figure 6-6 illustrates a normalized daily profile of the expected impacts from this program.

Table 6-1. Residential Water Heating Program Rebates

Residential Water Heating Existing	Average Rebate
High Efficiency Water Heater	$ 50.00
Solar Water Heater	$ 800.00
Heat Pump Water Heater	$ 275.00
Low Flow Shower Heads	Given away; one per household

Residential Water Heating New Construction	Average Rebate
High Efficiency Water Heater	$ 50.00
Solar Water Heater	$ 1,500.00
Heat Pump Water Heater	$ 725.00
Low Flow Shower Heads	Given away; one per household

Figure 6-6. September 2009 Normalized Typical Week Impacts, Residential Water Heating

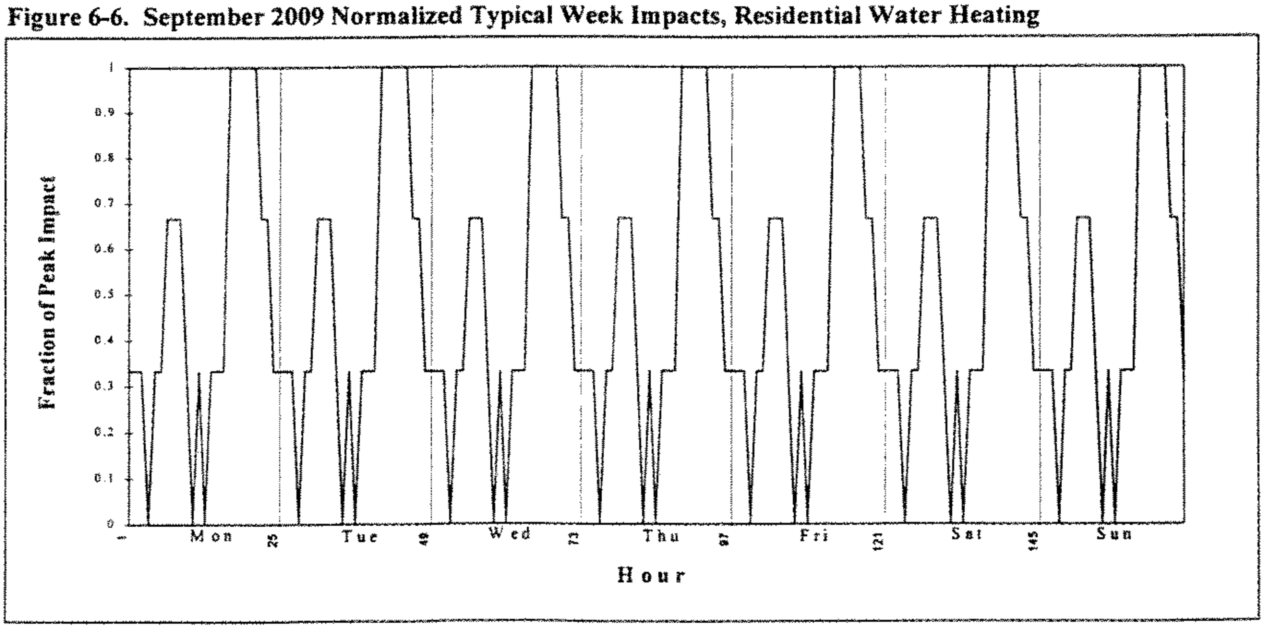


Table 6-2. Residential Water Heating Energy Savings (GWh Requirements)

	1999	2000	2001	2002	2003	2004	2006	2008	2010	2012	2014	2016	2018
Solar Water Heater	0.50	1.39	2.25	3.49	4.28	5.08	6.67	8.30	9.90	11.58	12.29	12.27	12.33
Integral Heat Pump Water Heater	0.03	0.08	0.12	0.19	0.22	0.25	0.30	0.34	0.38	0.41	0.37	0.30	0.25
Add On Heat Pump Water Heater	0.01	0.02	0.03	0.04	0.06	0.06	0.08	0.10	0.12	0.15	0.16	0.16	0.15
Electric Water Heater with Low Flow Showerhead	0.03	0.08	0.13	0.20	0.24	0.28	0.37	0.46	0.55	0.64	0.68	0.68	0.68
Solar Water Heater with Low Flow Showerhead	0.07	0.20	0.33	0.53	0.68	0.83	1.14	1.45	1.77	2.08	2.26	2.31	2.33
Heat Pump Water Heater with Low Flow Showerhead	0.00	0.00	0.01	0.03	0.05	0.06	0.10	0.13	0.17	0.20	0.23	0.25	0.25
Storage Water Heater	0.00	0.01	0.01	0.02	0.03	0.03	0.05	0.06	0.08	0.10	0.11	0.12	0.13
Total	0.64	1.78	2.89	4.49	5.54	6.61	8.70	10.85	12.96	15.16	16.11	16.09	16.12

Note: The impacts shown here are ramped for the first three years (refer to Section 6.6.1.5 for additional information on the ramp-up process applied).

Table 6-3. Residential Water Heating Peak Impacts (MW)

	1999	2000	2001	2002	2003	2004	2006	2008	2010	2012	2014	2016	2018
Solar Water Heater	0.19	0.38	0.56	0.73	0.90	1.07	1.40	1.74	2.08	2.43	2.59	2.58	2.60
Integral Heat Pump Water Heater	0.01	0.02	0.03	0.04	0.05	0.05	0.06	0.07	0.08	0.09	0.08	0.06	0.05
Add On Heat Pump Water Heater	0.00	0.01	0.01	0.01	0.01	0.01	0.02	0.02	0.03	0.03	0.03	0.03	0.03
Electric Water Heater with Low Flow Showerhead	0.01	0.02	0.03	0.04	0.05	0.06	0.08	0.10	0.12	0.14	0.14	0.14	0.14
Solar Water Heater with Low Flow Showerhead	0.03	0.05	0.08	0.11	0.14	0.17	0.24	0.30	0.37	0.44	0.48	0.49	0.49
Heat Pump Water Heater with Low Flow Showerhead	0.00	0.00	0.00	0.01	0.01	0.01	0.02	0.03	0.04	0.04	0.05	0.05	0.05
Storage Water Heater	0.00	0.00	0.00	0.00	0.01	0.01	0.01	0.01	0.02	0.02	0.02	0.03	0.03
Total	0.25	0.49	0.72	0.94	1.17	1.39	1.83	2.28	2.73	3.19	3.40	3.39	3.41

Note: The impacts shown here are ramped for the first three years (refer to Section 6.6.1.5 for additional information on the ramp-up process applied).

Table 6-4. Residential Water Heating Incentives ($000)

	1999	2000	2001	2002	2003	2004	2006	2008	2010	2012	2014	2016	2018
Solar Water Heater	237.2	231.0	221.7	216.8	212.9	213.2	218.9	222.9	228.2	232.5	236.9	241.7	243.8
Solar Water Heater with Low Flow Showerhead	15.3	14.2	12.2	11.2	11.2	10.2	9.2	8.1	8.1	9.1	8.1	8.1	8.1
Integral Heat Pump Water Heater	1.8	1.8	1.8	1.5	1.5	1.6	1.5	1.5	1.5	1.5	1.5	1.5	1.5
Add On Heat Pump Water Heater	6.5	6.2	5.6	5.4	5.4	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1
Heat Pump Water Heater with Low Flow Showerhead	13.3	13.8	14.5	14.8	15.1	15.8	16.8	17.3	17.6	17.5	17.2	17.1	17.1
Electric Water Heater with Low Flow Showerhead	0.1	0.2	0.4	0.5	0.7	0.7	0.7	0.7	0.7	0.8	0.7	0.8	0.8
Storage Water Heater	0.5	0.5	0.6	0.7	0.7	0.8	0.9	1.0	1.2	1.3	1.4	1.5	1.6
Total	274.7	267.8	256.8	251.1	247.5	247.4	253.2	256.8	262.5	267.8	271.0	276.0	278.1

Table 6-5. Residential Water Heating Annual Budget ($000)

	1999	2000	2001	2002	2003	2004	2005	2006	2008	2010	2012	2014	2016	2018
DSM Expense	$324.59	$333.16	$344.19	$355.58	$367.35	$379.51	$392.07	$405.41	$419.19	$433.44	$448.18	$463.42	$479.17	$495.46
Evaluation Expense	$59.93	$61.51	$63.55	$65.65	$67.83	$70.07	$72.39	$74.85	$77.40	$80.03	$82.75	$85.56	$88.47	$91.48
Shareholder Incentives	$0.00	$37.36	$46.55	$53.05	$60.52	$62.81	$67.42	$71.80	$74.29	$78.70	$80.83	$87.44	$96.27	$105.50
Total	$384.52	$432.04	$454.29	$474.29	$495.70	$512.39	$531.89	$552.06	$570.88	$592.17	$611.76	$636.42	$663.91	$692.44

Table 6-6. Residential Water Heating B/C Ratios

	Participant Test				Utility Test				Total Resource Cost Test				Societal Test				Rate Impact Measure Test			
	Benefits ($000)	Costs ($000)	Net Benefits ($000)	B/C Ratio	Benefits ($000)	Costs ($000)	Net Benefits ($000)	B/C Ratio	Benefits ($000)	Costs ($000)	Net Benefits ($000)	B/C Ratio	Benefits ($000)	Costs ($000)	Net Benefits ($000)	B/C Ratio	Benefits ($000)	Costs ($000)	Net Benefits ($000)	B/C Ratio
Res. Water Heating - 2 year	3,952	993	2,958	3.98	1,631	1,244	387	1.31	1,631	1,755	-124	0.93	1,650	1,755	-104	0.94	1,631	4,713	-3,082	0.35
Res. Water Heating - 20 year	20,048	5,372	14,676	3.73	11,411	8,007	3,404	1.43	11,411	10,852	560	1.05	11,483	10,852	631	1.06	11,411	25,528	-14,117	0.45

Note: Tax credits were taken into consideration by lowering the participant's purchase cost for solar and heat pump water heaters by the appropriate incentive amount. During the evaluation of the societal perspective, these incentives where brought back in as costs borne by society.

6.3.2.2 Commercial and Industrial Energy Efficiency Program

Docket No. 95-0174 (Application filed on July 6, 1995; D&O No. 14326 (Interim Approval) issued on October 26, 1995, D&O No. 14984 (Final Approval) issued on September 12, 1996). This program addresses existing commercial and industrial customers and includes the following features:

- Commercial Air Conditioning -

  Commercial buildings use large amounts of electrical energy to cool spaces and control humidity. This program attempts to influence customers to purchase higher efficiency equipment than they normally would to reduce the electrical energy consumption and peak capacity requirements of the cooling plant.

- Commercial Lighting -

  Lighting accounts for the largest consumption of electrical energy in the commercial sector. This program encourages customers to retrofit their existing lighting systems with high efficiency electronic ballasts, high performance lamps, and reflectors that allow fewer lamps to provide similar effective lighting levels.

- Industrial Motors -

  This program targets customers who have significant motor loads. Incentives are paid for motors of 1.0 horsepower or greater, whose efficiency meets or exceeds a qualifying level. Qualifying efficiency levels are set slightly higher than the federal government's EPACT motor efficiency standards which became effective in October, 1997.

Table 6-7. Commercial and Industrial Energy Efficiency Average Rebates

Commercial and Industrial Prescriptive Measures	Average Rebate
High Efficiency Chillers	$55/ton
Direct Expansion Chillers	$45/ton
Motors	$8/hp
T8 Lamps with Electronic Ballast	$6.50/fixture
Occupancy Sensor	$10/fixture
Reflector and Delamp	$10/fixture
T8 Lamps with Electronic Ballast, Reflector and Delamp	$15.60/fixture
Mechanical Subcooling	$58.52/ton

Figure 6-7. September 2009 Normalized Typical Week Impacts, Commercial & Industrial Energy Efficiency

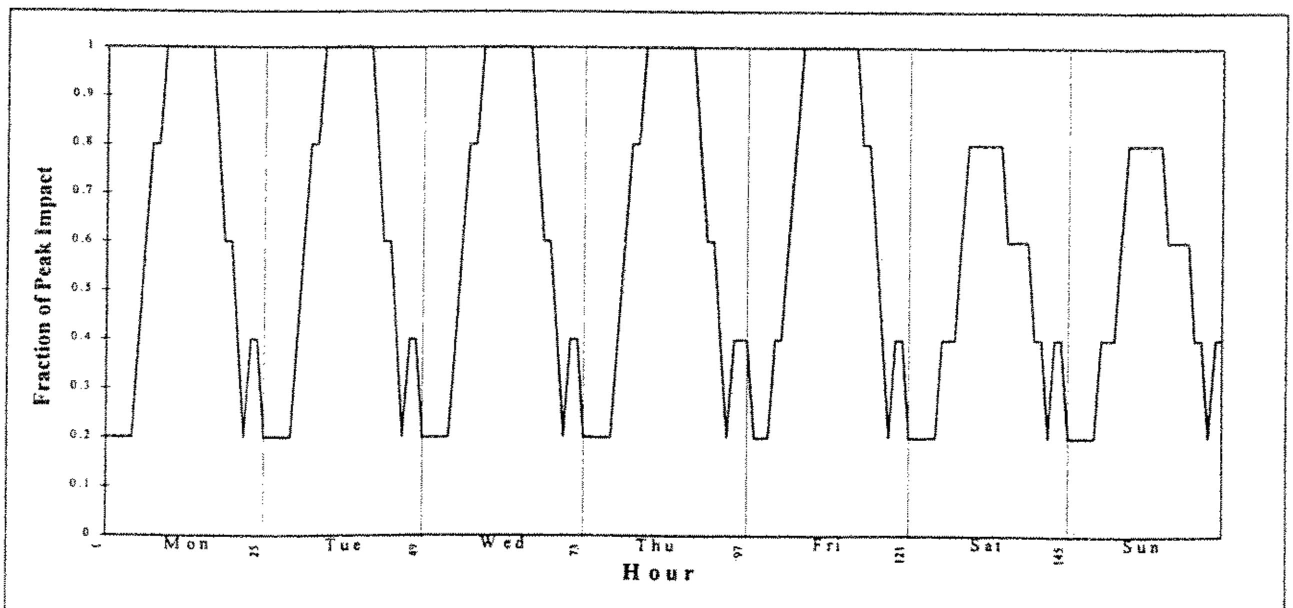


Table 6-8. Commercial and Industrial Energy Efficiency Energy Savings (GWh Requirements)

	1999	2000	2001	2002	2003	2004	2006	2008	2010	2012	2014	2016	2018
High Efficiency Chiller	0.57	1.35	1.98	2.85	3.33	3.76	4.47	5.10	5.63	6.13	6.12	5.93	5.88
High Efficiency Vent Motor	0.05	0.13	0.22	0.37	0.49	0.63	0.95	1.35	1.80	2.35	2.87	3.35	3.78
High Efficiency T8 Lamps with Electronic Ballasts	0.01	0.04	0.06	0.08	0.10	0.12	0.16	0.19	0.22	0.25	0.27	0.28	0.29
Occupancy Sensors	0.07	0.17	0.26	0.40	0.49	0.58	0.76	0.93	1.09	1.27	1.38	1.44	1.49
Reflector with Delamp	0.38	0.97	1.50	2.30	2.83	3.37	4.39	5.42	6.43	7.48	8.20	8.62	8.94
T8 Lamps with Electronic Ballasts, Reflector, and Delamp	0.56	1.41	2.18	3.33	4.10	4.87	6.32	7.74	9.07	10.38	11.15	11.44	11.60
Mechanical Subcooling	0.02	0.04	0.06	0.10	0.13	0.16	0.21	0.27	0.32	0.37	0.40	0.40	0.40
Total	1.66	4.10	6.27	9.43	11.48	13.49	17.27	21.00	24.57	28.23	30.39	31.47	32.37

Note: The impacts shown here are ramped for the first three years (refer to Section 6.6.1.5 for additional information on the ramp-up process applied).

Table 6-9. Commercial and Industrial Energy Efficiency Peak Impacts (MW)

	1999	2000	2001	2002	2003	2004	2006	2008	2010	2012	2014	2016	2018
High Efficiency Chiller	0.10	0.19	0.26	0.30	0.35	0.39	0.47	0.54	0.59	0.65	0.65	0.63	0.63
High Efficiency Vent Motor	0.01	0.02	0.03	0.04	0.05	0.07	0.10	0.14	0.19	0.25	0.30	0.36	0.40
High Efficiency T8 Lamps with Electronic Ballasts	0.00	0.00	0.01	0.01	0.01	0.01	0.02	0.02	0.02	0.03	0.03	0.03	0.03
Occupancy Sensors	0.01	0.02	0.03	0.04	0.05	0.06	0.08	0.10	0.12	0.13	0.15	0.15	0.16
Reflector with Delamp	0.07	0.14	0.20	0.24	0.30	0.35	0.46	0.57	0.68	0.79	0.87	0.91	0.95
T8 Lamps with Electronic Ballasts, Reflector, and Delamp	0.10	0.20	0.29	0.35	0.43	0.51	0.66	0.81	0.96	1.09	1.18	1.21	1.24
Mechanical Subcooling	0.00	0.01	0.01	0.01	0.01	0.02	0.02	0.03	0.03	0.04	0.04	0.04	0.04
Total	0.30	0.58	0.83	0.99	1.20	1.41	1.81	2.20	2.59	2.98	3.22	3.34	3.45

Note: The impacts shown here are ramped for the first three years (refer to Section 6.6.1.5 for additional information on the ramp-up process applied).

Table 6-10. Commercial and Industrial Energy Efficiency Incentives ($000)

	1999	2000	2001	2002	2003	2004	2006	2008	2010	2012	2014	2016	2018
High Efficiency Chiller	36.52	30.84	26.75	23.80	21.98	21.04	21.53	24.76	30.49	37.22	60.43	61.21	61.00
High Efficiency Vent Motor	1.44	1.62	1.92	2.22	2.64	3.24	4.44	6.24	8.75	11.46	13.85	15.54	16.68
High Efficiency T8 Lamps with Electronic Ballasts	1.10	1.09	1.08	1.11	1.15	1.20	1.39	1.51	1.85	2.24	3.02	3.23	3.35
Occupancy Sensors	5.16	5.04	5.00	5.07	5.21	5.42	6.13	7.06	8.50	10.16	13.79	14.44	14.86
Reflector with Delamp	17.58	17.16	17.02	17.21	17.69	18.39	20.67	24.23	29.31	35.17	47.78	50.16	51.12
T8 Lamps with Electronic Ballasts, Reflector, and Delamp	33.49	32.75	32.54	33.03	33.97	35.39	39.79	46.66	56.31	67.47	91.11	95.73	97.61
Mechanical Subcooling	0.70	0.70	0.76	0.82	0.82	0.88	1.05	1.17	1.23	1.40	1.46	1.58	1.70
Total	95.99	89.20	85.07	83.27	83.46	85.57	95.01	111.62	136.45	165.12	231.46	241.90	246.31

Table 6-11. Commercial and Industrial Energy Efficiency Annual Budget ($000)

	1999	2000	2001	2002	2003	2004	2005	2006	2008	2010	2012	2014	2016	2018
DSM Expense	$341.35	$350.36	$361.96	$373.94	$386.32	$399.11	$412.32	$426.34	$440.83	$455.82	$471.32	$487.34	$503.91	$521.04
Evaluation Expense	$43.73	$44.89	$46.37	$47.91	$49.50	$51.13	$52.83	$54.62	$56.48	$58.40	$60.39	$62.44	$64.56	$66.76
Shareholder Incentives	$0.00	$183.10	$175.28	$165.16	$156.02	$143.07	$133.26	$123.44	$111.13	$103.61	$101.30	$102.98	$108.88	$116.42
Total	$385.09	$578.35	$583.62	$587.01	$591.83	$593.31	$598.40	$604.40	$608.44	$617.83	$633.00	$652.76	$677.35	$704.22

Table 6-12. Commercial and Industrial Energy Efficiency B/C Ratios

	Participant Test				Utility Test				Total Resource Cost Test				Societal Test				Rate Impact Measure Test			
	Benefits ($000)	Costs ($000)	Net Benefits ($000)	B/C Ratio	Benefits ($000)	Costs ($000)	Net Benefits ($000)	B/C Ratio	Benefits ($000)	Costs ($000)	Net Benefits ($000)	B/C Ratio	Benefits ($000)	Costs ($000)	Net Benefits ($000)	B/C Ratio	Benefits ($000)	Costs ($000)	Net Benefits ($000)	B/C Ratio
C&I Prescriptive - 2 year	6,555	586	5,969	11.19	2,765	1,154	1,612	2.40	2,765	1,574	1,191	1.76	2,804	1,574	1,230	1.78	2,765	7,543	-4,778	0.37
C&I Prescriptive - 20 year	32,640	2,721	29,919	12.00	15,065	7,378	7,687	2.04	15,065	8,930	6,135	1.69	15,174	8,935	6,239	1.70	15,065	38,849	-23,785	0.39

Note: Tax credits were taken into consideration by lowering the participant's purchase cost for solar and heat pump water heaters by the appropriate incentive amount. During the evaluation of the societal perspective, these incentives where brought back in as costs borne by society.

6.3.2.3 Commercial and Industrial New Construction Program

Docket No. 95-0175 (Application filed on July 6, 1995; D&O No. 14326 (Interim Approval) issued on October 26, 1995, D&O No. 14984 (Final Approval) issued on September 12, 1996). This program addresses air conditioning, lighting, motors and other end uses in the commercial and industrial new construction market. The program provides for the unique differences between customers in existing buildings and customers who are building new facilities. The program will provide design and technical assistance for the design and engineering community. The program will also provide customers with the services of a consulting engineer to evaluate the cost-effectiveness of energy-saving measures under consideration by the customer, and to recommend measures that may have been overlooked by the customer. Technical workshops and other technical development activities for the design and engineering community will be held to familiarize and educate them on energy efficient design methods and new technologies. The program will also provide design and engineering consultants with utility validation of their prospective energy efficiency projects in presentations to clients.

Table 6-13. Commercial and Industrial New Construction Average Rebates

Commercial and Industrial New Construction	Average Rebate
High Efficiency Chillers	$55/ton
Direct Expansion Chillers	$60/ton
Motors	$8/hp
High Pressure Sodium Lamp	$55/fixture
Metal Halide Lamp	$55/fixture
Occupancy Sensor	$10/fixture
Reflector and Delamp	$10/fixture
Mechanical Subcooling	$140.18/ton
Multiplex Compressor	$175.15/ton
Stand Alone Compressor	$84.09/ton

Figure 6-8. September, 2009 Normalized Typical Week Impacts, Commercial & Industrial New Construction

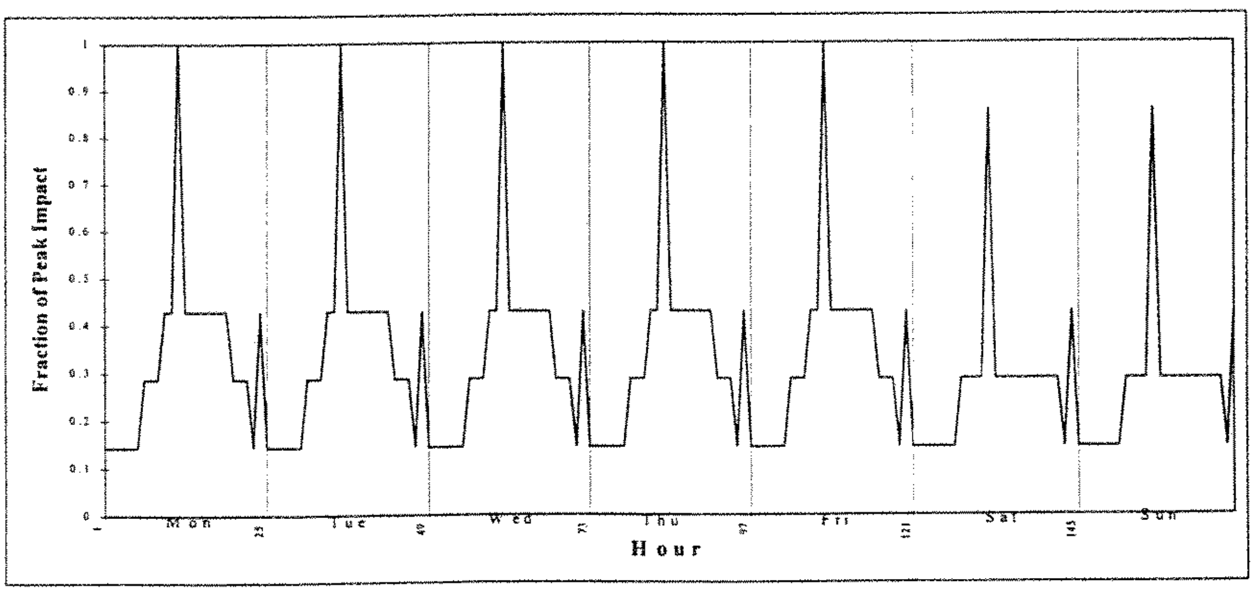


Table 6-14. Commercial and Industrial New Construction Energy Savings (GWh Requirements)

	1999	2000	2001	2002	2003	2004	2006	2008	2010	2012	2014	2016	2018
High Efficiency Chiller	0.0	0.0	0.1	0.1	0.2	0.3	0.5	0.8	1.2	1.7	2.3	2.9	3.5
High Efficiency Vent Motor	0.0	0.0	0.0	0.0	0.1	0.1	0.2	0.5	0.8	1.2	1.7	2.4	3.1
Occupancy Sensors	0.0	0.0	0.1	0.1	0.2	0.3	0.4	0.6	0.8	1.0	1.2	1.4	1.6
Reflector with Delamp	0.0	0.1	0.1	0.2	0.3	0.5	0.9	1.4	2.0	2.8	3.5	4.4	5.3
High Pressure Sodium Lamp	0.1	0.4	0.7	1.2	1.7	2.3	3.6	5.2	6.9	8.6	10.2	11.7	13.1
Metal Halide High Intensity Downlight	0.2	0.5	0.9	1.6	2.1	2.7	3.8	5.0	6.1	7.1	7.7	7.9	7.8
Mechanical Subcooling	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.2	0.2	0.2
High Efficiency Multiplex Compressor	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.1	0.2	0.2	0.3	0.3	0.3
High Efficiency Stand-Alone Compressor	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.1
Total	0.3	1.0	1.9	3.5	4.7	6.2	9.6	13.8	18.2	22.9	27.1	31.2	35.0

Note: The impacts shown here are ramped for the first three years (refer to Section 6.6.1.5 for additional information on the ramp-up process applied).

Table 6-15. Commercial and Industrial New Construction Peak Impacts (MW)

	1999	2000	2001	2002	2003	2004	2006	2008	2010	2012	2014	2016	2018
High Efficiency Chiller	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.2	0.3	0.3	0.4	0.5
High Efficiency Vent Motor	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.2	0.3	0.4	0.5
Occupancy Sensors	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.2	0.2	0.2	0.2
Reflector with Delamp	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.2	0.3	0.4	0.5	0.7	0.8
High Pressure Sodium Lamp	0.0	0.1	0.1	0.2	0.3	0.3	0.6	0.8	1.1	1.3	1.6	1.8	2.0
Metal Halide High Intensity Downlight	0.1	0.1	0.2	0.2	0.3	0.4	0.6	0.8	0.9	1.1	1.2	1.2	1.2
Mechanical Subcooling	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
High Efficiency Multiplex Compressor	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
High Efficiency Stand-Alone Compressor	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total	0.1	0.2	0.4	0.5	0.7	0.9	1.5	2.1	2.8	3.5	4.2	4.7	5.3

Note: The impacts shown here are ramped for the first three years (refer to Section 6.6.1.5 for additional information on the ramp-up process applied).

Table 6-16. Commercial and Industrial New Construction Incentives ($000)

	1999	2000	2001	2002	2003	2004	2006	2008	2010	2012	2014	2016	2018
High Efficiency Chiller	2.28	2.45	4.66	5.96	7.26	9.17	14.14	20.19	27.54	35.52	44.56	52.21	58.15
High Efficiency Vent Motor	0.18	0.18	0.30	0.42	0.54	0.78	1.91	3.64	6.56	10.20	14.02	16.58	18.19
Occupancy Sensors	2.05	2.18	3.23	3.64	4.00	4.59	6.05	7.38	8.71	10.19	12.04	13.78	15.16
Reflector with Delamp	1.55	1.87	2.89	3.78	4.75	6.12	10.14	15.16	20.85	27.21	34.53	41.19	46.34
High Pressure Sodium Lamp	45.25	49.49	73.23	86.55	98.41	115.41	159.02	201.65	241.73	285.64	340.70	394.07	439.14
Metal Halide High Intensity Downlight	94.27	91.50	119.50	126.96	129.91	137.41	155.79	165.84	170.10	174.99	187.25	198.02	206.15
Mechanical Subcooling	0.28	0.42	0.42	0.56	0.56	0.70	0.84	1.39	1.67	2.09	2.37	3.20	3.48
High Efficiency Multiplex Compressor	0.87	0.87	1.04	1.04	1.22	1.22	1.57	2.26	2.79	3.13	3.31	4.35	4.70
High Efficiency Stand-Alone Compressor	0.17	0.17	0.25	0.25	0.33	0.33	0.42	0.67	0.75	1.00	1.09	1.42	1.50
Total	146.91	149.12	205.52	229.15	246.97	275.72	349.88	418.19	480.71	549.99	639.88	724.82	792.82

Table 6-17. Commercial and Industrial New Construction Annual Budget ($000)

	1999	2000	2001	2002	2003	2004	2005	2006	2008	2010	2012	2014	2016	2018
DSM Expense	$62.31	$63.96	$66.07	$68.26	$70.52	$72.85	$75.27	$77.83	$80.47	$83.21	$86.04	$88.96	$91.99	$95.11
Evaluation Expense	$20.92	$21.47	$22.19	$22.92	$23.68	$24.46	$25.27	$26.13	$27.02	$27.94	$28.89	$29.87	$30.89	$31.94
Shareholder Incentives	$0.00	$48.70	$55.17	$85.17	$100.65	$109.37	$125.13	$143.87	$156.56	$172.02	$182.85	$196.25	$214.40	$235.11
Total	$83.23	$134.13	$143.43	$176.35	$194.85	$206.69	$225.67	$247.83	$264.05	$283.17	$297.77	$315.08	$337.27	$362.16

Table 6-18. Commercial and Industrial New Construction B/C Ratios

	Participant Test				Utility Test				Total Resource Cost Test				Societal Test				Rate Impact Measure Test			
	Benefits ($000)	Costs ($000)	Net Benefits ($000)	B/C Ratio	Benefits ($000)	Costs ($000)	Net Benefits ($000)	B/C Ratio	Benefits ($000)	Costs ($000)	Net Benefits ($000)	B/C Ratio	Benefits ($000)	Costs ($000)	Net Benefits ($000)	B/C Ratio	Benefits ($000)	Costs ($000)	Net Benefits ($000)	B/C Ratio
C&I New Construction - 2 yr	1,976	327	1,649	6.04	819	498	321	1.64	819	562	257	1.46	830	562	268	1.48	819	2,211	-1,392	0.37
C&I New Construction - 20 yr	25,513	3,057	22,456	8.34	14,505	6,065	8,440	2.39	14,505	5,643	8,862	2.57	14,573	5,647	8,926	2.58	14,505	28,098	-13,594	0.52

6.3.2.4 Commercial and Industrial Customized Rebate Program

Docket No. 95-0176 (Application filed on July 6, 1995; D&O No. 14326 (Interim Approval) issued on October 26, 1995, D&O No. 14984 (Final Approval) issued on September 12, 1996) Although a number of strategies for increasing energy efficiency were examined, the demand-side resource assessment could not identify all the energy efficiency opportunities that may exist in customers' facilities. The purpose of the custom rebate program is to provide a mechanism to develop energy efficiency opportunities that otherwise might go undeveloped. Customers will be able to identify opportunities in their facilities, develop a proposal, and present it to HELCO. HELCO will then evaluate the proposal, determine if it is a cost-effective application, and establish a cost-sharing arrangement with the customer.

Table 6-19. Commercial and Industrial Customized Rebate Average Rebates

Commercial and Industrial Customized Rebate	Average Rebate
Customize Rebate	$125/kw peak reduction and 5 cents per annual KWH saved. Note: qualifying projects must have greater than two year simple payback without incentives.

Figure 6-9. September, 2009 Normalized Typical Week Impacts, Commercial and Industrial Customized Rebate

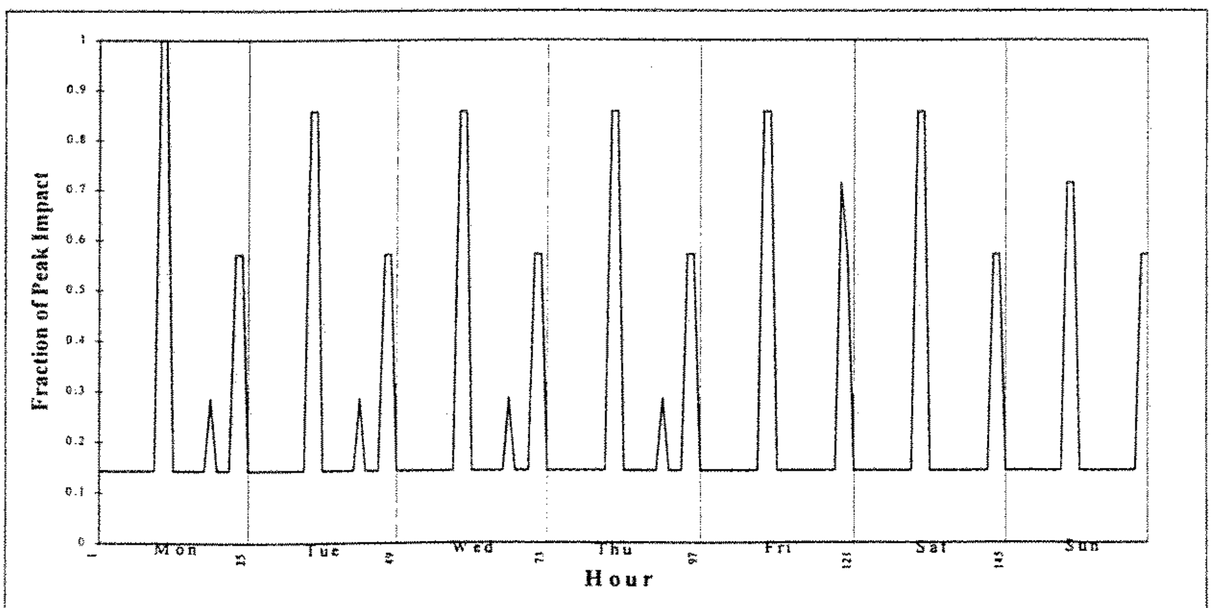


Table 6-20. Commercial and Industrial Customized Rebate Energy Savings (GWh Requirements)

	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
Commercial Industrial Customized Rebate	0.40	1.48	2.29	3.13	4.01	4.70	5.61	6.55	7.52	8.53	9.58	10.65	11.76	12.90	14.08	15.29	16.54	17.81	19.13	20.47
Total	0.40	1.48	2.29	3.13	4.01	4.70	5.61	6.55	7.52	8.53	9.58	10.65	11.76	12.90	14.08	15.29	16.54	17.81	19.13	20.47

Note: The impacts shown here are ramped for the first three years (refer to Section 6.6.1.5 for additional information on the ramp-up process applied).

Table 6-21. Commercial and Industrial Customized Rebate Peak Impacts (MW)

	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
Commercial Industrial Customized Rebate	0.10	0.21	0.33	0.45	0.58	0.69	0.82	0.96	1.10	1.25	1.40	1.56	1.72	1.88	2.06	2.23	2.42	2.60	2.79	2.99
Total	0.10	0.21	0.33	0.45	0.58	0.69	0.82	0.96	1.10	1.25	1.40	1.56	1.72	1.88	2.06	2.23	2.42	2.60	2.79	2.99

Note: The impacts shown here are ramped for the first three years (refer to Section 6.6.1.5 for additional information on the ramp-up process applied).

Table 6-22. Commercial and Industrial Customized Rebate Incentives ($000)

	1999	2000	2001	2002	2003	2004	2006	2008	2010	2012	2014	2016	2018
Commercial Industrial Customized Rebate	45.0	47.7	49.9	52.3	54.5	56.8	61.3	65.5	69.9	74.2	78.6	83.0	87.3
Total	45.0	47.7	49.9	52.3	54.5	56.8	61.3	65.5	69.9	74.2	78.6	83.0	87.3

Table 6-23. Commercial and Industrial Customized Rebate Annual Budget ($000)

	1999	2000	2001	2002	2003	2004	2005	2006	2008	2010	2012	2014	2016	2018
DSM Expense	$38.02	$39.02	$40.31	$41.65	$43.02	$44.45	$45.92	$47.48	$49.09	$50.76	$52.49	$54.27	$56.12	$58.03
Evaluation Expense	$8.31	$8.53	$8.81	$9.10	$9.40	$9.71	$10.03	$10.37	$10.73	$11.09	$11.47	$11.86	$12.26	$12.68
Shareholder Incentives	$0.00	$65.52	$75.67	$81.85	$87.87	$92.39	$97.85	$103.58	$107.44	$113.24	$119.63	$129.02	$139.99	$152.35
Total	$46.32	$113.06	$124.79	$132.59	$140.29	$146.55	$153.80	$161.43	$167.26	$175.10	$183.59	$195.15	$208.37	$223.06

Table 6-24. Commercial and Industrial Customized Rebate B/C Ratios

	Benefits ($000)	Costs ($000)	Net Benefits ($000)	B/C Ratio	Benefits ($000)	Costs ($000)	Net Benefits ($000)	B/C Ratio	Benefits ($000)	Costs ($000)	Net Benefits ($000)	B/C Ratio	Benefits ($000)	Costs ($000)	Net Benefits ($000)	B/C Ratio	Benefits ($000)	Costs ($000)	Net Benefits ($000)	B/C Ratio
C&I Custom Rebate - 2 Year	2,182	398	1,784	5.49	1,052	282	771	3.74	1,052	597	455	1.76	1,064	597	467	1.78	1,052	2,381	-1,329	0.44
C&I Custom Rebate - 20 Year	15,663	2,861	12,801	5.47	10,155	2,244	7,911	4.53	10,155	4,514	5,641	2.25	10,214	4,515	5,699	2.26	10,155	17,315	-7,160	0.59

6.3.3 Calculation of Shareholder Incentive and Lost Margin Estimates

6.3.3.1 Differential Cost Effectiveness Approach

The PROSCREEN II® Differential Cost Effectiveness (DCE) module was used in IRP-98 to estimate shareholder incentives and lost margins for use in the determination of program cost-effectiveness and the integration analysis. The DCE methodology used to calculate DSM avoided costs for the calculation of shareholder incentives is different from the methodology established in IRP-93. The DCE methodology is not meant to be a replacement for the IRP-93 shareholder incentive calculation methodology, but provides a quick estimate which can be used to assess the cost-effectiveness of the various programs without going through extensive, plan-specific calculations. The DCE shareholder assessment methodology estimates the net present value of benefits and costs for each alternative individually against a reference supply resource optimization. As a result, the diminishing returns that would be determined by a full integrated optimization are not captured. The absence of diminishing returns results in estimates of shareholder incentives that will likely exceed, by a slight margin, the values produced using the IRP-93 methodology. Estimates of shareholder incentives and lost margin for both 2-year and 20-year energy efficiency DSM programs, using the DCE method, are shown in Tables 6-25 and 6-26.

Table 6-25. DCE Shareholder Incentive Estimates (Dollars)

Year	2-year Residential Water Heating	2-year Commercial & Industrial Energy Efficiency	2-year Commercial & Industrial New Construction	2-year Commercial & Industrial Custom Rebate	Total 2-year Approved Energy Efficiency
1999	-	-	-	-	-
2000	37,360	183,100	48,700	65,520	334,680
2001	46,550	175,280	55,170	75,670	352,670
2002	-	-	-	-	-
2003	-	-	-	-	-
2004	-	-	-	-	-
2005	-	-	-	-	-
2006	-	-	-	-	-
2007	-	-	-	-	-
2008	-	-	-	-	-
2009	-	-	-	-	-
2010	-	-	-	-	-
2011	-	-	-	-	-
2012	-	-	-	-	-
2013	-	-	-	-	-
2014	-	-	-	-	-
2015	-	-	-	-	-
2016	-	-	-	-	-
2017	-	-	-	-	-
2018	-	-	-	-	-

Year	20-year Residential Water Heating	20-year Commercial & Industrial Energy Efficiency	20-year Commercial & Industrial New Construction	20-year Commercial & Industrial Custom Rebate	Total 20-year Energy Efficiency
1999	-	-	-	-	-
2000	37,360	183,100	48,700	65,520	334,680
2001	46,550	175,280	55,170	75,670	352,670
2002	53,050	165,160	85,170	81,850	385,230
2003	60,520	156,020	100,650	87,870	405,060
2004	62,810	143,070	109,370	92,390	407,640
2005	67,420	133,260	125,130	97,850	423,660
2006	71,800	123,440	143,870	103,580	442,690
2007	74,290	111,130	156,560	107,440	449,420
2008	78,700	103,610	172,020	113,240	467,570
2009	80,830	101,300	182,850	119,630	484,610
2010	87,440	102,980	196,250	129,020	515,690
2011	96,270	108,880	214,400	139,990	559,540
2012	105,500	116,420	235,110	152,350	609,380
2013	116,100	125,940	269,100	166,280	677,420
2014	125,590	133,040	293,760	179,340	731,730
2015	141,040	313,180	344,840	199,760	998,820
2016	159,430	325,710	391,720	221,700	1,098,560
2017	175,160	331,450	447,330	241,850	1,195,790
2018	189,480	335,240	505,770	262,360	1,292,850

Table 6-26. DCE Lost Margin Estimates ($000)

Year	2-year Residential Water Heating	2-year Commercial & Industrial Energy Efficiency	2-year Commercial & Industrial New Construction	2-year Commercial & Industrial Custom Rebate	Total 2-year Approved Energy Efficiency
1999	180	319	83	87	669
2000	311	533	143	131	1,119
2001	266	499	120	174	1,058
2002	216	391	98	99	804
2003	209	371	94	94	768
2004	200	348	88	96	732
2005	192	326	83	91	693
2006	277	481	127	136	1,021
2007	297	552	143	151	1,144
2008	300	557	145	153	1,155
2009	308	592	157	161	1,218
2010	303	583	157	160	1,203
2011	310	587	161	163	1,220
2012	315	582	164	166	1,227
2013	318	576	166	167	1,227
2014	149	326	82	162	718
2015	0	0	0	152	152
2016	0	0	0	155	155
2017	0	0	0	140	140
2018	0	0	0	108	108

Year	20-year Residential Water Heating	20-year Commercial & Industrial Energy Efficiency	20-year Commercial & Industrial New Construction	20-year Commercial & Industrial Custom Rebate	Total 20-year Energy Efficiency
1999	180	319	83	87	669
2000	311	533	143	131	1,119
2001	427	729	227	192	1,575
2002	417	746	232	213	1,608
2003	496	871	293	259	1,919
2004	562	974	351	318	2,205
2005	626	1,052	411	358	2,447
2006	1,022	1,725	820	625	4,192
2007	1,232	2,200	1,123	797	5,352
2008	1,378	2,457	1,347	915	6,096
2009	1,580	2,866	1,729	1,109	7,284
2010	1,673	3,116	1,952	1,196	7,937
2011	1,882	3,472	2,296	1,347	8,998
2012	2,016	3,710	2,582	1,499	9,808
2013	2,214	4,002	2,895	1,655	10,766
2014	2,037	3,995	2,978	1,720	10,731
2015	2,063	4,041	3,212	1,874	11,189
2016	1,876	3,907	3,212	1,886	10,882
2017	1,858	3,891	3,318	1,995	11,062
2018	1,165	3,314	2,728	1,555	8,762

6.3.3.2 Shareholder Incentive Calculation

DCE calculates shareholder incentives as follows:

1. A least-cost, supply-only resource plan is selected as a base case. Each of the supply-side resources are considered deferrable in incremental MW (partial unit) amounts (i.e., 1 MW of a 30 MW unit can be deferred.) The base reference supply-only plan used in this analysis is shown in Figure 6-10.

2. Each DSM program is added separately to the base reference supply-only plan. When the DSM program is added, capacity benefits are quantified as the economic carrying charge of the incremental portion of the supply resources deferred. Production cost savings are equal to the reduction in variable costs due to DSM energy savings.

3. Shareholder incentives are calculated by accumulating the avoided capacity and production costs for a single year of implementation (absent evaluation expenses) and 14 residual years of impacts for each program, and applying the formula below. This is repeated for each year of the program.

$$\boxed{SI = (NB * 0.10) / (1 - CTR)}$$

Figure 6-10. Base Reference Supply-Only Plan

Date	Description of Unit Type and Size (net MW)
2002	Puna return from standby
2006	Add Keahole ST-7 (17MW)
2007	Add Hill 5 Repower (58.3MW)
2015	Add 1 on 1 diesel fired combined cycle (29.7MW)
2019	Add 2 on 1 diesel fired combined cycle (60.7MW)
2023	Add 2 on 1 diesel fired combined cycle (60.7MW)
2025	Add 2 on 1 diesel fired combined cycle (60.7MW)
2029	Add 2 on 1 diesel fired combined cycle (60.7MW)
2030	Add 2 on 1 diesel fired combined cycle (60.7MW)
2035	Add 2 on 1 diesel fired combined cycle (60.7MW)

Where:

SI = Shareholder incentives for one program in a single year
NB = Present value of net benefits associated with a 15 year life (Excluding evaluation expenses)
CTR = Corporate tax rate

6.3.3.3 Lost Margin Calculation

Lost margin was calculated as follows:

1. A least-cost, supply-only resource plan is selected as a base case. The base reference supply-only plan used in this analysis is the same as was used for the calculation of shareholder incentives.

2. Each DSM program is added separately to the base case plan. When the DSM program is added, production cost savings are calculated as the difference between total production costs (fuel + O&M + emission fees) with the DSM program and total production costs without the DSM program.

3. The following formula is used to calculate lost margin:

$$\boxed{LM = RC - RPC}$$

Where:

LM = Lost margin for one program for one year
RC = Total reduced revenue resulting from one program during one year
RPC = Total reduced production cost resulting from one program during one year

6.3.4 Summary of Total Program Revenue Requirements

Table 6-27 is a summary of total DSM program revenue requirements, including lost margin, shareholder incentives and revenue taxes, for a 5-year period beginning in 1999. Note that this table reflects continuation of the energy efficiency programs beyond their currently approved 5-year period, which terminates in the year 2000.

Table 6-27. Five-Year Summary of Total DSM Revenue Requirements

Year	*Utility Administrative Costs (1)*	*Customer Incentives (2)*	*Program Evaluation Costs (3)*	*Total Program Cost (4)*	*Shareholder Incentives (5)*	*Total Program Costs + S I Subject to Revenue Taxes (6)*	*Revenue Taxes (7)*	*Lost Margin (8)*
Commercial and Industrial Energy Efficiency								
1999	$341,352	$95,991	$43,734	$481,077	$0	$481,077	$45,702	$318,714
2000	$350,364	$89,203	$44,889	$484,455	$183,100	$667,555	$63,418	$533,499
2001	$361,961	$85,069	$46,374	$493,404	$175,280	$668,684	$63,525	$728,510
2002	$373,942	$83,266	$47,909	$505,117	$165,160	$670,277	$63,676	$746,450
2003	$386,319	$83,460	$49,495	$519,275	$156,020	$675,295	$64,153	$871,368
2004					$143,070	$143,070	$13,592	
Total	$1,813,937	$436,989	$232,402	$2,483,328	$822,630	$3,305,958	$314,066	$3,198,542
Commercial and Industrial New Construction								
1999	$62,312	$146,906	$20,922	$230,140	$0	$230,140	$21,863	$83,461
2000	$63,957	$149,120	$21,474	$234,552	$48,700	$283,252	$26,909	$142,673
2001	$66,074	$205,525	$22,185	$293,784	$55,170	$348,954	$33,151	$226,863
2002	$68,261	$229,152	$22,919	$320,333	$85,170	$405,503	$38,523	$231,993
2003	$70,521	$246,973	$23,678	$341,171	$100,650	$441,821	$41,973	$293,424
2004					$109,370	$109,370	$10,390	
Total	$331,125	$977,676	$111,179	$1,419,980	$399,060	$1,819,040	$172,809	$978,414
Commercial And Industrial Custom Rebate								
1999	$38,016	$45,042	$8,306	$91,364	$0	$91,364	$8,680	$87,213
2000	$39,020	$47,659	$8,525	$95,203	$65,520	$160,723	$15,269	$131,438
2001	$40,311	$49,921	$8,807	$99,040	$75,670	$174,710	$16,597	$192,212
2002	$41,645	$52,255	$9,099	$102,999	$81,850	$184,849	$17,561	$213,281
2003	$43,024	$54,517	$9,400	$106,942	$87,870	$194,812	$18,507	$258,721
2004					$92,390	$92,390	$8,777	
Total	$202,016	$249,394	$44,138	$495,548	$403,300	$898,848	$85,391	$882,865
TOTAL COMMERCIAL AND INDUSTRIAL PROGRAMS								
1999	$441,680	$287,939	$72,962	$802,581	$0	$802,581	$76,245	$489,388
2000	$453,340	$285,982	$74,888	$814,210	$297,320	$1,111,530	$105,596	$807,609
2001	$468,346	$340,515	$77,367	$886,228	$306,120	$1,192,348	$113,273	$1,147,585
2002	$483,848	$364,673	$79,928	$928,449	$332,180	$1,260,629	$119,760	$1,191,724
2003	$499,864	$384,951	$82,573	$967,388	$344,540	$1,311,928	$124,633	$1,423,513
2004					$344,830	$344,830	$32,759	
Total	$2,347,078	$1,664,060	$387,718	$4,398,856	$1,624,990	$6,023,846	$572,266	$5,059,821
TOTAL RESIDENTIAL PROGRAMS								
Residential Water Heating								
1999	$324,594	$274,717	$59,931	$659,242	$0	$659,242	$62,628	$179,719
2000	$333,163	$267,789	$61,513	$662,466	$37,360	$699,825	$66,483	$311,328
2001	$344,191	$256,763	$63,549	$664,504	$46,550	$711,054	$67,550	$427,452
2002	$355,584	$251,117	$65,653	$672,353	$53,050	$725,403	$68,913	$416,579
2003	$367,354	$247,474	$67,826	$682,654	$60,520	$743,174	$70,602	$495,605
2004					$62,810	$62,810	$5,967	
Total	$1,724,885	$1,297,860	$318,472	$3,341,218	$260,290	$3,601,508	$342,143	$1,830,683
TOTAL, ALL PROGRAMS								
1999	$766,274	$562,656	$132,893	$1,461,823	$0	$1,461,823	$138,873	$669,107
2000	$786,504	$553,771	$136,401	$1,476,676	$334,680	$1,811,356	$172,079	$1,118,937
2001	$812,537	$597,278	$140,916	$1,550,732	$352,670	$1,903,402	$180,823	$1,575,037
2002	$839,432	$615,790	$145,581	$1,600,802	$385,230	$1,986,032	$188,673	$1,608,304
2003	$867,217	$632,425	$150,399	$1,650,041	$405,060	$2,055,101	$195,235	$1,919,118
2004					$407,640	$407,640	$38,726	
Total	$4,071,963	$2,961,920	$706,191	$7,740,074	$1,885,280	$9,625,354	$914,409	$6,890,503

Notes:

1 Total Program Costs and Shareholder Incentives Subject to Revenue Taxes are composed of Admin Costs, Customer Incentives, and Before Tax Shareholder Incentives.

2 Revenue Taxes are assessed at a rate of 9.5% of Program Costs and Before Tax Shareholder Incentives.

3 Shareholder Incentives are collected at the end of each year. Other costs are collected at the beginning.

4 Includes reduced customer incentives for C&I lighting measures and residential water heating measures.

6.4 VALIDATION OF UPDATED DSM IMPACT AND COST ESTIMATES

6.4.1 Comparison to Previous DSM Impact and Cost Estimates

Figure 6-11 and Table 6-28 present comparisons between previous and current estimates of 20-year DSM program impacts and costs. Evident is a significant decrease in market penetration, and a corresponding decrease in program costs. This comes primarily as a result of the change from the COMPASS model, used in all previous DSM analyses, to the DSVIEW model. DSVIEW is a more refined DSM evaluation model, as it allows multiple technologies to compete for market share whereas COMPASS relies simply on base and DSM pairs of technologies. Because the same base technology may be used repeatedly within COMPASS, the available market can be overstated.

Figure 6-11. Comparison of 20-year Energy Efficiency Program Estimates

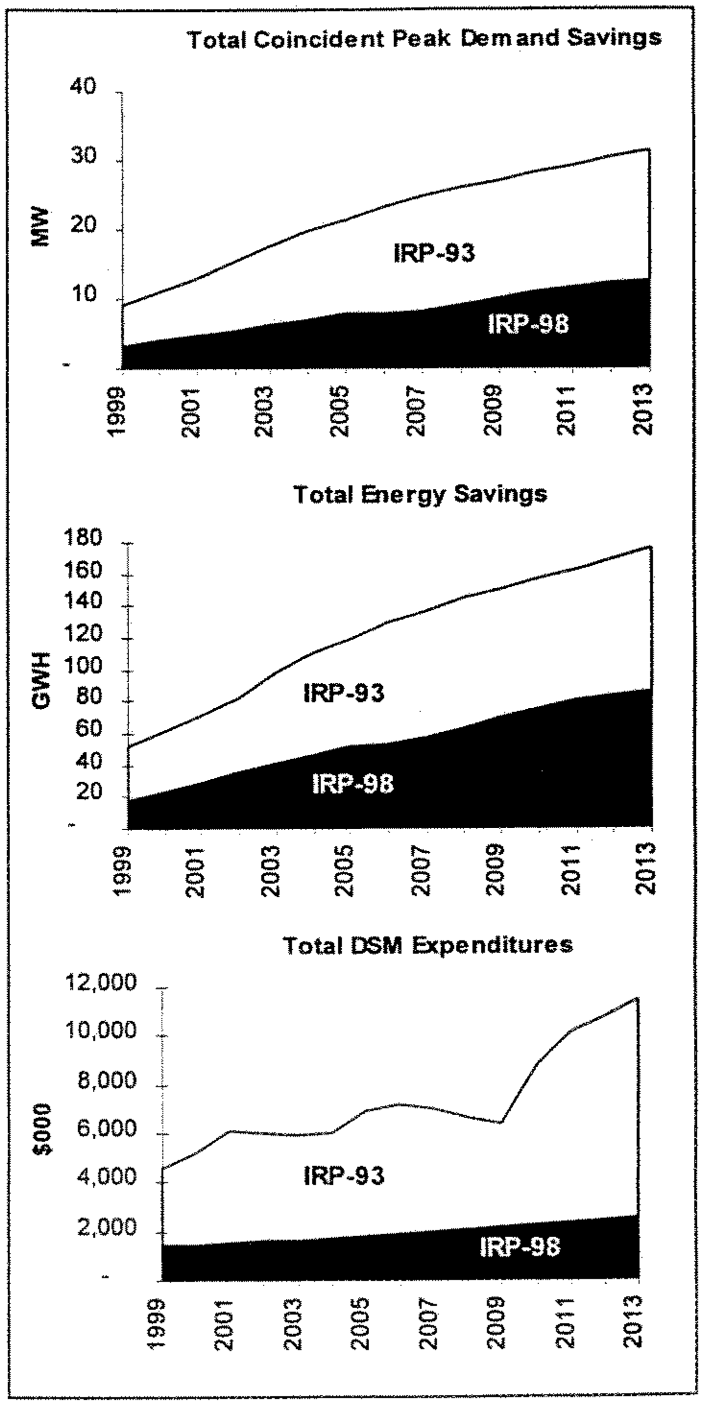


Table 6-28. Comparison of 20-year Energy Efficiency Program Estimates

	Coincident Peak Impact (MW)			Energy Savings (GWh)			Program Cost ($000)			Shareholder Incentives ($000)		
Year	IRP-93	IRP-98	Difference	IRP-93	IRP-98	Difference	IRP-93	IRP-98	Difference	IRP-93	IRP-98	Difference
1999	9.2	3.2	-6.0	51.3	18.1	-33.2	4,555.0	1,461.8	-3,093.2	-	-	0.0
2000	11.1	3.9	-7.2	61.9	23.5	-38.4	5,214.4	1,476.7	-3,737.7	2,884.9	334.7	-2,550.2
2001	13.0	4.7	-8.3	70.2	28.4	-41.8	6,130.5	1,550.7	-4,579.7	2,910.9	352.7	-2,558.2
2002	15.3	5.3	-9.9	82.4	35.5	-46.8	6,042.0	1,600.8	-4,441.2	2,618.5	385.2	-2,233.3
2003	17.6	6.1	-11.5	98.0	40.8	-57.2	5,930.3	1,650.0	-4,280.2	2,393.3	405.1	-1,988.2
2004	19.8	6.9	-12.9	110.2	46.0	-64.2	5,975.8	1,716.8	-4,259.1	2,272.1	407.6	-1,864.4
2005	21.4	7.7	-13.7	118.8	51.4	-67.3	6,885.8	1,798.0	-5,087.8	2,897.9	423.7	-2,474.2
2006	23.3	7.7	-15.6	129.0	53.5	-75.5	7,124.8	1,882.5	-5,242.3	2,563.5	442.7	-2,120.8
2007	24.6	8.2	-16.4	136.2	57.5	-78.7	7,009.7	1,970.3	-5,039.3	3,336.5	449.4	-2,887.1
2008	26.1	9.0	-17.1	145.0	63.2	-81.8	6,607.0	2,052.9	-4,554.1	2,855.7	467.6	-2,388.1
2009	27.0	9.9	-17.1	149.9	69.2	-80.7	6,387.8	2,139.4	-4,248.4	3,299.2	484.6	-2,814.6
2010	28.2	10.8	-17.4	157.4	75.4	-82.0	8,731.6	2,233.4	-6,498.2	4,880.0	515.7	-4,364.3
2011	29.1	11.6	-17.5	162.4	80.2	-82.2	10,104.5	2,331.8	-7,772.7	3,260.6	559.5	-2,701.1
2012	30.2	12.1	-18.1	169.6	83.2	-86.4	10,721.2	2,429.6	-8,291.6	5,515.6	609.4	-4,906.2
2013	31.2	12.6	-18.6	175.3	86.4	-88.9	11,422.1	2,530.0	-8,892.1	4,363.3	677.4	-3,685.9
2014	-	13.1	-	-	89.8	-	-	2,688.4	-	-	731.7	-
2015	-	13.7	-	-	93.5	-	-	2,786.6	-	-	998.8	-
2016	-	14.2	-	-	97.4	-	-	2,894.6	-	-	1,098.6	-
2017	-	14.7	-	-	100.7	-	-	3,001.5	-	-	1,195.8	-
2018	-	15.2	-	-	104.0	-	-	3,081.9	-	-	1,292.8	-

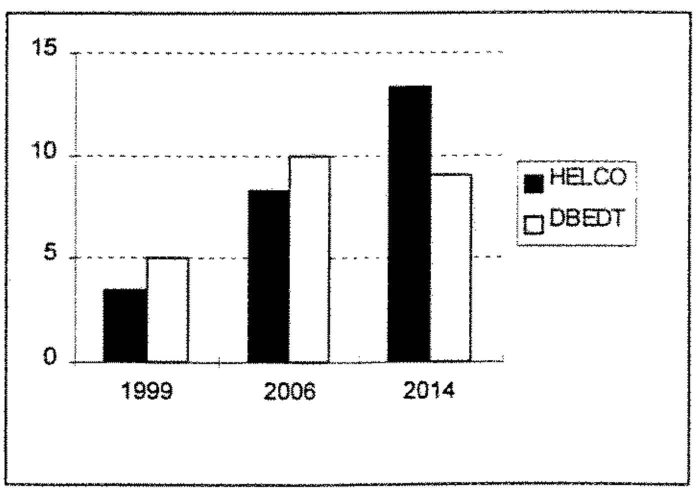
Notes:
(1) Utility Admin. costs, Customer Incentives & Program evaluation (does not include shareholder incentives or lost margin)
(2) IRP-98 DSM data as of 10/97
(3) IRP-93 EE DSM program cost & shareholder incentive estimates from HELCO's IRP Plan Reassessment filed on June 6, 1994
(4) IRP-93 EE DSM program peak & energy impacts from:

- RWHE Docket No. 94-0206, Attachment A, p. 11 of 21
- RWHN HECO-WP-104, Docket No. 94-0216, p.4 of 117
- CIEE Docket No. 94-012, Attachment A, p. 11 of 21
- CINC Docket No. 94-010, Attachment A, p. 11 of 21
- CICR Docket No. 94-011, Attachment A, p. 11 of 18

6.4.2 Comparison to State of Hawaii Department of Business, Economic Development and Tourism (DBEDT) Study Results

The 1995 DBED&T study, *Hawaii Demand-Side Management Opportunity Report*, served as a guideline in validating the reduced size of the HELCO market. Figure 6-12 contrasts the DBED&T study results (presented by DBED&T during a meeting of the HECO DSM Advisory Group on September 19, 1996) against HELCO DSM assessment results for total demand reduction. In order to arrive at a fair comparison of the two studies it was necessary to use cumulative from program inception rather than cumulative beginning in 1999 impacts for the HELCO numbers. Despite the fact that long-term projections of DSM impacts have been reduced significantly from 1993 levels, they are still aggressive when contrasted to the results of DBED&T's study. While the results of final integration will determine the optimal duration of program activity, the results shown here assume that all four approved energy efficiency DSM programs remain active for 20 years.

Figure 6-12. Comparison of DBEDT Potential Study and 1997 HELCO DSM Assessment Results



6.5 Determination of Program Cost-Effectiveness

6.5.1 Standard Practice Tests

A key step in the DSM assessment process for IRP-98 was the benefit/cost analysis. In 1987 the California Energy Commission and the California Public Utilities Commission introduced the Joint Standard Practice Methodology for Benefit/Cost Analysis of DSM Programs. The five standard practice tests as they apply to PROSCREEN II® analyses are as follows:

Utility Cost Test — Compares utility costs (fuel, O&M and capacity) with utility DSM program costs. Values greater than one indicate that the life-cycle fuel and capacity savings exceed the life-cycle DSM program costs. Values greater than one indicate that the net present value of revenue requirements will be reduced.

Total Resource Cost Test — Compares fuel, O&M and capacity savings against utility DSM program costs plus customer costs (to participate in the DSM program).

Participant Test — Quantifies the benefit a participant can derive from a DSM program. This test measures whether the DSM measure is economically attractive to the participating customer.

Ratepayer Impact Measure Test — Includes the lost revenue from reduced electricity sales as a cost. Values less than one indicate that average rates may increase over the life of the program. This test needs to be interpreted cautiously, since rate increases in the years immediately following the implementation of the program are weighted much higher than the rate impacts (which often decrease) in future years.

Societal Cost Test — Compares fuel, O&M and capacity savings against the sum of utility program costs, customer costs and externalities costs. Tax credits are added back in to total societal costs, since society as a whole bears these costs.

Table 6-29 summarizes the components of each Standard Practice Test as calculated in the PROSCREEN II® model used in this study.

Table 6-29: Standard Practice Test Components

		Participant	Utility	Total Resource Cost	Societal	Rate Impact Measure
Benefits	Customer Bill Savings	x				
	Other Customer Benefits	x		x	x	
	Production Cost Savings		x	x	x	x
	Deferred T&D Capacity Costs		x	x	x	x
	Deferred Generation Capacity Costs		x	x	x	x
	Retail Fuel Switch Savings	x				
	Wholesale Fuel Switch Benefit			x	x	
	Utility Revenue Increase					x
	External Benefits				x	
	Customer Impact Benefits			x	x	
	Incentive Payments	x				
	Value Increase Participant	x		x	x	
Costs	Direct Customer Costs	x		x	x	
	Production Cost Increase		x	x	x	x
	T&D Capacity Cost Increase		x	x	x	x
	Generation Capacity Cost Increase		x	x	x	x
	Utility DSM Expenses		x	x	x	x
	Evaluation Expenses		x	x	x	x
	Capital Charges		x	x	x	x
	Incentive Payment		x			x
	External Cost Increase				x	
	Customer Interrupt Costs	x				
	Customer Impact Costs			x	x	
	Utility Revenue Decrease					x
	Customer Bill Increase	x				
	Retail Fuel Switch Costs	x				
	Wholesale Fuel Switch Costs			x	x	
	Shared Savings Costs		x	x	x	x
	Value Decrease Participant	x		x	x	
	Alternative O&M Costs		x	x	x	x
	Alternative Fuel Costs		x	x	x	x

6.5.2 Summary of IRP-98 Benefit/Cost (B/C) Test Results

Although the true value of individual DSM programs in a resource plan can only be determined through integration with the specific supply resources in that same plan, benefit/cost ratios provide an initial indication of program cost-effectiveness in this assessment phase. Tables 6-30 and 6-31 summarize results of the cost-effectiveness tests defined above with and without shareholder incentives for the four energy efficiency programs reviewed and updated as part of this DSM assessment process. Detailed benefit and cost dollar amounts for each program appear in Section 6.3.2. The PROSCREEN II® DCE module was used to calculate these B/C ratios from five perspectives: Utility, DSM Participant, Total Resource Cost (TRC), Ratepayer Impact Measure (RIM) and Societal.

Note that while all programs pass the Participant Test, no programs pass the Ratepayer Impact Measure Test. The fact that conservation-oriented programs fail the RIM test is not unexpected since average rates tend to exceed marginal avoided costs.

6.5.3 Comparison of IRP-98 B/C Test Results to Prior Analyses

The IRP-98 benefit/cost analysis reflects an improvement from the approach previously taken to evaluate DSM resources. In IRP-93 and the DSM applications, SRC's COMPASS model was used to evaluate the DSM programs. Since COMPASS relied on the entry of static avoided costs, the interactive effects that DSM has on the operation of the HELCO system were not captured. DSVIEW avoids this pitfall by actually performing a production cost simulation with and without DSM programs in place to assess the benefits and costs associated with the DSM programs. This modeling refinement, as well as the reduction in DSM market size, has resulted in a shift in program cost-effectiveness ratings.

Table 6-32 shows the difference in B/C ratios between previous and current analyses. In this table, 20-year programs are compared without shareholder incentives.

Table 6-30. Summary Of Cost Effectiveness, With Shareholder Incentives

	Participant Test	Utility Test	Total Resource Costs Test	Societal Test	Rate Impact Measure Test
Residential Water Heating - 2 year	3.98	1.31	0.93	0.94	0.35
Commercial Industrial Prescriptive Measures - 2 year	11.19	2.40	1.76	1.78	0.37
Commercial Industrial New Construction - 2 year	6.04	1.64	1.46	1.48	0.37
Commercial Industrial Customized Rebate - 2 year	5.49	3.74	1.76	1.78	0.44
Residential Water Heating - 20 year	3.73	1.43	1.05	1.06	0.45
Commercial Industrial Prescriptive Measures - 20 year	12.00	2.04	1.69	1.70	0.39
Commercial Industrial New Construction - 20 year	8.34	2.39	2.57	2.58	0.52
Commercial Industrial Customized Rebate - 20 year	5.47	4.53	2.25	2.26	0.59

Table 6-31. Summary Of Cost Effectiveness, Without Shareholder Incentives

	Participant Test	Utility Test	Total Resource Costs Test	Societal Test	Rate Impact Measure Test
Residential Water Heating - 2 year	3.98	1.39	0.97	0.98	0.35
Commercial Industrial Prescriptive Measures - 2 year	11.19	3.22	2.16	2.19	0.38
Commercial Industrial New Construction - 2 year	6.04	1.98	1.72	1.74	0.39
Commercial Industrial Customized Rebate - 2 year	5.49	6.35	2.19	2.21	0.46
Residential Water Heating - 20 year	3.73	1.57	1.13	1.14	0.46
Commercial Industrial Prescriptive Measures - 20 year	12.00	2.55	2.02	2.03	0.40
Commercial Industrial New Construction - 20 year	8.34	3.22	3.55	3.56	0.55
Commercial Industrial Customized Rebate - 20 year	5.47	8.74	2.96	2.97	0.63

Table 6-32. Comparison of B/C Ratios to Previous Analyses (Without Shareholder Incentives)

	Participant Test		Utility Test		Total Resource Cost Test		Societal Test		Rate Impact Measure Test	
	IRP-98	IRP-93	IRP-98	IRP-93	IRP-98	IRP-93	IRP-98	IRP-93	IRP-98	IRP-93
Residential Water Heating - 20 year	3.73	1.85	1.57	1.82	1.13	1.10	1.14	0.99	0.46	0.52
Commercial Industrial Prescriptive Measures - 20 year	12.00	6.74	2.55	3.77	2.02	2.28	2.03	2.28	0.40	0.45
Commercial Industrial New Construction - 20 year	8.34	6.55	3.22	7.28	3.55	3.66	3.56	3.66	0.55	0.57
Commercial Industrial Customized Rebate - 20 year	5.47	4.80	8.74	4.73	2.96	2.71	2.97	2.71	0.63	0.68

6.6 PROSCREEN II Modeling Data and Assumptions

The remainder of the DSM program assessment is a detailed documentation of the process and assumptions used in the assessment of DSM resources for IRP-98. The PROSCREEN II® DSVIEW model used in this DSM assessment relies on four primary components of PROSCREEN II®:

- The Load Forecast Adjustment (LFA) Module models chronological seasonal loads (by end-use and/or class) and hourly impacts of DSM programs (including seasonal peaks and energies, fixed and variable costs, customer costs, penetration curves, etc.).
- The Generation and Fuel (GAF) Module provides production costing simulation and capacity deferral benefit assessment.
- The Demand-Side Program Design (DPD) Module explicitly evaluates the impacts of end-use level competition, rate structure, incentive levels and stock turnover on the program's effectiveness. When DPD analysis is complete, representations of DSM programs are stored in the LFA for further benefit/cost, optimization and financial analysis.
- The Differential Cost Effectiveness (DCE) Module develops detailed estimates of standard benefit/cost ratios of DSM options modeled in the LFA Module. Avoided energy and capacity costs are calculated through detailed supply system modeling in the GAF Module.

6.6.1 PROSCREEN II® Input Data and Assumptions

In addition to the PROSCREEN II® input data used in the integration analysis, DSVIEW required additional information such as market size, technology cost and performance, and customer rates for DSM design and evaluation.

6.6.1.1 Market Size Assessment

New residential and commercial construction forecasts were provided by the Forecast Division in the form of REEPS and COMMEND reports, respectively. REEPS provided a forecast of new residential accounts, shown in Table 6-33. The commercial forecast was given in thousands of new square feet (Table 6-34).

Table 6-33. Residential Construction Forecast (number of accounts)

	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
Single Family	518	484	459	573	646	716	802	862	909	910	924	953	970	978	989	1012	1030	1239	1268

Table 6-34. Commercial Construction Forecast (millions of square feet)

	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
Office	50	50	110	120	130	130	150	150	160	160	160	160	170	170	180	180	180	190	190
Restaurant	30	40	40	50	50	50	50	50	60	60	60	60	60	60	60	60	70	70	70
Retail	100	80	80	90	90	90	100	100	100	110	100	110	110	110	120	130	130	130	140
Grocery	30	30	30	30	30	30	30	30	40	40	40	40	40	40	40	40	40	50	50
Warehouse	100	90	80	90	90	90	90	90	90	100	100	100	100	100	100	100	100	100	110
Education	20	20	50	60	70	80	80	90	90	90	100	100	100	100	100	110	110	110	110
Health	50	40	40	50	50	50	60	60	60	70	70	70	70	80	80	90	100	100	110
Lodging	490	510	480	470	450	470	500	550	550	530	540	550	560	550	550	560	550	570	590
Misc.	240	240	390	380	370	400	420	440	440	430	430	420	420	420	410	430	430	440	450

6.6.1.2 Technology Data

DPD uses a stock model to track competition amongst multiple technologies competing for end-use market share. As a result of this approach, it is possible to have more than just a single "base" and "DSM" technology pair within each specified end-use. For each technology being analyzed, whether it is a promoted technology or not, it was necessary to define the following information:

- Technology cost information including purchase price, installation expenses and maintenance costs. The introduction of full scale DSM activity on the Big Island of Hawaii and Oahu in 1996 has allowed Hawaii-specific information to be collected and used in the development of IRP-98. Technology cost data was updated for all technologies based on the DSM data collected to date. The process of obtaining accurate cost estimates is an ongoing effort, and new estimates will be incorporated as additional information is tracked and analyzed.
- Energy usage characteristics including the maximum connected load (in kW for electric technologies) and a usage profile indicating the likelihood of use by hour. Since HELCO's first year of monitoring and evaluation results will not be available until late 1998, it was necessary to rely on previous estimates of Unit Energy Consumption (UEC) developed in IRP-93. UEC information was developed from manufacturers' information, simulations in the Hawaii environment, federal energy efficiency standards, the SRC Technology Database and meetings with the HELCO Advisory Group. UEC data for residential technologies was based on energy usage per household, usage for commercial lighting technologies was based on energy usage per fixture and usage for HVAC and refrigeration technologies was based on energy usage per ton.
  Load shapes for commercial sector technologies were developed from commercial load shapes created by SRC for Hawaii in the 1990 EPRI Reload study. In that study, five prototypical building types were simulated in the ADM-2 hourly model using Honolulu weather data. Residential load shapes were taken from HEI's 1986 Water Heater Load Study and from EPRI Reload data.

6.6.1.3 System Losses

The HELCO Generation Planning Division uses a system-wide loss factor of 8.64% which is entered into PROSCREEN II® as a seasonal loss percent. Seasonal loss percentages represent the ratio of losses to total requirements, and are used to differentiate total energy requirements from energy sales and the system peak from the peak-at-meter. These loss factors are applied on a seasonal (monthly) basis at the program group level.

Total energy requirements =
Energy sales ÷ (1.0 - seasonal loss percent)

System peak =
peak-at-meter ÷ (1.0 - seasonal loss percent)

6.6.1.4 Rate Schedules

Lost revenue estimates, which are used in the estimate of lost margin, are calculated by PROSCREEN II® using average residential and commercial rates. Residential, commercial and industrial average rates were provided by the Pricing Division of the Energy Services Department in the form of a demand charge and a base energy charge. These charges were then used to calculate a general rate for residential and commercial customers. The average residential rate was calculated to be 20.03 cents/kWh. The average commercial rate used a weighted average of the commercial and industrial rates and was calculated to be 17.36 cents/kWh.

6.6.1.5 Seasonal Ramp-Ups

Penetrations for the first three years of each DSM program were manually modified in order to accurately model the steady ramping-up of these programs. Since the incremental analysis focused on implementation in 1999 and beyond, ramping was performed for the three years from 1999 to 2001. For each year that seasonal ramping was simulated it was assumed that 1/12th of an entire year's additions would occur in each month.

For the longer term, beyond 2001, DSM energy and peak impacts were annualized; i.e., peak impact for the year is acquired as of January 1st.

7. ASSESSMENT OF SUPPLY-SIDE RESOURCES

7.1 IDENTIFICATION OF SUPPLY-SIDE RESOURCE OPTIONS

In IRP-93, HELCO commissioned Black & Veatch (B&V) to identify, examine and categorize all feasible supply-side resource options. A comprehensive list of candidate resource options was identified in the IRP-93 report, following a review of the *Generation Technology Assessment* (GTA) report prepared by B&V for HECO in 1990 and the *Energy Technology Status Report* (ETSR) prepared by the California Energy Commission (CEC) in 1990, and updated in 1992. These resource options were first screened for developmental status and applicability to meeting HELCO's present and future needs for electrical power generation. Resource options were submitted for time frame placement in the final screening if they passed four initial screening criteria:

1. unit size appropriate for the HELCO system
2. technology status of commercially available within the 20-year planning horizon
3. resource requirements and availability of resource
4. capital cost

The options remaining after the initial screening were grouped into three categories: commercial, developing or other. Commercial resources considered viable in the 0- to 5-year time frame are those that satisfy five criteria:

1. vendor availability
2. proven technology
3. utility scale
4. well-established capital and operating costs
5. resource availability

Developing resources considered viable in the 6- to 20-year time frame are those that satisfy four criteria:

Table 7-1. Candidate Resource Options

Steam Recuperated Gas Turbine (SRGT or STIG)
Phosphoric Acid Fuel Cell (PAFC)
Solar Parabolic Dish Collector with Stirling Engine
Cascaded Humid Air Turbine Cycle (CHAT)
Kalina Cycle
Air Bottoming Cycle

1. sole or multiple vendors
2. emerging technologies
3. potential for competitive capital and operating costs
4. resource availability

IRP-98 built upon the findings and results of the IRP-93 effort. In IRP-98, Black & Veatch performed an update to the IRP-93 *Supply-side Resource Option Portfolio Development* report. The IRP-98 update identified resource options that were previously considered developing, but since IRP-93 have been progressing toward commercial status. The six identified resources are shown in Table 7-1. Of the six, only the steam recuperated gas turbine (STIG) and phosphoric acid fuel cell (PAFC) options have become sufficiently common within the power industry to achieve commercial status. Appendix G contains the Black & Veatch report, which discusses the status of the remaining four developing resources in addition to details of the commercial resources considered in IRP-98.

Table 7-2 identifies all commercial fossil-fired supply-side resources considered in IRP-98. Through bus-bar and PROSCREEN analyses, these fossil-fired resources were screened down to a smaller set for consideration in the integration phase of the IRP (indicated by * in Table 7-2). The bus-bar analysis compared the total costs (capital, O&M and fuel) of units with similar operating modes. Results of the bus-bar analysis are shown in Tables 7-3 through 7-5. Iterative PROSCREEN

Table 7-2. Commercial Fossil-Fired Supply-Side Resource Options

	Simple Cycle Combustion Turbines	MW
	GE LM-1600 Simple Cycle	11.7
*	GE LM-2500 Simple Cycle	20.9
*	GE LM-2500 STIG	23.2
	GE PG-5371 Simple Cycle	24.5
*	GE LM6000 Simple Cycle	38.8
	GE PG-6551(B) Simple Cycle	34.7
	Single Train Combined Cycle Resources	**MW**
	GE LM-1600 1 on 1 Combined Cycle	16.7
*	GE LM-2500 1 on 1 Combined Cycle	30.2
	GE PG-5371 1 on 1 Combined Cycle	37.1
	GE LM6000 1 on 1 Combined Cycle	50.4
	GE PG-6551(B) 1 on 1 Combined Cycle	55.3
	Dual Train Combined Cycle Resources	**MW**
	GE LM-1600 2 on 1 Combined Cycle	34.2
*	GE LM-2500 2 on 1 Combined Cycle	60.8
	GE PG-5371 2 on 1 Combined Cycle	71.4
	Steam Units	**MW**
	Pulverized Coal	30
	Atmospheric Fluidized Bed	15
*	Atmospheric Fluidized Bed	30
	Oil Fired Steam	15
	Oil Fired Steam	30
	Repower Resource Options	**MW**
*	Hill 5 Repowering	58.3
*	Puna Steam Turbine Repowering	55.7
*	Hill 6 Repowering	65.1
	Diesel Engine Resources	**MW**
*	Diesel Engine	8.9[1]
	Diesel Engine	7.6
	Diesel Engine	2.1
*	Diesel Engine	1.0
*	Phosphoric Acid Fuel Cell	0.19

* Retained for consideration in integration analysis

[1] 8.9 MW unit evaluated in bus-bar screening later replaced with 10.4 MW diesel due to unit availability

Unit capacities in net MW at SRO screening phase. Unit performance data refined for integration analysis shown in Table 4-7.

dynamic optimization runs were performed to compare supply-side resource options through simulation of their operation in the HELCO system. A preference was given to those resources that consistently showed up in the least cost plans. Results of the bus-bar and PROSCREEN analyses validated each other, with the most cost-effective options ranking high in each screening method.

The screening process also took into account the size of units suitable for the HELCO system, using a guideline of 15-20% of the annual system peak as the maximum unit size allowable. While the LM6000 simple cycle was retained for consideration in the integration analysis, it was not considered until 2010, when it would no longer violate this size constraint based on the reference case peak forecast.

Table 7-3. Bus-bar Cost Rank of Baseload Units

Description	Bus-Bar Cost Rank	Rating, MW
* Hill 6 Repowering	1	65.1
* Puna Steam Turbine Repowering	2	55.7
* Hill 5 Repowering	3	58.3
GE PG-6551(B) 1 on 1 Combined Cycle	4	55.3
* GE LM-2500 2 on 1 Combined Cycle	5	60.7
GE LM6000 1 on 1 Combined Cycle	6	50.4
* GE LM-2500 1 on 1 Combined Cycle	7	30.2
GE LM-1600 2 on 1 Combined Cycle	8	34.2
GE PG-5371 1 on 1 Combined Cycle	9	37.1
GE PG-5371 2 on 1 Combined Cycle	10	71.4
GE LM-1600 1 on 1 Combined Cycle	11	16.7
Oil Fired Steam	12	30
* Atmospheric Fluidized Bed	13	30
Pulverized Coal	14	30
Oil Fired Steam	15	15
* Phosphoric Acid Fuel Cell	16	0.19
Atmospheric Fluidized Bed	17	15

Table 7-4. Bus-bar Cost Rank of Cycling Units

Description	Bus-Bar Cost Rank	Rating, MW
* GE LM6000 Simple Cycle	1	38.8
* GE LM-2500 STIG	2	23.2
GE PG-6551(B) Simple Cycle	3	34.7
* GE LM-2500 Simple Cycle	4	20.9
GE LM-1600 Simple Cycle	5	11.7
GE PG-5371 Simple Cycle	6	24.5

Table 7-5. Bus-bar Cost Rank of Peaking Units

Description	Bus-Bar Cost Rank	Rating, MW
* Diesel Engine	1	1.0
Diesel Engine	2	2.1
* Diesel Engine	3	8.9[1]
Diesel Engine	4	7.6

* Retained for consideration in integration analysis

[1] 8.9 MW unit evaluated in bus-bar screening later replaced with 10.4 MW diesel due to unit availability

Unit capacities in net MW at SRO screening phase. Unit performance data refined for integration analysis shown in Table 4-7.

Table 7-6. Indigenous and Renewable Resources

10MW (rated maximum) Wind energy (Lalamilo)
5MW (rated maximum) Wind energy (Lalamilo)
10MW (rated maximum) Wind energy (N. Hawaii)
5MW (rated maximum) Wind energy (N. Hawaii)
10MW (rated maximum) Wind energy (N. Hawaii)
5MW (rated maximum) Wind energy (N. Hawaii)
Battery Energy Storage: 3 hrs @ 5MW or 1.5 hrs @ 10MW
Battery Energy Storage Spinning Reserve: 20 min @ 10MW
0.9 kW (rated maximum) PV Energy-Distributed
4MW (rated maximum) PV Energy
Pumped Storage Hydro: 5 hrs @ 30MW (Kona)
Pumped Storage Hydro: 5 hrs @ 30MW (S. Hawaii)
13.8MW Run of River Hydro (E. Hawaii)
25MW Geothermal
25MW Biomass

All indigenous and renewable technologies shown in Table 7-6 were carried forward to the integration analysis.

7.1.1 Combined Cycle Fuels

Combined cycle units are able to burn heavy fuels, such as MSFO, or light distillate fuels, such as No. 2 diesel or naphtha. For the purpose of this screening evaluation, no distinction was made between No. 2 diesel and naphtha. Although naphtha is more volatile than diesel fuel and requires more expensive fuel handling equipment, the site-specific, detailed engineering needed to estimate the capital cost differences between diesel-fired and naphtha-fired plants was not done at this level of planning.

7.2 FUTURE NON-UTILITY GENERATION

For the purposes of integrated resource planning, HELCO evaluated commercial supply-side technologies that could be developed either by the utility or by Non-Utility Generators. (See Section 5.5) For purposes of IRP evaluation, the utility's cost estimates for supply-side resources and the utility's financing structure were used.

7.3 DISTRIBUTED GENERATION

As a result of IRP-93, HELCO commissioned an Electric Power Research Institute (EPRI) study which documented a new and different approach and methodology to assess the technical and economic feasibility of implementing distributed generation technologies. The study was initiated to assist HELCO in assessing the potential benefits and costs of distributed generation technologies in the context of an integrated resource planning process. Distributed generation is a relatively new concept to the utility industry and is only now being examined in similar feasibility studies.

In the study, HELCO examined combustion technologies, renewable technologies and fuel cells. Site locations are confidential as they are customer-owned sites. The study focused on areas where technology could benefit from transmission and distribution savings.

While diesel engine and combustion turbine technologies are well-developed, HELCO concluded that the concept of distributed generation as a strategy in generation planning is still in its infancy. Distributed generation provides a new and different generation planning concept from traditional centralized generation, and the study provides the foundation for a possibly different approach in future generation planning. The feasibility and cost-effectiveness of distributed generation resources are specific to technology and its assumptions (i.e., site location, permitting, operations, emissions and other considerations). As a result, distributed generation should be handled on a case-by-case basis, since site, technology and assumptions can vary substantially.

7.4 RENEWABLE RESOURCES

7.4.1 Biomass

Pursuant to HELCO integrated resource planning action plans, the potential to generate electricity from biomass on the island of Hawaii was investigated. Key technical and economic factors, such as land suitability and availability, energy crop yield, delivery costs and potential quantities were examined for a model production unit located in Ka'u.

Banagrass, a variety of Napiergrass (Pennisetum purpureum), is a promising crop species for conversion into electricity through direct firing in boilers. Lands presently planted in sugarcane at Ka'u have adequate supplies of irrigation water, and terrain, soils and climatic conditions that are highly suitable for banagrass production. The estimated cost of producing banagrass feedstock, Freight on Board (FOB) conversion-facility gate, was approximately $65 per ton, dry basis. The unit information form for the 25 MW biomass facility, utilizing a crop grown solely for electricity generation, was based on this in-house analysis.

7.4.2 Geothermal

The integration analysis considered a range of capital costs for a 25 MW geothermal unit from $3,700/kW to $5,100/kW to address uncertainties in the cost of future geothermal development. The capital cost estimates differ in the number of wells that would have to be drilled to find an adequate geothermal resource and the cost to drill each well.

HELCO is concerned with the operational compatibility of additional geothermal on the system due to the unknown reliability of the resource over the long term and its impact on the system during minimum load periods. Longevity of the steam resource from each supply well varies on a case by case basis, and steam production could decline unexpectedly. Problems could also arise with injection wells. In either situation, the expected firm capacity from geothermal would not be maintained, jeopardizing HELCO's ability to serve the system load. Restoring firm power output from geothermal would require drilling additional wells, which could include mobilization of the drilling rig to the islands and permitting for the additional wells. The cost of drilling each well could be as high as $3.5 million, with no guarantee of success in finding an adequate resource for power production.

Additional geothermal would add to the minimum capability of the system. The geothermal resource does not allow the turbine generator to load follow well. Low ramp rates also prevent it from contributing to frequency control and spinning reserve. In the case of PGV the minimum rated load is 22 MW, or about 73% of the maximum rating of 30 MW. A lower minimum load could possibly be achieved by having more supply wells, which would increase the cost of the resource. As discussed in Section 5.2, the sum of the minimum capability of all baseload units must be less than the system minimum load in order to avoid increased O&M costs and thermal stress on the baseload units if cycled. Due to uncertainties in the minimum load forecast, geothermal was not considered until later in the IRP planning period where sufficient margin between system load and minimum capability is forecasted.

7.4.3 Wind

While it is the nature of as-available resources to exhibit some degree of variation in output, wind generation poses an operational concern for HELCO because of sub-minute power fluctuations caused by gusty wind conditions. From HELCO's experience, such excursions drive significant system frequency disturbances from the norm of 60 Hz such that, if not moderated by sufficient operating reserve, may cause underfrequency load shedding to occur.

The ability for the system to withstand sub-minute fluctuations depends on the inertia characteristics (mass of the turbine/generators) of the generating units on-line. The HELCO system is particularly sensitive to frequency excursions because:

- HELCO's small, isolated system has a small composite inertia. By contrast, for mainland utilities, all generators on-line in an interconnected system support frequency for the interconnected utilities.
- Geothermal, hydroelectric and wind farms, which make up between 18-30% of the Big Island's generation at all times, do not contribute to frequency regulation.

HELCO presently carries enough operating reserve to cover the maximum output of the wind farms when their output is highly variable. However, because of the unpredictable nature of the wind output from minute-to-minute and day-to- day, it is not possible to precisely simulate expected wind patterns, and calculate the cost of carrying operating reserve for the wind resources. For this reason, HELCO did not include the cost of operating reserve for wind in the finalist plan costs. Instead, the cost of additional operating reserves necessary if additional wind resources are added to the system in the future was captured in a sensitivity analysis.

In the sensitivity analysis, it was determined that the incremental cost of operating reserve for a 10 MW future addition of wind could be as high as $4.5 million ($1999) over the 20-year planning period. As expected, increased operating reserve requirements result in higher production costs and reduced fuel efficiency since generating units are committed earlier to provide the reserve.

As previously mentioned in Section 5.2, if wind is operating during the system minimum load period, it will raise the minimum capability of the system. If the minimum capability of the system exceeds the minimum load, HELCO would have to curtail wind generation.

7.4.4 Photovoltaic (PV)

The IRP integration analysis considered a range in capital cost of a 4 MW PV unit between $7,340 and $12,400 per kW, recognizing that there is some movement within the industry to reduce costs for PV systems. Similar to wind, PV is considered to provide as-available, non-firm energy. Unlike wind, PV does not impact the system minimum since PV would operate during the daytime period.

7.4.5 Storage Technologies

HELCO considered two types of storage technologies: battery and pumped storage hydro (PSH). The primary benefit of storage technologies is a "flattening" of the system load curve; i.e., providing capacity during the peak period and increasing load during the system minimum when the storage unit is charging. Ideally, charging (battery) or pumping (PSH) can occur in the off-peak period, when system loads are low and marginal costs are relatively low compared to peak period costs. Then, during the system peak period, the stored energy can be released to serve load.

Kona and South Hawaii sites were identified as having potential for PSH development. The 30MW capability and 5-hour availability of the resource is governed by the geographical nature of these sites. Because the resource cannot provide firm capacity throughout the 24-hour day, for

IRP-98 evaluation purposes, the 30MW PSH unit was given capacity value determined by the following calculation:

$$30\text{MW} \times \frac{5 \text{ available hours}}{14 \text{ on-peak hours}} = 10.7\text{MW}$$

This assumption would have to be further reviewed if PSH is a component of the preferred plan.

8. INTEGRATION OF SUPPLY AND DEMAND-SIDE RESOURCES

The integration analysis was a multi-step process in which DSM and supply-side resources were combined to produce resource plans capable of meeting the Big Island's forecasted electrical energy needs. The process entailed the following steps, and is further detailed in Sections 8.1 through 8.6 below.

Step 1: Development of base case IRP assumptions, including the Sales & Peak Forecast, Fuel Forecast, and existing unit data.
Step 2: Identification and screening of DSM options and supply-side alternatives
Step 3: Development of Candidate Plans, representing a broad array of objectives and including various combinations of DSM and supply-side resources
Step 4: Elimination of redundancies within the Candidate Plan set, to arrive at a set of Finalist Plans.
Step 5: Detailed attribute and sensitivity analysis on the Finalist Plans; and analysis of the impact of other "special considerations" to the Finalist Plans.
Step 6: Selection of the IRP Preferred Plan.

8.1 STEP 1: DEVELOP BASE CASE ASSUMPTIONS

The 20-year forecasted electricity sales and peak demand provided the basis to determine the need for future resources, either demand-side or supply-side. With exception of as-available resources, timing of the addition of future supply-side resources was determined based on HELCO's Generation Capacity Planning Criteria (Section 5.1).

The existing HELCO system, including both HELCO-owned generation and purchased power, was modeled in order to assess the compatibility of future resource additions with existing units. Operating cost and performance data was derived from actual test data and is representative of operation over the long-term. Projected fuel costs were used to estimate and compare fuel costs for both existing generation and future resource options.

Sales and peak and fuel forecasts, existing and new generating unit data and other significant assumptions are further discussed in Section 4.

8.2 STEP 2: IDENTIFY & SCREEN DSM AND SUPPLY OPTIONS

Both DSM programs and future supply-side options were identified, characterized and screened to determine cost-effective resource alternatives for the HELCO system.

8.2.1 DSM Options

DSM impacts through the end of 1998 for the four approved energy efficiency programs were considered as on-going, and therefore fixed in all plans.

As for future DSM, benefit-cost ratios for the individual DSM programs indicated that all four 20-year programs were cost-effective (B/C>1.0) from the Utility, TRC, Societal and Participant perspectives. In addition, preliminary integration runs confirmed that from the Utility, TRC and Societal perspectives, plans that included all four 20-year programs were lower cost than plans with a combination of 2-year and 20-year programs. As a result, the integration analysis did not consider a mix of 2 and 20-year DSM programs, but instead considered bundles of all four 2-year programs or all four 20-year programs. The case with all four 2-year programs represents continuation of DSM through the 5-year PUC approved period which began in 1996. A No DSM (from 1999) case was also developed for comparison purposes.

8.2.2 Supply-side Options

Section 7-1 described the screening of fossil-fired alternatives. Through preliminary PROSCREEN II optimizations of DSM and supply resources, the 15 renewable resources under consideration were also screened to a smaller set. This iterative process revealed the most cost-effective renewable resources, and was necessary to limit PROSCREEN II optimization time to a reasonable duration.

8.3 STEP 3: DEVELOP CANDIDATE PLANS

The intent of this step in the process was to generate a diverse set of plans with various resource (supply and DSM) combinations. With the base case assumptions established, and supply-side and DSM resources identified and screened, a number of PROSCREEN II optimization runs were set up to generate plans with the following objectives:

- Plans with 2-year and 20-year DSM bundles
- Plan with No DSM from 1999
- Plans with a coal unit
- Plans with repowering
- Plans with indigenous and renewable resources
- Plans with and without Keahole ST-7 as the next unit addition
- Plans optimized by either 20-year (planning period) or 50-year (study period including 30-year end effects) cost perspectives

8.3.1 Consideration of Various Perspectives

The IRP Framework states that the "integrated resource plans shall give consideration to the plans' impacts upon the utility consumers, the environment, culture, community lifestyles, the State's economy, and society"[42] and that the utility "shall conduct such analyses from varying perspectives, including the utility cost perspective, the ratepayer impact perspective, the participant impact perspective, the total resource cost perspective, and the societal cost perspective."[43] HELCO complied with these requirements by utilizing PROSCREEN II "objective functions" in generating and evaluating resource plans in conjunction with a rates and bills analysis. Each PROSCREEN II "objective function" accounts for only those plan costs which are incurred from the perspective being considered, such that the relative economics of plans generated within a single objective function can be compared. Thus, the PROSCREEN II Utility Cost, Total Resource Cost and Societal objective functions represented the utility, customer and societal perspectives, respectively. Ratepayer and participant impacts were measured through the rate and bill impact analysis.

Utility Cost Perspective

The PROSCREEN II Utility Cost (UC) objective function optimizes resource plans around the objective of minimizing the accumulated present worth of revenue requirements for the utility. PROSCREEN II utility revenue requirements include future generation capital, fuel, operation and maintenance costs for both existing and future generation, emission fees and utility DSM costs (rebates, evaluation expense, shareholder incentives). Revenue requirements for existing capital and non-generation related expenses were assumed to be equivalent between plans and were not modeled within PROSCREEN II.

In anticipation of an increasingly competitive environment, the Company is

[42] IRP Framework, Section II.B.4, Page 4.

[43] IRP Framework, Section II.B.4, Section IV.H.2, Page 22.

placing more emphasis on the near-term impacts of resource plans. Thus, resource plans optimized by the UC objective function used the 20-year IRP planning period without end-effects. Longer term impacts were taken into consideration, though, by generating plans using a 30-year end-effects period and making comparisons to determine whether or not substantial changes in the plan would occur with a longer term study horizon.

Total Resource Cost Perspective

The PROSCREEN II Total Resource Cost (TRC) objective function includes total costs incurred by both the utility and its customers. That is:

TRC = UC + Customer cost

Since customer cost (cost to customers to participate in DSM programs) only differs between plans when the amount of DSM is changed, the relative difference between UC and TRC is the same when considering plans with identical amounts of DSM. This means that within the 2-year, 20-year and no DSM optimizations, the ranking of the plans by the UC and TRC tests is identical. For this reason, separate optimizations were not performed for the TRC objective function.

Societal Cost Perspective

The PROSCREEN II Societal Cost (SC) objective function optimizes resource plans around costs to society as a whole, including utility costs, customer costs and externality costs. Plans with renewable resources were optimized using the Societal objective function, since they would realize their greatest potential benefits when externality values were included. Although plans were optimized around both the 20-year planning period and 50-year study period, greater emphasis was given to the 50-year study period horizon in the selection of plans optimized around the Societal objective function.

Using the Societal objective function, plans were also optimized using 1% and 3% real discount rates, to test the sensitivity of the optimizations to the discount rate assumed.[44] The 1% real discount rate translates to a nominal rate of 3.6% to 4.4% based on the inflation rates given in Table 4-8. These nominal rates can be compared to the 8.177% nominal discount rate, the utility's after-tax weighted cost of capital, used as the base assumption. Once the resources and timing of unit additions were determined using the lower real discount rate, the present value of plan costs were recalculated using the 8.177% nominal discount rate so that cost comparisons could be made on an equal basis between plans.

8.3.2 Advisory Group input to the candidate plans

Prior to development of the Candidate Plans, HELCO scheduled a meeting with its Advisory Group. At this December 16, 1997 meeting and through written correspondence, individual members of the Advisory Group provided the types of resources that they wanted to see within the Candidate Plan list. Advisory Group members were also asked to provide a preference of where in the 20-year plan (i.e., early or late) the suggested resources should be added. Where no preference on resource timing was given, HELCO developed plans based on a least-cost optimization using the PROSCREEN II model.

At the next Advisory Group meeting, HELCO went over the plans developed according to the Advisory Group's input. With exception of a few modifications, the Advisory Group agreed that the plans developed by HELCO were representative of the suggestions that they had provided. At the meeting, HELCO gave to the

[44] A member of HECO's IRP-97 Advisory Group suggested the use of a 1% real discount rate for the societal cost perspective.

Advisory Group for review and comment, its proposed list of candidate plans. The proposed candidate plans included all Advisory Group suggested plans. Since no input regarding additional plans or revisions to the proposed Candidate Plans was received, HELCO issued a Final Candidate Plan list which incorporated revisions to the Advisory Group plans received at the February 13, 1998 meeting. Appendix J contains a copy of the Candidate Plans.

8.4 STEP 4: SELECTION OF FINALIST PLANS

In the development of the Candidate plans, it became apparent that repowering Hill 5 was a lower cost alternative for the next unit addition in 2006 than completing the Keahole dual train combined cycle with the addition of ST-7 <u>when only considering generation costs</u>. However, as discussed later in Section 8.6.2, when transmission capital costs and line losses associated with additional East Hawaii generation were considered, ST-7 on the West side was identified as the least cost next unit addition. ST-7 would provide much needed efficient baseload generation at the load center in West Hawaii. Until the transmission study was completed upon which this conclusion was based, two sets of plans were carried forward: one with ST-7 as the next unit addition in 2006 and the other with Hill 5 repowering as the next unit addition. Each set of plans was identical in terms of plan objectives, but differed in the next unit addition. Upon selection of the Finalist Plans, the set with Hill 5 repowering as the next unit was dropped. A single plan with Hill 5 repowering as the next unit addition (after addition of 1 MW diesels) was retained as a finalist plan to represent a possible alternative to ST-7.

The Candidate Plans were further narrowed to 14 Finalist plans to enable HELCO to conduct more detailed attribute and sensitivity analyses. A key objective in the determination of the finalist plan set was to retain diversity in the combinations of resource options and plan objectives. Within the Candidate Plans, certain plans could be eliminated since they were either identical or very similar to other plans within the set. Certain plans were eliminated that had similar resources to another candidate plan, but were higher in cost. The rationale for elimination of all candidate plans not carried forward as Finalist Plans is stated in Table J-1 of Appendix J, which contains plans that add ST-7 in 2006. As stated above, all plans with Hill 5 repowering as the next unit in 2006 (shown in Table J-2) were eliminated, except for a plan similar in concept to Candidate Plan CE23. Each candidate plan retained as a finalist plan had some distinguishing trait that HELCO and/or its Advisory Group felt deserved further consideration.

While certain candidate plans (in Table J-1) were retained in concept, slight modifications were made to the plans in the finalist plan stage. These changes were primarily related to the timing of unit additions. One such change was due to a deration of Hill 6 from a net reserve rating of 21.75 MW to 19.6 MW (see Section 4.3.1). Other changes in timing came as the result of Advisory Group input as noted in Section 8.4.1.

The resulting 14 Finalist Plans are shown in Table 8-1.

8.4.1 Advisory Group input to the Finalist Plans

HELCO presented a preliminary list of finalist plans to the Advisory Group (AG) on March 11, 1998. Although all AG-suggested candidate plans were retained as finalist plans, the AG was given an opportunity to add back into the finalist plan list any candidate plans they felt should be carried further. The AG generally

Last revised 04/03/98

YEAR	1 K1 No 1 MW Diesels	2 K2 Wind Only (AG)	3 K3 PV & Wind	4 K4 Hydro & Wind	5 K5 Geotherm & Wind (AG)	6 K6 Pump Storage & Wind (AG)	7 K7 All West Side	8 K8 Coal	9 K9 2 yr DSM	10 K10 No DSM	11 K11 Biomass (AG)	12 K12 Minimize Oil (AG)	13 K13 1 MW Dies (AG)	14 H12 1 MW Dies H5RP (AG)
1999	Encogen (60 MW) 20-yr REWH 20-yr CIEE 20-yr CINC 20-yr CICR	Encogen (60 MW) 20-yr REWH 20-yr CIEE 20-yr CINC 20-yr CICR	Encogen (60 MW) 20-yr REWH 20-yr CIEE 20-yr CINC 20-yr CICR	Encogen (60 MW) 20-yr REWH 20-yr CIEE 20-yr CINC 20-yr CICR	Encogen (60 MW) 20-yr REWH 20-yr CIEE 20-yr CINC 20-yr CICR	Encogen (60 MW) 20-yr REWH 20-yr CIEE 20-yr CINC 20-yr CICR	Encogen (60 MW) 20-yr REWH 20-yr CIEE 20-yr CINC 20-yr CICR	Encogen (60 MW) 20-yr REWH 20-yr CIEE 20-yr CINC 20-yr CICR	Encogen (60 MW) 2-yr REWH 2-yr CIEE 2-yr CINC 2-yr CICR	Encogen (60 MW)	Encogen (60 MW) 20-yr REWH 20-yr CIEE 20-yr CINC 20-yr CICR	Encogen (60 MW) 20-yr REWH 20-yr CIEE 20-yr CINC 20-yr CICR	Encogen (60 MW) 20-yr REWH 20-yr CIEE 20-yr CINC 20-yr CICR	Encogen (60 MW) 20-yr REWH 20-yr CIEE 20-yr CINC 20-yr CICR
//	//	//	//	//	//	//	//	//	//	//	//	//	//	//
2002		10MW Wind-Lalamilo	10MW Wind-Lalamilo 4MW PV (low cost)	10MW Wind-Lalamilo	10MW Wind-Lalamilo				Puna return from Standby (15MW)	Puna return from Standby (15MW)	10MW Wind-Lalamilo	10MW Wind-Lalamilo		
2003	Puna return from Standby (15MW)	Puna return from Standby (15MW)	Puna return from Standby (15MW)	Puna return from Standby (15MW) Hydro (13.8MW)	Puna return from Standby (15MW)	Puna return from Standby (15MW)	Puna return from Standby (15MW)	Puna return from Standby (15MW)			Puna return from Standby (15MW)	Puna return from Standby (15MW)	Puna return from Standby (15MW)	Puna return from Standby (15MW)
2004														
2005														
2006	Keahole ST7 (17MW)	Keahole ST7 (17MW)	Keahole ST7 (17MW)	Keahole ST7 (17MW)	Keahole ST7 (17MW)	Keahole ST7 (17MW)	Keahole ST7 (17MW)	Keahole ST7 (17MW)	Keahole ST7 (17MW)	Keahole ST7 (17MW)	Keahole ST7 (17MW)	Keahole ST7 (17MW)	Keahole ST7 (17MW)	1 MW Diesel (5 units)
2007									Hill 5 Repower, 1st CT (21.6 MW)	Hill 5 Repower, 1st CT (21.6 MW)				1 MW Diesel (4 units)
2008														1 MW Diesel (4 units)
2009	Hill 5 Repower, 1st CT (21.6 MW)	Hill 5 Repower, 1st CT (21.6 MW)	Hill 5 Repower, 1st CT (21.6 MW)	Hill 5 Repower, 1st CT (21.6 MW)	Hill 5 Repower, 1st CT (21.6 MW)	Pumped storage Hydro (Puu Enuhe, 30MW) 10MW Wind-Lalamilo	W. HI DTCC, 1st CT (20.9 MW)	Coal (26.7MW)			Biomass (25MW)	Biomass (25MW)	1 MW Diesel (7 units)	Hill 5 Repower, 1st CT (21.6 MW)
2010						Hill 5 Repower, 1st CT (21.6 MW)							Hill 5 Repower, 1st CT (21.6 MW)	
2011									Hill 5 Repower, 2nd CT (21.6 MW)	Hill 5 Repower, 2nd CT (21.6 MW)				
2012	Hill 5 Repower, 2nd CT (21.6 MW)	Hill 5 Repower, 2nd CT (21.6 MW)	Hill 5 Repower, 2nd CT (21.6 MW)	Hill 5 Repower, 2nd CT (21.6 MW)	Hill 5 Repower, 2nd CT (21.6 MW)		W. HI DTCC, 2nd CT (20.9 MW)				Hill 5 Repower, 1st CT (21.6 MW)	Biomass (25MW)		Hill 5 Repower, 2nd CT (21.6 MW) Hill 5 Repower conversion to DTCC (58.3MW)
2013								Hill 5 Repower, 1st CT (21.6 MW)						
2014									Hill 5 Repower conversion to DTCC (58.3 MW) Hill 6 Repower, 1st CT (21.6MW)	Hill 5 Repower conversion to DTCC (58.3 MW) Hill 6 Repower, 1st CT (21.6MW)			Hill 5 Repower, 2nd CT (21.6 MW)	
2015	Hill 5 Repower conversion to DTCC (58.3 MW)	Hill 5 Repower conversion to DTCC (58.3 MW)	Hill 5 Repower conversion to DTCC (58.3 MW)	Hill 5 Repower conversion to DTCC (58.3 MW)	Hill 5 Repower conversion to DTCC (58.3 MW)	Hill 5 Repower, 2nd CT (21.6 MW) Hill 5 Repower conversion to DTCC (58.3 MW)		Conversion of Hill 5 Repower 1st CT to 1/2DTCC (29.3 MW)			Conversion of Hill 5 Repower 1st CT to 1/2DTCC (29.3 MW)		Hill 5 Repower conversion to DTCC (58.3 MW)	
2016	LM2500 SCCT (20.9MW)	LM2500 SCCT (20.9MW)	LM2500 SCCT (20.9MW)	LM2500 SCCT (20.9MW)	Geothermal (25MW, low cost)		W. HI DTCC - conversion to DTCC (60.7MW)	Hill 5 Repower, 2nd CT (21.6 MW) Conversion of Hill 5 Repower 2nd CT to 1/2DTCC (29 MW)			Hill 5 Repower, 2nd CT (21.6 MW)	LM2500 STIG (22.7 MW)		
2017							W. HI DTCC, 1st CT (20.9 MW)		Hill 6 Repower, 2nd CT (21.6MW)	Hill 6 Repower, 2nd CT (21.6MW)				LM2500 SCCT (20.9MW)
2018		5MW wind - N. Kohala				LM2500 SCCT (20.9MW)							LM2500 SCCT (20.9MW)	
20-yr Utility Cost ($000)	1,317,816.1	1,320,180.0	1,344,258.0	1,351,981.8	1,322,635.5	1,362,038.8	1,322,207.1	1,384,598.6	1,339,891.6	1,342,122.9	1,382,241.3	1,421,017.1	1,314,326.4	1,302,452.5
Net Customer Cost ($000)	5,487.1	5,487.1	5,487.1	5,487.1	5,487.1	5,487.0	5,486.9	5,487.3	1,213.4	0.0	5,487.0	5,486.9	5,486.9	5,487.1
Externality Cost ($000)	13,980.1	13,762.1	13,726.4	13,765.3	13,530.0	13,873.1	14,060.8	13,540.8	12,558.3	12,215.5	13,856.0	13,665.4	13,933.8	13,793.4
TRC Planning Period Cost ($000)	1,323,303.3	1,325,667.1	1,349,745.1	1,357,468.9	1,328,122.6	1,367,525.8	1,327,694.0	1,390,085.9	1,341,105.0	1,342,122.9	1,387,728.3	1,426,504.0	1,319,813.3	1,307,939.6
SOC Planning Period Cost ($000)	1,337,283.4	1,339,429.3	1,363,471.5	1,371,234.1	1,341,752.6	1,381,398.9	1,341,754.8	1,403,626.6	1,353,663.3	1,354,338.4	1,401,364.3	1,440,169.4	1,333,747.0	1,321,733.0
30-yr End-Effects ($000)	784,698.1	781,549.5	795,022.0	788,697.8	763,908.0	815,795.5	795,215.1	830,701.4	816,981.5	817,546.9	835,634.8	894,376.4	794,236.9	785,149.0
UC Study Period Cost ($000)	2,102,514.3	2,101,729.5	2,139,280.0	2,140,679.5	2,086,543.5	2,177,834.3	2,117,422.3	2,215,300.0	2,156,873.5	2,159,669.8	2,217,876.0	2,315,393.5	2,108,563.3	2,087,601.5
TRC Study Period Cost ($000)	2,108,866.3	2,108,081.3	2,145,631.8	2,147,031.3	2,092,865.4	2,184,186.0	2,123,773.8	2,221,652.0	2,158,087.0	2,159,669.8	2,224,227.8	2,321,745.0	2,114,914.8	2,093,993.4
SOC Study Period Cost ($000)	2,129,439.8	2,128,253.8	2,165,810.0	2,167,270.3	2,112,310.5	2,204,533.3	2,144,362.5	2,241,263.3	2,176,890.8	2,178,136.3	2,244,286.0	2,341,777.0	2,135,413.3	2,114,322.0

HIGH CAPITAL COST

	K1	K5
20-yr Utility Cost ($000)	1,362,486.9	1,332,604.3
TRC Planning Period Cost ($000)	1,367,973.9	1,338,091.4
SOC Planning Period Cost ($000)	1,381,700.1	1,351,721.3
UC Study Period Cost ($000)	2,167,647.5	2,120,114.5
TRC Study Period Cost ($000)	2,174,159.3	2,126,466.3
SOC Study Period Cost ($000)	2,194,377.3	2,145,881.5

Note: Finalist Plans K2, K5, K6, K11, and K12 were suggested by members of the HELCO Advisory Group (AG) at the December 1997 and February 1998 AG meetings and through written input. Finalist Plans K3, K4, and K8 were developed by HELCO and further modified by the HELCO AG at the March AG meeting.

DEFINITIONS:

Utility Cost: Capital costs plus fixed and variable O&M costs
Net Customer Cost: DSM cost to customer, less rebates and less tax credits
Externality Cost: Total monetized externalities plus tax credits
Total Resource Cost (TRC): Utility Cost + Net Customer Cost
Societal Cost: Utility Cost + Net Customer Cost + Externality Cost
Planning Period (PP) Cost: 20-year costs from 1998 - 2017
30 year End Effects: Calculated costs for 30 years beyond the planning period
Study Period (SP) Cost: Sum of planning period cost plus end-effects
Plan Reference: Run file name - study period plan ranking
Planning Period No.: Plan ranking for that run based on planning period costs

concurred with the types of plans in HELCO's proposed finalist plan list. However, in the discussion, AG members collectively agreed that modifications should be made to the timing of certain renewable resource additions. Specifically, the AG requested that:

- The as-available resources (PV, hydro, wind) in the plans should be added at the earliest possible addition date, regardless of the next capacity need date. The Advisory Group's intention was to consider renewable resource additions within the five-year Action Plan period. Advisory Group members were made aware that moving these renewable resources earlier in the plan results in a higher plan cost.
- The biomass units in the "minimize oil" plan should be consecutive, even though having Hill 5 repowering between the two biomass units results in a lower cost plan. The AG sought to have the biomass units installed consecutively to reduce oil use.

While HELCO's intention was to finalize the timing of resource additions in the plans at the candidate plan stage, these AG modifications were made and are reflected in the final Finalist Plan list.

8.5 STEP 5: ATTRIBUTE AND SENSITIVITY ANALYSIS, SPECIAL CONSIDERATIONS

Selection of a reasonable number of Finalist Plans allowed for more in-depth analyses to be performed. An attribute analysis was conducted to identify significant differences in satisfying the IRP objectives that are caused by selection of various resource types. A sensitivity analysis determined how resource selection could change with deviation of actual sales or fuel prices away from the current base forecasts. In addition, other special considerations that could affect the selection of a preferred plan were taken into account at this stage of the IRP process. This included:

- the Hawaii Energy Strategy,
- climate change and
- an updated fuel price forecast.

These analyses are further discussed below.

8.5.1 Attribute Analysis

As explained in Section 3.4.2, HELCO conducted an attribute analysis on the Finalist Plans using a direct comparison method. Appendix K contains the compiled attributes in tabular and graphical format, as applicable. Better performing plans with respect to each attribute are identified, and the criteria used to rate plans for the qualitative attributes are provided as well. The rates and bills analysis methodology and results are shown in Appendix L.

8.5.2 Sensitivity Analyses

Sensitivity analyses were performed on the finalist plans to determine how their relative costs would change under various scenarios, including:

- High fuel price forecast
- Low fuel price forecast
- High sales and peak forecast
- Low sales and peak forecast

These analyses provide insight as to how resilient each plan is under various scenarios. Given the uncertainties facing the electric utility industry, the more favorable plans are those which provide a high degree of flexibility and which perform well under a number of scenarios.

The results of the sensitivity analyses are shown in Appendix M. The plans were initially ranked in order of lowest to highest utility, TRC and societal cost. Then, under each scenario, plan costs were recalculated and the plans were re-ranked. In order to be able to recognize the magnitude of the cost differences between the plans under the various scenarios, the plan costs were indexed on a scale from zero to one.

8.5.3 Special Considerations

8.5.3.1 Consideration of the Hawaii Energy Strategy in the Development of IRP-98

The Hawaii Energy Strategy (HES) began on March 2, 1992 under a Cooperative Agreement with the United States Department of Energy (USDOE) and the Department of Business, Economic Development and Tourism (DBEDT). The seven projects of the HES program were designed to increase understanding of Hawaii's energy situation and to produce recommendations to achieve the state energy objectives of dependable, efficient, and economical state-wide energy systems capable of supporting the needs of the people, and increased energy self-sufficiency. The HES final report was completed in October 1995.

The purpose of the HES study was to develop an integrated State of Hawaii energy strategy including an assessment of the state's fossil fuel reserve requirements and the most effective way to meet those needs, the availability and practicality of increasing the use of native energy resources, potential alternative fossil energy technologies such as coal gasification and potential energy efficiency measures which could lead to demand reduction. The HES study was intended to contribute to the USDOE mission, reduce the state's vulnerability to energy supply disruptions, and contribute to the public good.

The work of the HES program was divided into seven projects.

1. develop an analytical energy forecasting model for the State of Hawaii;
2. fossil fuel review and analysis;
3. renewable energy resource assessment development program;
4. demand-side management program;
5. transportation energy strategy;
6. energy vulnerability assessment report and contingency planning; and
7. energy strategy integration and evaluation system.

Project 7 integrated the findings of the overall HES program into a comprehensive state energy strategy. Project 7 identified, assessed and recommended the potential public policy mechanisms by which to implement a "least-cost" strategy for energy development in Hawaii. Existing energy policy and planning management frameworks were used for synthesis, integration and evaluation of policy and planning initiatives that emerged from the component projects. This included facilitating the integration of information among the other six projects and inclusion of that information in the final report. The draft final report was presented to the public to obtain feedback for inclusion in the final published report. Policy, legislative, and regulatory initiatives for implementation and evaluation were developed and recommended.

Project 7 also developed, evaluated and recommended policy initiatives and plans to formalize an energy planning and policy evaluation system within the state government; e.g., institute a statutory requirement to conduct integrated energy planning on a biennial basis. Project 7 of the HES also developed an energy planning and policy evaluation model based on ENERGY 2020, and by providing requisite staff training, would strengthen the state's in-house capabilities and reduce dependence on outside consultants.

Project 7 included an analysis of three scenarios using the ENERGY 2020 model which incorporated preferred resource options (developed by DBEDT Energy Division) to move Hawaii's energy system toward the state's statutory energy policy objectives as outlined in Section 226-18(a) of the Hawaii Revised Statutes, as amended by Act 96, Session Laws of Hawaii 1994.

- Dependable, efficient and economical state-wide energy systems capable of supporting the needs of the people;
- Increased energy self-sufficiency where the ratio of indigenous to imported energy use is increased; and
- Greater energy security in the face of threats to Hawaii's energy supplies and systems.

The energy policy objectives were the basis of three scenarios in the HES report: Cost-Effective Energy Diversification (CEED); Maximum DSM/Maximum Renewable Energy (DSMRE); and Energy Security (ES). These were compared against Baseline 2020, the energy forecast produced by ENERGY 2020 based upon the requirements of the economic forecast, types of generation planned by the utilities in their current IRPs, and the DSM programs in the utility IRPs. Baseline 2020 provides the "business as usual" future of Hawaii against which the scenarios incorporating Hawaii's energy policy objectives were compared in the HES report.

The HES report stated that the Project 7 results of the scenario runs clearly show that the use of additional DSM and increased use of renewable energy to meet state energy policy objectives over the planning period yield highly favorable results. The report stated that costs are not significantly higher and there are slight improvements in Gross State Product and employment. The report also said that substitution for oil by renewables in the electricity sector is limited somewhat by the fact that extensive new generation is not required over the 20-year period. The HES report stated that given the 30-50 year life of fossil-fueled generation, now is clearly the time to begin the transition.

A number of recommendations were made and reported in the HES report:

- Diversify fuels and sources of supply;
- Focus diversification on power generation and ground transportation energy;
- Pursue coal as an option for Oahu energy diversification;
- Encourage Hawaii's refineries to upgrade capabilities;
- Increase use of renewable energy;
- Focus first on cost-effective energy efficiency and conservation;
- Consider HES DSM measures in utility integrated resource planning (IRP);
- Evaluate DSM mandates;
- State and utilities should cooperate on DSM data gathering;
- Adopt transportation energy conservation measures;
- Improve fleet efficiency;
- Adopt travel reduction measures;
- Increase the focus on energy in transportation planning process;
- Increase the focus on energy in land use planning process;
- Expand use of alternative fuels and vehicles;
- Conduct transportation energy research and development programs;
- Improve state energy analysis;
- Improve energy planning and policy development;
- Improve energy modeling;
- Improve DSM modeling and programs;
- Improve power purchase contract terms for renewable energy;
- Conduct additional renewable energy research and development;
- Conduct additional renewable energy assessments;
- Obtain access to land for renewable energy projects;
- Develop cost-effective renewable energy projects now;
- Consider renewable energy implementation plan, and;
- Enhance energy emergency contingency planning.

The utility DSM programs and IRP-98 work effort already include most of the HES DSM recommendations. HELCO developed, filed applications to the PUC for approval, and is currently implementing four DSM programs:

- Residential Efficient Water Heating Program
- Commercial and Industrial New Construction Program
- Commercial and Industrial Energy Efficiency Program
- Commercial and Industrial Customized Rebate Program

The DSM programs involve preparing measurement and evaluation plans, launching the programs, initiating measurement and evaluation activities and preparing annual reports. Details of the programs are discussed in Section 6.

Among the resource plans generated in IRP-98, a large number were directed toward examining various scenarios which address the state energy policy objectives and HES recommendations. These included:

- Plans which increase the quantity and type of renewable resources (geothermal, biomass, wind, PV, pumped storage hydro, run of the river hydro, battery)
- Plans with additional cost-effective energy efficiency DSM
- Plans with coal as an option for energy diversification (although the HES specifically targeted Oahu, coal was considered for HELCO as well)

One of the nine IRP-98 objectives was to "Support the State of Hawaii Energy Objectives". IRP-98 Finalist plans were judged on how well they meet the state energy objectives by the following attributes:

- Increase system fuel heat rate efficiency
- Increase system fuel cost efficiency
- Increase DSM penetration
- Increase the ratio of energy produced by commercially viable indigenous and renewable resources as a proportion of total energy produced
- Reduce use of fuel oil as an energy resource

Differences in assumptions between the HES study and HELCO's IRP-98 result in contradictory conclusions regarding the cost-effectiveness of certain renewable resources. HELCO's analysis indicates that DBEDT's cost estimates and certain assumptions are highly optimistic:

- 55 MW of wind energy generation: With Hawaii's natural wind conditions it would be beneficial to have reliable wind energy projects integrated into the electrical system. However, HELCO is experiencing frequency stability problems even with the wind energy it currently has on the system. 55 MW of wind would increase HELCO's wind penetration from about 5% to about 20%. A wind penetration study conducted for the Big Island in 1997 determined a limit for wind penetration at 4 to 8 percent of the system peak.

- While battery storage could be used to stabilize a large wind penetration, at this time, wind/battery operations have not yet been demonstrated for utility scale installations. In addition, the use of battery costs taken from HELCO's IRP-93 information for use as the HES battery cost is inappropriate since that cost was developed for a different type of operation. A higher cost would be necessary in the HES report to account for more frequent replacement of spent battery units.

- A key discussion point with renewable energy developers for intermittent technologies (e.g., wind, solar and run-of-river hydroelectric) has been the subject of output curtailment during periods of low power demand, such as the late evening and early morning. It is not clear how or if this issue was addressed in the HES analyses of renewable energy economics.

- Mandated demand-side management programs: The HES assumed state-mandated control of all electric water heating in the residential sector. This does not seem reasonable since it saves no energy and if implemented would mandate controls on units where capacity savings would be limited. In an earlier HECO water heater load control pilot project it was found that a lot of customers dropped out of the program because their service was impacted to unacceptable levels. Mandated control of all water heating would have a large impact on customer satisfaction.

  The state-mandated control of commercial/industrial air-conditioning and water heating would also impact customer satisfaction and could disrupt many retail and office facilities. The private sector should be given the option to weigh the choices open to them in this area.

- 25 MW of Geothermal: HELCO's analysis in IRP-98 determined that an additional 25 MW of geothermal should not be installed as the next unit after ST-7 in 2009, in order to avoid a potential minimum load problem (under the assumption that the geothermal resource cannot load follow.) As further discussed in Section 5.2, this is based on consideration of the difference between the system minimum load forecast and the minimum capability of baseload units on-line, with some margin for uncertainties.

- The state-mandated use of biomass in industrial boilers may not be practical. A number of boilers, mostly associated with sugar mill operation, are specially designed and permitted for specific fuels, including biomass. However, accommodating for a biomass fuel may not be technically possible with other existing industrial boilers, which would incur additional cost to deal with fuel storage, fuel handling, ash and particulate collection and control, and will reduce the overall plant efficiency. In addition, it is not clear where the biomass fuel would come from, since the sugar mills have closed.

These highly optimistic cost estimates and assumptions of commercial availability for certain technologies are used in the HES modeling runs for the various scenarios (cost-effective Energy Diversification, Maximum Demand-Side Management/Maximum Renewable Energy, Energy Security and Baseline 2020) and result in unrealistic and potentially misleading conclusions and expectations. The differences in the HES charts and graphs presented (i.e., large peak demand, Hawaii average electricity prices, greenhouse emissions and economic effects) should be much less than shown.

Another major concern involves the oil price spike analysis in the HES report. It provides a misleading indication of the effects on the Hawaii economy of relying upon oil. Recent economic research questions earlier views of the negative economic impacts stemming from oil price volatility.[45] Studies have shown that fiscal

[45] References:
Bohi, Douglas R. 1989. *Energy Price Shocks and Macroeconomic Performance*. Washington, DC: Resources for the Future
Darby, Michael. 1982. "The Price of Oil and World Inflation and Recession." American Economic Review 72(4):September
Hickman, Bert G., Hillard Huntington, and James L. Sweeney. 1987. *Macroeconomic Impacts of Energy Shocks*. Amsterdam: North Holland Press.
Lobsenz, George. 1996. "GAO Challenges U.S. Policy on Reducing Oil Imports as Costly, Counterproductive." *The Energy Daily* 24(238):1-2.

and monetary policy measures have the potential to mitigate much of the negative effects of transient oil price increases. Moreover, the growth of petroleum futures markets and other contractual instruments to deal with the risk of higher oil prices further decreases the economic impact effects of an oil price shock.

The oil price spike analysis in the HES report seems to overstate the effects of oil price volatility on the Hawaii economy. The basis for the assertion that fluctuations in oil prices have direct adverse macroeconomic consequences seems weak. What once seemed to be strong evidence of a statistical relationship between oil prices and macroeconomic activity has now been refuted, or at least put in doubt, especially where the price change is transitory.

Finally, the oil price spike analysis does not appear to take into account the impact suggested elsewhere in the HES policy recommendations. Higher electricity prices due to reliance on more expensive indigenous generating options suggest that they would adversely affect the Hawaii economy in the long term.

8.5.3.2 Climate Change

Climate change due to the effect of greenhouse gas (GHG) emissions has become an intensely contested issue at the international level. Negotiations are currently ongoing regarding commitments for GHG emission reductions on a country-specific basis. Particularly challenging is establishing the levels of GHG emissions reductions that are reasonable and the timeframe in which the reductions can be achieved, taking into account the economic impacts of GHG emissions control.

McCormack, John. 1996. "Market Protection Against Another Oil Shock." *Regulation* 1:19-21.
Verlergerm Philip K. Jr. 1993. *Adjusting to Volatile Energy Prices*. Washington, D.C.: Institute for International Economics, November.

Although there is still much debate within the scientific community as to whether global warming is being caused by anthropogenic GHG emissions, the underlying assumption to the international negotiations is that climate change is indeed occurring and that GHG emissions must be reduced. HELCO has adopted no position on whether global warming is occurring and will not debate the adequacy of the scientific basis for such conclusions.

Under a grant from the U.S. EPA, DBEDT has been working for the past few years in partnership with the State Department of Health (DOH) to develop a Hawaii Climate Change Action Plan. HELCO participated in the first phase of the project, development of an inventory of 1990 Hawaii GHG emissions, by providing detailed fuel use data and reviewing drafts of the GHG emissions inventory report. DBEDT is now in the second phase of the project which is to identify goals and formulate state policy towards controlling GHG emissions. On October 30, 1997, DBEDT held a workshop to report on progress in developing the emissions inventory and to solicit input from the public on specific goals and measures to reduce GHG emissions in Hawaii.

Although HELCO will continue to cooperate with state efforts to collect data on greenhouse gas emissions, HELCO believes it is prudent to wait until national policy is set before dealing with the issue on a local level. The setting of national goals is necessary to establish the context by which Hawaii-specific goals may be developed. Furthermore, factors such as cost impact and projected growth in energy usage in the islands must be taken into account in identifying reasonable and achievable goals. As such, HELCO will not support state efforts to unilaterally impose limitations on utility GHG emissions by legislation or regulation. Any actions to develop state policy or rules concerning climate change should be based on thorough evaluations of the costs and benefits of such, and should allow adequate public participation according to formal policy or rule making procedures.

Notwithstanding these positions, HELCO has already taken proactive, voluntary measures to limit GHG emissions from its system. The Company will continue to identify and implement prudent cost effective measures to reduce, avoid or sequester GHG emissions consistent with our commitments to the U.S. Department of Energy (DOE) Climate Challenge program.

8.5.3.3 Climate Challenge

The Climate Challenge program is a joint, voluntary effort of the DOE and the electric utility industry to reduce, avoid or sequester greenhouse gas emissions through the year 2000. It reflects the intention of the parties to play a leadership role in pursuit of the President's goals for reducing greenhouse gas emissions.

A Climate Challenge Participation Accord between HECO and DOE was signed on March 19, 1997. HECO (including its subsidiaries MECO and HELCO) has made the following voluntary Climate Challenge commitments:

- Participate in the Edison Electric Institute industry initiative *Utility Forest Carbon Management Program (UFCMP)*: HECO contributed $5,000 to pay for initial program startup costs, and $10,000 to support carbon sequestration projects. HECO will evaluate on an annual basis whether further contributions to projects will be made.

- Limit, through the year 2000, CO_2 emissions per kWh from Company owned fossil fuel generating units to 1.76 lbs CO_2/kWh, calculated as a weighted system wide average: HECO will continue to phase in cleaner, more efficient generation systems such as combined cycle combustion turbines. Additionally, HECO has implemented plant betterment projects such as control system upgrades to improve generating unit efficiency.

- Cumulatively avoid 380,000 tons of CO_2 emissions through the year 2000 through DSM programs: In 1996, HECO began five DSM programs. To improve commercial and industrial energy efficiency, HECO is promoting energy efficient air conditioning, lighting, and motors. Residential energy efficiency is being encouraged by promoting the use of high efficiency water heating technologies.

- Annually purchase or produce at least 500,000 MWh of renewable energy, resulting in a five year cumulative avoidance of 2,200,000 tons of CO_2 through the year 2000: HECO has a long-standing commitment to purchase and produce renewable energy. The Company will continue to purchase or produce power from geothermal, wind, hydroelectric, and waste to energy sources. HECO will also continue its purchases of biomass power from sugar companies to the extent feasible, notwithstanding recent reductions in the local sugar industry.

- Continue with local forestry management programs, transportation and electric vehicle programs, energy efficiency education and information projects, and renewable energy research investments.

Under the terms of its Participation Accord, HECO will monitor its performance in meeting these commitments and will annually report on its progress to DOE. The first report is due to DOE in 1998.

8.5.3.4 Change in the Fuel Price Forecast

On May 22, 1998, HECO adopted an updated fuel price forecast, which forecasts fuel prices for HECO, HELCO and MECO. As indicated in Figures 8-1 through 8-3 and Table 8-2, the 1998 fuel price forecasts for diesel and MSFO are lower than the 1995 forecast used in the IRP-98 analysis. The 1998 forecast for coal is higher in the near term, but lower in the long term.

By the time the 1998 fuel forecast was issued, the IRP-98 analysis was near completion. Therefore, the 1998 fuel forecast was not used in the development of the IRP preferred plan. However, the 1998 fuel forecast does not affect the selection of the preferred plan for the following reasons:

- The supply-side resources in the IRP preferred plan were determined to be all oil-fired units using the 1995 fuel forecast. Lower oil prices in the 1998 forecast will increase the cost premium for renewable energy, as avoided fuel costs are reduced. Similarly, since the cost differential between coal and oil is expected to be narrower in the 1998 forecast, the relative cost-effectiveness of coal-fired and oil-fired generation would not change; i.e., coal would continue to be more expensive with the new forecast.

- The new forecast would reduce avoided fuel costs due to energy efficiency DSM. HELCO performed an analysis which indicated that all four 20-year energy efficiency DSM programs remain cost-effective with the 1998 forecast. In the analysis, fuel costs were changed, but escalation rates for O&M and capital, which are implied by the fuel forecast, were not changed. In addition, shareholder incentive estimates were not adjusted downward to reflect reduced net benefits from DSM that would result with the lower fuel forecast.

- Lower fuel prices in the 1998 fuel forecast would reduce the cost of transmission energy losses. However, this would not change HELCO's preference to install efficient generation closer to the load in West Hawaii.

Figure 8-1. Comparison of MSFO price forecasts (delivered to Hill)

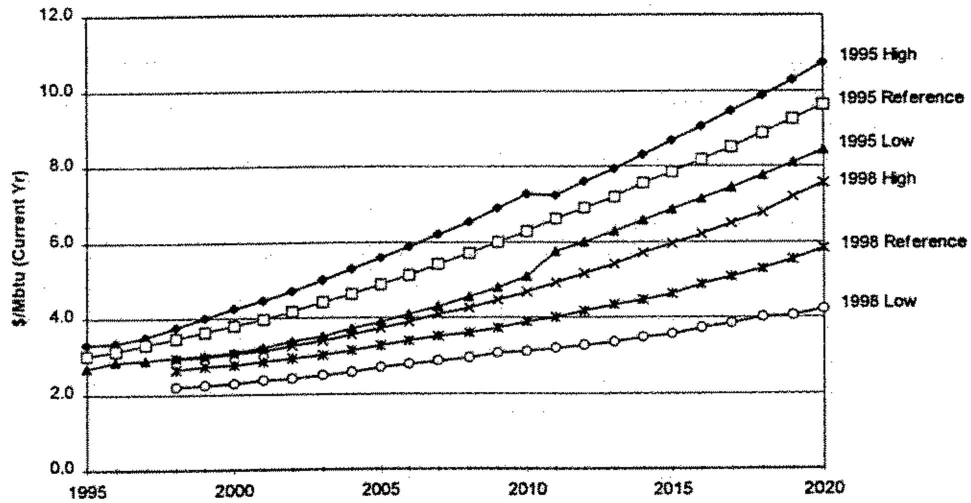


Figure 8-2. Comparison of Diesel price forecasts (delivered to Puna)

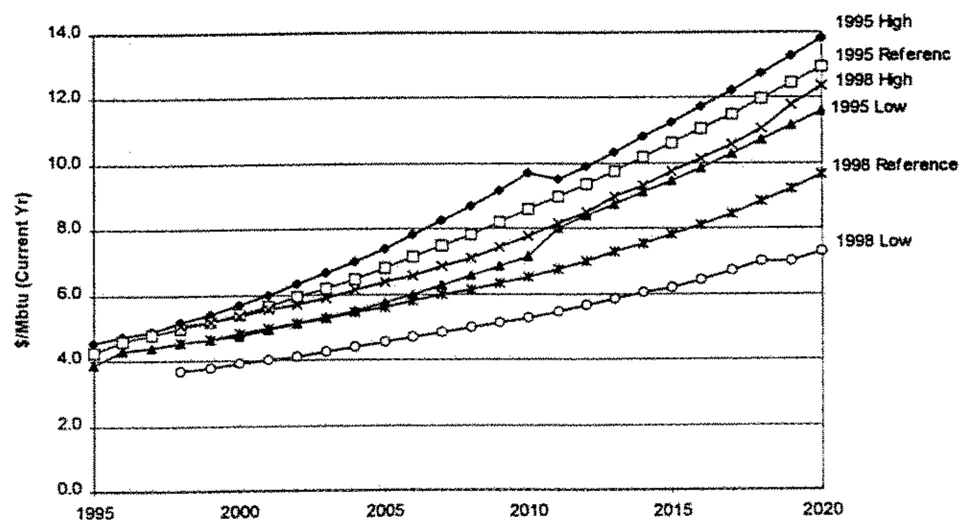


Figure 8-3: Comparison of Coal price forecasts (transport to HELCO not included)

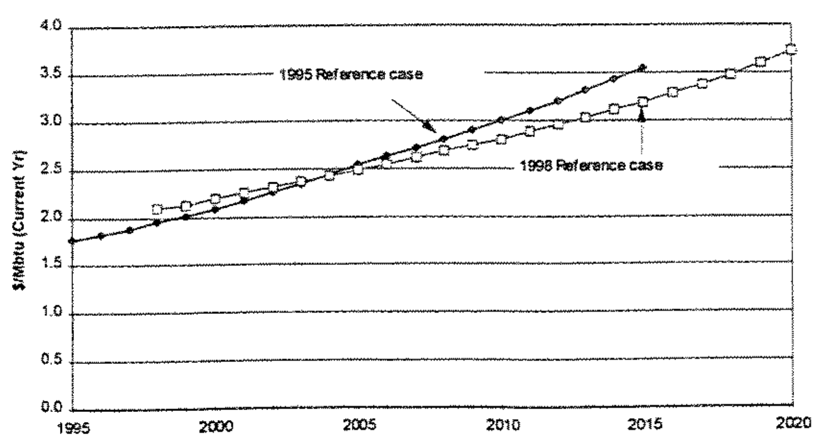


Table 8-2: Comparison of 1995 and 1998 Fuel Price Forecasts (Current year $/MBtu)

Year	May 1995 Reference Forecast			May 1998 Reference Forecast			Difference 1998-1995 Forecast		
	MSFO	Diesel	Coal	MSFO	Diesel	Coal	MSFO	Diesel	Coal
1986	-	-	-	-	-	-	-	-	-
1987	-	-	-	-	-	-	-	-	-
1988	-	-	-	-	-	-	-	-	-
1989	-	-	-	-	-	-	-	-	-
1990	-	-	-	-	-	-	-	-	-
1991	-	-	-	-	-	-	-	-	-
1992	-	-	-	-	-	-	-	-	-
1993	-	-	-	-	-	-	-	-	-
1994	-	-	-	-	-	-	-	-	-
1995	3.02	4.23	1.77	-	-	-	-	-	-
1996	3.15	4.59	1.82	-	-	-	-	-	-
1997	3.28	4.76	1.89	-	-	-	-	-	-
1998	3.45	4.98	1.95	2.65	4.54	2.09	-0.80	-0.44	0.14
1999	3.62	5.19	2.01	2.70	4.65	2.12	-0.91	-0.54	0.11
2000	3.78	5.39	2.08	2.77	4.81	2.20	-1.01	-0.57	0.12
2001	3.97	5.65	2.16	2.85	4.96	2.26	-1.13	-0.68	0.09
2002	4.18	5.92	2.25	2.93	5.12	2.31	-1.24	-0.80	0.06
2003	4.39	6.19	2.34	3.03	5.28	2.37	-1.36	-0.92	0.03
2004	4.62	6.49	2.44	3.13	5.44	2.42	-1.49	-1.05	-0.01
2005	4.86	6.80	2.53	3.26	5.62	2.48	-1.61	-1.18	-0.05
2006	5.12	7.12	2.62	3.37	5.79	2.54	-1.75	-1.33	-0.08
2007	5.39	7.47	2.71	3.49	5.97	2.61	-1.90	-1.49	-0.10
2008	5.67	7.82	2.80	3.61	6.15	2.68	-2.07	-1.67	-0.12
2009	5.97	8.20	2.90	3.73	6.34	2.74	-2.24	-1.86	-0.16
2010	6.29	8.60	2.99	3.86	6.54	2.80	-2.43	-2.06	-0.19
2011	6.58	8.96	3.10	4.00	6.77	2.88	-2.57	-2.19	-0.22
2012	6.89	9.36	3.20	4.15	7.02	2.95	-2.73	-2.34	-0.25
2013	7.20	9.76	3.31	4.31	7.27	3.03	-2.89	-2.50	-0.28
2014	7.53	10.18	3.42	4.47	7.53	3.11	-3.05	-2.66	-0.31
2015	7.84	10.60	3.54	4.64	7.80	3.19	-3.20	-2.80	-0.35
2016	8.16	11.03	5.03	4.85	8.13	3.28	-3.32	-2.91	-1.75
2017	8.50	11.49	5.20	5.06	8.47	3.37	-3.44	-3.02	-1.83
2018	8.85	11.96	5.38	5.29	8.83	3.47	-3.56	-3.13	-1.91

8.6 STEP 6: SELECTION OF THE IRP PREFERRED PLAN

The IRP Framework states that the overall objective of the IRP process is to identify "the resources or mix of resources for meeting the near and long-term consumer energy needs in an efficient and reliable manner at the lowest reasonable cost"[46] and that the "ultimate objective of utility's integrated resource plan is meeting the energy needs of the utility's customers over the ensuing 20 years."[47] It is with this primary intent that HELCO has selected its preferred integrated resource plan, placing emphasis on being able to provide reliable electric service to the Big Island at the lowest reasonable cost over the next 20 years. In the plan selection process, the Company also gave substantial consideration, and incorporated where possible, those resources that provide non-monetary benefits to both customers and society in general.

In selecting the preferred integrated resource plan, HELCO, in accordance with the IRP Framework, gave consideration to all finalist plans' impacts to the utility's customers, the environment, culture, community lifestyles, the state's economy and society. HELCO also took into consideration the utility's financial integrity, size and physical capability.[48]

Selecting the preferred integrated resource plan required the consideration of many and sometimes competing objectives amidst much uncertainty over the future of the electric business environment. HELCO appreciated the various perspectives offered by the Advisory Group throughout the process, and the Advisory Group's many suggestions and comments were taken under advisement. However, HELCO was unable to incorporate or comply with all Advisory Group input given certain conflicting objectives.

In its review of the finalist plans, HELCO identified four major distinguishing characteristics among the plans:

- Length of commitment to energy efficiency DSM programs
- Location of future generation additions
- Future renewable energy development
- Distributed generation to defer large scale, central station generation

Thorough examination of each of the four differentiating factors consequently led to the selection of the IRP-98 Preferred Plan. The plan attributes, results of the sensitivity analyses, special considerations discussed in Section 8.5.3 and Advisory Group input were all considered in the analysis to arrive at the preferred plan. Each of the four major issues are discussed at length below.

8.6.1 DSM

As discussed in detail in Section 6, all four 20-year energy efficiency programs continue to be cost effective from the utility, total resource cost (TRC) and societal perspectives even with a reduced level of penetration from what was expected at the time of the program applications. The fact that the programs are cost-effective from the TRC perspective is especially important, since this indicates that customer costs, as a whole, will be reduced relative to a no DSM case. This means that while there are direct costs to both the utility (program costs) and the participating customers (DSM measure costs), economic benefits in the form of avoided production (fuel and o&m) costs and capacity deferral benefits outweigh the costs of the programs. Table 8-3 is a comparison of 2-year and 20-year DSM plans against a No DSM (from 1999)

[46] IRP Framework, Section II.A, page 3.

[47] IRP Framework, Section IV.B.1, page 20.

[48] IRP Framework, Section II.B, page 4, paragraphs 4 and 5.

Table 8-3. Comparison of No DSM (from 1999), 2-year and 20-year DSM plans

Year	No DSM (K10)	2-yr DSM (K9)	20-yr DSM (K1)
1999	Encogen DTCC	Encogen DTCC 2-yr DSM	Encogen DTCC 20-yr DSM
//			
2002	Puna return from standby	Puna return from standby	
2003			Puna return from standby
2004			
2005			
2006	Keahole ST-7	Keahole ST-7	Keahole ST-7
2007	Hill 5 Repower, 1st CT	Hill 5 Repower, 1st CT	
2008			
2009			Hill 5 Repower, 1st CT
2010			
2011	Hill 5 Repower, 2nd CT	Hill 5 Repower, 2nd CT	
2012			Hill 5 Repower, 2nd CT
2013			
2014	Hill 5 Repower, conversion to DTCC Hill 6 Repower, 1st CT	Hill 5 Repower, conversion to DTCC Hill 6 Repower, 1st CT	
2015			Hill 5 Repower, conversion to DTCC
2016			LM2500 SCCT
2017	Hill 6 Repower, 2nd CT	Hill 6 Repower, 2nd CT	
2018			
Cost in 99 $000s			
20-yr Util cost	1,342,123	1,339,892	1,317,816
Diff. in UC	-	(2,231)	(24,307)
20-yr TRC	1,342,123	1,341,105	1,323,303
Diff. in TRC	-	(1,018)	(18,820)

baseline plan. It illustrates the deferral of unit additions with 20-year DSM and the difference in utility and total resource costs between the three DSM cases.

Aside from economic benefits, there are also reductions in air emissions and fuel usage associated with implementation of energy efficiency programs. Solar water heating in the residential water heating program will support HELCO's participation in the federal Million Solar Roofs Program. DSM can provide HELCO flexibility in the timing of generating unit additions, to the extent that program ramp rates can be modified.

At the same time, though, energy efficiency

Figure 8-4. Difference in Average system ¢/kWh against No DSM (from 1999) baseline

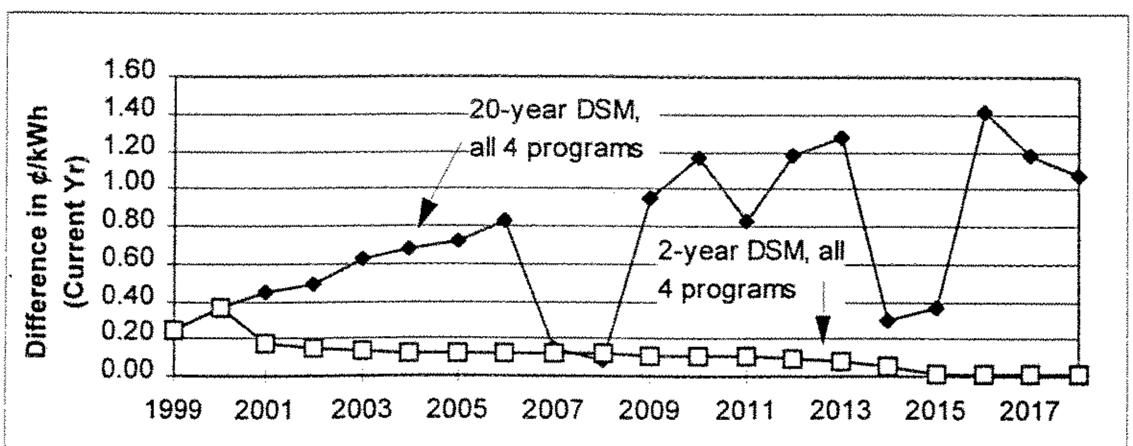
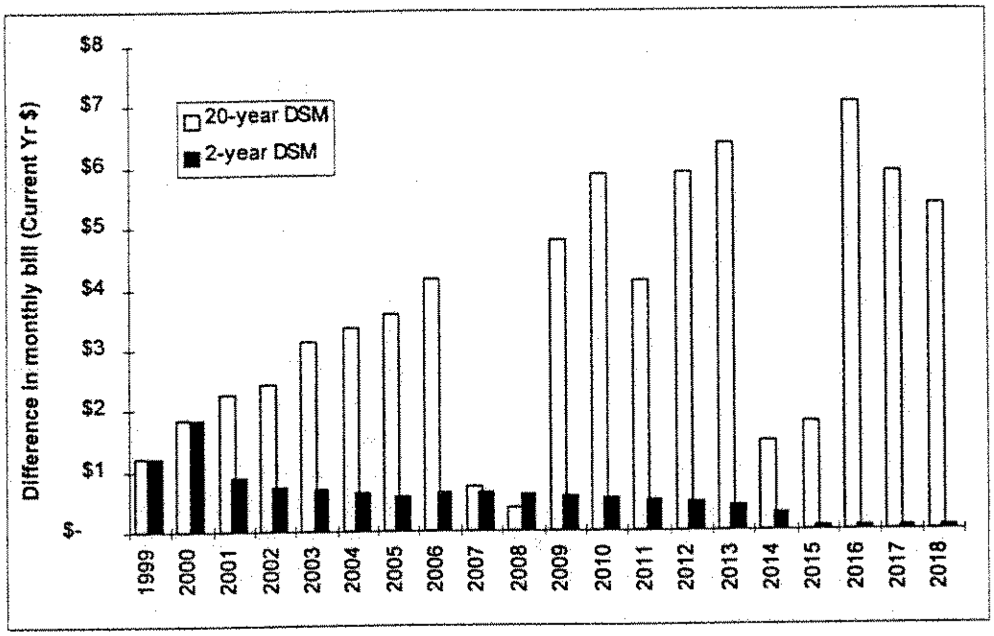


Figure 8-5. Difference in Residential Non-participant Monthly bill from No DSM (from 1999) Plan



DSM does increase the per unit cost of electricity, seen by the consumer as higher electric rates. The reason for this is that DSM reduces total energy consumption, causing fixed utility costs to be recovered over a smaller sales base. This is illustrated in Figure 8-4, which provides an indication of the differential in average cents per kWh from a no DSM (from 1999) baseline caused by 2-year or 20-year commitments to DSM. Figure 8-5 depicts the effect these rate impacts would have on a typical 500 kWh per month residential (non-participant) bill over the 20-year IRP planning period.

HELCO believes that the advantages of continuing energy efficiency DSM programs outweigh the drawback of increased rate impacts at this time, and therefore is including all four 20-year DSM programs in its preferred plan. The Advisory Group has also demonstrated support for 20-year DSM, assigning the IRP attribute of "increase DSM penetration" the highest weight in their rank-and-weight attribute analysis. Having the 20-year DSM programs in the IRP plan will give HELCO the flexibility to continue with these programs over the long term, provided they are justified in applications and approved by the Commission beyond the currently approved 5-year period. Future changes in the nature of the electric utility business environment may justify an increased weight placed on mitigating rate impacts to the point where it may be high enough to offset the favorable attributes of DSM. In that case, HELCO would need to be able to scale back or phase out the DSM programs in order to reduce rate impacts. With lower rates, customers would be less likely to leave the system for alternate suppliers or be inclined to self-generate.

8.6.2 Preferred Location of Future Generation

In the year 2000, HELCO forecasts approximately 56 percent of the total system load to be situated on the West side of the Big Island. However, only about 26 percent of total generation, comprised of three relatively inefficient combustion turbines, will be located in West Hawaii at Keahole.

Thus, a large proportion of the energy needs on the west side must be exported across the island, incurring high losses across transmission lines (losses are proportional to the square of the current on the line). Or, if the West side CTs need to be run for voltage support, then losses will be reduced, but operating fuel costs will increase. This obvious mismatch between the location of generation and load will continue to grow if future generation is not sited in West Hawaii, as more than half of future load growth is projected to be on the West side of the island.

Completion of the Keahole dual-train combined cycle with the addition of ST-7 will contribute an additional 18 MW (gross) of capacity as well as significant gains in efficiency to West Hawaii. This capacity addition and efficiency improvement will be achieved without burning more fuel or generating additional emissions. Moreover, the conversion of CT-4 and CT-5 at Keahole to combined cycle will provide voltage support from efficient generation on the West side. However, even with ST-7, total generation on the West side will only amount to about 30 percent.

Future generation additions beyond ST-7 at a new West Hawaii site will bring a closer balance between generation and load to the west side of the island. This will not only serve to reduce transmission losses, but will increase the chances that the system will remain stable in case a transmission line or lines are out of service and system separation should occur. The closer generation is to the load, energy delivery becomes less dependent on the transmission system, thereby increasing system reliability.

HCPC and PGV, independent power producers currently providing firm power to the HELCO system, have expressed interest to expand their power generation operations on the Big Island. Since these existing facilities are located in East Hawaii, and contracts could be negotiated with these parties in the future through PURPA, there is even more reason for HELCO to pursue efficient generation on the west side to serve that local load.

The initial integration of supply and demand-side resources in the PROSCREEN II model only accounted for generation-related costs. The PROSCREEN II model does not account for transmission requirements beyond interconnection of future generation into the transmission system. As shown in Table 8-4, without consideration of transmission costs, repowering of Hill 5 in 2006 appeared to be the least cost next unit alternative. The PROSCREEN II analysis (without transmission costs) also indicated that if ST-7 was added in 2006, repowering Hill 5 in 2009 would be a lower cost option than installing a dual train combined cycle at a new West Hawaii site.

As further discussed in Appendix N, a separate transmission study was conducted which used the PSS/E (Power System Simulator) model developed by Power Technologies, Inc. to simulate load flows given the three generation resource plans in Table 8-4. The transmission study identified the transmission capital projects (new lines or reconductoring of existing lines), if any, that would be required with each plan, as well as the transmission losses associated with each plan. Estimates of total transmission costs, including capital and losses, are indicated in Table 8-4. Clearly, consideration of total costs, including both transmission and generation, makes a difference in determining the least cost plan. Comparing Plans K7 and H1, generation savings with Plan H1 is outweighed by increased transmission costs incurred with additional East side generation. That is, when transmission costs are accounted for, it is lower cost to add ST-7 at Keahole as the next unit in 2006 than repowering Hill 5.

A similar comparison of Plans K7 and K1 revealed a slightly higher total cost (generation + transmission) to add a dual train combined cycle at a new West Hawaii site than to repower Hill 5 after ST-7. However, in consideration of the non-cost aspects of siting future generation noted above, HELCO's preference is that the next unit after ST-7 be sited in West Hawaii near the load center. Moreover, increases in West Hawaii load above the base forecast or increases in fuel prices above the reference forecast used in the analysis would result in increased transmission losses and associated costs.

As a result of this analysis, HELCO's preferred plan includes Keahole ST-7 as the next unit addition in 2006 followed by a dual train combined cycle at a new West Hawaii site.

8.6.3 Future renewable energy development

In 1997, about 30 percent of total generation on the HELCO system came from renewable sources, ranking HELCO among the top utilities in the nation in terms of renewable energy as a percent of total generation. HELCO's existing grid-connected renewable sources include geothermal, run-of-the-river hydro and wind. Assuming continued operation of all existing renewable facilities through 2018,

Table 8-4. Plans analyzed in IRP transmission study

Year	ST-7, W. HI DTCC (K7)	ST-7, Hill5 Repower (K1)	Hill5 Repower (H1)
1999	Encogen DTCC 20-yr DSM	Encogen DTCC 20-yr DSM	Encogen DTCC 20-yr DSM
2000			
2001			
//			
2002			
2003	Puna return from standby	Puna return from standby	Puna return from standby
2004			
2005			
2006	Keahole ST-7	Keahole ST-7	Hill 5 Repower, 1st CT
2007			
2008			
2009	West HI DTCC, 1st CT	Hill 5 Repower, 1st CT	Hill 5 Repower, 2nd CT and conversion to DTCC
2010			
2011			
2012	West HI DTCC, 2nd CT	Hill 5 Repower, 2nd CT	
2013			
2014			West HI DTCC, 1st CT
2015		Hill 5 Repower, conversion to DTCC	
2016	West HI DTCC, conversion to DTCC	LM2500 SCCT (W. HI)	
2017	West HI DTCC, 1st CT		
2018			West HI DTCC, 2nd CT
Cost in 1999 $000s			
20-yr Generation & DSM Cost	1,322,207	1,317,816	1,309,495
Difference in Gen & DSM cost	-	(4,391)	(12,712)
20-yr Transmission Cost	39,284	43,201	64,703
Difference in Trans. Cost	-	3,917	25,419
Total Diff. (Gen. & Trans.)	-	(474)	12,707

HELCO would surpass the federal Comprehensive Electricity Competition Plan proposal of a 5.5 percent minimum energy from renewable sources by more than four times over the 20-year IRP planning period.

As shown in Table 8-5, the integration analysis determined that plans with future addition of renewable resources (K2-K6, K11-K12) are more expensive than a comparable all-fossil plan (K1) within the 20-year IRP planning horizon. This is true even under a high fuel price sensitivity analysis or including the highest value externality adders. In the 50-year study period horizon, the plan that adds wind generation has a slightly lower present value of revenue requirements (estimated difference of about $800,000 over a 50-year period, using the base case fuel forecast). It should be noted that the PROSCREEN II model is not capable of modeling the curtailment of supplemental energy sources, therefore the integration analysis overstates the energy from wind during the minimum load periods. Only if the low capital cost estimate is assumed for geothermal is the plan with geothermal and wind (K5) lower in estimated cost than the all-fossil plan (K1) in the 50-year study period. All other plans, including the PV and wind plan (K3), hydro and wind plan (K4), pumped storage and wind plan (K6), biomass plan (K11) and minimize oil plan (K12), are more expensive than an all-fossil plan even when considering the longer term study period and including the highest value externality adders. Fuel cost savings over the 20-year IRP planning horizon of all renewable resources considered is not sufficient to offset the higher capital costs of these renewable alternatives relative to oil-fired generation.

Supplemental Resources:

Supplemental energy sources are those which provide non-firm electrical power. Non-firm means that the generating unit does not provide a specified capacity, either at a specified schedule or upon demand of the system. Supplemental energy sources that were considered in this IRP are:

- Run-of-river hydropower units
- Wind turbines
- Photovoltaic panel generating systems

A key characteristic of supplemental resources is their unpredictable variability. The output of a run-of-the-river hydro unit depends upon the flow of water available in the river, which can vary significantly over time scales of hours or days. The output of wind turbines can vary significantly from minute to minute. Photovoltaic panel output varies according to the sun angle and cloud cover. Since each of these resources depends either directly or indirectly on the weather, they are non-firm generation sources.

HELCO utilizes supplemental resources to reduce fuel oil consumption. The output of these units can, at times, enable HELCO to turn down or turn off units that use oil for fuel. Fuel savings also has the effect of reducing air emissions. To a small extent, incremental additions of supplemental renewable resources will increase the fuel diversity of the system and support the State of Hawaii energy objective to increase the proportion of energy from indigenous and renewable resources.

However, there are limitations to the amount of supplemental generation that can be incorporated into the utility system. During minimum demand periods, the supplemental sources can only provide the difference between the minimum output of the baseload units and the system demand. Currently, due to a relatively small margin at the minimum load, HELCO must curtail existing hydro and wind resources. Another operational concern stems from the sometimes rapid variation in wind output due to gusty conditions. HELCO is incurring increased production costs with existing wind resources because of

Table 8-5: Ranking of plans with renewables by cost

Rank	20-year Planning period, w/out Externalities	20-year Planning period, with Externalities	50-year Study period, w/out Externalities	50-year Study period, with Externalities
1	K1: All DTCC	K1: All DTCC	K5: Geothermal (low capital cost) & Wind	K5: Geothermal (low capital cost) & Wind
2	K2: Wind	K2: Wind	K2: Wind	K2: Wind
3	K5: Geothermal (low capital cost) & Wind	K5: Geothermal (low capital cost) & Wind	K1: All DTCC	K1: All DTCC
4	K5: Geothermal (high capital cost) & Wind	K5: Geothermal (high capital cost) & Wind	K5: Geothermal (high capital cost) & Wind	K5: Geothermal (high capital cost) & Wind
5	K3: PV (low capital cost) & Wind	K3: PV (low capital cost) & Wind	K3: PV (low capital cost) & Wind	K3: PV (low capital cost) & Wind
6	K4: Hydro & Wind	K4: Hydro & Wind	K4: Hydro & Wind	K4: Hydro & Wind
7	K6: Pumped storage & Wind	K6: Pumped storage & Wind	K3: PV (high capital cost) & Wind	K3: PV (high capital cost) & Wind
8	K3: PV (high capital cost) & Wind	K3: PV (high capital cost) & Wind	K6: Pumped storage & Wind	K6: Pumped storage & Wind
9	K11: Biomass & Wind	K11: Biomass & Wind	K11: Biomass & Wind	K11: Biomass & Wind
10	K12: Minimize Oil (2 biom & wind)	K12: Minimize Oil (2 biom & wind)	K12: Minimize Oil (2 biom & wind)	K12: Minimize Oil (2 biom & wind)

operating reserve that must be carried by oil-fired units capable of regulating system frequency. The operating reserve is necessary to counter excursions of the system frequency away from 60 Hz, such that power quality will not be compromised and load shedding will not occur. Operating reserve increases the cost premium for the wind plan (K2) relative to an all oil-fired plan (K1) within the 20-year IRP planning period.

HELCO is aware of the growing development of the wind industry and the gains that have been made with new technology. These new technologies, however, need to withstand field testing and performance verification. The various advanced wind turbines are currently being field tested at various locations on the mainland. These new advanced wind turbines do not have any significant track record to measure their performance over a long period.

As explained in Section 3.4.2, HELCO facilitated an Advisory Group multi-attribute analysis similar to the rank-and-weight method used in IRP-93. While HELCO could not endorse this method for reasons explained in Section 3.4.2, the Advisory Group collectively agreed that this analysis was necessary for them to arrive at consensus on a preferred plan recommendation. The plan with a 4 MW PV unit and a 10 MW wind resource in 2002 (Plan K3) was the highest ranked plan using the Advisory Group method and attribute weights.

In consideration of the result of the Advisory Group rank-and-weight analysis which indicated a preference for wind and PV, and the positive aspects of these resources such as fuel savings and reduced emissions, HELCO is proceeding to concentrate its efforts on acquiring additional wind and PV resources as listed below.

HELCO is currently negotiating with Zond Pacific, Inc. ("Zond") for purchase of as-available energy from a 10 MW windfarm which would be located at Kahua Ranch. HELCO has also received a proposal from Amoco/Enron Solar Power Development ("Amoco/Enron") for purchase of as-available energy from a 4 MW PV resource. These proposed wind and PV resources are similar to the units assumed in the IRP analysis and selected in the Advisory Group's preferred plan. As part of its IRP Action Plan, HELCO will continue to negotiate with Zond and Amoco/Enron for wind and PV resources, respectively. However, in the case that either or both projects do not materialize, HELCO will consider the purchase of wind and/or PV resources through one of the following avenues:

a. Renewable Resource Request for Proposal (RFP)—HELCO will develop a Renewable RFP to invite renewable developer(s) to submit a proposal to provide energy to the HELCO system in return for payments at or below HELCO's avoided energy cost;
b. Green Pricing Expansion--HELCO will expand and extend the current Green Pricing program filed with the PUC to include a wind and/or photovoltaic projects. HELCO customers will be given the choice to pay a premium for these renewable resources; or
c. Utility Installation--HELCO will consider installing a wind and/or a photovoltaic project as part of its utility-owned electrical generating system.

This is discussed in more detail in the Supply-side Action Plan in Section 9.2.

In addition to these utility scale projects, HELCO and the Big Island community are participating in the federal Million Solar Roofs Program, with a vision to have 20,000 solar systems in place on the Big Island by the year 2010. The types of solar systems include both water heating and photovoltaics. The solar water heating system portion of the vision is reflected in HELCO's Residential Water Heating DSM program and therefore is reflected in HELCO's IRP plan. The photovoltiac systems may involve a number of different types of applications such as remote homes, solar communities, remote water pumping and PV lighting, commercial building rooftop grid-connected systems and residential grid-connected systems. While HELCO envisions having a role in this new PV energy development activity, the precise nature of that role is presently undetermined. Other possible partners in the realization of this vision for the Big Island include the solar industry, government, educational institutions, and related professional groups like architects, realtors, and engineers. As the estimated PV installations in the federal Million Solar Roofs Program is a vision and is still in the conceptual stage, it was not possible to reflect it in HELCO's IRP plan.

Firm Renewable Resources

Geothermal

The Advisory Group developed a plan (K5) with 25 MW of additional geothermal. The Advisory Group actually requested that the geothermal resource be added following ST-7 in 2009. However, due to potential minimum load constraints and uncertainties in the forecasts, geothermal was added where sufficient margin is forecasted between the system minimum load and minimum baseload capability (see Section 5.2). Geothermal power is normally designed and operated as a baseload resource because it has a high capital cost but essentially no fuel costs. Minimum load conflicts could require future geothermal plants to be designed to be dispatchable and for cycling duty.

HELCO recognizes that, if successfully developed and operated, and if it can be integrated with existing resources on the system, geothermal can be a highly beneficial source of firm power. Geothermal does not consume fuel oil. It releases relatively insignificant amounts of the criteria pollutants into the atmosphere as compared to fossil fired generation.[49] It would increase the ratio of energy from indigenous and renewable resources in support of the State of Hawaii energy objectives, and improve fuel diversity.

However, geothermal is only cost-effective if considering a long-term, 50-year study period horizon <u>and</u> if geothermal can actually be acquired at the low capital cost estimate of about $3,700 per kW. Realization of this installed cost would depend on the number of wells that would have to be drilled to find an adequate geothermal resource to provide 25 MW of firm power, and the cost to drill each well. Enhancing load following capability would probably require more wells at a greater capital cost.

Aside from this uncertainty in initial development cost, geothermal faces a number of uncertainties and risks throughout the period in which it is operational. Geothermal facilities are limited to certain areas of the Big Island where there is some risk of either lava flow or earthquake, which could cause long-term damage to the generation facility. Since HELCO depends on geothermal to provide firm capacity to the system, additional geothermal on the system may require HELCO to increase its reserve margin requirement. There is also uncertainty in the long term reliability of geothermal. Steam production could decline unexpectedly, or problems could arise with injection wells. In either case, firm capacity of the geothermal resource would not be

[49] see Unit Information Form for 25 MW geothermal in Appendix G, "IRP-98 Supply-Side Resource Option Portfolio Development" (Black & Veatch)

maintained. Depending on the magnitude of the deration, HELCO may not be able to serve the system load. In such a situation, restoring firm output would not be immediate, as it would require drilling additional wells. Restoring firm output could be prolonged if permitting is required. Costs could also be prohibitive, since the estimated cost of drilling each well could be as high as $3.5 million, with no guarantee of success in finding an adequate geothermal resource.

There are also members of the Big Island community that are strongly opposed to geothermal development, as voiced during recent efforts by PGV to obtain permits from the EPA to continue operation of existing wells and to drill additional wells. These opponents to geothermal say that hydrogen sulfide presents a health risk, that "drawing volcanic steam is an affront to Madame Pele, a goddess of fire in the Hawaiian religion", and that water to the east of the existing PGV plant has been affected. [50]

In consideration of these factors, geothermal was not included in the preferred IRP plan.

Biomass

The Advisory Group developed two plans (K11 and K12) which added 25 and 50 MW, respectively, of biomass capacity after ST-7. HELCO recognizes that biomass resources have a number of environmental and societal benefits, including: promotion of fuel diversity with the use of banagrass as feedstock, increasing energy from indigenous and renewable resources, consistent with the State of Hawaii energy objectives, reducing total fuel oil consumption, and reducing PM and SOx emissions. While biomass has these favorable attributes, HELCO does not believe that it supports the IRP objective of meeting consumer energy needs in a "reliable manner at the lowest reasonable cost" for the following reasons:

- Biomass resources are still not cost-competitive when compared to conventional technologies, and would thus add a cost-premium to utility ratepayers if implemented. This is true even assuming a high price scenario for fuel oil, including the highest value externality adders or considering the longer term 50-year study period.
- Biomass plants carry substantial risks. The dependability as well as the cost of the feedstock may be subject to much variability, as the result of inclement weather or crop damage due to pests.
- Opportunities already exist at former sugar plantations to grow and utilize a biomass feedstock. However, none of the former plantations are currently pursuing this, indicating that it may not be economically attractive to do so.
- Biomass resources require significantly more land area than an equivalent sized oil-fired generating unit for cultivation of the banagrass crop. In order to produce the banagrass necessary to fuel a 25 MW biomass unit, approximately 7600 acres of land are required, which is more than 2000 times the land requirements for an oil-fired unit. Members of the Advisory Group expressed a view that there could be aesthetic value to biomass cultivation over lands which might otherwise remain fallow.
- According to EPRI, at this time there are no commercial, dedicated biomass-to-electricity facilities in the United States.

Due to these factors, biomass was not included in the IRP preferred plan.

Pumped Storage Hydro

The Advisory Group suggested a plan that paired a 10 MW wind resource with pumped storage hydro (PSH) in 2009 after the addition of ST-7. The idea behind the

[50] "Hearings on drilling to begin tomorrow", *The Honolulu Advertiser*, April 2, 1998.

concurrent installation of wind and PSH was that the negative effects on system frequency of wind fluctuations could be avoided by having wind energy directly provide pumping power for the PSH resource. However, the physical location of wind (Lalamilo) and PSH would not be able to accommodate such a configuration. There are also uncertainties as to whether or not the PSH resource can actually withstand the volatility in power input, as would be realized with wind.

Pumped storage can provide system benefits by pumping at, and thereby increasing, the system minimum load. This would serve to reduce the probability that the minimum baseload capability of the system would exceed the minimum load. Storage technologies such as PSH are designed to take advantage of the differential in system production costs between the peak and off-peak periods. If off-peak energy costs for pumping are less than the avoided costs of on-peak generation, even when the pumping cycle efficiency (70% was assumed for PSH) is accounted for, then production cost savings can be achieved. The differential in on-peak and off-peak costs are not wide enough to make PSH cost effective at HELCO. Based on economics, PSH is hardly dispatched in the modeling runs. If the unit were forced to cycle daily in order to increase the system minimum load, the unit would be operating out of economic dispatch and production costs would increase.

For IRP analysis purposes, PSH was given partial firm capacity due to its limited availability over a 24 hour period (see section 7.4.5). Even with this assumption, PSH was not cost-effective. With these cost and operational considerations in mind, PSH was not selected as a resource in the preferred plan.

8.6.4 Distributed Generation

In the integration analysis, HELCO found that the installation of multiple 1 MW diesels in 2009 may be cost-competitive with large-scale generation resources. Comparison of plans K1 and K13, for example, show approximately $3.5 million savings in present value of revenue requirements over the 20-year planning period if seven 1 MW diesels are installed to defer the unit addition after ST-7. In the plan with 1 MW diesels, generation is added in small increments commensurate with the growth in system load, thus having the potential to defer large-scale generation additions. Distributed generation could also provide system cost savings if it is sited to defer the need for transmission or distribution lines. Operationally, the 1 MW diesels would provide quick-start capability to the system in times of system emergency.

The costs and benefits of distributed generation, however, are highly sensitive to the site and case under consideration. The IRP analysis has assumed planning level cost estimates, and the specific location of each 1 MW unit has not yet been identified. Thus, rather than interpreting the integration result as reason to include distributed generation in its preferred plan, HELCO has taken it to mean that distributed generation has the potential to be cost-effective, and further study is warranted.

Also, the installation of multiple 1 MW diesels was not cost-effective over the 50-year study period.

As a component of its Action Plan, HELCO will evaluate distributed generation in further detail on a site-specific basis. This includes identifying specific sites for each unit, refining capital and O&M costs and determining the ability to obtain air, noise and land use permits. Selection of the site and timing of the distributed resource addition may depend on the identification of transmission or distribution projects that can be deferred if distributed generation is located in a certain area. Community acceptance is also a consideration, depending on the proximity of the proposed site to populated areas. If siting and permitting issues can be resolved, the refined cost of distributed generation is determined to be less than or equal to the costs assumed in this IRP planning analysis, and if system benefits can be achieved, then HELCO will pursue installation of distributed resources. Action Plan activities are further detailed in Section 9.2.

8.7 IRP-98 PREFERRED PLAN

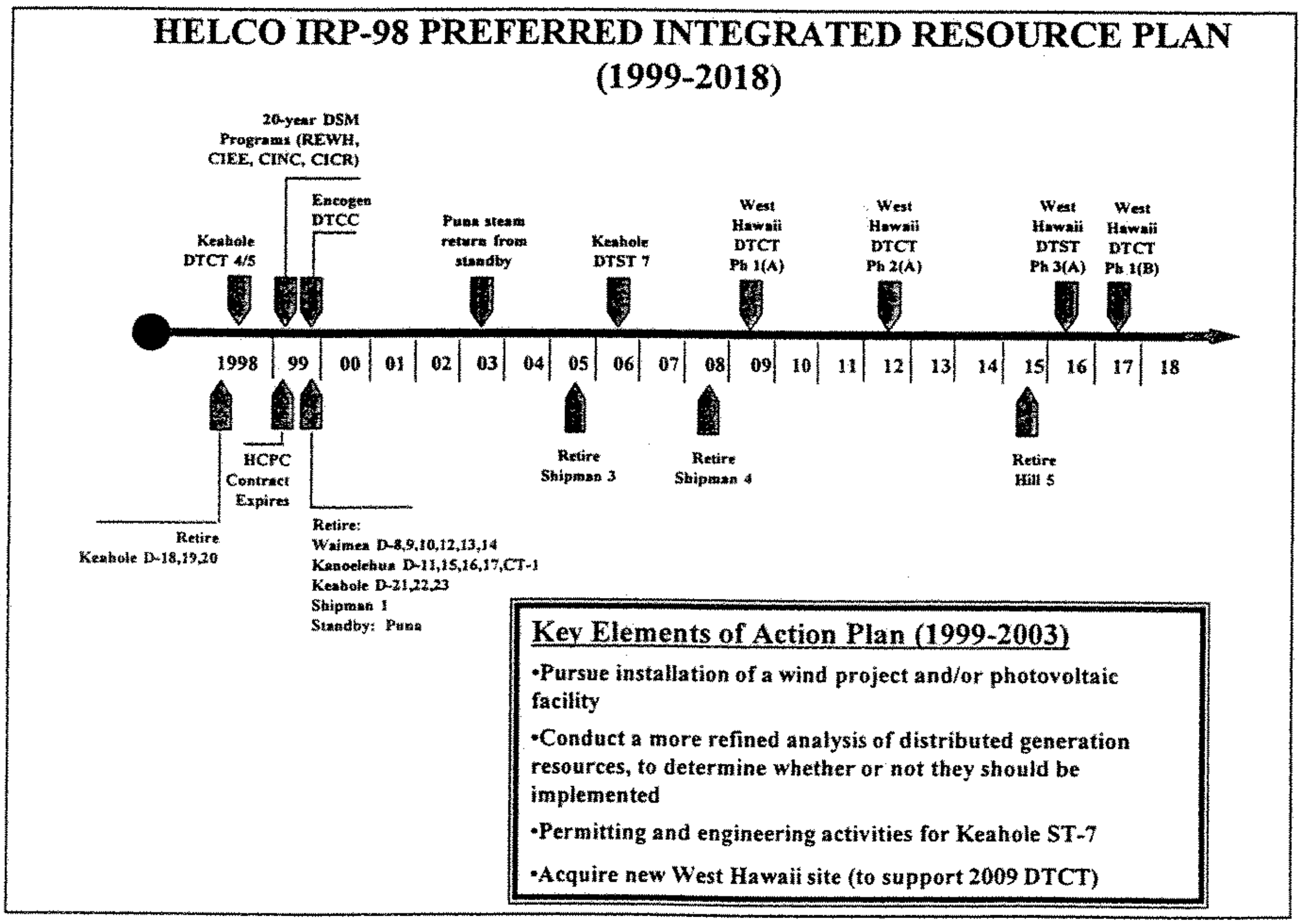
In consideration of the IRP Framework, current trends in the electric utility environment, forecasts, IRP objectives, premises and results of the various analyses and Advisory Group input, HELCO proposes Finalist Plan K7 as the preferred integrated resource plan. This preferred plan is illustrated in Figure 8-6.

8.7.1 Demand-Side Features of the Preferred Plan

The preferred plan includes the following demand-side features:

- Four energy efficiency DSM programs implemented over the 20-year period, 1999-2018. The programs include: Residential Water Heating, Commercial & Industrial Energy Efficiency, Commercial & Industrial New Construction and Commercial & Industrial Custom Rebate programs.
- A forecasted maximum energy efficiency DSM peak impact of about 15.2 MW, reducing the forecasted peak load in 2018 from 263.6 to 248.4 MW
- A forecasted total energy savings of roughly 1300 GWh, or about 3 million barrels of oil, from energy efficiency DSM over the 20-year planning period.
- While not an energy efficiency DSM

Figure 8-6. IRP-98 Preferred Plan



DTCC - Dual-train Combined Cycle
DTCT - Combustion Turbine
DTST - Steam Turbine with conversion of DTCTs to Combined Cycle

REWH - Residential Efficient Water Heating
CIEE - Commercial & Industrial Energy Efficiency
CINC - Commercial & Industrial New Construction
CICR - Commercial & Industrial Custom Rebate

program, continuation of existing load management rates and rider contracts are estimated to reduce the system peak demand by more than 6.7 MW.

Table 8-6 summarizes the forecasted system peaks with 20-year DSM impacts of the preferred plan.

8.7.2 Supply-Side Features of the Preferred Plan

The preferred plan includes the following supply-side features:

- Retire Keahole D18-20 (8.25 MW) with the addition of CT-4 and CT-5 in December 1998
- Retire Shipman 1, Waimea D8-10 and D12-14 (total of 14.3 MW) upon completion of Encogen Phase 1[51], currently estimated to be in April 1999
- Retire Kanoelehua D11 and D15-17, Keahole D21-23 and CT-1 (total of 30 MW) upon completion of Phase 2[52] of the Encogen combined cycle, currently estimated to be in August 1999
- Place the Puna steam unit on cold standby upon completion of Phase 2 of the Encogen combined cycle[53], currently estimated to be in August 1999
- Expiration of the contract between HELCO and HCPC for the purchase of 22 MW of firm capacity on December 31, 1999
- Return the Puna steam unit to service from cold stand-by for cycling operation in 2003
- Install Keahole ST-7 in 2006, converting CT-4 and CT-5 to an efficient baseloaded dual train combined cycle unit
- Install a 60.7 MW dual train combined cycle at a new West Hawaii site in phases, with the first phase combustion

Table 8-6. Summary of DSM Impacts in the Preferred Plan

	Base Peak Forecast, Without Peak Reduction Benefits of DSM		Energy Efficiency DSM Peak Reduction Benefit		Base Peak Forecast, With Peak Reduction Benefits of DSM		Total System Capability for Preferred Plan	
Year	Gross MW	Net MW	Gross MW	Net MW	Gross MW	Net MW	Gross MW	Net MW
1999	172.7	166.8	0.8	0.8	171.9	166.1	239	235
2000	174.4	168.5	1.5	1.5	172.8	167.0	217	213
2001	177.2	171.2	2.3	2.2	174.8	168.9	217	213
2002	180.9	174.7	3.0	2.9	177.9	171.8	217	213
2003	184.9	178.6	3.8	3.7	181.1	174.9	232	228
2004	188.9	182.5	4.6	4.4	184.3	178.0	232	228
2005	193.1	186.5	5.4	5.2	187.7	181.3	232	228
2006	198.8	192.1	6.3	6.1	192.5	186.0	243	238
2007	204.2	197.3	7.2	6.9	197.0	190.4	243	238
2008	209.5	202.4	8.1	7.8	201.4	194.6	243	238
2009	214.7	207.5	9.0	8.7	205.7	198.7	256	251
2010	220.0	212.6	10.0	9.7	210.0	202.9	256	251
2011	226.0	218.4	11.0	10.6	215.0	207.8	256	251
2012	232.3	224.5	11.9	11.5	220.4	213.0	278	272
2013	239.0	230.9	12.9	12.5	226.0	218.4	278	272
2014	245.3	237.0	13.4	13.0	231.8	224.0	278	272
2015	251.7	243.2	14.0	13.5	237.6	229.7	278	272
2016	258.5	249.8	14.6	14.1	243.9	235.7	284	278
2017	265.5	256.6	15.1	14.6	250.4	242.0	305	299
2018	272.8	263.6	15.7	15.2	257.1	248.4	305	299

[51] Consistent with HELCO Rate Case, Docket No. 97-0420 (HELCO T-4, p. 43)

[52] Ibid.

[53] Ibid.

turbine added in 2009. The second combustion turbine and steam turbine would be installed in 2012 and 2016, respectively.

- Install the first combustion turbine of a second 60.7 MW dual train combined cycle at the new West Hawaii site in 2017.

8.7.2.1 Future Non-Utility Generation

The resources in the preferred plan are shown without regard to ownership. While (aside from Encogen) there are no NUG-specific projects shown within the 20-year planning horizon, this does not mean that there will not be any additional NUG-operated facilities added during the period covered by the IRP. However, a NUG proposal for firm capacity should be consistent with the timing of HELCO's need for additional capacity. HELCO's policy is that any power purchase resources, proposed or under negotiation, which do not have an executed agreement, will not be shown in the integrated resource plan.

8.7.2.2 Combined Cycle Units in the Preferred Plan

Combined cycle units offer substantial flexibility in both installation and operation. Installation in phases can better match load growth and reduce rate shock, and fuel flexibility grants HELCO production cost saving options. This flexibility, detailed in the points that follow, allows HELCO to be responsive to a number of future scenarios.

Combined cycle units can be configured in different ways:

- 1-on-1: One combustion turbine, with the exhaust heat directed to one heat recovery steam generator (HRSG) with the steam output directed to one steam turbine.
- 2-on-1: Two combustion turbines, each one directing exhaust heat to its own HRSG and the two HRSGs directing steam to a single steam turbine.

Combined cycles offer flexibility in installation and scheduling:

- In a 1-on-1 configuration, the combustion turbine and steam turbine can be installed in two separate phases. In the first phase, the combustion turbine would be installed and operated as a simple cycle unit. In the second phase, the HRSG, steam turbine and condenser would be added to form the combined cycle unit. The second phase could be added either when needed to satisfy load growth or when an economic analysis showed that it would be cost-effective to install the second phase and operate the more efficient combined cycle before the capacity was actually needed.
- In a 2-on-1 configuration, the two combustion turbines and the steam turbine can be installed in three separate phases. The first phase would be the installation of the first combustion turbine, which would be operated in simple cycle mode. The second phase would be the installation of the second combustion turbine, also operated in simple cycle mode. The third phase would consist of the installation of the two HRSGs, the steam turbine and the condenser to form the 2-on-1 combined cycle.
- As an option in the 2-on-1 combined cycle, the second phase could consist of the installation of one HRSG, the steam turbine and the condenser. In this case, the generating plant would be temporarily configured as a 1-on-1 combined cycle with an oversized steam turbine and condenser. The third phase would consist of the installation of the second combustion turbine and HRSG. The steam output from this second HRSG would be directed to the same steam turbine. Depending on the cost of fuel and the rate of load growth, this sequence of construction could be more cost-effective than the previously described sequence.

- In addition to the flexibility in the sequence of construction, combined cycles also offer flexibility with respect to scheduling of the phased installation. Depending on the rate of load growth and the cost of fuel, the phases subsequent to the first phase could be accelerated or delayed.
- In the integration analysis, dual train combined cycles, including repowering options, were given the option to add in the most cost-effective sequence of construction within each developed plan. With only a few exceptions, it was found that the sequence of Phase 1-combustion turbine, Phase 2-combustion turbine and Phase 3-steam turbine, 2 HRSGs and condenser was the most economically attractive.

Combined cycle units also offer flexibility in terms of the fuels they can burn. Certain models of combustion turbines can burn No.2 diesel, naphtha, medium sulfur fuel oil, or gasified fuels produced from high sulfur fuel oil, coal or a water/bitumen emulsion.

A combined cycle allows operational flexibility because it can operate at low loads during the off-peak hours. A 2-on-1 combined cycle can be designed to operate with only one combustion turbine, one HRSG and the steam turbine and condenser in service (that is, with the other combustion turbine and HRSG off-line).

The combined cycle can also be designed to operate with both combustion turbines in service and the steam turbine and condenser out of service. These design features provide maintenance flexibility in that individual components can be taken out of service for planned maintenance without having to take the entire plant out of service.

The combined cycle system can also be designed such that the loss of any one turbine-generator of the combined cycle due to a forced outage will not result in the loss of more than one-half of the total generating output of the combined cycle.

While combined cycle units installed in phases offer substantial flexibility, certain practical considerations must be taken into account before proceeding with implementation. If the entire combined cycle is covered by a single Covered Source Permit for air emissions, there is a requirement that construction be continuous. Depending on the length of time between the phases, this requirement may or may not be met. It may be possible to obtain a variance from this requirement, but this cannot be determined at this time. Equipment warranty conditions must also be considered. For example, conversion of the combustion turbine from simple cycle to combined cycle may take place beyond the period in which the warranty is valid. Considerations such as these will be taken into account at the time firm commitments for purchase are made.

8.7.3 Comparison with the IRP-93 Preferred plan

Table 8-7 shows a side-by-side comparison of the preferred resource plan in the current IRP and the preferred resource plan in IRP-93. Aside from the timing of resource additions, the plans are identical in terms of the type of generation technology added; i.e., phased, dual-train combined cycles. The IRP-98 plan, like its IRP-93 predecessor, includes 20-year DSM, but at a lower penetration.

8.7.4 Risks and Uncertainties

HELCO faces a number of risks and uncertainties in planning future resource additions for the next 20 years. The following paragraphs describe the major uncertainties and their expected impacts on the IRP preferred plan.

Near-term Unit Additions
For IRP purposes, HELCO has assumed that Keahole CT-4 and CT-5 are installed by December 1998 and that the Encogen DTCC is completed by August 1999. Uncertainties associated with, as well as alternatives to these projects, will continue to be addressed as appropriate in near-term contingency planning.

Table 8-7. Comparison of IRP-98 and IRP-93 Preferred Plans

Year	IRP-98 Preferred Plan	IRP-93 Preferred Plan ('94 Reassessment)
1994		
1995	DSM (1995-1998, 20-yrs from 1999)	20-yr DSM (1995-2015) Keahole CT-4/5
1996		
1997		Keahole ST-7
1998	Keahole CT-4/5	
1999	Encogen DTCC	
2000		West HI DTCC, 1st CT
2001		
//		
2002		
2003	Puna return from standby	
2004		West HI DTCC, 2nd CT
2005		
2006	Keahole ST-7	
2007		
2008		West HI DTCC, conversion to DTCC
2009	West HI DTCC, 1st CT	West HI DTCC, 1st CT
2010		
2011		
2012	West HI DTCC, 2nd CT	
2013		
2014		
2015		
2016	West HI DTCC, conversion to DTCC	
2017	West HI DTCC, 1st CT	
2018		

Business Environment
The business environment for electric utilities is anticipated to be increasingly competitive in the future. If Hawaii follows the trend on the mainland, utility-sponsored DSM programs may be phased out because DSM is not favorable where minimizing rates is of primary importance. The changing business environment for electric utilities may also impact the selection of supply-side resources, where greater emphasis is placed on minimizing costs and rates such that renewable resources and externality considerations will decline in priority within the context of utility resource planning. However, they would continue to be addressed elsewhere such as in legislative activities.

Forecasts
Deviations from the sales and peak forecast may alter the timing of supply-side resource additions. While plans with a combined cycle unit installed in phases are resilient (i.e., they are low cost plans regardless of whether the high, base or low sales and peak forecast is used), deviations from the base sales and peak forecast has a dramatic effect on the timing of firm supply-side resources added to meet load growth. If actual system peaks are higher than the base forecast, additional firm generating capacity may be required earlier. The extent of the acceleration will depend on the magnitude of the deviation. On the other hand, if actual system peaks are lower than forecast, the need for firm capacity additions may be deferred.

Deviations from the fuel price forecast could alter the optimal mix of demand-side and supply-side resources. Within the range of the 1995 high and low forecast, plans with phased combined cycles are consistently lowest cost. More pronounced, long-term deviations from the base forecast than projected in the 1995 forecast, however, could result in changes to the least cost mix of resources.

Demand-side Resources
If the actual impacts realized by energy efficiency DSM programs are lower than

forecasted, the result could be an earlier need date for the next supply-side unit. Greater than forecasted impacts could result in deferral of the next unit addition, depending on the variance. The uncertainty in future DSM peak impacts is the result of the following conditions:

Baseline data: Energy and capacity savings estimates assume certain baseline conditions. However, little baseline data exists on the size of end-use markets, the intensity of electricity use and the penetration of energy-efficient equipment in Hawaii.

Market risk: HELCO has designed the DSM plan assuming certain levels of market penetration. To the extent that actual participation is less than expected, forecasted peak and energy savings are less likely to be achieved.

Infrastructure risk: The Hawaii market has not had extensive promotion of DSM measures or programs. As a result, many equipment vendors may not have sufficient capacity to meet the demand created by HELCO's DSM programs. Also, the volume of equipment existing in Hawaii may be insufficient to service the programs.

Performance risk: Most of the DSM programs rely on equipment to improve energy efficiency. To the extent that the DSM measure does not perform as assumed, the savings may not materialize.

Program design: The programs have been designed on the basis of certain technology pairings and equipment sizing protocols. To the extent that these are off-mark, the savings may be less than expected or participation may suffer.

The timing of the Commission's approval of, and the commencement of the Company's implementation of future DSM programs could affect the timing of supply-side additions. Later than expected implementation of the programs could result in an earlier need for additional firm generating capacity.

Supply-side Resources

Changes in the relative costs of supply-side technologies could alter the optimal mix of resources. While the cost and performance data for the supply-side technologies were based on the most current data available, improvements in technology or changes in the price of raw products could result in relative shifts in the ranking of generating technologies by cost. This could affect the selection of resources in the least cost plan.

The ability to site a power generating facility is also a risk. While the IRP may be definitive in stating its preferred plan or plans, circumstances during actual implementation may warrant changes in assumptions or the plan itself.

8.7.5 Other Scenarios and Impacts on the Preferred Plan

The preferred plan is sensitive to a number of variables, such as the sales and peak forecast, the fuel price forecast, projections of DSM penetration and the state of technology at the time the 20-year IRP plan is developed. Significant changes in the sales and peak forecast or in the expected DSM penetration could change the timing of firm capacity additions. Long-term variances from the fuel price forecast would change the relative cost-effectiveness of candidate generation alternatives, which could result in a change in resource selection. Selection of the preferred plan is also sensitive to the planning context, which determines the relative weighting and importance of each IRP objective. For example, if the utility were subject to retail competition, greater emphasis would be placed on the short-term, meaning end-effects could be given less to no consideration, and the importance of rates could be elevated to the highest priority such that DSM programs would be quickly phased out.

Given the uncertainties identified in Section 8.7.4, and possible changes in HELCO's preferred resource plan that could result, HELCO needs the flexibility to pursue plans which would be appropriate in other future scenarios. This would also include implementation of resources as a result of IRP-98 Action Plan activities. The following sections illustrate possible alternative plans and describe the conditions under which each might be pursued. HELCO is not requesting Commission approval of these alternative plans in this IRP-98 filing.

8.7.5.1 Alternate Plan A: Possible acquisition of additional wind and PV facilities

This is being addressed as an IRP-98 action plan item. If wind and PV are added at any time during the 20-year IRP planning period, firm capacity additions in HELCO's preferred plan would not be affected. This plan would be pursued if current negotiations with wind and PV developers result in purchase power contracts for as-available energy. In the case that these currently proposed projects do not materialize, HELCO may also acquire wind and/or PV through the following IRP-98 action plan activities:

a. Renewable Resource Request for Proposal (RFP) — HELCO will develop a Renewable RFP to invite renewable developer(s) to submit a proposal to provide energy to the HELCO system in return for payments at or below HELCO's avoided energy cost;
b. Green Pricing Expansion — HELCO will expand and extend the current Green Pricing program filed with the PUC to include a wind and/or photovoltaic projects. HELCO customers will be given the choice to pay a premium for these renewable resources; or
c. Utility Installation — HELCO will consider installing a wind and/or a photovoltaic project as part of its utility-owned electrical generating system.

8.7.5.2 Alternate Plan B: Possible installation of Distributed Generation resources

As part of the IRP-98 supply-side action plan, site-specific analyses will be conducted to determine the cost-effectiveness of specific distributed generation applications. This alternate plan would be implemented if the action plan analyses find that the benefits of installing distributed technologies exceed the costs. While multiple 1 MW distributed diesels considered in the IRP-98 analysis derived cost savings through deferral of centrally located, large-scale units, generation may or may not be deferred in actuality. Realization of capacity deferral would depend on the magnitude and timing of the distributed capacity installed. Distributed generation could also be installed prior to system capacity need if, for example, it can accrue sufficient T&D deferral benefits to justify its cost.

Since the timing and size of possible future distributed generation projects are presently unknown, its effect on the timing of supply-side additions in the IRP preferred plan cannot be determined at this time.

8.7.5.3 Alternate Plans C1, C2 and C3: Alternatives to firm capacity additions in West Hawaii

The preferred IRP-98 plan includes the installation of ST-7 at Keahole to complete the dual train combined cycle (DTCC) in 2006. Subsequent phased DTCCs in the preferred plan are assumed to be located at a new West Hawaii site.

Installation of efficient generation closer to the load in West Hawaii is desirable to achieve both transmission cost savings and improvements in area reliability. However, uncertainties do exist in the implementation of HELCO's preferred course of action. Completing the DTCC at Keahole with the addition of ST-7 in 2006 would require HELCO to re-apply for its air permit, due to a continuous construction provision in the existing air permit for the Keahole DTCC (CT-4, CT-5, ST-7). In order to implement the 2009 phased DTCC on the west side, HELCO must first acquire a site in West Hawaii.

If, for whatever reason, ST-7 cannot be installed, HELCO's next best alternative would be to accelerate construction of the West Hawaii DTCC in the preferred plan. Although there would be some efficiency loss without ST-7, HELCO would maintain the strategy of installing generation closer to the load on the West side. The resulting plan is illustrated as Alternate Plan C1 in Figure 8-7.

If the new West Hawaii site cannot be acquired to meet the capacity need date, whether it be as an alternate to ST-7 or for the subsequent DTCC, the IRP-98 analysis has identified repowering on the East side as the next best alternative to firm generating capacity in West Hawaii. Repowering options include conversion of the existing Hill 5 or Hill 6 steam units to dual train combined cycle, or conversion of Puna CT-3 and the Puna steam unit to DTCC.

The IRP-98 analysis determined Hill 5 repowering to be the least cost repowering alternative in the 20-year IRP planning period. However, this result is due to an assumption made in the analysis that Hill 5 would retire in 2015 upon reaching its 50-year expected service life, if not repowered prior to this date. The analysis demonstrated that, for Hill 5, it is more expensive to replace the retired capacity with new capacity than to incur the cost of repowering. Cost estimates for repowering used in the analysis did not take into account possible life extension costs for the Hill 5 turbine generator. Hill 6 and Puna have planned retirement dates outside of the 20-year IRP planning horizon (past 2018, based on a 50-year expected service life for steam units). Therefore, unlike Hill 5, Hill 6 and Puna had the option of continued operation through 2018 if not repowered. Plans that do not opt for repowering of Hill 6 and Puna require less new generation capacity over the 20-year planning period. For Hill 6 and Puna, the analysis showed that although the repowered units are more efficient than the existing units, this efficiency benefit was not enough to offset the cost of additional new capacity in the plan.

While the PROSCREEN II analysis points to Hill 5 repowering as the least cost repowering alternative, other project viability considerations, such as permitting, would have to be examined in the determination of which repowering option should be pursued. Additional analysis would be performed if HELCO is faced with not being able to complete the Keahole DTCC with ST-7 or if the Company is unable to acquire a new West Hawaii site.

The resulting plan (shown with Hill 5 repowering) with repowering as an alternative to ST-7 is illustrated as Alternate Plan C2 in Figure 8-8. Plan C3 in Figure 8-9 shows the unit additions if ST-7 is installed, but repowering serves as an alternate to the next West Hawaii dual train combined cycle.

Figure 8-7. Alternate Plan C1

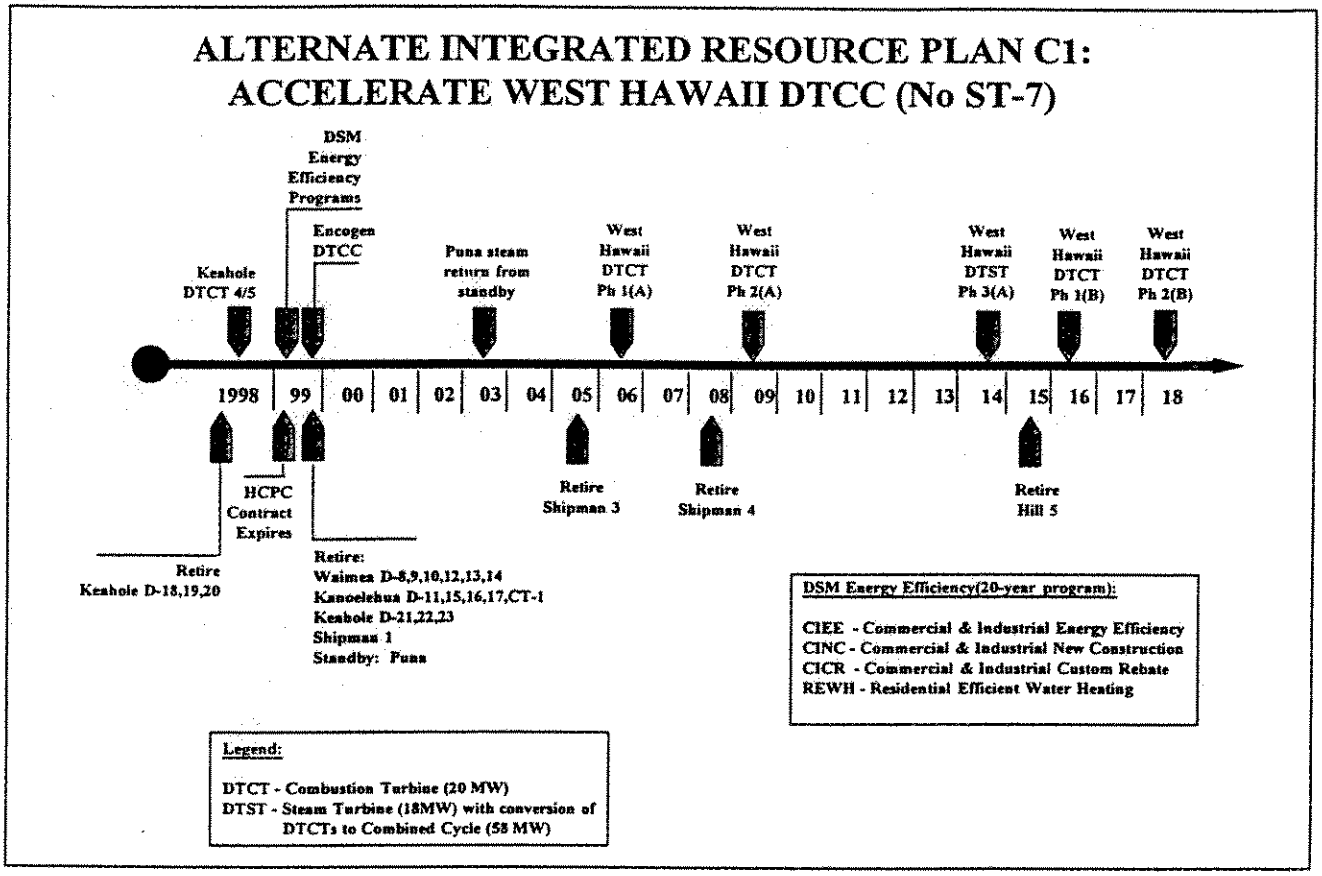


Figure 8-8. Alternate Plan C2

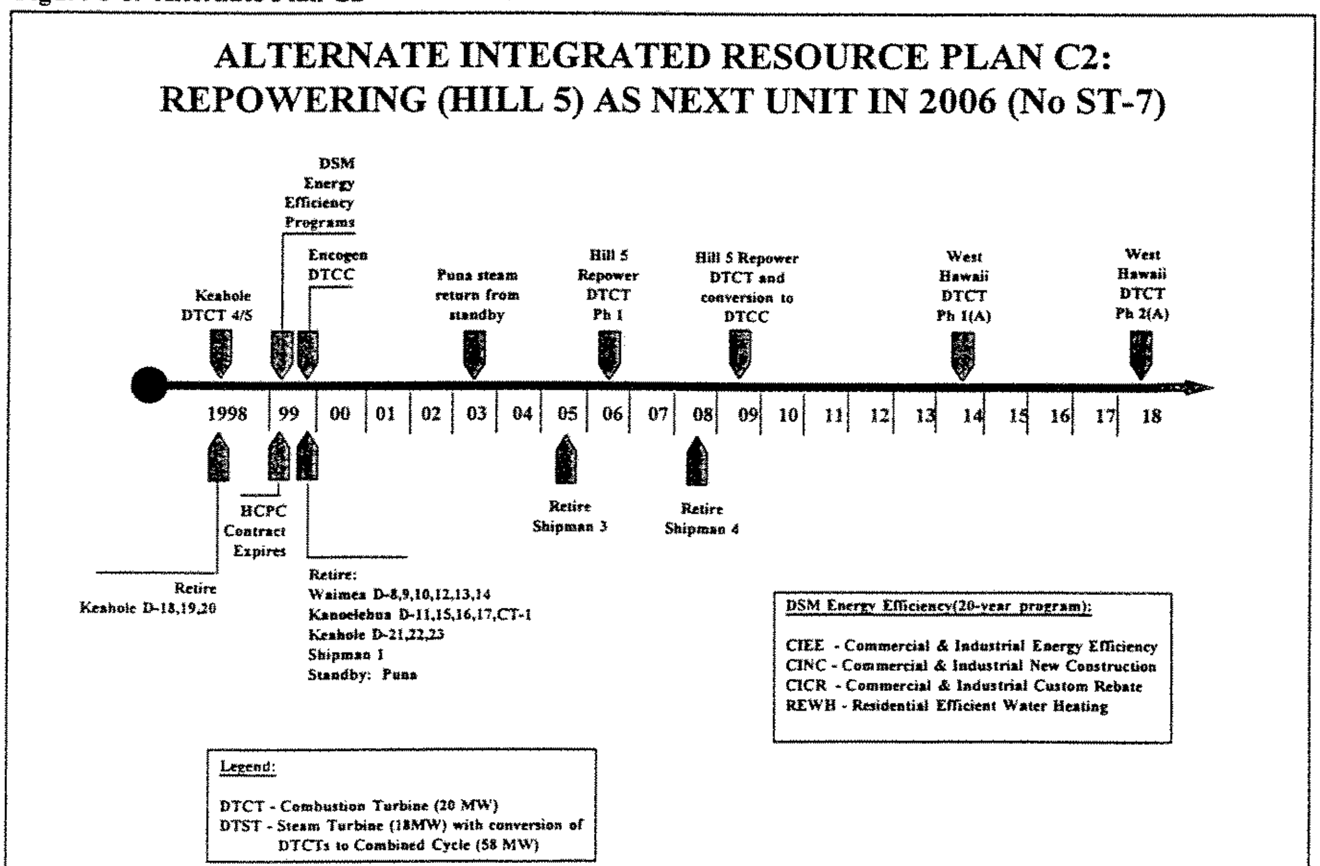
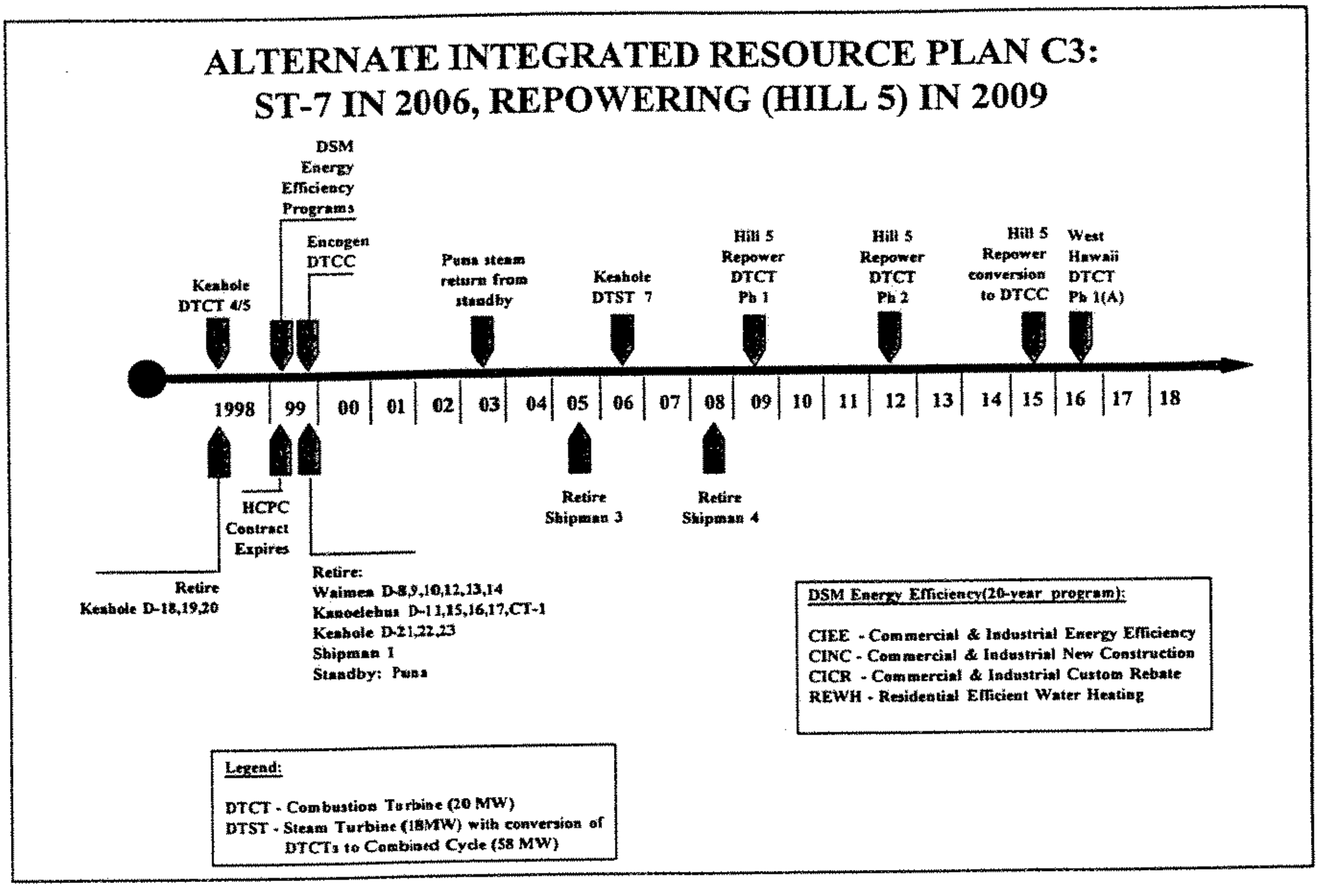


Figure 8-9. Alternate Plan C3



9. ACTION PLANS

This section describes the process by which HELCO's long-range resource program plans are scheduled for implementation over the five-year period 1999 to 2003. This includes, for each of the five years, the programs or phases of programs to be implemented, the expected level of achievement, the expected level of penetration of any DSM program, the expected supply-side capacity additions, and the estimated expenditures that would be required by the utility in order to implement each resource.

9.1 DEMAND-SIDE MANAGEMENT (DSM) ACTION PLAN

9.1.1 Overview

HELCO developed a broad and aggressive DSM plan as part of IRP-93. The objectives of the DSM plan were to:

- Acquire cost-effective energy efficiency and peak reduction resources that were less expensive than supply alternatives;
- Enhance customer value by providing energy services not previously offered by the Company; and
- Promote technologies which are environmentally sensitive and minimize environmental damage to Hawaii's unique ecosystem.

In IRP-98, HELCO has elected to continue to maintain and develop the DSM resources identified in IRP-93. These resources include the approved existing energy efficiency programs described in Section 6.

9.1.2 Planned Tasks and Activities

In order to implement the DSM Action Plan, there are a number of activities that must continue to be accomplished.

- HELCO will continue to monitor the DSM programs for their effectiveness and will continue to identify methods by which the programs can be better targeted, implemented and administered. Evaluations should focus both on the process of implementation as well as the measurement of impacts.
- Programs will continue to be adjusted as the implementation process moves forward. The DSM plans must be flexible and allowed to change over the IRP cycle as experience with the DSM programs is developed.
- The Residential Direct-Install Effort (referred to as the Residential Retrofit Program in the 1996 and 1997 M&E Reports and A&S Reports) will make free energy efficiency measures available to qualified customers which include those with delinquent bills due to medical needs or other hardships. HELCO is working with community organizations, government and the company credit division to identify potential participating customers.
- Budget flexibility shall continue to be required as some programs will exceed their goals and others will fall short due to customer interest and market conditions.
- Baseline data collection efforts shall be implemented to strengthen the basis for DSM planning in the next IRP cycle. (The baseline data consist of the prototypical costs and energy usage characteristics of existing facilities and newly designed and built facilities that are used as the base cases in DSM program planning.) These information gathering efforts should focus on the data most critical to the development of the plan, and that which is subject to the greatest uncertainty in the plan development phase of the programs.

Several actions are included in the task and activity statement to reflect these concerns. First, an evaluation plan has been developed and implemented. This evaluation plan is dependent on the specific methods used to implement the program and will highlight the timing of evaluation efforts, the types of information to be produced, the data that must be collected in order to generate the measurements, and the costs of evaluation. This plan must continue to be conducted.

HELCO believes that the DSM plans must continue to be flexible and must continue to be adjusted as experience in DSM implementation is gained. To provide information to the Commission and interested parties on the progress and upcoming changes to the DSM program, HELCO has already filed Annual Program Modification and Evaluation (M&E) Reports on DSM activities for 1996 and 1997, in addition to the annual IRP and DSM Action Plan Updates. Another M&E Report will be filed in November 1998 covering program modifications to be implemented in calendar year 1999. To recover costs for the programs, HELCO has filed Annual Program Accomplishments and Surcharge (A&S) Reports in 1997 and 1998. The 1998 A&S Report, filed on March 20, 1998, provided information on program accomplishments, costs, shareholder incentives earned, and surcharge activity for calendar year 1997. The 1999 A&S Report will be filed in March 1999 covering calendar year 1998.

Finding the need to allow program flexibility to deal with the market between the annual program plan reasonable, the Commission approved HELCO's request to have the ability to: (1) carry unspent program funds forward into future program years; (2) decrease customer incentives during a program year if a program is significantly oversubscribed before the end of the program year; and (3) exceed a yearly program budget by not more than 25 per cent if a program is oversubscribed and lower incentive levels appear to reduce customer participation. As described in its two annual DSM reports, HELCO has found it necessary to utilize only the first of these abilities in the first year of program implementation.

Finally, HELCO recognizes that substantial amounts of baseline information gathering will be required for the next IRP, which will be filed three years after this IRP-98 is filed. Since these activities are closely linked with the measurement and evaluation activities, a baseline information gathering plan was developed and implemented along with the measurement and evaluation plans.

The implementation steps now under way and that will continue include:

1. *Ongoing Staffing, Training, and Program Procedures.*

2. *Ongoing Measurement and Evaluation Activities.* Two reports are to be filed at the end of every even-numbered year. (See Table 9-1 for reporting schedule.) The Commercial and Industrial Impact Evaluation Report will report on the measurement and evaluation of the savings achieved by the commercial and industrial sector programs. The Residential Impact Evaluation Report will report on the measurement and evaluation of the actual savings achieved by the residential sector programs.

3. *Prepare Annual Reports* - Two reports are to be filed in each year. The Annual Program Modification and Evaluation Report, intended to be filed in the Fall of each year, will propose modifications to the program design, marketing, and implementation strategy. It will also set new goals for the coming year and establish budgets. Evaluation results for the previous year will also be introduced through this report.
   The second report is the Annual Program Accomplishments and Surcharge Report. This report, intended

to be filed in the Spring of each year, describes the accomplishments of the program and reassesses the cost-effectiveness of the DSM programs. Costs will be reported for the previous year, and surcharges necessary to recover the current year's projected expenditures for the DSM program, reconciliation of the previous year's over or under collection of DSM-related costs, and resulting lost margins will be proposed. In addition, the surcharge for the previous year's shareholder incentive will be calculated.

4. *Prepare Next IRP Plan.* Activities are being considered to develop the DSM programs for the next IRP.

Based on these tasks, a schedule for DSM plan implementation is provided in Table 9-1.

In order to mitigate the risks described in Section 6 with respect to the DSM programs, HELCO has undertaken, and will continue to undertake, the following efforts:

- *Baseline Data Collection* - A substantial baseline data collection effort will continue to be undertaken to 1) prepare information for the next IRP cycle, 2) support program planning as information becomes available, and 3) support market assessment and demand forecasting efforts. The baseline data collection plan, prepared and filed with the evaluation plan, will continue to be implemented in order to coordinate data collection efforts and reduce costs.

- *Measurement and Evaluation* - Considerable measurement and evaluation efforts are being undertaken as part of the programs. These

Table 9-1. Projected Schedule of DSM Plan Implementation

Task	Start	End
1. Ongoing Staffing, Training, & Program Procedures	11/15/95	On-going
1.1 Hire Staff & Acquire Contractors as Required	11/15/95	On-going
1.2 Conduct Training as Required	11/15/95	On-going
2. Ongoing Measurement & Evaluation Activities	1/1/98	7/1/03
2.1 1998 M&E Activities	1/1/98	6/30/98
2.2 1999 M &E Activities	1/1/99	6/30/99
2.3 2000 M&E Activities	1/1/00	6/30/00
2.4 2001 M&E Activities	1/1/01	6/30/01
2.5 2002 M&E Activities	1/1/02	6/30/02
2.6 2003 M&E Activities	1/1/03	6/30/03
3. Prepare Annual Reports	6/1/98	4/1/03
3.1a 1998 Program Modification and Evaluation Report	6/1/98	11/1/98
3.1b 1999 Program Accomplishments and Surcharge Report	1/1/99	4/1/99
3.2a 1999 Program Modification and Evaluation Report	6/1/99	11/1/99
3.2b 2000 Program Accomplishments and Surcharge Report	1/1/99	4/1/00
3.3a 2000 Program Modification and Evaluation Report	6/1/99	11/1/00
3.3b 2001 Program Accomplishments and Surcharge Report	1/1//00	4/1/01
3.4a 2001 Program Modification and Evaluation Report	6/1/00	11/01/01
3.4b 2002 Program Accomplishments and Surcharge Report	1/1/01	4/1/02
3.5a 2002 Program Modification and Evaluation Report	6/1/01	11/01/02
3.5b 2003 Program Accomplishments and Surcharge Report	1/1/02	4/1/03
4. Prepare Next IRP Plan	1/1/00	9/1/01

evaluations will continue to be used not only to measure the impacts of the programs, but also to diagnose what aspects of the programs are working well and which parts can be improved. One component of the effort will be a Net-to-Gross Study. This study will attempt to determine what portion of each program's participants are freeriders - participants who would have installed the measure even if the program had not been available. The study will rely on interviews and surveys of a sampling of participants to ascertain the actual impact of the programs on their actions.

- *Work with Vendors and Contractors* - Even before the programs were officially rolled out, HELCO worked successfully with vendors and contractors to identify and resolve problems in the DSM programs. HELCO expects to increase the frequency of contact with these trade allies to be able to monitor problems that can occur and identify actions HELCO can take to assure performance from the trade allies.

- *Research and Development* - Some of the concerns about equipment performance stem from the lack of operating data in the Hawaii environment. Thus, HELCO will initiate, where appropriate, pilot programs or exploratory research to determine the viability of DSM options and identify appropriate design options for Hawaii. HELCO has already completed pilot lighting programs in the commercial and industrial and residential sectors. A potential future pilot program will look at residential load control in conjunction with HECO's planned Residential Load Control (RLC) DSM program.

- *Load Management DSM Programs* - HELCO has elected not to pursue load management DSM programs at this time. Instead, it will focus its efforts on acquiring additional curtailed loads in load management rates and rate riders.

- *Annual Program Plans* - Finally, because DSM is a new enterprise to Hawaii and HELCO, HELCO will continue to update program plans on an annual basis. The purpose of the updates is to modify the programs in order to best acquire the DSM resource based on lessons learned from operation of the programs.

9.1.3 Impacts

The recorded 1996 and 1997 incremental impacts, the short-term forecasted 1998 incremental impacts, and the intermediate-term 1999-2003 incremental impacts of the DSM Action Plan are provided in Tables 9-2 and 9-3. The 1996 and 1997 incremental impacts, as well as the short-term forecasted 1998 incremental impacts, were obtained from the 1998 A&S Report filed on March 20, 1998. The 1996, 1997, and 1998 impacts have been adjusted to the net generation level assuming a total loss factor of 11.68% of gross generation and a system loss factor of 8.64% of net generation. (E.g., from Table I of the 1998 A&S Report, the 1997 system level impacts for the CIEE program were 2.999155 GWh and 0.384 MW, net of free riders. These values were multiplied by [1-11.68%]/[1-8.64%], or 96.673%, to obtain the values in Tables 9.2 and 9.3 respectively.) The intermediate-term 1999-2003 incremental impacts were derived from Section 6, Assessment of Demand-Side Resources. After 1999, the incremental impacts were obtained by subtracting prior year cumulative impacts (e.g. the 2000 incremental impacts for the CIEE program was derived by subtracting 4.10-1.66 GWh and 0.58-0.30 MW).

A major factor that could alter the DSM Action Plan is the advent of a significant level of wholesale and retail electricity market competition. Since the costs of the energy efficiency programs (i.e. the CIEE, CINC, CICR, and REWH programs), in conjunction with their associated sales reductions, result in higher rates, HELCO would have to take into serious consideration the rate impacts of these programs on HELCO's competitive position.

In its 1997 Contingency Plan Update, HELCO elected not to pursue load management DSM programs at this time. Instead, it will focus its efforts on acquiring additional curtailed loads in load management rates and rate riders.

9.1.4 Expenditure Schedules

The recorded 1996 expenditures, estimated 1997 expenditures, and forecasted 1998-2003 expenditure schedules for the programs in the DSM Action Plan are provided below in Tables 9-4 through 9-7.

As explained in the previous section, the advent of significant wholesale and retail electricity market competition may alter the expenditure schedules for all energy efficiency programs.

Table 9-2. Summary of DSM Action Plan Incremental Energy Savings (GWh)

Program	1996	1997	1998	1999	2000	2001	2002	2003
CIEE	1.35	2.90	2.68	1.66	2.44	2.17	3.16	2.05
CINC	0.11	0.72	0.56	0.30	0.70	0.90	1.60	1.20
CICR	0.02	0.24	0.23	0.40	1.08	0.81	0.84	0.88
REWH	0.48	1.07	1.75	0.64	1.14	1.11	1.60	1.05
HESH	3.24	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Total	5.20	4.93	5.23	3.00	5.36	4.99	7.20	5.18

Table 9-3. Summary of DSM Action Plan Incremental Peak Impacts(MW)

Program	1996	1997	1998	1999	2000	2001	2002	2003
CIEE	0.198	0.371	0.409	0.300	0.280	0.250	0.160	0.210
CINC	0.018	0.082	0.079	0.100	0.100	0.200	0.100	0.200
CICR	0.005	0.037	0.037	0.100	0.110	0.120	0.120	0.130
REWH	0.121	0.260	0.433	0.250	0.240	0.230	0.220	0.230
HESH	1.273	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Total	1.615	0.750	0.958	0.750	0.730	0.800	0.600	0.770

Table 9-4. Expenditure Schedule for CIEE Program ($000)

Expense Type	1996	1997	1998	1999	2000	2001	2002	2003
Incentives	91	201	200	96	89	85	83	83
Direct Labor	27	32	59	59	61	63	65	67
Outside Services	177	192	357	263	270	279	288	298
Advertising/Marketing	25	30	51	53	55	56	58	60
Materials, Travel, & Misc.	21	11	10	10	10	10	11	11
Total	342	466	676	481	484	493	505	519

*Expected 1998 expenditures are as provided in the 1998 A&S Report. Expenditures for 1999-2003 are as provided in Chapter 6.

Table 9-5. Expenditure Schedule for CINC Program ($000)

Expense Type	1996	1997	1998	1999	2000	2001	2002	2003
Incentives	12	73	60	147	149	206	229	247
Direct Labor	6	12	12	12	12	13	13	13
Outside Services	25	34	77	60	61	63	65	67
Advertising/Marketing	-	9	10	10	10	11	11	11
Materials, Travel, & Misc.	0	0	2	2	2	2	2	2
Total	44	128	161	230	235	294	320	341

*Expected 1998 expenditures are as provided in the 1998 A&S Report. Expenditures for 1999-2003 are as provided in Chapter 6.

Table 9-6. Expenditure Schedule for CICR Program ($000)

Expense Type	1996	1997	1998	1999	2000	2001	2002	2003
Incentives	2	19	40	45	48	50	52	55
Direct Labor	3	9	6	6	6	6	6	7
Outside Services	12	24	61	30	31	32	33	34
Advertising/Marketing	-	7	10	10	10	11	11	11
Materials, Travel, & Misc.	0	1	1	1	1	1	1	1
Total	18	60	117	91	95	99	103	107

*Expected 1998 expenditures are as provided in the 1998 A&S Report. Expenditures for 1999-2003 are as provided in Chapter 6.

Table 9-7. Expenditure Schedule for REWH Program ($000)

Expense Type	1996	1997	1998	1999	2000	2001	2002	2003
Incentives	173	393	547	275	268	257	251	248
Direct Labor	65	57	57	57	59	61	63	65
Outside Services	414	258	303	216	237	245	253	262
Advertising/Marketing	42	56	59	59	61	63	65	67
Materials, Travel, & Misc.	12	11	62	37	38	39	41	42
Total	706	775	1,029	659	662	665	672	683

*Expected 1998 expenditures are as provided in the 1998 A&S Report. Expenditures for 1999-2003 are as provided in Chapter 6.

**1996 Expenses include HESH costs of $204,401.

9.2 SUPPLY-SIDE ACTION PLAN

9.2.1 Overview

Hawaii Electric Light Company, Inc. ("HELCO") last updated its five-year action plan for Supply Side Resource Options ("SRO") in the IRP Annual Evaluation in July 1997 in Docket No. 7259. This update of the SRO Action Plan includes an update of HELCO's SRO activities and expenditures scheduled for implementation over the five-year period 1999 - 2003.

HELCO's SRO action plan activities are focused on the planning for generating unit additions in the 1999 - 2003 service date time frame. Activities for the Keahole ST-7 unit fall within this time frame.

HELCO's next unit addition after Keahole ST-7 is a simple cycle combustion turbine targeted for installation in 2009 and identified as DTCT-PH1. The current plans call for this unit to be installed at a new West Hawaii generation site. Included in the SRO action plan are the site selection and site acquisition efforts to support this DTCT-PH1 unit.

HELCO has also included a plan to further investigate the cost effectiveness of distributed generation utilizing 1 MW diesel engines.

Renewable energy activities are also provided.

9.2.2 SRO Action Plan Activities

1. Keahole ST-7
   The current plans for the installation of ST-7 and the subsequent conversion of CT-4 and CT-5 into a dual trained combined cycle unit call for a service date of 2006. Although the planned service date for ST-7 falls outside the scope of the 5-year action plan, project activities such as permitting and engineering need to occur within the 5-year planning period.

   A summary of the estimated annual expenditures for the Keahole project is provided in Table 9-8.

2. West Hawaii Site Acquisition
   HELCO's current base plan includes the phased installation of a dual trained combined cycle plant to be located at a new site in West Hawaii. The first two phases, simple cycle combustion turbines CT-6 and CT-7 have target service dates of 2009 and 2012 respectively. Although these service dates fall well outside the scope of the five-year action plan period, HELCO will begin efforts to select and acquire the new West Hawaii site within the five-year action plan period with the intent of securing the new site prior to initiating permitting and engineering efforts on the CT-6 unit.

   Siting studies for this West Hawaii unit began with the 1988 West Hawaii Site Study. Since that time, HELCO has worked with landowners of the top sites recommended by the 1988 Study, as well as landowners for areas not included in the initial study, to acquire

Table 9-8. Summary of Keahole ST-7 Expenditures ($000)

Resource	Prior Years	1999	2000	2001	2002	2003	Future Years	Total
Keahole ST-7	898	0	100	0	0	0	40,508	41,506

a site for development of the power generation facility. Once the issues of concern are addressed with the landowners, HELCO plans to conduct a site evaluation study which is intended to select the most suitable site for HELCO's long term generation needs in West Hawaii.

A summary of the major milestones is provided in Table 9-9.

A summary of the estimated annual expenditures for the West Hawaii site acquisition activities is provided in Table 9-10. Costs are shown in 1998 dollars with no AFUDC.

As stated in HELCO's June 1998 Generation Resource Contingency Plan Update, if CT-4 and CT-5 are installed by early 1999, but the Encogen PPA is not approved, or is terminated, one of HELCO's contingency options is to install generation at a new West Hawaii site. Or, if CT-4 and CT-5 and the Encogen facility are delayed, one of HELCO's options is to install new capacity at a new site. [54] If this contingency option is implemented, HELCO may have to acquire the West Hawaii site sooner than indicated in the schedule presented in Table 9-9.

3. Distributed Generation
HELCO's initial analysis in IRP-98 shows that distributed generation in the form of 1 MW diesel engines has the potential to be cost effective. IRP-98 evaluated the case where multiple 1 MW diesels are added in 2009 to defer the next generating unit after ST-7. Some of the potential benefits include the ability to defer large capital additions, flexibility to add generation commensurate with load growth, potential to manage rate impacts, ability to provide T&D benefits depending on location, and quick start capability.

In order to conduct a more refined analysis of the use of distributed generation, HELCO plans to conduct studies to identify sites which can be prime candidates for distributed generation. This will allow HELCO to better define site specific costs such as permitting, interconnection, fueling, and overall design. Once sites are identified, specific T&D and other system benefits can also be assessed. These costs and benefits could then be

Table 9-9. Summary of Major Milestones for West Hawaii Site Acquisition

Complete site acquisition negotiations	2002
File PUC application to acquire site	2003
Receive PUC approval to acquire site	2004

Table 9-10. Summary of West Hawaii Site Acquisition Expenditures ($000)

Resource	Prior Years	1999	2000	2001	2002	2003	Future Years	Total
West Hawaii Site Acquisition	0	50	50	50	50	50	950	1200

[54] HELCO Generation Resource Contingency Plan Update #4, Docket No. 96-0029, June 1998, p. 19.

compiled and analyzed against the costs used in the IRP planning analysis to determine if distributed generation should be implemented. The study is planned to be initiated in 2002 and completed by 2003 such that the results of the study can be used in HELCO's 2004 IRP. Evaluation in the 2004 IRP should allow sufficient time for possible implementation of distributed diesels in the 2009 timeframe. Costs to complete such a study should not exceed $50,000.

4. Renewable Resource Acquisition
To increase renewable energy development and public awareness and to meet state policy objectives for the increased use of renewable energy, HELCO will continue to pursue a renewable energy installation. In the event that current negotiations with renewable energy developers for a wind farm and photovoltaic facility do not result in a power purchase agreement, HELCO will consider the purchase of a wind project and/or a photovoltaic project from other renewable energy developers and manufacturers through the following options:

a. Renewable Resource Request for Proposal (RFP) — HELCO will develop a Renewable RFP to invite renewable developer(s) to submit a proposal to provide energy to the HELCO system in return for payments at or below HELCO's avoided energy cost;
b. Green Pricing Expansion — HELCO will expand and extend the current Green Pricing program filed with the PUC to include a wind and/or photovoltaic projects. HELCO customers will be given the choice to pay a premium for these renewable resources; or
c. Utility Installation — HELCO will consider a wind and/or a photovoltaic project as part of its utility-owned electrical generating system.

Table 9-11 shows a summary of the major milestones for the Renewable Resource Acquisition work effort. Table 9-12 shows an expenditure schedule for the Renewable Resource Acquisition.

5. Renewable Energy Activities
The following renewable energy activities will continue throughout the IRP five-year action plan.

Table 9-11. Summary of Major Milestones for Renewable Resource Acquisition

Complete on-going negotiations[1]	December 1999
Evaluate renewable resource acquisition options[2]	January 2000
Develop renewable energy acquisition option	January 2001
Implement renewable resource acquisition option	January 2002

[1] estimated milestone date—negotiations may be completed earlier or may extend beyond milestone date
[2] only if current negotiations does not result in a power purchase agreement

Table 9-12. Expenditure Schedule Renewable Resource Acquisition ($000)

	Previous	1999	2000	2001	2002	2003	Later	Total
Labor	90	25	26	27	29	30	0	227
Non-Labor	0	15	66	36	24	25	0	166
TOTAL	90	40	92	63	53	55	0	393

a. PUC Renewable Energy Action Plan Implementation
HELCO will continue its commitment to assist in renewable energy development as presented in the PUC Renewable Energy Resource Investigation, Docket No. 94-0226. HELCO's renewable energy work efforts as documented in the docket report are listed below:

1) Implement demand-side management ("DSM") programs that utilize solar renewable resources, and that shift load from on-peak to off-peak periods.
Accomplishment: HELCO is implementing this DSM program.
Future: HELCO will continue this program.
Schedule: on-going
2) Streamline and simplify the permitting process for renewable resources.
Accomplishment: HECO has met with Department of Business, Economic Development & Tourism (DBEDT, lead agency) on this issue.
Future: HECO and its subsidiaries will work with DBEDT this issue.
Schedule: on-going
3) Facilitate (through the purchase of power) the implementation of renewable projects that are currently cost-effective.
Accomplishment: HELCO is currently negotiating with several renewable developers.
Future: HELCO will continue to work to complete these negotiations. In the event that current negotiations with renewable energy developers for a wind farm and a photovoltaic facility does not result in power purchase agreements, HELCO will consider the purchase of a wind project and/or a photovoltaic project from other renewable energy developers and/or manufacturers (see p. 9-9).
Schedule: on-going
4) Participate in and monitor on-going renewable energy research, development and demonstration ("RD&D") projects.
Accomplishment:
a) A 1.5 kW demonstration remote photovoltaic system has been installed at the Ahalanui County Beach Park.
b) A 15 kW grid-connected photovoltaic system located on the County of Hawaii Kona gymnasium has been operational since 1995.
c) A pilot program has begun to evaluate remote photovoltaic residential and lighting technologies.

Grant monies have been secured from Federal sources including Sandia National Laboratories and the UPVG to supplement the cost of these activities.
Future: HELCO will continue to examine potential projects. HELCO will also consider a demonstration wind turbine at its Lalamilo wind farm.
Schedule: on-going
5) Develop and implement a limited number of RD&D projects targeted to Hawaii-specific barriers.
Accomplishment: HELCO assisted the Pacific International Center for High Technology Research work on the wind/battery/pumped storage hydroelectric demonstration facility. Unfortunately, the operation of the wind/pumped storage hydroelectric system was not completed.
Future: HELCO will explore funding options that could be used for the completion of the wind/pumped storage hydroelectric

project and will continue to examine potential projects.
Schedule: on-going

6) Implement a "Green Pricing" program.
Accomplishment: HECO and its subsidiaries' Sun Power for Schools pilot program is in place. A pool of funds from the utilities, customer contributions, and Federal government are directed towards the photovoltaic installations at public high schools. Two-kW photovoltaic systems have been installed at Kaimuki, Waianae, and McKinley High Schools on Oahu. One-kW systems are installed at Baldwin (Maui) and Kealakehe (Hawaii) High Schools.
Future: Similar installations are planned for Waipahu, Campbell, Mililani, and Waialua on Oahu, Molokai High School on Molokai, and Hilo High School on the Big Island in 1998. HELCO will also examine an expanded "Green Pricing" program as part of the Renewable Resource Acquisition option (see p. 9-9).
Schedule: 2000

7) Improve evaluation and consideration of beneficial impacts of renewable energy resources in utility resource planning processes.
   - quantify externalities in IRP process, if and to the extent feasible, with input of Externalities Advisory Group.
     Accomplishment: HECO and its subsidiaries completed the Externalities Workbook and it was submitted to the PUC. IRP modeling runs were made using the externality information.
     Future: HELCO used the externality information in the IRP evaluation.
     Schedule: completed
   - consider models and criteria that are sensitive to contribution to as-available renewable resources and distributed generation to system reliability.
     Accomplishment: HECO and its subsidiaries are examining the limitations with its present model and potential for other commercial models.
     Future: HECO and its subsidiaries will model selection and evaluate probabilistic parameters.
     Schedule: on-going
   - participate in and monitor renewable energy demonstration projects, and analyze the potential for distributed and remote applications for photovoltaic.
     Accomplishment: HELCO has completed a preliminary market survey of potential off-grid applications on the island. Three different sized photovoltaic modules have been built and tested at a number of off-grid sites. HELCO has also tested a number of photovoltaic area lighting demonstrations at off-grid locations.
     Future: HELCO will pursue photovoltaic applications as part of its regular service to its customers.
     Schedule: on-going
   - undertake or update studies to determine the level of intermittent power that each island can absorb.
     Accomplishment: HELCO has completed wind penetration studies for the Big Island. There is a limit on the amount of wind turbines that the present system can accommodate.
     Future: HELCO will examine how this information will be

used in the planning process. HELCO will also explore funding options that could be used for the completion of the wind/pumped storage hydroelectric demonstration project and will continue to examine potential projects.
Schedule: 1999

- continue IRP analyses of energy storage systems.
  Accomplishment: HELCO continues to examine energy storage systems (i.e., battery energy storage and pumped storage hydroelectric).
  Future: HELCO will explore funding options that could be used for the completion of the wind/pumped storage hydroelectric project and will continue to examine potential projects and will continue to examine energy storage technologies.
  Schedule: on-going

b. Education
HELCO will increase its commitment to educate our customers on renewable energy technologies through our Consumer Lines bill stuffers, school programs, HELCO In Your Community fairs, Speaker's Bureau, and other methods.

c. Assessment and Evaluation
HELCO will continue to evaluate and assess renewable energy resources and technologies. Proper evaluation of renewable energy resources and technologies require access to accurate and reliable information. This can be accomplished by reviewing renewable energy newsletters, journals and reports, etc. HELCO will also continue membership in renewable energy organizations (i.e., Electric Power Research Institute renewable energy group; Utility Photovoltaic Group, Photovoltaics for Utilities, and other wind, solar, hydrogen, geothermal, energy organizations).

HELCO will continue to coordinate, communicate and interact with other local, state, and federal and international renewable energy technology development activities. This includes groups such as Electric Power Research Institute, national laboratories, U. S. Department of Energy, renewable energy developers, other utilities (Sacramento Municipal Utility District, Central and South West, Northern States Power, and others), universities, international organizations and other groups. HELCO will attend, when appropriate, renewable energy workshops, seminars, and conferences.

d. Research, Development, and Demonstration
HELCO will examine and, if prudent, develop the renewable energy technology through small-scale demonstration and pilot projects or expand existing demonstration or pilot projects in situations where knowledge can be gained through hands-on experience. Cost-sharing, joint ventures, or other forms of partnerships (from Electric Power Research Institute, national laboratories, U. S. Department of Energy, renewable energy developers, other utilities, etc.) will be sought in these types of projects when it is appropriate.

HELCO will continue to examine potential sites for appropriate renewable energy technologies.

Hawaii Electric Light Comnany, Inc. • PO Box 1027 • Hilo, HI 96721-1027

March 31, 2004

Warren H. W. Lee, P.E.
President

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PUBLIC UTILITIES COMMISSION

The Honorable Chairman and Members of
the Hawaii Public Utilities Commission
Kekuanaoa Building
465 South King Street, 1st Floor
Honolulu, Hawaii 96813

Dear Commissioners:

Subject: Docket No. 97-0349
HELCO IRP-2 Plan

Pursuant to Order No. 20792, filed February 4, 2004, attached is HELCO's IRP-2 Evaluation Report.

Sincerely,

Attachment

cc: Division of Consumer Advocacy
A. M. Oshima, Esq.
S. P. Golden

INTEGRATED RESOURCE PLAN 1999-2018

2004 EVALUATION REPORT

Docket No. 97-0349

March 2004

Hawaii Electric Light Company, Inc.

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EXECUTIVE SUMMARY

Hawaii Electric Light Company, Inc (HELCO) filed its second and most recent integrated resource plan (IRP-2 plan) in September 1998. This Evaluation Report provides an update of the recent developments and events, including changes in forecasts, since the filing of HELCO's IRP-2 plan that may or will have a significant impact on HELCO's IRP plan, and provides an update of HELCO's IRP supply-side and demand-side action plans. As described later in this report, HELCO is beginning its third IRP cycle (IRP-3) and therefore the focus of this report is on the near-term (2004-2006) resource plan action items with the intent that longer-term resource planning issues will be addressed in HELCO's IRP-3 process.

ES.1 Introduction

Integrated Resource Planning (IRP) is the planning process required of each energy utility in the State of Hawaii to systematically and thoroughly develop long-range plans for meeting Hawaii's future energy needs. IRP evaluates and integrates both resources that *supply* electricity and resources that reduce or better manage the *demand* for electricity. The IRP plan consists of a long-term 20-year preferred IRP resource plan, and also near-term 5-year IRP action plans.

HELCO filed its IRP-2 in September 1998. The HELCO IRP-2 preferred IRP resource plan included a mix of resources that included, among other things, the continuation of demand-side management programs for 20 years, retirement of certain existing generating units, and the installation of Hamakua Energy Partners' (HEP,formerly known as Encogen) 60 MW facility and two combustion turbines (Keahole CT-4 and CT-5).

A number of recent developments that may or will have a significant impact on HELCO's IRP plan have occurred since September 1998. This IRP-2 Evaluation Report provides an update of the demand-side and supply-side resources in HELCO's IRP-2 20-year preferred resource plan. This report also updates the supply-side and demand-side Program Implementation Schedules (or Action Plans). This includes demand-side management programs (e.g., energy efficiency and conservation), renewable energy, other new technologies such as distributed generation, and conventional generation activities in the period 2004 through 2008. On February 26, 2004, the PUC issued Order No. 20821, Docket No. 04-0046, which opened HELCO's IRP-3 cycle and ordered HELCO to submit its major review of its IRP plan no later than October 31, 2005. Given the amount of time that has elapsed since the filing of HELCO's IRP-2, a new IRP cycle is appropriate in which to take these impacts, including updated forecasts and planning assumptions, into account. Consequently, HELCO and the Consumer Advocate (CA) in HELCO's IRP-2 docket (Docket No. 97-0349) reached a stipulation that, among other things, allowed for the IRP-2 docket to be closed and proposed that HELCO's IRP-3 be filed no later than October 31, 2005.[1] The Commission, on February 4, 2004 in Order No. 20792, approved the parties' stipulation. Accordingly, the focus of this IRP-2 Evaluation report is on the near-term (2004 through 2006).

ES.2 Demand-side Management

HELCO began its four energy efficiency demand-side management (DSM) programs in 1996. These DSM programs promote technologies that help HELCO's customers use electricity more efficiently and thereby reduce their overall consumption of electricity. In addition to a nationally recognized residential solar water heating program, which is a part of the Residential Efficient Water Heating program for existing homes and new homes, three additional programs target commercial and industrial customers and provide incentives for the installation of energy efficient technologies such as chillers, motors, and lighting. The programs through December 2003 have reduced the peak demand for electricity on HELCO's system by an estimated 5.3 megawatts (MW).

Despite Hawaii's economic downturn during 1997 to 1998 and the increase in energy efficiency through HELCO's DSM programs, the demand for electricity continues to grow. HELCO's recorded system peak has increased from 166 MW in 1996 to 187 MW in 2003. This growth is forecasted to continue with an estimated demand for electricity of 214 MW in 2010. To help meet this expected demand and to continue to offer demand-side management options to its customers, HELCO plans to pursue the continuation of its existing energy efficiency DSM programs.

[1] The Gas Company (TGC), also a party to HELCO's IRP-2, did not enter into the stipulation. Instead, on January 9, 2004, TGC filed a letter with the PUC stating it received the stipulation and had no objections to the requested relief.

Originally, HELCO received Commission approval to conduct its four energy efficiency DSM programs until the end of 2001. HELCO subsequently received Commission approval in Amended Order No. 19094, issued December 11, 2001, to temporarily continue its four existing DSM programs beyond 2001. The Amended Order No. 19094 allows HELCO to continue its existing DSM programs until one year after the Commission makes a determination in Hawaiian Electric Company, Inc's (HECO's) next rate case of HECO's revenue requirements in an interim decision and order (D&O), or a final decision and order, whichever comes first. HECO intends to file its rate case application with the PUC by September 1, 2004.

ES.3 Renewable Energy

HELCO has been a strong supporter of renewable energy[2] in Hawaii. Geothermal, wind, run-of-river hydroelectric facilities, and solar water heating supplied HELCO with approximately 23% of its 2003 energy requirements. The Island of Hawaii has always had significant renewable energy development activities, and HELCO continues its efforts to incorporate more renewable energy resources into its electric grid system, while maintaining acceptable and reliable levels of service to all customers.

Since HELCO filed its IRP-2 in 1998, there has been an increased interest in renewable energy by policy makers at the local and national levels. In Hawaii, a Renewable Portfolio Standard (RPS) was enacted into law in 2001. RPS considerations will be addressed in HELCO's IRP-3 process.

Significant windfarm facilities are expected to be added to the HELCO system in the near-term. A power purchase agreement (PPA) between HELCO and Hawi Renewable Development (HRD) for a new windfarm was filed for approval by the Public Utilities Commission (PUC) on December 30, 2003. HELCO has been negotiating with Apollo Energy Corporation (AEC) for a power purchase agreement to purchase as-available wind energy from a proposed repowering of Apollo's Kamaoa facility. In total, it is estimated that approximately 10 to 24 MW of wind turbines could be added to the HELCO grid in the near future, which could more than triple the amount of wind energy currently on the HELCO system. Also, HELCO is evaluating repowering options at the Lalamilo windfarm.

[2] Renewable energy is energy from sources that are renewed or replenished through natural forces such as wind, solar, biomass (including municipal solid waste), and geothermal.

In addition to the wind farms described above, HELCO plans to support the use of renewable energy resources by initiating a run-of-river (no reservoir for storage) hydroelectric rehabilitation project. In September 2002, the 1.5 MW run-of-river generator at HELCO's Puueo hydroelectric plant was severely damaged. In August 2003, HELCO filed a PUC application to undertake and complete the Puueo Hydroelectric Plant Rehabilitation project, which sought to install a modern, more efficient turbine generator with a capacity of roughly 2.3 to 2.4 MW. The PUC approved the project in November 2003. Preliminary estimates indicate that the work to rehabilitate the Puueo facility can be completed in the 2005 timeframe.

On January 22, 2004, Renewable Hawaii Inc. (RHI), a subsidiary of the HECO companies, released a renewable energy request for project proposal (RE RFPP) for the Big Island of Hawaii. This RE RFPP seeks to increase the amount of renewable energy resources on the island by providing passive investment in cost-effective, commercial renewable energy projects. Proposals to this RE RFPP are due by April 22, 2004.

To facilitate development of renewable energy technologies, HELCO has installed a 5.4 KW photovoltaic net energy metering project at their Kailua baseyard and will install a 38 KW photovoltaic project at the NELHA gateway facility (expected to be in operation by mid 2004).

ES.4 Distributed Generation

Distributed generation (DG) is the application of small generators, typically ranging in capacity from a dozen to several thousand kWs and scattered throughout a power system, to provide the electric power needed by electric consumers. As ordinarily applied, the term *distributed generation* includes the use of small electric power generators, whether utilizing fossil fuels or renewable energy resources, located at a utility site or at a customer site, which is either connected to the utility's power grid or off-grid (not connected). In Order No. 20582 filed on October 21, 2003, the PUC opened Docket No. 03-0371 instituting a proceeding to investigate distributed generation in Hawaii.

As an example of DG, customers with large heating or air-conditioning loads may benefit from the use of waste heat generated by a DG resource located at a customer site. The waste heat could be used to heat water and/or through an absorption chiller, to drive an air-conditioning system, reducing the energy that would otherwise be needed for these functions. These applications, referred to as Combined Heat and Power (CHP) applications, can be economical given the right customer site and project. Generally, most of the current CHP systems remain connected to the utility grid as back up or to obtain the additional power needed beyond what is produced on site.

HELCO, together with HECO and Maui Electric Company, Ltd (MECO), recently analyzed the economics of utility-owned, customer-sited CHP systems and have found them to be an attractive resource in certain situations. Consequently, HELCO believes that CHP units will begin to play a larger role in the Big Island's energy future and filed an application for a CHP Program with the PUC on October 10, 2003, Docket No. 03-0366. Additional details regarding the CHP Program are available in Section 3.2.2 of this report. In Order No. 20831, filed March 2, 2004, the Commission suspended HECO, MECO, and HELCO's application for the Utility CHP program. Thus, HELCO will have to file applications for approval of contracts entered into under Rule 4 of its Tariffs for the installation of CHP projects on a customer-by-customer basis. It is very difficult for HELCO to forecast the rate at which customer-site CHP projects will proceed, although the pace will undoubtedly be slower than if HELCO was authorized to proceed with its CHP Program at this time. With the suspension of HELCO's CHP Program application, there is greater uncertainty as to how soon utility CHP systems can be installed.

ES.5 Keahole Status

HELCO had been endeavoring for several years to install at its Keahole power plant two 20 MW combustion turbines (CT-4 and CT-5), followed by an 18 MW heat recovery steam generator (ST-7) as specified in the action plans from IRP-1 and IRP-2. The construction of CT-4 and CT-5 commenced in April 2002 after HELCO had obtained a final air permit and the Circuit Court had lifted a stay on construction. However, in a Final Judgment dated November 7, 2002, the Third Circuit Court of the State of Hawaii suspended the construction at Keahole.

On November 6, 2003, a settlement agreement was signed by most, but not all, of the parties to the various proceedings affecting the Keahole power plant and its proposed expansion. On November 12, 2003, the Third Circuit Court of the State of Hawaii issued a ruling to vacate the Final Judgment dated November 7, 2002, which has allowed construction at Keahole to resume as long as the conditions of the settlement agreement are met.

On November 25, 2003, HELCO filed a Petition For Land Use District Boundary Amendment with the State of Hawaii Land Use Commission to amend the land use classification of certain lands at Keahole from the Conservation District to the Urban district. This reclassification is necessary for the installation of ST-7 with selective catalytic reduction emissions control equipment.

It is expected that CT-4 and CT-5 will go online in the second quarter of 2004 and be fully operational by year-end 2004. HELCO has retired diesel units D18-19 in February 2004 and will retire D20 at Keahole in accordance with the air permit requirements for CT-4 and CT-5.

ES.6 Updated IRP Resource Plan

HELCO has updated its forecasts and planning assumptions since it filed its IRP-2. The following is a summary comparison of the changes that have occurred:

Table ES.6-1
Comparison of Assumptions: IRP-2 and 2003 IRP-2 Evaluation Report

IRP-2	*2004 IRP-2 Evaluation Report*
• September 1997 Sales and Peak Forecast	• May 2003 Sales and Peak Forecast
• May 1998 Fuel Price Forecast (IRP Supplement)	• July 2002 Fuel Price Forecast
• Acquired DSM program impacts for 1996	• Acquired DSM program impacts from 1996 to 2003
• DSM impact estimates for 1998 – 2018 as of August 1997	• DSM impact estimates for 2004 – 2018 as of April 2003
• No Utility or 3rd Party CHP	• Includes Utility and 3rd Party CHP
• Keahole CT-4 and CT-5 operational in 1998	• Keahole CT-4 and CT-5 operational in 2004
• HEP (formerly Encogen) operational in 1999	• HEP operational in 2000
• 13 HELCO diesel units, Kanoelehua CT-1, and Shipman 1 retired after HEP and Keahole CT-4 and CT-5 are operational	• Waimea D8-10 and Shipman 1 retired in 2002. Keahole D18-19 were retired in February 2004 and D20 to be retired in accordance with Keahole CT-4 and CT-5 air permit requirements
• Puna steam unit placed on cold standby after HEP and Keahole CT-4 and CT-5 are operational	• No units placed on cold standby
• Expiration of HCPC PPA on December 31, 1999	• Uncertainty of HCPC PPA termination on December 31, 2004
• Retirement of Shipman 3 and Shipman 4, in 2005 and 2008, respectively	• Retirement of Shipman 3 and Shipman 4 deferred due to the uncertainty of Keahole installation
	• Installation of a new Hawi Renewable Energy wind farm in 2005
	• Rehabilitated Puueo Hydro returned to service in 2005

This IRP-2 Evaluation report provides a current look at HELCO's IRP resource plan, incorporating recent events including HELCO's Keahole power plant expansion situation, and analyzes the changes in forecasts and assumptions upon which the IRP plan and actions plans are based.

The results of this updated analysis and assessment indicate four significant resource considerations in the near-term that may occur before the next IRP major review is completed. First, CT-4 and CT-5 are expected to be on-line in the second quarter of 2004 and fully operational by year-end 2004.

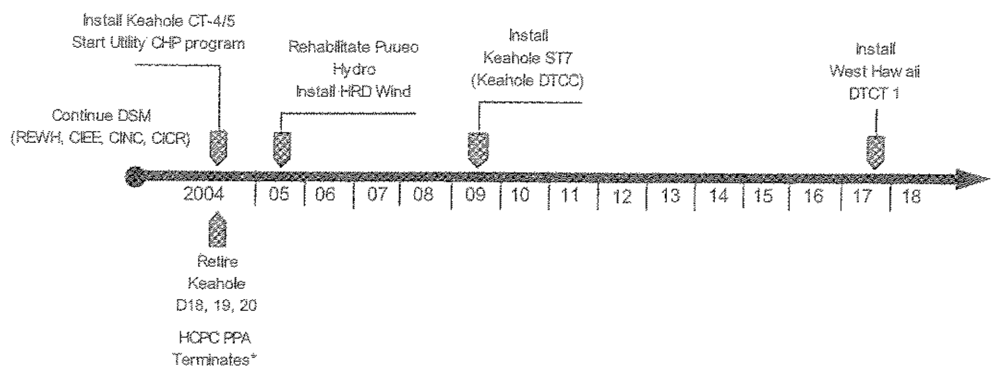
Second, the five-year term of HCPC's Second Amended and Restated Purchase Power Agreement (PPA) will end on December 31, 2004. After 2004, the PPA can continue on a year-to-year basis with either HCPC or HELCO able to terminate the contract by providing written notice by May 30th of the termination year. Any decision to give notice of termination would be based on the facts and circumstances at the time. The decision of whether or not to terminate the HCPC PPA will be reflected in HELCO's IRP-3 supply-side resource update.

Third, HELCO anticipates installing Keahole ST-7 (and converting CT-4 and CT-5 to a dual train combined cycle) in the 2009 timeframe, which necessitates that various older generating units that were previously targeted for retirement will no longer be retired. These older units are already permitted and grid-connected so that they can mitigate some of the uncertainty in the schedule for adding new generation. Also, a 5-year generation asset management program has been implemented in 2003.

Fourth, HELCO plans to pursue maintaining its current level of commitment to DSM and analyzing new DSM as part of IRP-3, while developing the new and emerging CHP market. Both the DSM and CHP programs have the potential to mitigate some of the uncertainty in the schedule for adding new generation, depending on how fast they can be ramped up.

The figure below illustrates the timing of demand side resources, renewable resources, central station resources and combined heat and power resources discussed in previous sections. (The Apollo repowering/expansion project is not yet included, because a PPA has not been finalized.)

HELCO IRP-98 MODIFIED PREFERRED INTEGRATED RESOURCE PLAN (2004-2018)



Legend:

DTCC - Dual Train Combined Cycle
DTCT - Combustion Turbine
DTST - Steam Turbine with conversion of DTCTs to Combined Cycle
REWH - Residential Efficient Water Heating
CIEE - Commercial and Industrial Energy Efficiency
CINC - Commercial and Industrial New Construction
CICR - Commercial and Industrial Customized Rebate

*NOTE: The five year term of HCPC's Second Amended and Restated PPA will end on December 31, 2004. After 2004, it the PPA can continue on a year-to-year basis with either HCPC or HELCO able to terminate the contract by providing written notice by May 30th of the termination year..

ES.7 Conclusion

This IRP-2 Evaluation report provides updated information on the key demand-side and supply-side elements in HELCO's IRP-2 resource plan, and assesses the continuing validity of the forecasts and assumptions upon which the IRP plan and action plans were fashioned, with a focus on the near-term (2004-2006) planning period.

To meet HELCO's near-term future energy needs, a portfolio of resources will be required. Demand-Side resources allow both commercial and residential customers to reduce electricity usage, and help to defer the need for additional generation. Increased renewable energy generation from as-available resources will reduce the consumption of fossil fuels. HELCO and non-utility central station resources will continue to provide firm power in order to meet the growing demand for electricity. Lastly, it is also estimated that customer-sited CHP units will begin to play a larger role in Hawaii's energy future.

HELCO is currently in the process of commencing with the next major review of its IRP plan (IRP-3), which will result in a comprehensive re-evaluation of all considerations in meeting both near-term and long-term future energy needs. All appropriate and feasible supply-side and demand-side resources will be examined, and all pertinent assumptions will be assessed in HELCO's IRP-3 process, which is expected to be filed with the PUC by October 31, 2005, in Docket No. 04-0046.

1. INTRODUCTION

Integrated Resource Planning (IRP) is a planning process required of each energy utility in the State of Hawaii to systematically and thoroughly evaluate the choices for meeting Hawaii's future energy needs. The IRP Framework issued by the Hawaii Public Utilities Commission (PUC) contains the guidelines for the IRP process. The goal of Integrated Resource Planning as specified in the IRP Framework is:

> "...the identification of the resources or the mix of resources for meeting near and long term consumer energy needs in an efficient and reliable manner at the lowest reasonable cost."[3]

For an electric utility, "resources" supply electricity (e.g. supply-side resources such as conventional power plants and renewable energy installations) as well as reduce or better manage the demand for electricity (i.e. demand-side management, or DSM, resources such as energy efficiency and conservation programs). IRP is the process by which the electric utility integrates the planning for supply-side resources and demand-side resources into a plan to meet its customers' future electricity needs.

The IRP Framework requires utilities to submit a long-term resource plan (IRP plan) covering a 20-year planning period, and program implementation schedules or "action plans", covering a 5-year period. The resource plan shows both the demand-side and supply-side resources, and provides a chronological view of when they occur in the 20-year planning period. The action plans provide a more detailed look at the near-term activities for the resources in the 20-year planning period. HELCO currently has two action plans, one for demand-side resources and one for supply-side resources. Both the IRP plan and the action plans will be re-evaluated in HELCO's third IRP process, which commenced in January 2004, with four Ad Hoc working group meetings. Two initial meetings were held on January 8 (Kona) and January 9 (Hilo), with follow up meetings on January 29 (Hilo), and January 30 (Kona). On February 26, 2004, the PUC issued Order No. 20821, Docket No.

[3] Hawaii Public Utilities Commission, Decision and Order No. 11630, Docket No. 6617.

04-0046, which opened HELCO's third IRP (IRP-3) cycle and ordered HELCO to submit its major review of its IRP plan no later than October 31, 2005.

1.1 Framework Requirements for the Evaluation Report

Section III.D.3 of the IRP Framework requires HELCO to submit its IRP evaluation report as follows:

a. The utility shall include in its annual evaluation, an assessment of the continuing validity of the forecasts and assumptions upon which its integrated resource plan and its program implementation schedule were fashioned.

b. The utility shall also include for each program or phase of program included in the program implementation schedule for the immediately preceding year a comparison of:

   (1) The expenditures anticipated to be made and the expenditures actually made by cost categories and cost elements.

   (2) The level of achievement of objectives anticipated and the level actually attained.

   (3) The target group size or level of penetration anticipated for each demand-side management program and the size or level actually realized.

   (4) The effects of program implementation anticipated and the effects actually experienced.

c. The utility shall provide an assessment of all substantial differences between original estimates and actual experience and of what the actual experience portends for the future.

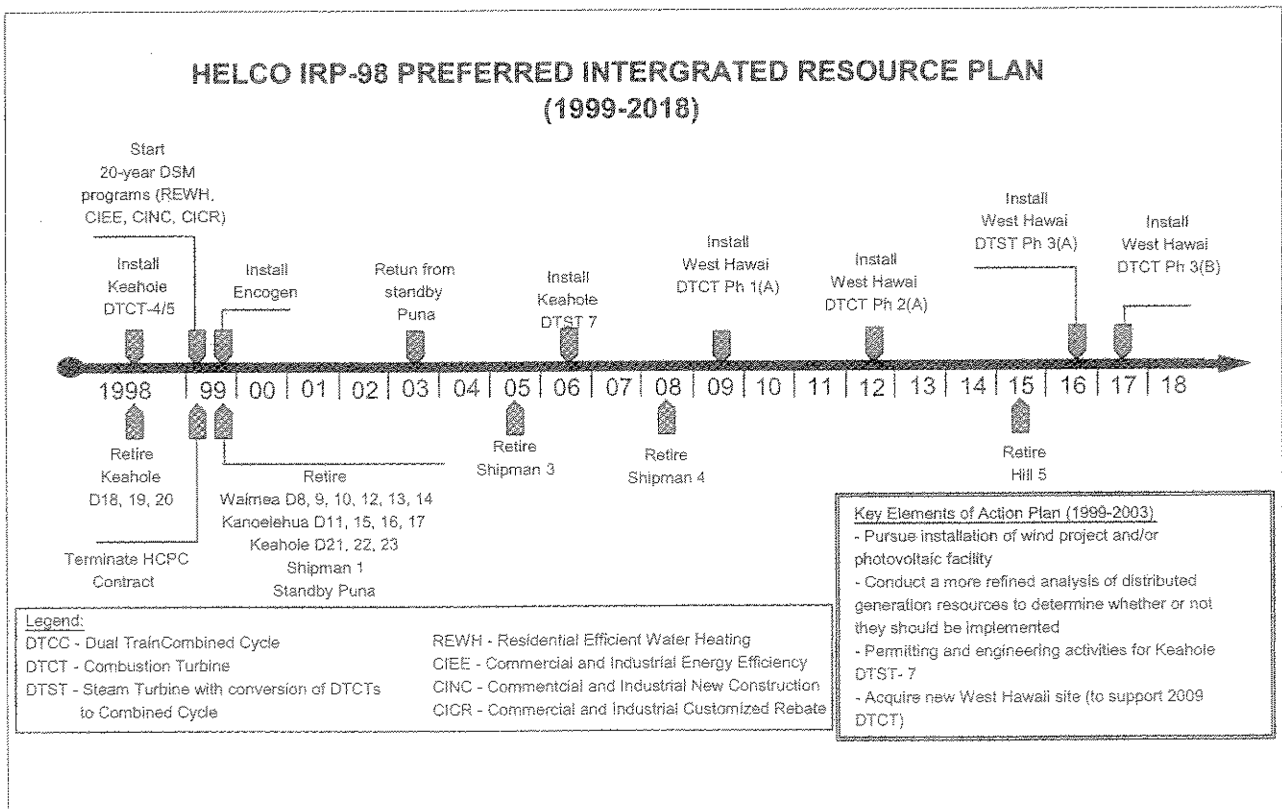
d. Together with its annual evaluation, the utility shall submit a revised program implementation plan that drops the immediately preceding year from the schedule and includes a new year. The program implementation plan must always reflect a five-year time span.

This evaluation provides an interim status update and a validity assessment of the most recent IRP plan and is not intended to be a major review of the plan. HELCO is conducting a major review of its IRP plan and will file its third IRP plan by October 31, 2005.

1.2 Summary of HELCO's Second IRP (IRP-2)

HELCO filed its second integrated resource plan, also referred to as the IRP-2 preferred plan, with the PUC in September 1998. The IRP-2 preferred plan, also called the IRP-98 Preferred Integrated Resource Plan, (hereinafter referred to as "IRP-2 plan"), is shown in Figure 1.2-1 below:

Figure 1.2-1
IRP-2 Plan



In terms of DSM resources, the IRP-2 plan included:

- Continuation of four energy efficiency programs over a 20-year period, 1999-2018, including one residential program and three commercial and industrial programs. These programs provide incentives to customers to install energy efficiency measures such as solar water heating (for residential customers) or high efficiency lighting, air-conditioning or motors (for commercial and industrial customers) therefore reducing the overall demand for electricity on the HELCO system;

In terms of supply-side resources, the IRP-2 plan included:

- Retire Keahole D18-20 (a total of 8.25 MW) with the addition of CT-4 and CT-5 in December 1998.
- Retire Shipman 1, Waimea D8-10 and D12-14, (total of 14.3 MW) upon completion of Encogen (now known as Hamakua Energy Partners, HEP) Phase 1 in April 1999.
- Retire Kanoelehua D11, D15-17, and CT1, and Keahole D21-23 (total of 30 MW) upon completion of Encogen (HEP) Phase 2 in August 1999.
- Place the Puna steam unit on cold standby upon completion of Encogen (HEP) Phase 2 in August 1999.
- Termination of the contract between HELCO and Hilo Coast Power Company (HCPC) for the purchase of 22 MW of firm capacity on December 31, 1999.
- Return of the Puna steam unit to service from cold standby for cycling operation in 2003.
- Install Keahole ST-7 in 2006, converting CT-4 and CT-5 to dual train combined cycle.
- Install a 60.7 MW dual train combined cycle at a new West Hawaii site in phases, with the first phase combustion turbine added in 2009. The second combustion turbine and steam turbine would be installed in 2012 and 2016, respectively.
- Install the first combustion turbine of a second 60.7 MW dual train combined cycle at the new West Hawaii site in 2017.

The updated IRP Plan, as part of this evaluation report, is discussed in Section 4.3 of this report.

1.3 Regulatory Procedural History

HELCO submitted its IRP preferred plan and action plans to the PUC on September 1, 1998 by Order No. 15977 in Docket No. 97-0349 (HELCO IRP-2 docket).

On March 5, 1999, HELCO filed a Supplement to September 1, 1998 Integrated Resource Plan. This supplement provided revised status on planned generation additions and responded to requests for cost impacts of resource plans (preferred plan and plans where near-term planned unit additions do not occur).

On June 15, 1999, HELCO filed a Revision to Supplement to September 1, 1998 Integrated Resource Plan. The revision updated assumptions used to determine revenue requirements in the March 5, 1999 Supplement.

HELCO filed responses to information requests and supplemental information requests on July 23, 1999 and October 8, 1999, respectively.

Between 1999 and 2003 there were various proceedings and court actions related to the planned expansion of the Keahole power plant, which prevented closure of the IRP-2 docket. This is discussed in detail in Section 3.1 of this report.

On November 25, 2003, the participants in the HELCO IRP-2 docket, HELCO, the Consumer Advocate (CA), and The Gas Company, participated in a status conference held by the PUC to discuss the HELCO IRP-2 docket. At that conference, the parties shared ideas for bringing IRP-2 to closure, and committed to working together to develop and file a stipulated agreement that would allow closing the HELCO IRP-2 docket.

On January 9, 2004, HELCO and the Consumer Advocate filed a stipulation with the PUC. The stipulated agreement stated, among other things, that HELCO would submit an Evaluation Report of its IRP-2 Plan and Action Plans no later than March 31, 2004, and would submit its IRP-3 plan by no later than October 31, 2005.[4]

On February 4, 2004, the PUC issued Order No. 20792, which approved the stipulation, ordered HELCO to submit its IRP-2 Evaluation report no later than March 31, 2004, ordered HELCO to conduct the next major review of its IRP plan (i.e. IRP-3) for submittal no later than October 31, 2005, and closed Docket No. 97-0349. On February 26, 2004, the PUC issued Order No. 20821, Docket No 04-0046, which opened HELCO's IRP-3 cycle and ordered HELCO to submit its major review of its IRP plan no later than October 31, 2005.

[4] The Gas Company (TGC), also a party to HELCO's IRP-2, did not enter into the stipulation. Instead, on January 9, 2004, TGC filed a letter with the PUC stating it received the stipulation and had no objection to the requested relief.

2. CURRENT PLANNING CONTEXT

Events in Hawaii, the nation, and the world since IRP-2 was filed in September 1998 have affected the context in which HELCO develops and implements its IRP. This section describes the current context within which HELCO evaluates its IRP-2.

2.1 Energy Roundtable

HELCO participated in the Hawaii Energy Roundtable, held November 22-23, 2002 at the Outrigger Waikoloa Beach Hotel. The event was organized by the Kohala Center, a private nonprofit independent academic research center in Waimea. The objective of the Roundtable was to bring together the island's major stakeholders to build community consensus on practical solutions and actions to meet the island's energy needs. The Roundtable was attended by representatives from HECO and HELCO.

The Roundtable provided HELCO with an opportunity to present an overview of the historic, present, and future energy situation on the Island of Hawaii. Key challenges facing HELCO, as indicated in this overview, included the current system generation, the generation capacity and load imbalance between East and West Hawaii, the limitations of the present transmission system, and HELCO's plans to meet future energy needs through firm and non-firm resources, including renewables.

HELCO continued its participation in the Roundtable by attending an update meeting on January 8, 2004. At the meeting, HELCO provided an update of the overview on the HELCO system provided at the original Roundtable meeting. HELCO plans to continue participating in future collaborative efforts such as the Roundtable as a means of obtaining community input to the IRP process. HELCO requested and received representation from the Roundtable on its Advisory Group for it's IRP-3 process.

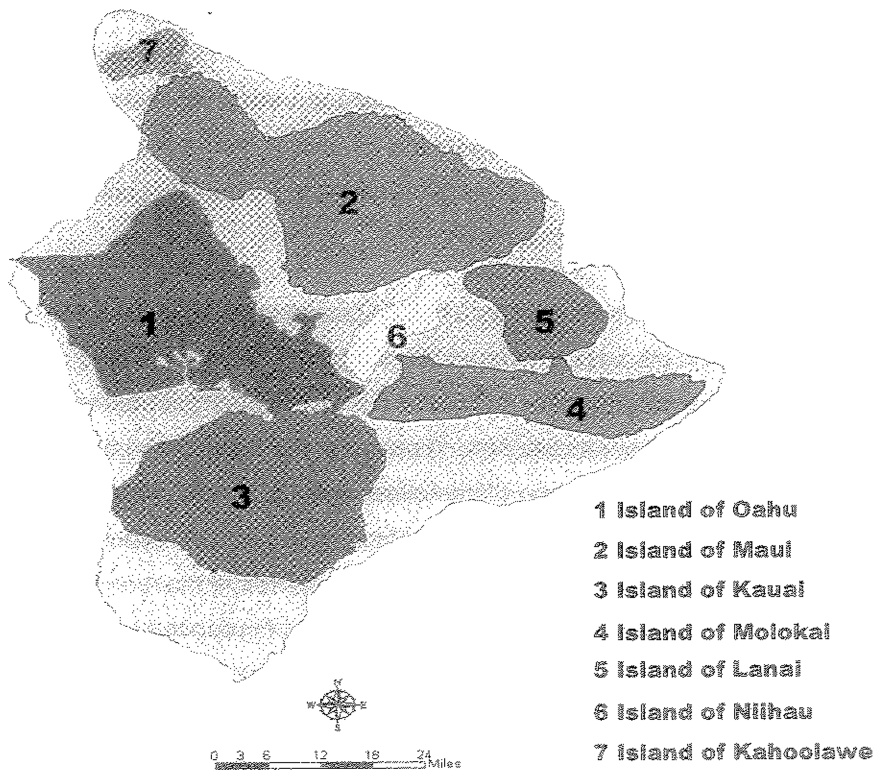
2.2 Unique Situation on the Big Island

There are many challenges to developing a resource plan for HELCO due to uncertainties and its unique situation. The resource plan must be able to account for these circumstances in order to provide reliable, reasonably priced power to HELCO's customers.

As shown in Figure 2.2-1, the HELCO service territory is larger than the combined landmass of the other seven major Hawaiian Islands, which includes the service territories for HECO and MECO. Much of HELCO's existing generation is located on the east side of the island. However, load growth on the west side has been increasing at a much faster pace. For example, the combined energy sales of the Kona and Waimea districts in the five-year period 1998 thru 2003 have grown at an approximately 35-40% faster rate than Hilo sales. Over the ten-year period 1993 thru 2003, combined energy sales growth in the Kona and Waimea districts was approximately 100% higher than the in Hilo district. Consequently, it is preferable to locate new generating units on the west side, where they would be closer to the faster-growing loads. If generating units are placed on the east side, existing transmission lines need to be reconductored with larger capacity conductors, or new transmission lines need to be built.

Another unique challenge that HELCO faces is the large amount of as-available energy produced on the system from wind and hydro. Because of their intermittent nature and non-dispatchability, they are not counted as firm capacity in the resource plan. Furthermore, the variable nature of wind can adversely impact the utility. In a system like HELCO's, where the percentage of intermittent generating resources is high, fluctuating windfarm power output can have significant impacts on system operations. To keep the impacts at a manageable level, the firm capacity generators that are on-line must have sufficient inertial characteristics. Hence, the amount of proposed as-available generation must include technological improvements to minimize the impacts on the operation of the existing system.

Figure 2.2-1
Comparative Size of the Big Islands to the Other Major Hawaiian Islands



2.3 Capital Expenditures and the Planning Process

IRP Plans may be better characterized as planning "strategies", rather than as fixed courses of action. The IRP process identifies the information that is critical to the decision making process, and also identifies when the strategic decisions need to be made. HELCO has also strived to have plans that are flexible enough to account for changes in planning assumptions and forecasts. This allows for major decisions regarding the implementation of program options (both supply-side and demand-side resources) to be made incrementally, based on the best available information at the time decisions must be made.

While an IRP Plan is effective in identifying the major demand and supply resources, HELCO's capital projects may be driven by a variety of requirements, including environmental regulations, safety, security of infrastructure and employees, reliability, efficiency and effectiveness, power quality, and the support of corporate goals and strategies. These requirements may not necessarily be directly related to the IRP, and the precise timing and scope of expenditures can often be difficult to predict in advance. For example, projects to replace or upgrade the Utility's accounting systems or customer service systems can be significant, but are usually not examined in the context of demand-side and supply-side resources.

Paragraph III.D.5 of the IRP Framework states, in relevant part, that: "The integrated resource plan and program implementation schedule approved by the commission shall govern all utility expenditures for capital projects, purchased power, and demand-side management programs." As the Commission explained, "expenditures for all capital projects should be made consistent with the integrated resource plan. ... In essence, an integrated resource plan is intended to 'control, direct, or strongly influence' all capital expenditures." (Decision & Order No. 11630, Docket No. 6617, at 8.)

Projects do not have to be included in an approved IRP Plan to be consistent with the plan. With a few exceptions, specific capital expenditure projects are not identified or discussed in an IRP Plan. The exceptions are planned central station generating unit additions, which generally are described as generic projects, rather than specific project proposals. They have been described as specific projects when they have already been the subject of review proceedings pursuant to paragraph 2.3(g)(2) of G.O. 7. The plan does not include Independent Power Producer (IPP) projects, unless there is a signed power purchase agreement for the project. Nonetheless, it is contemplated that IPP firm capacity projects may defer utility generation additions, and that IPP as-available energy projects may be added to the utility's system even though there is no explicit reference to these projects in the plan.

Other types of projects, such as transmission and distribution (T&D) projects generally have not been considered in the IRP process. IRP Plans contemplate that measures and projects will be undertaken when necessary to maintain system reliability and security, regardless of whether the projects have been specifically identified in the plan. However, that does not mean that T&D costs are irrelevant in the IRP process, or that an IRP Plan is irrelevant to transmission planning. Avoided T&D costs may be relevant to evaluating the cost-effectiveness of DSM programs. Transmission interconnection requirements for new generation resources should be considered in evaluating the costs of those resources. In the case of HELCO, planning for the transmission system is done in a manner that is consistent with and takes into account the resource additions in the latest resource plan. See Section 3.6 of the IRP-2 Evaluation report for more information.

3. UPDATED RESOURCE INFORMATION

3.1 Demand-Side Management (DSM) Programs

3.1.1 Background

In its IRP Framework, the PUC defines Demand-Side Management (DSM) programs as follows:

> "Demand-side management programs" mean programs designed to influence utility customer uses of energy to produce desired changes in demand. It includes conservation, load management, and efficiency resource programs"

HELCO's three current commercial and industrial (C&I) energy efficiency programs include the C&I Energy Efficiency program (CIEE), the C&I Custom Rebate program (CICR), and the C&I New Construction program (CINC). HELCO's residential energy efficiency program is the Residential Efficient Water Heater program (REWH). Interim status updates are provided for these programs in this IRP-2 Evaluation report. All DSM resources will be re-evaluated in HELCO's IRP-3 process.

3.1.2 HELCO's Current Energy Efficiency DSM Programs

HELCO's current DSM programs were approved for a five-year implementation period by the Commission in 1996 in Dockets Nos. 95-0173 (REWH), 95-0174 (CIEE), 95-0175 (CINC), and 95-0176 (CICR). Approval of the continuation of the C&I and residential programs was granted by the PUC in Order No. 18242, dated December 8, 2001, for one additional year. Subsequently, by Order No. 19094, dated November 30, 2001, the Commission approved the extension of the C&I and residential programs until one year after the Commission makes a determination in Hawaiian Electric Company, Inc.'s (HECO) next rate case in an interim decision and order, or a final decision and order, whichever comes first. These programs, which are discussed in detail in Section 6.0 of HELCO's IRP-2 report, improve the efficiency of the major energy consuming equipment of our residential, and commercial and industrial customers.

3.1.2.1 Commercial and Industrial Energy Efficiency (CIEE) Program

This program, which provides prescriptive incentives to customers for purchasing and installing energy efficient motors, air conditioning systems, and lighting systems, has resulted in a net reduction[5] of 1.154 MW of demand and 40,108 MWH of energy since its inception in the beginning of 1996 through 2003. Total expenses during this period were $2.59 million. Net impacts and expenses by year are shown in Table 3.1.2.1-1.

Table 3.1.2.1-1
C&I Energy Efficiency (CIEE) Program
Recorded Results 1996-2003

Year	Megawatt Hours (MWH)*	Megawatts (MW)	Expenses $
1996	903	0.139	341,570
1997	2,839	0.265	466,266
1998	3,341	0.076	332,380
1999	4,529	0.171	249,354
2000	5,794	0.193	306,517
2001	6,614	0.092	292,857
2002	7,603	0.129	268,498
2003	8,485	0.089	337,258
TOTAL	40,108	1.154	2,594700

* Includes the cumulative effects of energy savings from projects completed in preceding years.

Many large customers have completed their lighting retrofits from standard lamps and ballasts to more efficient T-8 lamps and electronic ballasts. In order to continue to realize additional impacts from this technology, HELCO will need to work with the owners of medium and smaller sized businesses to encourage them to adopt the newer T-8 lamps and electronic ballast lighting systems. HELCO has developed an approach to the smaller

[5] Net impacts exclude impacts that resulted from customers who participated in the DSM programs but who when questioned later in the program impact evaluation indicated that they would have installed the DSM measure without the presence of the DSM program.

customer segment through its Energy Efficiency Program for small business marketing effort.[6] In 2004, HELCO plans to expand this marketing effort to include small and medium sized customers.

HELCO also plans to increase its customer awareness efforts targeting medium and small businesses. In particular, HELCO will focus on industrial customers to promote energy efficient motors, high efficiency industrial lighting systems, and high efficiency industrial process cooling allocations.

3.1.2.2 Commercial and Industrial Customized Rebate (CICR) Program

This program was developed to address the large number of DSM measures that are available which, due to the limited potential size of the market for these measures or to the site-specific savings resulting from their installation, do not lend themselves to a prescriptive incentive program design. These measures include variable frequency drives for electric motors, redesign of air-conditioning systems, and the installation of controls on various energy using systems

Since each CICR application can be unique, this program is more labor intensive than the prescriptive CIEE program. However, since the implementation of the CICR program in 1996, HELCO has adopted spreadsheets and computer models developed by HECO, which make the analysis of many projects much simpler.

The CICR program also contains a strong educational component since many of the DSM measures available to customers are new or have not been implemented in Hawaii. To educate customers regarding new and existing DSM technologies, HELCO has sponsored workshops and seminars featuring experts from both Hawaii and the mainland to address measures such as building commissioning, new lighting applications, variable speed drives, and building controls.

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[6] This program is designed to compensate for small businesses' general lack of technical resources in energy efficiency matters. It includes lighting audits and retrofit proposals of their facilities conducted by a HELCO representative or a lighting vendor under contract to HELCO. To date, HELCO has completed audits of 120 sites. Of these sites, 41 businesses have completed their retrofits. These businesses included grocery stores, fast food establishments, food manufacture facilities, and construction material outlets.

The CICR program also provides up to 100% of the cost for a project feasibility study, which is required for a CICR application, with a maximum share of up to $10,000 per project. Pre-approval of funding is required for customers who wish to retain an engineering firm to determine the feasibility of a DSM project or measure. This facet of the program has been popular with customers and has resulted in several major projects being implemented.

In addition, HELCO has used outside engineering companies to complete Preliminary Energy Assessments (PEAs), which are general energy efficiency studies to identify energy efficiency opportunities in a customer's facility. The PEA identifies the measures, provides an estimate of potential savings and an estimate of the cost to install the measures. These PEAs have resulted in several major projects being completed that otherwise would not have been undertaken.

The CICR program has resulted in a net reduction[7] of 0.612 MW of demand and 11,380 MWH of energy since its inception in the beginning of 1996. Total expenses during this period were $0.902 million. Impacts and expenses by year are shown in Table 3.1.2.2-1 below.

[7] See Footnote 5, page 12.

Table 3.1.2.2-1
C&I Customized Rebate (CICR) Program
Recorded Results 1996-2003

Year	Megawatt Hours (MWH)*	Megawatts (MW)	Expenses $
1996	19	0.004	17,665
1997	247	0.030	59,585
1998	704	0.046	77,227
1999	971	0.072	83,171
2000	1,508	0.121	167,121
2001	2,184	0.169	219,521
2002	2,636	0.106	135,659
2003	3,111	0.064	142,476
TOTAL	11,380	0.612	902,425

* Includes the cumulative effects of energy savings from projects completed in preceding years.

As illustrated in Table 3.1.2.2-1, impacts produced by the CICR program vary from year to year. This is due to the nature of the applications and projects, which can vary between relatively small projects to very large retrofits of major cooling plants. However, HELCO expects the CICR program to remain effective in part due to the number of potential retrofits identified in the PEAs and feasibility studies completed by HELCO in the past and that are now pending.

3.1.2.3 Commercial and Industrial New Construction (CINC) Program

The CINC program addresses energy efficiency measures in new commercial and industrial buildings and in major renovations of commercial/industrial facilities. In addition to offering financial incentives for both prescriptive and customized DSM measures, the CINC program provides design assistance funding for new construction projects. This funding allows the developer to explore alternative approaches to lighting, air-conditioning, and other design features to ensure that the project will integrate the most energy efficient measures. Design assistance can either be used by the developer to fund additional studies by its design team, or to retain outside engineers to review the recommended design. As new and emerging technologies develop, HELCO believes this design assistance feature will have a growing influence on the success of DSM in the new construction market segment in Hawaii. To date the CINC program has resulted in a net reduction[8] of 0.458 MW of demand and 18,540 MWH of energy since its inception in the beginning of 1996. Total expenses during this period were $1.21 million. Impacts and expenses for the CINC program are shown by year in Table 3.1.2.3-1.

Table 3.1.2.3-1
C&I New Construction (CINC) Program
Recorded Results 1996-2003

Year	Megawatt Hours (MWH)*	Megawatts (MW)	Expenses $
1996	98	0.017	43,920
1997	736	0.076	128,020
1998	1,302	0.073	129,532
1999	1,957	0.069	146,754
2000	2,452	0.042	159,912
2001	3,162	0.061	191,931
2002	4,060	0.065	213,036
2003	4,773	0.055	196,237
TOTAL	18,540	0.458	1,209,342

* Includes the cumulative effects of energy savings from projects completed in preceding years.

3.1.2.4 Residential Efficient Water Heating (REWH) Program

The REWH program offers financial incentives to customers in new and existing residences and to developers to encourage the installation of energy efficient water heating technologies, such as solar and heat pump water heating systems and high efficiency electric resistance water heaters. The incentives are currently offered in conjunction with

[8] See Footnote 5, page 12.

available State of Hawaii Energy Conservation tax credits. In addition, HELCO has encouraged residential customers to install low-flow showerheads and compact fluorescent lamps (CFLs) within this program. The REWH program has resulted in a net reduction[9] of 3.051 MW of demand and 54,012 MWH of energy since its inception in the beginning of 1996. Total expenses during this period were $6.30 million. Impacts and expenses for the REWH program are shown by year in Table 3.1.2.4-1 below.

Table 3.1.2.4-1
Residential Efficient Water Hearing (REWH) Program
Recorded Results 1996-2003

Year	Megawatt Hours (MWH)*	Megawatts (MW)	Expenses $
1996**	3,776	1.416	910,076
1997	4,728	0.234	775,073
1998	5,716	0.238	707,511
1999	6,851	0.274	927,152
2000	7,711	0.198	658,943
2001	8,930	0.281	774,287
2002	9,872	0.211	722,028
2003	10,759	0.199	819,218
TOTAL	58,344	3.051	6,294,288

* Includes the cumulative effects of energy savings from projects completed in preceding years.

** Showerhead program included in 1996.

3.1.3 Recent Changes in DSM Technologies Since IRP-2

Several recent developments in electro-technologies since IRP-2 have the potential of providing additional impacts from HELCO's existing DSM programs.

The conversion of standard incandescent traffic signals to light emitting diodes (LED) traffic signals during the past two to three years has greatly increased with the

[9] See Footnote 5, page 12.

development of green and yellow LEDs. Prior to that time only red LEDs were suitable due to their high light output and reasonable cost. Significant energy savings could be realized by changing out the red incandescent lamps with red LEDs. With the large-scale production of green and yellow LEDs, price reductions have made them economically feasible. Since the yellow lamps have very short on times, some intersections use long-life yellow incandescent lamps due to the small energy savings relative to the cost of the LED fixture. The County of Hawaii has converted a significant number of its traffic signals with red LEDs and plans to continue its conversion to green and yellow LED traffic signals.

Another significant DSM measure that has gained acceptance since the development of HELCO's IRP-2 is variable speed drive controls.[10] During the past years, HELCO has conducted a number of workshops and seminars on variable speed drive controls and has monitored the energy use before and after installation of the variable speed drive control on various motor applications. With this introduction of the technology and documentation of the savings, variable speed drives have gained in popularity and are expected to be a source of significant energy savings in the C&I market.

Other emerging DSM technologies that are expected to increase the effectiveness of HELCO's existing DSM programs include advanced commercial refrigeration applications, advanced lighting control systems, super efficient electric motors, room management systems for hotel rooms, and numerous other improvements to new and existing DSM measures.

3.1.4 Modifications to HELCO's DSM Programs

New motor efficiency standards

HELCO aligned its electric motor incentive requirements within the CIEE and CINC programs in its 2002 DSM Modification and Evaluation report with the specification for NEMA PremiumTM as defined by the National Electrical Manufacturers Association's

[10] Variable speed drive controls, also known as variable frequency drives, control the speed of motors to better match the motor output with the work to be done. For example, a motor driving a pump supplying hot water to a hotel guest room may not need to supply a lot of water during the late evening hours but must increase that supply in the mornings and early evenings. Thus, by reducing the energy used by the motor during the period of low water usage, significant energy can be saved.

(NEMA). Adopting this national specification for premium efficiency electric motor made it easier for equipment vendors and customers to quickly identify which motors are considered high efficiency and qualify for HELCO incentives.

Increased focus on education and engineering studies

As HELCO's energy efficiency programs have progressed, certain end-use markets have matured, such as the efficient fluorescent lighting market in office buildings. In order to continue to realize energy and demand impacts in these programs, HELCO will have to rely more heavily on education and marketing to encourage more mid-sized and smaller facilities to retrofit their old inefficient lighting, and more engineering studies to help the larger customer go beyond simple lighting projects.

HELCO has developed the Energy Efficiency Program for small businesses to assist small commercial customers with their lighting retrofit projects. This program is designed to provide all the information necessary for a small customer to make a good business decision on lighting retrofits. Under this program, a HELCO representative conducts a comprehensive lighting audit for the customer and provides the customer with a detailed presentation of the cost, savings and expected simple payback for an efficient fluorescent lighting retrofit. If the customer elects to proceed with the project, HELCO will contract with a lighting contractor to complete the installation. Following completion of the project the customer can elect to pay for the project in one lump sum or in four equal interest free payments. This program has been very successful in promoting efficient lighting retrofits to customers whose main focus is generally on reducing up-front cost, rather than on energy conservation. HELCO will also be looking in the future to develop similar programs designed to educate customers and simplify the process of becoming more energy efficient.

Within the CICR program during the past few years, HELCO has been funding PEAs for larger customers. These assessments are conducted by outside consulting engineering firms and help to provide customers with ideas and information on energy efficiency projects that they might not otherwise consider. These studies have been successful in promoting major projects by providing facility maintenance managers with enough detailed information on energy efficiency projects to allow them to solicit capital improvement funds from their managing boards or parent companies. Based on the success of these assessments in promoting future energy efficiency projects, HELCO plans to expand the future program budgets to increase the number of assessments conducted.

Impact evaluations

Since 1996, HELCO has conducted two complete and extensive impact evaluations for its four energy efficiency DSM programs. These evaluations have resulted in very detailed information on the expected savings of various conservation measures in different building and business types. This information is now probably the most detailed and accurate reflection of what customers in Hawaii can expect in savings from the conservation measures offered under the current programs.

3.1.5 Continuation of Existing DSM Programs: Stipulation and Order No. 19094

HELCO's current DSM programs for a 5-year implementation period were approved by the Commission in 1996 in Dockets Nos. 95-0173 (REWH), 95-0174 (CIEE), 95-0175 (CINC), and 95-0176 (CICR). Approval of the continuation of the C&I and residential programs was granted by the PUC in Order No. 18242, dated December 8, 2001, for one additional year. Subsequently, on October 31, 2001 the parties (HELCO & CA) filed for commission review and approval of a stipulation. By Order No. 19094, dated November 30, 2001, the commission approved the parties' stipulation, subject to certain conditions and modifications.

Order No. 19094 stated, in relevant part, that:

- HELCO may temporarily continue its three existing commercial and industrial DSM programs and its existing residential DSM program until one year after the commission makes a determination in HECO next rate case of HECO's revenue requirements in an interim decision and order or a final decision and order, whichever comes first (HELCO's DSM Temporary Continuation Period),

- HELCO may continue to recover through its existing surcharge mechanism the DSM lost margins and shareholder incentives for its three existing commercial and industrial DSM programs and its existing residential DSM program accrued through the date that interim rates are established as a result of HECO's next rate case,

- HELCO may request to extend the time of such accrual and recovery of lost margins and shareholder incentives for up to a year subsequent to the date that interim rates are established as a result of HECO's next rate case,

- HELCO may continue to recover through its existing surcharge mechanism the DSM program costs for its three existing commercial and industrial DSM programs and its existing residential DSM program accrued through the date that HELCO's Temporary Continuation Period ends, and

- HELCO agrees to take the necessary steps to implement any changes ordered or approved by the PUC in HECO's next rate case with respect to program costs within one year from when such costs are incorporated into HECO's rates as a result of HECO's next rate case.

3.1.6 Load Management Programs and Interruptible Load Initiatives

HELCO's IRP-2 did not include any load management programs, and HELCO is not proposing any new C&I or residential load management programs at this time. DSM load management programs will be evaluated, along with other load curtailment mechanisms, in HELCO's IRP-3 process.

HELCO does have 26 Rider M and one Schedule U curtailable contracts totaling 6.6 MW of curtailable loads. These contracts reduce loads by up to 6.6 megawatts (MW) during peak demand periods. HELCO constantly seeks additional contracts with qualified water pumping commercial and industrial customers. In concept, the load management rates and rate riders offer benefits to customers through incentives, and provide reliability benefits to HELCO generation needs. This program builds strong partnerships in meeting Hawaii's energy needs. These contracts reduce peak load demand by requiring customers to curtail a portion of their load sometime during on-peak hours of 7 am to 9 pm (Rider M) or charging customers a higher rate during on-peak hours (Schedule U).

To date, HELCO has been able to achieve substantial and effective load reductions through Rider M and Schedule U, rather than through DSM load management programs. However, load reduction through these mechanisms may or may not be sufficient in the future due to changing customer participation and/or the level of curtailable load which may not meet HELCO's need for additional load curtailment in the future. HELCO will consider implementation of other means to curtail load, including new DSM load management programs, as part of the IRP-3 process.

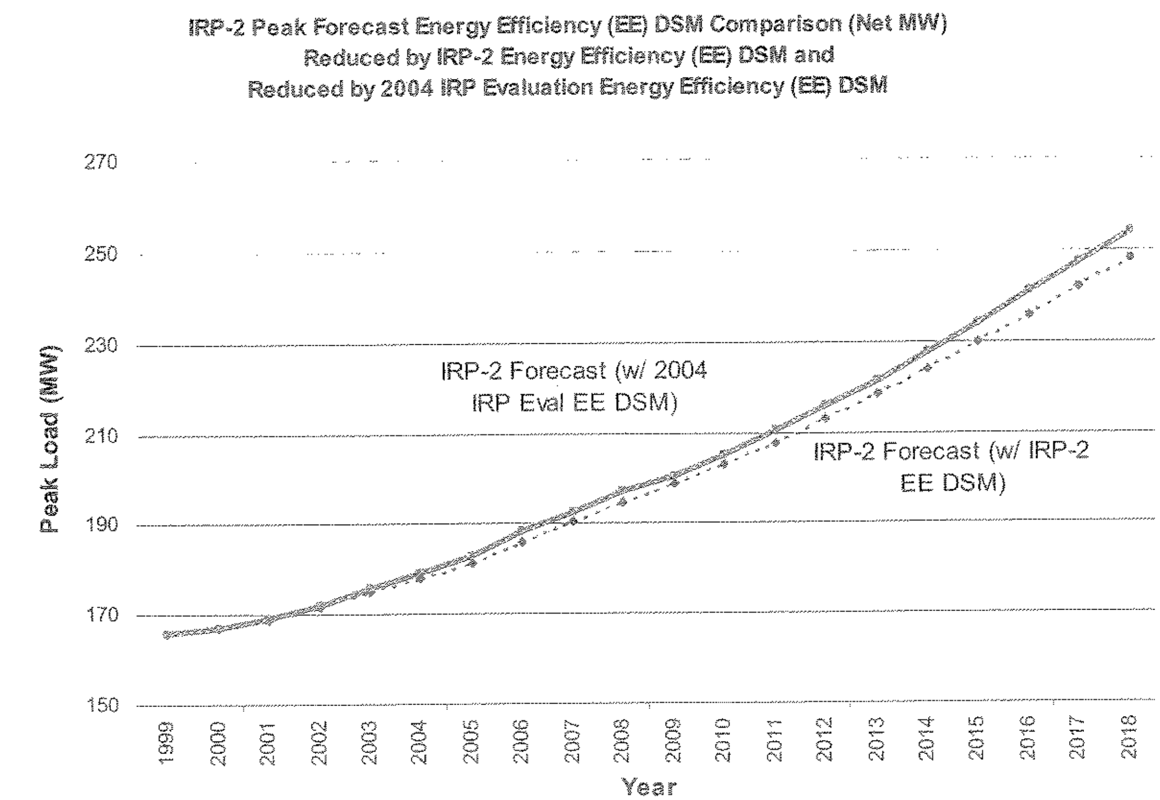
3.1.7 DSM Programs Impact Update

In preparing this evaluation report, HELCO estimated its DSM impacts in a manner similar to that used in its request for extension of energy efficiency programs filed in October of 2001.[11] HELCO reviewed the historical performance and expenses of the programs, and projected their impacts and budgets for the next five year period. For this evaluation report, these short-term impacts and expenses were then projected out for the remaining years of the IRP planning period. Figure 3.1.7-1 below shows a comparison between the IRP-2 DSM impacts and the IRP-2 Evaluation report DSM impacts.

Changes in DSM technologies, higher local and federal efficiency levels for new equipment, and new emerging technologies can make estimating long-term impacts of DSM programs challenging. All DSM resource options will be re-evaluated as part of HELCO's IRP-3 process.

[11] On December 11, 2001, the PUC approved a stipulation between HELCO and the CA in Order No. 19094 for an extension of HELCO's existing DSM programs until one year after the next HECO rate case.

Figure 3.1.7-1
DSM Energy Efficiency Demand Savings Comparison



3.2 Distributed Generation (DG)

Distributed generation (DG) is the application of small generators, typically ranging in capacity from a dozen to several thousand kWs, scattered throughout a power system, to provide electric power needed by electric consumers. As ordinarily applied, the term *distributed generation* includes the use of small electric power generators, whether utilizing fossil fuels or renewable energy resources, located at a utility site or at a customer site, and either connected to the utility's power grid or off-grid (not connected). These generators may be owned and operated by HELCO (utility) or by a third-party (non-utility).

Most types of distributed generators utilize traditional power generation technologies – reciprocating engines, combustion turbines, combined-cycle combustion turbines, and other rotating machinery. Other types of DG utilize fuel cells or renewable power generation methods such as small-scale wind, solar, or low-head hydro generation.

3.2.1 Potential Benefits of DG

Integration of DG in a utility's grid can potentially yield benefits, including a reduction in transmission and distribution line losses, the deferral of central station generation, and the deferral of distribution (and perhaps even transmission) network expansion or improvements. These distribution and transmission system benefits can only be determined by evaluating the specific site under a set of specific planned uses for the candidate DG. In addition, the feasibility and cost-effectiveness of DG is specific to technology and assumptions (i.e. site location, permitting, operations, emissions and other considerations) of each individual project. This makes evaluation of this DG benefit and the complete evaluation of DG resources in the IRP process difficult because the IRP process analyzes resources at the system level prior to the identification of specific projects. Therefore, the resource information used in the IRP process is typically generic information, and is not developed in detail for specific projects.

Customers with large heating or air-conditioning loads may benefit from the use of waste heat generated by a DG resource located at a customer site. The waste heat could be used to heat water and/or through an absorption chiller to drive an air-conditioning system and thereby reduce the use of electric energy that would otherwise be needed by these functions. Typically, DG plants used in these Combined Heat and Power (CHP) applications are operated to meet the heating/air-conditioning load. Electric energy is a by-product of the process and is usually lower in output than the customer's load. This necessitates continued connection to the utility grid to make up for the difference in electricity demand.

Another potential benefit of DG is that its small size, modularity, and location at or near an end use site provides flexibility and choice that a traditional utility system may not be able to offer. DG may provide additional reliability to a customer whose operation is willing to pay for a higher level of reliability for certain loads that cannot be economically achieved through central station generation and T&D systems. Utility DG located at customer sites may complement central station power in small increments with the added benefit of not requiring additional land.

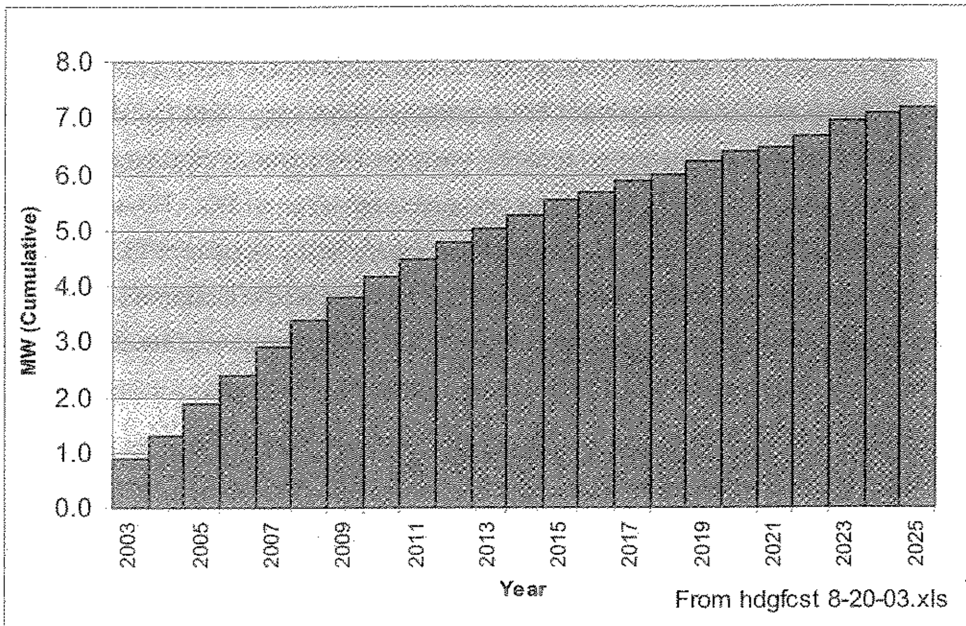
3.2.2 Recent Developments in DG

The number of customer self-generation projects that are being proposed or installed in Hawaii, particularly those involving CHP systems, is growing. HELCO, HECO, and MECO have initiated several demonstration projects and other activities, including a small CHP demonstration project on Maui, to provide on-going evaluation of DG. The electric utilities also have made a limited number of proposals to customers, subject to PUC review and approval, to install and operate utility-owned CHP systems at the customers' sites. Incremental generation from such customer-sited CHP systems, and other DG, is expected to complement traditional central station power, as part of the electric utilities' plans to serve their forecast load growth.

Several of HELCO's customers are evaluating the costs and benefits of installing DG or CHP systems on their property to serve a portion or all of their electrical demand with the added benefit of serving a portion of their thermal demand as well. Some of these customers have received proposals from third-party DG/CHP developers. Customers who are considering DG/CHP installations are evaluating the costs of installing, operating and maintaining these facilities compared to the cost of receiving service from HELCO. In some cases, these customers have determined that their overall energy bills can be reduced by CHP installations.

In one particular example, the Fairmont Orchid, a resort in west Hawaii, elected to install an 800 kW CHP system. They installed four 200 KW generators, whose electrical output serves 50% of the resorts electrical demand. The heat from the engines' exhaust is used to drive an absorption chiller and heat domestic hot water for the hotel rooms. Supplemental and standby service is still provided by HELCO for periods where their CHP facility is out of service. Figure 3.2.2-1 shows the equivalent demand-side load reduction benefits that non-utility CHP projects may have on HELCO's peak load. These projected impacts were revised in August 2003, after the May 2003 Sales and Peak Forecast.

Figure 3.2.2-1
Projected Amount of Non Utility CHP Impacts on the HELCO System
(Equivalent Demand-side Load Reduction Benefits)

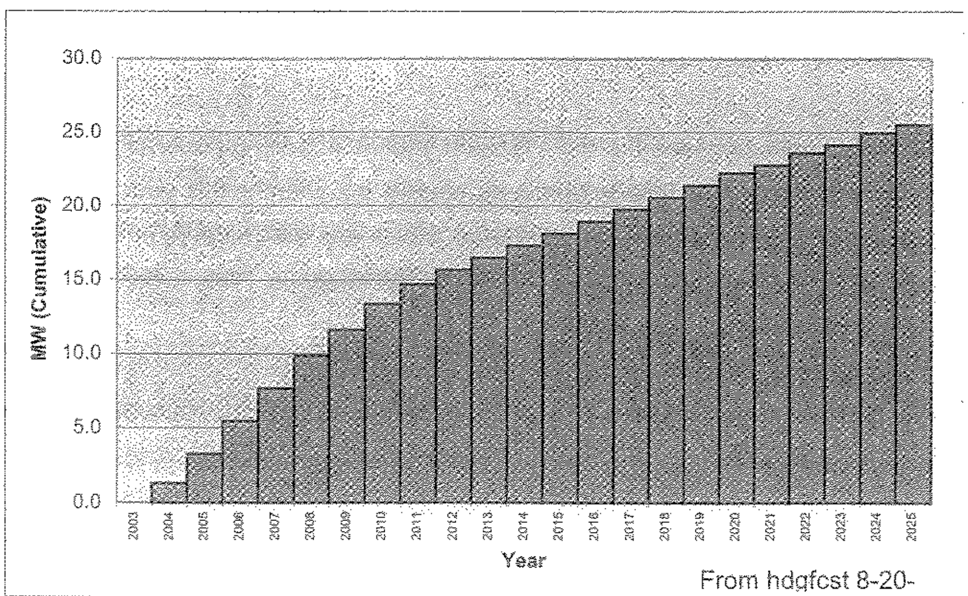


In July 2003, three vendors of DG/CHP equipment and services proposed, in an informal complaint to the PUC, that the PUC open a proceeding to investigate the electric utilities' provision of CHP services and the teaming agreement with another vendor, and to issue rules or orders to govern the terms and conditions under which the electric utilities will be permitted to engage in utility-owned DG at individual customers sites. In August 2003, the electric utilities responded to the informal complaint, and to information requests from the PUC on the CHP demonstration project and teaming agreement. In October 2003, the PUC opened an investigative docket to determine the potential benefits and impact of DG on Hawaii's electric distribution systems and markets and to develop policies and a framework for DG projects deployed in Hawaii. The PUC also plans to address issues raised in the informal complaint filed by the three vendors of DG/CHP equipment.

In October 2003, HELCO, together with HECO and MECO, filed an application for approval of a utility-owned CHP Program, under which they would provide CHP services to eligible commercial customers. To facilitate the offering of CHP systems, the electric utilities signed a teaming agreement with a manufacturer of packaged CHP systems in early 2003 (although the teaming agreement does not commit the electric utilities to make any CHP system purchases). Pending approval of a CHP program, the electric utilities plan to request approval for individual CHP projects. Based on the interest received and the potential market for utility-owned CHP, HELCO estimates that the utility-owned CHP program might have the equivalent supply-side generation capacity benefits shown in Figure 3.2.2-2. The projected impact will help defer the need for additional central-station generation. Additional details on the differences between utility-owned and non-utility CHP are provided in Docket No. 03-0366, which covers the Utility CHP program application.

In Order No. 20831, issued on March 2, 2004, the PUC suspended HECO, MECO, and HELCO's application for the Utility CHP program. It is anticipated that Utility CHP projects will continue on an individual project basis rather than a program basis until the final decision regarding Docket No. 03-0366 is made. However, this will increase the uncertainty of timely project implementation due to the nature of doing individual project applications.

Figure 3.2.2-2
Projected Amount of Utility-Owned CHP Installations on the HELCO System
(Equivalent Supply-side Generation Capacity Benefits)



3.2.3 HELCO Interconnection Standards

HELCO recognizes the growing interest in customer-sited DG. To facilitate the development of customer-sited DG, HELCO (and HECO and MECO) developed interconnection standards and a standard interconnection agreement for customers wanting to install DG operating in parallel with the utility's electric system.

By Decision and Order No. 20056, filed March 6, 2003, the PUC approved HELCO's (and HECO and MECO's) interconnection standards and standard interconnection agreement, effective March 21, 2003. (By Order No. 20220, filed May 30, 2003, the PUC approved a modification to the insurance provision to the standard interconnection agreement, and the revised standard interconnection agreement for the Companies became effective June 6, 2003.) HELCO currently has 8 existing DG customers, and has executed letters of intent with 2 new DG customers to do engineering for HELCO owned and operated CHP systems (the CHP systems would not be installed unless contracts are executed, and approved by the PUC).

3.2.4 HELCO's Experience with Distributed Generation at Substations

Four 1 MW DG units were installed at Panaewa, Ouli, Kapua, and Punaluu Substations in late 1997. The sites were determined to be the most feasible sites out of over 30 possible candidate sites through a ranking of various criteria (including environmental impacts, community impact, cost, and fuel).

These DG units provided the most feasible means of adding generation capacity in the least amount of time. The time to obtain air permits is 6 months to a year, which is considerably less than a central station generator, which can take 5 years or more. They provide quick start capability by being able to start in 90 seconds. This is beneficial when a generator unit or transmission line trips.

They were originally installed as mitigation measures in HELCO's contingency plan, but are now included as firm capacity since they are expected to remain in service until they are no longer needed to maintain reliability. Appropriate modifications have been made to the units, and to HELCO's operational and planning procedures to regard them as firm capacity.

3.2.5 Distributed Generation in IRP

HELCO has been actively monitoring non-utility DG developments in its service territory. Based on known current and proposed DG projects, HELCO believes non-utility

DG will play a role in reducing overall demand on the grid in the near and long-term. For Integrated Resource Planning, HELCO reflects an estimate of non-utility DG in its sales and peak forecast. An estimate of non-utility CHP impacts included with HELCO's proposed CHP program indicates that the impacts of non-utility CHP would grow to 3.4 MW in 2008. HELCO will continue to actively monitor non-utility DG developments and update the non-utility DG penetration in its sales and peak forecast as new information becomes available.

The peak forecast also accounts for the possibility that the utility may have to provide backup service for customer-owned self or co-generators. With an estimated availability factor of 91% for base-loaded co-generators, the system peak forecast anticipates that the utility must have enough standby capacity to cover 9% of the distributed generation capacity on-line, which is approximately 0.3 MW.

HELCO's proposed CHP Program is consistent with its IRP Plan, and the energy efficiency objectives of the plan. HELCO's IRP-2 Plan, adjusted for current circumstances, was utilized in analyzing and justifying HELCO's proposed CHP program as filed with the PUC in Docket No. 03-0366. The program approach to CHP, as proposed in HELCO's CHP program, makes it possible to consider CHP projects in an IRP process. Accordingly, HELCO's IRP-3 process will consider a utility CHP program as a resource option.

3.3 Renewable Energy

Renewable energy is an important contributor to increasing the State's energy self-sufficiency. Various issues relating to the development of renewable energy in Hawaii need to be addressed and successfully managed.

3.3.1 Summary of Renewable Energy Issues

The State of Hawaii has adopted four statutory energy objectives: (1) Dependable, efficient, and economical statewide energy systems capable of supporting the needs of the people; (2) Increased energy self-sufficiency where the ratio of indigenous to imported energy use is increased; (3) Greater energy security in the face of threats to Hawaii's energy supplies and systems; and (4) Reduction, avoidance, or sequestration of greenhouse gas emissions from energy supply and use.[12] There are a variety of issues relating to renewable energy that must be addressed when trying to balance the four statutory energy objectives. These issues include: higher costs and technical maturity, integration with the existing electric system (intermittency, output variability and system minimum load), site and resource availability, and environmental and social issues.

Most renewable energy technologies that are applicable for use in Hawaii cost more than conventional fossil fuel technologies. Higher costs of renewable energy technologies are attributable to the lack of technical maturity and market development, as well as characteristics inherent in obtaining the energy from the renewable resource. For example, photovoltaics, ocean, and hydrogen fuel cell energy systems require further technological advancements and subsequent cost reductions. Though photovoltaic energy systems are technologically mature, the current high cost of photovoltaics limits their adoption. Also, the cost to obtain the energy from ocean and closed-loop biomass resources can be high. Commercially viable renewable energy technologies will be re-evaluated during the next full review of HELCO's IRP.

Unlike electric utilities in the continental United States that are able to obtain power from other states through transmission lines, utilities in Hawaii do not have interconnections to other utilities to provide backup power. Hawaii utilities, therefore, must rely on dependable firm power that can be dispatched to customers when needed. Many renewable resources, such as solar, wind, and run-of-river hydro, are not available on demand, thus requiring backup generation or energy storage to ensure power is available when needed. The variability of the resource must also be considered. For example, the intermittent and gusty nature of wind can negatively affect the quality of power, especially on small island-based electric grid systems. Existing wind farms on the island of Hawaii have a measurable impact on system frequency deviations, especially during periods of low system load.

Hawaii has a variety of renewable resources, including geothermal heat, sun, wind, hydroelectric (flowing rivers and streams), biomass, and ocean sources (ocean thermal, current, and wave sources). However, commercial utilization of these resources is limited by their availability and availability of suitable sites on which to place these resources and their infrastructure. Geothermal resources are difficult to locate and drilled wells can degrade,

[12] Hawaii Revised Statutes, Section 226-18(a), as amended.

reducing output. Biomass, wind, and solar resources have high land requirements. For each MW of electricity, biomass needs 250 to 500 acres, wind needs 11 to 15 acres, and solar (photovoltaic) requires 5 to 10 acres. Solar, wind, and hydroelectric are not considered firm resources since they are not available 24 hours a day and cannot be relied upon to provide electricity during peak load periods. Also, technology cost and technical maturity for other renewable energy resources, such as closed-loop biomass[13], and ocean energy, are not in a commercial state at this time. These factors must be taken into consideration in the evaluation of the level of implementation of renewable resources.

3.3.2 HELCO Renewable Energy Strategy

Electricity is, and will continue to be, essential to the security and economic growth of Hawaii. The aforementioned issues relating to renewable energy must be successfully managed to achieve the competing objectives of increasing energy self-sufficiency and maintaining reliable and cost-effective electrical energy generation and delivery. Therefore, HELCO will actively work towards development and implementation of both commercial and emerging renewable technologies, in concert with planning for DSM and the best use of fossil fuel generation, until renewable energy technologies reach full maturity. HELCO will also continue to evaluate and develop partnerships that facilitate renewable energy projects.

HELCO is actively seeking to increase its renewable energy portfolio. Although HELCO is already a leader in the United States in renewable energy – about 23% of the electricity sold by HELCO in 2003 was generated from a diverse portfolio of renewable resources – planned renewable energy projects could provide more renewable energy for the island of Hawaii (see the Renewable Portfolio Standards Status Report to the Hawaii Public Utilities Commission 2003 report, filed February 27, 2004). Due to the high penetration of intermittent wind generation on the island, HELCO faces many challenges with additional renewable energy development. To this end, HELCO will be participating in projects and studies to address the challenges associated with increasing its renewable energy portfolio. These challenges include the mitigation of negative impacts on HELCO's system caused by the high penetration of intermittent energy generation, the curtailment of

[13] Closed-loop biomass refers to the dedicated growing, harvesting, and processing of crops and subsequent conversion into energy.

generation during periods of low system load, and the lack of transmission and distribution capacity from the east side to the west side of the island.

To meet these challenges, HELCO plans to implement a strategy that incorporates a multi-pronged approach in IRP-3: (1) facilitate commercialization of renewable energy technologies, (2) facilitate integration of intermittent resources, and (3) facilitate the development of renewable energy technologies.

3.3.2.1 Facilitate Commercialization of Renewable Energy Technologies

Renewable Hawaii

HECO, HELCO's parent company, created a non-regulated subsidiary in December 2002 called Renewable Hawaii, Inc. to seek passive investment (providing a reasonable return) opportunities in cost-effective, commercial renewable energy projects in the State. With an initial approval to invest up to $10 million, Renewable Hawaii's formation builds on HECO's (and HELCO's) ongoing commitment to increase Hawaii's use of renewable energy. The primary objectives of Renewable Hawaii's creation are to stimulate the addition of cost-effective, commercial renewable energy in Hawaii, promote viable projects that will integrate positively with the utility grid and encourage renewable energy generation activity where such is lacking in targeted categories.

Renewable Hawaii is attempting to stimulate the renewable energy market by releasing a series of island-specific Renewable Energy Request for Project Proposals (RE RFPP). To meet Renewable Hawaii's objective, renewable projects must utilize cost-effective, commercial technologies with a proven track record and established costs and be 1 MW or larger. Technologies requiring research and design, prototype development, or demonstration will not be considered. Separate RE RFPPs for the island of Oahu and Maui County were released in 2003. Renewable Hawaii is currently reviewing several proposals submitted in response to the requests for Oahu and Maui County. A RE RFPP for the Big Island of Hawaii was released on January 22, 2004 and proposals to this RE RFPP are due April 22, 2004.

Renewable Energy Project Development

The following projects have the potential to increase renewable energy generation on the island of Hawaii. These projects are in various stages of development and are subject to change. Figure 3.3.2.1-1 indicates the location of the proposed projects.

- On August 17, 1999, HELCO entered into a PPA with Kahua Power Partners LLC (KPP) for the purchase of as-available energy from KPP's proposed 10 MW wind farm. The PPA was amended by Amendment No. 1 dated April 4, 2000. The PUC approved the PPA, as amended, on June 1, 2001. KPP did not, however, construct its wind farm. GE Wind Energy completed the acquisition of certain assets of Enron Wind Corporation in May 2002, including the proposed KPP project. On October 7, 2003, GE Wind Energy assigned the KPP PPA to Hawi Renewable Development, Inc. (HRD). On December 9, 2003, HELCO terminated the KPP PPA pursuant to HRD's notice that it does not plan to develop that wind farm, and its request that the PPA be terminated.

  On January 8, 2001, HELCO entered into a PPA with HRD for the purchase of as-available energy from HRD's proposed 5 MW wind farm. An amendment to the PPA was completed on April 30, 2002. The PPA, as amended, was approved by the PUC on January 14, 2003. Due to transmission line limitations, the output of HRD would have been limited to 3 MW if the KPP wind farm was connected to the electric grid through the same 34.5 kilovolt (kV) line.

  On December 30, 2003, HELCO and HRD entered into a PPA under which HRD would sell energy from an expanded wind farm (approximately 10.6 MW) at HRD's 5 MW wind farm site (which can accommodate the expanded wind farm). Since the KPP wind farm would not be built, it is anticipated that the output of the 10.6 MW wind farm would not be limited by another wind farm on the 34.5 kV line (although the output of the 10.6 MW wind farm may be limited on occasion due to other factors). PUC approval of the PPA is pending.

- Apollo Energy Corporation (AEC), the owner of the existing wind farm in Kamaoa, has an existing contract to provide HELCO with up to 7 MW of as-available wind power through June 29, 2002 (and extending thereafter until terminated by HELCO or Apollo). Apollo filed a petition for hearing with the PUC on April 28, 2000, alleging that it had unsuccessfully attempted to negotiate a new power purchase agreement with HELCO. Apollo had offered to repower its existing 7 MW facility by the end of 2000 and to install additional wind turbines, up to a total allowed capacity of 15 MW, by the end of 2001. The parties agreed to limit to four issues the matters being presented to the PUC for guidance: whether Apollo is entitled to capacity payments; whether Apollo is entitled to a minimum purchase rate; whether certain performance standards should apply; and whether HELCO's proposed dispute resolution provision should apply. A hearing on these issues was held on October 3 to 5, 2000. On May 30, 2001, the PUC issued a D&O in which it ordered HELCO and Apollo to continue to negotiate a PPA, consistent with the terms of the D&O, and to submit either a finalized PPA or status reports informing the PUC of matters preventing finalization of a PPA. HELCO and Apollo were unable to agree to a PPA by the specified date, and each submitted a status report. The parties continued to negotiate through March 2003, and while agreement was reach on pricing and other matters (such as increasing the allowed capacity to 20 MW), final agreement has not been reached on certain technical and interconnection cost issues. The PUC issued an Order on February 26, 2004 for Apollo and HELCO to file (1) a joint status report or individual status reports, and (2) a stipulated procedural order establishing a scheduled of procedural or target dates, culminating in the filing of a new amended PPA with the PUC. On March 18, 2004, Apollo filed a Motion for Expedited Resolution of Issue in which it contested the necessity for a previously accepted three-breaker switching station and contended that a one-breaker switching station is sufficient. On March 25, 2004, HELCO filed a Memorandum in Opposition to Apollo's motion in which HELCO explained the necessity for a three-breaker switching station. On March 29, HELCO filed its status report with the PUC in which HELCO explained that technical and pricing issues addressed since the last status report (January 2003) and the present (March 2004) have been resolved, and that the remaining issues were generally created by Apollo by reopening previously agreed upon cost issues after the technical and pricing issues were resolved. The status report also includes HELCO's procedural proposal to resolve the remaining issues.

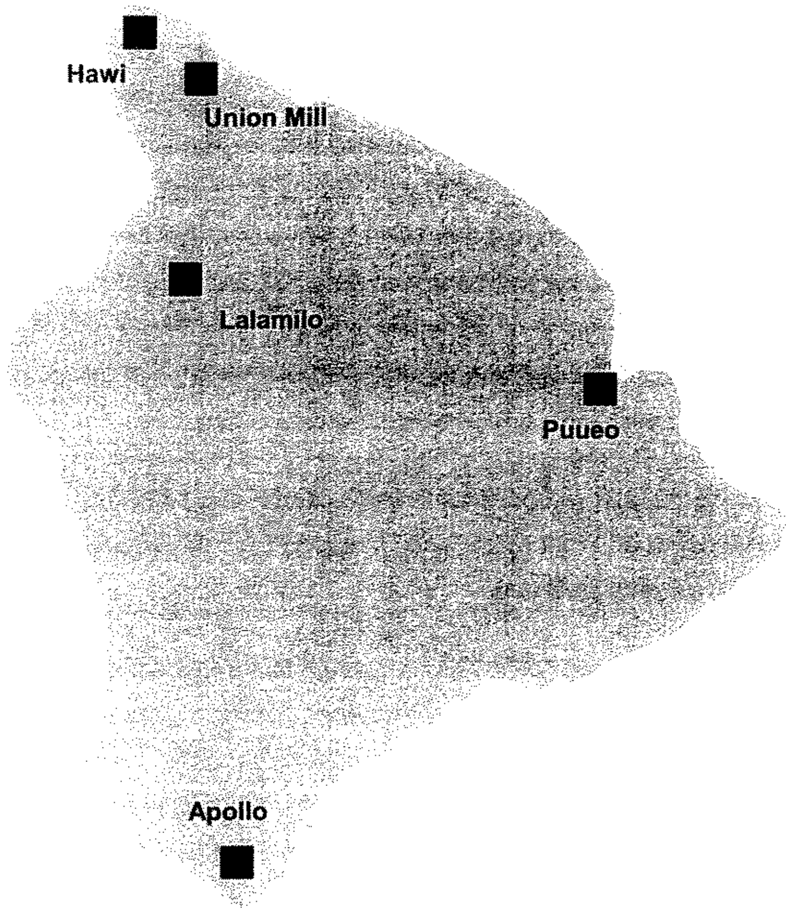
- Lalamilo is an existing 2.28 MW HELCO-owned wind farm located in the Waimea area. HELCO is presently considering repowering options for this facility.

- The existing HELCO-owned 1.5 MW run-of-river generator at HELCO's Puueo hydroelectric plant was severely damaged. In September 2002, HELCO assessed the damage and decided to rehabilitate the hydroelectric system. In August 2003, HELCO filed a PUC application in Docket No. 03-0222 to undertake and complete the Puueo Hydroelectric Plant Rehabilitation project, which sought to replace the existing 1.5 MW and 0.750 MW generators with a modern, more efficient turbine generator with a capacity of roughly 2.28 to 2.4 MW. The PUC approved the project in November 2003. Preliminary estimates indicate that the work to rehabilitate the Puueo facility can be completed in the 2005 timeframe.

- Union Mill proposes to build a 0.8 MW hydroelectric plant with water storage on the northern side of the Big Island. Union Mill is studying various technical and financial issues at this time.

- HECO, HELCO, and DBEDT are funding a study to assess the hydroelectric resource potential of water systems operated by the County of Hawaii Water Department, State of Hawaii Department of Agriculture, and private landowners. In addition, existing water reservoirs will be evaluated to determine the feasibility of in-line hydroelectric power production and pumped storage hydroelectric (PSH) applications. PSH has the potential to decrease curtailment of wind farms by providing a load (i.e., pumping water from a lower elevation reservoir to a higher elevation reservoir) during periods of low electrical demand on the HELCO grid. This study is targeted for completion in late 2004. In addition, HELCO has committed funding to cost-share with the County of Hawaii Water Department for an in-line hydroelectric demonstration project. Based on an assessment of water systems conducted by the County of Hawaii Water Department, several feasible sites were identified. The County of Hawaii Water Department is assessing the next steps, including the selection of the location of the demonstration project. Installation of the in-line hydroelectric system is targeted to start by the end of 2004.

Figure 3.3.2-1
Proposed Renewable Projects



3.3.2.2 Facilitate Integration of Intermittent Resources

Due to the gusty and turbulent nature of wind, the energy output of a wind farm can change very rapidly. Rapidly changing energy output of a wind farm on either a weakly supported transmission line or an isolated island grid system can create fluctuations in both frequency and voltage on the transmission system. The fluctuations may require disconnection of the wind farm from the transmission system or compensation by load-following thermal generation units. To mitigate these fluctuations HELCO is studying various technologies and assessment tools.

- Electronic Shock Absorber

  To help stabilize grid operation and maintain power quality on a grid system with a high penetration of wind farms, HECO, HELCO, and MECO have teamed with a private company to examine if a device can be developed from commercial products for installation between a wind farm and the utility grid. The purpose of the device, called the Electronic Shock Absorber (ESA), is to help the electric utility ride through short duration power fluctuations (frequency, voltage, etc.) from the wind farm caused by the variable nature of wind. The intent is to have a product that is commercially available to all wind farm developers to address this issue thereby increasing the potential usage of wind energy.

  HECO has filed a patent application and a study has been conducted to identify available technologies. An assessment study concluded that an ESA device using commercial products could be fabricated. A demonstration unit is planned to be fabricated and tested in the near future.

- Intermittent Generation Assessment Protocol (IGAP) Study

  To improve existing planning and evaluation tools, HECO and HELCO have funded a study to address the impact of intermittent renewable energy generation on small, isolated electric utility systems (a unique problem faced by Hawaii utilities). In the IGAP study, the consultant will work with HECO and HELCO to develop a system of policies and standards for integrating and operating existing intermittent generation on island electric utility systems; planning tools and methodologies to assess quantitatively on a discrete and aggregate basis the impacts of existing and future intermittent generation on the utility system's power quality, reliability, and economics; and a means to appropriately allocate the costs of integrating future intermittent generation into utility systems. The study is scheduled to be completed by the end of 2004.

- Grid Quality Assessment Project

  Through its membership with the Utility Wind Interest Group (UWIG), HECO is participating in a project to develop assessment tools related to grid quality. The purpose of the grid quality assessment project is to determine and characterize the voltage fluctuations caused by wind farms on distribution feeder lines.

Software that calculates voltage fluctuation and voltage flicker is being beta-tested by HELCO using the proposed Hawi wind farm (Big Island of Hawaii) as a model. This wind farm was selected as an ideal candidate because it is a relatively small wind farm, by mainland standards, and is connected to a radial line. Results will be made available to UWIG members, thus expanding the knowledge base of the utility industry.

- Distributed Energy Resources Management as a Microgrid

  Funding under a U.S. Department of Energy competitive grant program has been received to conduct a study in which HELCO and the State of Hawaii Department of Business, Economic Development and Tourism (DBEDT) will evaluate the combination of hybrid, controllable distributed energy resources (DER) systems that will encourage development of renewable and distributed energy resources. Hybrid DER combines distributed generation from renewable resources, electrical storage, thermal energy storage, and building energy management systems. Integrating these technologies with HELCO's network control and monitoring systems has the potential to help alleviate system problems and constraints. The study is targeted for completion in mid 2004.

- Battery Energy Storage System Study

  Funding under a U.S. Department of Energy competitive grant program has been received to conduct a battery energy storage system study (BESS) in which HELCO and DBEDT will examine the ability to charge a BESS with off-peak energy (primarily from excess renewable energy sources), validate the applicability of a BESS to improve system reliability and power quality, evaluate the potential to defer new transmission lines and re-conductoring, and support the implementation of renewable energy. The project will be completed in the second quarter of 2004.

3.3.2.3 Facilitate Development of Renewable Energy Technologies

HELCO is participating in several renewable energy pilot and demonstration projects.

Hydrogen Power Park Study

One of the key components necessary for commercial utilization of hydrogen is a safe and reliable hydrogen storage and distribution system. HELCO and HECO are partnering with DBEDT, Hawaii Natural Energy Institute (HNEI), Sentech, Sunline, Stuart Energy, and United Technologies Company (UTC) Fuel Cells in a project to introduce and demonstrate hydrogen-based infrastructure in Hawaii. The design of the hydrogen production and storage infrastructure has been initiated.

NELHA Gateway Project

HELCO is partnering with the Natural Energy Laboratory of Hawaii Authority (NELHA), DBEDT, HNEI, and Sentech in a project to construct distributed energy systems at the Gateway Center located at the entrance to NELHA's Hawaii Ocean Science and Technology Park. The Gateway Distributed Energy Resources Center is part of NELHA's ongoing efforts to help Hawaii become an international model for clean energy technologies through education, research, demonstration, development, and bringing clean, distributed and sustainable energy technologies to commercialization. Construction of the Gateway Center is targeted for completion by the end of June, 2004 with the construction of this project to follow thereafter.

In partnership with NELHA, HELCO will be installing two separate photovoltaic (PV) systems within NELHA's Gateway Distributed Energy Resources Center to demonstrate solar technology applications. The first solar electric system of 20 kW AC will be installed on the Gateway Outreach Center and the second system of approximately 18 kW AC will be installed on the first of several laboratories planned for the site. In addition, HELCO has received a grant on behalf of the Island of Hawaii Million Solar Roofs Partnership of $46,000 through the U.S. Department of Energy's Million Solar Roofs program to build an educational display for the Outreach Center focusing on energy efficient building construction (zero energy homes) utilizing solar and other technologies along with the multiple uses of solar and how solar can be used as an energy source to generate hydrogen. Partnering on the grant project are NELHA and DBEDT.

Solar Thermal/Cooling Pilot Project

HELCO is partnering with Pacific Energy Services, Solel, and the Waikoloa Beach Marriott, an Outrigger Resort, on a pilot-scale project to evaluate and demonstrate the feasibility for full-scale solar thermal and solar cooling installations for West Hawaii hotels and resorts. The purpose of the project is to gather and record operational data from the high temperature, solar thermal panel for an engineering feasibility study to evaluate the economics of full-scale production of domestic hot water, and production of chilled water by an absorption chiller process. The pilot project has been in operation and recording operational data since May 2003, and has been used to demonstrate the technology to interested hotel customers and engineers.

Sun Power for Schools Program Extension

HECO, HELCO, and MECO have extended their Sun Power for Schools program with the State of Hawaii Department of Education for another two-year period (2003 and 2004). Through the Sun Power for Schools program, the utilities will continue to install photovoltaic systems at Hawaii public schools using voluntary customer contributions and by providing in-kind utility contributions, including engineering, project management, administration, advertising, and marketing. To date, nineteen public schools have received photovoltaic systems (nine on Oahu, four on the island of Hawaii, and five in Maui County) and benefited from the educational material developed as part of the program. About 0.7% of the electric utilities' customers are participating in this green pricing program. Program efforts will continue in 2003 and 2004 and may be extended beyond 2004.

U.S. Department of Energy, Million Solar Roofs Initiative (MSR)

In 1997, the Hawaii Island MSR Partnership, formed and led by HELCO, was one of the first partnerships in the United States to commit to the national MSR program. Partnership members currently consist of representatives from the solar industry, government agencies, and the general public. The Million Solar Roofs Initiative is designed to support states and local communities as they develop a strong commitment to the sustained deployment of solar energy technologies. The local partnership has worked to identify and reduce the local barriers to the adoption of solar technologies.

Through MSR, HELCO has written several grants and received funds to conduct several workshops and projects. These endeavors have included:

- Development of an Island of Hawaii MSR web site, www.hawaiiislandsolar.org
- Workshops on financing solar projects
- Workshops on designing and installing code-compliant solar electric systems
- Workshops for educators on including solar energy education in their classes

Current projects include the development of an educational display for NELHA's Gateway Outreach Center to showcase energy efficient building design incorporating solar technologies.

Through the MSR, and in partnership with the County of Hawaii, HELCO also installed a solar demonstration and educational kiosk as well as solar powered lighting for the public restrooms at the Hilo bay front. In addition, HELCO has promoted the applicability of PV installations and net-energy metering by installing a 5.4 kW PV system, which features an educational display, on its Kailua-Kona Engineering Office.

3.3.3 Recent Developments in Renewable Energy Since IRP-2

The following are some of the recent developments in renewable energy since IRP-2.

- Renewable Portfolio Standard
  The 2001 Hawaii State Legislature passed a law introducing a Renewable Portfolio Standard (RPS) for Hawaii. Act 272 established RPS levels for electric utilities to guide them in incorporating renewable resources into their resource portfolios and to reduce the use of imported oil.[14] HECO, HELCO and MECO, were among the supporters of this law.

  Act 272 states that the RPS is the percentage of electricity sales that is represented by renewable energy. Renewable energy is the electrical energy produced by wind, solar energy, hydropower, landfill gas, waste-to-energy, geothermal resources, ocean thermal energy conversion, wave energy, biomass including municipal solid waste, biofuels or fuels derived from organic sources, hydrogen fuels derived entirely from renewable energy, fuel cells where the fuel is derived entirely from renewable resources, or the savings brought about by the use of solar and heat pump water heating. Act 272 further specifies that the RPS levels shall be 7% of electricity sales by December 31, 2003, 8% by December 31, 2005, and 9% by December 31, 2010. An electric utility company and its electric utility affiliates may aggregate their renewable portfolios in order to achieve the RPS.

[14] Act 272, Part I, codified as sections 269-91 to 269-94, Hawaii Revised Statutes.

As of December 31, 2003, 8.40% of electricity sales from the HECO Utilities came from renewable energy sources (including the energy sales equivalent of the energy savings from solar water heating and heat pump systems installed under the companies' DSM programs).

- Net Energy Metering

Act 272 passed by the 2001 Hawaii State Legislature makes net energy metering (NEM) available to eligible customers until the total rated generating capacity of eligible customers equals 0.5 percent of the electric utility's system peak demand.[15] HECO, HELCO, and MECO were among the supporters of this legislation.

The NEM law states that eligible customers who own and operate a solar, wind turbine, biomass, or hydroelectric energy generating facility, or a hybrid system consisting of two or more of these facilities, with a capacity of not more than 10 kilowatts, shall be credited at the retail rate (of the rate class the customer is normally assigned to) for electrical energy generated by the eligible customer and fed back to the electric grid. Over a monthly billing period, the difference (i.e., net) between the customer-generated electrical energy and the electrical energy supplied through the electric grid is determined. In essence, customers are able to "bank" the renewable energy they generate for later use. Excess kilowatt-hours generated during this period are retained by the utility unless the electric utility enters into a purchase agreement with the customer.

In response to the passage of Act 272 of the 2001 Hawaii State Legislature, HECO, HELCO, and MECO completed implementation activities for net energy metering (NEM) prior to the signing of Act 272 into law on June 25, 2001. This allowed HECO to implement the customer billing modification, a NEM Agreement, and a NEM Tariff on the same day the legislation was signed into law.

In December 2001, HELCO completed installation of a grid-connected 5.4 kW photovoltaic system at HELCO's Kona Engineering Office. The system is an example of a NEM generating system and features an educational display describing NEM, the photovoltaic system, and the benefits of solar. In addition to

[15] Act 272, Part II, codified as sections 269-101 to 269-111, Hawaii Revised Statutes.

providing customer education, the system provides HELCO staff an opportunity to gain experience with a NEM solar electric system.

As of December 31, 2003, one hundred and sixty information packets were sent to HELCO customers. Eleven NEM projects (photovoltaic systems) with a total rating of 42.9 kilowatts have been completed.

3.4 Existing HELCO Generation

HELCO considers retiring its generating units based on the individual unit's age, condition, operation and maintenance costs, reliability, availability of spare parts, potential modernization costs, load growth, and ability to install or purchase additional firm capacity. In consideration of these factors, HELCO's IRP-2 had previously planned to retire many of its units after new capacity was added at the Keahole Generation Station. Table 4-5 on page 4-13 of HELCO's IRP-2 report in Docket No. 97-0349 shows the planned retirement dates for various HELCO units at the time the IRP-2 report was filed.

Consistent with this retirement assumption from IRP-2, some of the maintenance of the HELCO units had been deferred. However, the aging units could not be retired due to the difficulties encountered in adding new generation at Keahole. HELCO's experience has demonstrated that obtaining permits for adding new generating capacity to the system is extremely difficult. Therefore, the retirement of units that are already grid-connected and permitted must be carefully considered. Additional expenditures to keep the units operating reliably are often warranted, with the need for expenditures being considered on a case-by-case basis.

Kanoelehua CT-1, D11, D15-17, Waimea D12-14, and Keahole D21-23 (38.25 MW total) will be kept in service until the units are no longer needed to maintain system reliability or maintain quick start capability. The diesel units have fast-starting capability and can be on line within 90 seconds from when they are started. The fast-start diesel units are used to balance generation and load during post-contingency situations such as a generating unit trip or a transmission line outage. In addition, the fast-staring diesel units provide flexibility in adjusting the amount of firm capacity and regulating capacity HELCO has to have on line to match system load and maintain system frequency and voltage, which can fluctuate instantaneously depending on the amount and intermittent nature of the as-available energy being provided to the system.

Based on these considerations, HELCO's preferred integrated resource plan contains no planned discretionary retirements of any of its existing generating units. Keahole Diesels D18-20 retirements are mandatory and they must be retired in accordance with the CT-4 and CT-5 air permit requirements. The current status of HELCO's existing units will be reviewed as part of the IRP-3 process. Capital and maintenance projects to maintain acceptable levels of reliability will be performed as needed.

3.5 Keahole CT–4, CT–5, and ST-7

HELCO had been endeavoring for several years to install at its Keahole power plant two 20 megawatt (MW) combustion turbines (CT-4 and CT-5), followed by an 18 MW heat recovery steam generator (ST-7). As a result of a September 19, 2002 decision embodied in an order dated October 3, 2002 and a final judgment dated November 7, 2002 (the November 7, 2002 Final Judgment) by the Third Circuit Court of the State of Hawaii (Circuit Court), relating to an extension of the construction deadline, the construction of CT-4 and CT-5, which had commenced in April 2002 after HELCO had obtained a final air permit and the Circuit Court had lifted a stay on construction, was suspended.

With installation of CT-4 and CT-5 halted and the proceedings described above pending and unresolved, the parties that opposed the Keahole power plant expansion project (other than Waimana, which did not participate in the settlement discussions and opposes the settlement), including Keahole Defence Coalition (KDC), the Individual Plaintiffs, and Department of Hawaiian Home Lands (DHHL), engaged in a mediation process with HELCO and several Hawaii regulatory agencies in an attempt to achieve a resolution of the matters in dispute that would permit the project to be constructed and put in service. This process led to an agreement in principle ultimately embodied in the Settlement Agreement, executed by the last party to it on November 6, 2003, under which, subject to satisfaction of several conditions, HELCO would be permitted to proceed with installation of CT-4 and CT-5, and, in the future, ST-7. In addition to KDC, the Individual Plaintiffs, DHHL and HELCO, parties to the Settlement Agreement also include the Department of Health (DOH), the Director of the DOH, the Department of Land and Natural Resources (DLNR), and the Board of Land and Natural Resources (BLNR).

In connection with efforts to implement the agreement in principle and Settlement Agreement:

- On October 10, 2003, the BLNR conditionally approved a 19-month extension of the previous December 31, 2003 construction deadline, but subject to court action allowing construction to proceed (BLNR 2003 Construction Period Extension).

- On October 14, 2003, the Hawaii Supreme Court granted a motion to remand the pending appeal of the November 2002 Final Judgment (which was halting construction) in order to permit the Third Circuit Court to consider a motion to vacate that judgment.

- On October 17, 2003, a motion to vacate the November 2002 Final Judgment was filed in the Third Circuit Court by KDC and DHHL.

- On November 5, 2003, Waimana filed a complaint in the United States District Court for the District of Hawaii in which it sought, among other things, a temporary restraining order enjoining the Third Circuit Court from granting the motion to vacate the November 2002 Final Judgment. The United States District Court denied this motion on November 7, 2003 and dismissed Waimana's complaint on November 14, 2003.

- On November 12, 2003, the motion to vacate the November 2002 Final Judgment was granted by the Third Circuit Court, over Waimana's objections, and, on November 28, 2003, the Third Circuit Court entered its first amended final judgment (November 2003 Final Judgment) vacating the November 2002 Final Judgment.

- On November 17, 2003, HELCO resumed construction of CT-4 and CT-5.

- On January 13, 2004, the Hawaii Supreme Court granted, over Waimana's objection, HELCO's motion to dismiss HELCO's original appeal of the November 2002 Final Judgment (since that judgment had been vacated).

Full implementation of the Settlement Agreement is conditioned on obtaining final dispositions of all litigation and proceedings pending at the time the Settlement Agreement was entered into. While substantial progress has been made in achieving such dispositions, final dispositions of all such proceedings have not yet been obtained. HELCO has agreed in the Settlement Agreement that it will undertake a number of actions, in addition to complying with the stricter noise standards, to mitigate the impact of the power plant in terms of air pollution and potable water and aesthetic concerns. These actions relate to providing additional landscaping, expediting efforts to obtain the permits and approvals necessary for installation of ST-7 with selective catalytic reduction (SCR) emissions control equipment, operating existing CT-2 at Keahole within existing air permit limitations rather than the less stringent limitations in a pending air permit revision, using primarily brackish instead of potable water resources, assisting DHHL in installing solar water heating in its housing projects and in obtaining a major part of HELCO's potable water allocation from the County of Hawaii, supporting KDC's participation in certain PUC cases, paying legal expenses and other costs of various parties to the lawsuits and other proceedings, and cooperating with neighbors and community groups, including a Hot Line service for communications with neighboring DHHL beneficiaries.

Since the time construction activities resumed in November 2003, HELCO has laid the groundwork for implementation of many of its commitments under the Settlement Agreement. However, despite the numerous rulings against Waimana described above, it has continued to pursue efforts to stop or delay the Keahole project and to interfere with implementation of the Settlement Agreement, including (a) filing a notice of appeal to the Hawaii Supreme Court of the Third Circuit Court's November 2003 Final Judgment (vacating the November 2002 Final Judgment), (b) appealing to the Third Circuit Court the BLNR 2003 Construction Period Extension and (c) appealing to the Third Circuit Court the BLNR's approval, on December 12, 2003, of HELCO's request for a revocable permit to use brackish well water as the primary source of water for operating the Keahole plant. In January 2004, the Third Circuit Court denied Waimana's motion to stay the effectiveness of the BLNR 2003 Construction Period Extension, and granted HELCO's motion (joined in by the BLNR) to dismiss Waimana's appeal of that extension. In February 2004, the Third Circuit Court denied Waimana's motion to stay the effectiveness of the revocable permit to use brackish water, and granted HELCO's motion (joined in by the BLNR) to dismiss Waimana's appeal of that permit.

After previously submitting and withdrawing a petition, HELCO submitted to the Hawaii State Land Use Commission (LUC) on November 25, 2003 a new petition to reclassify the Keahole plant site from conservation land use to urban land use. The installation of ST-7, with SCR as contemplated by the Settlement Agreement, is dependent upon this reclassification. In December 2003, Waimana filed a Notice of Intent to Intervene in the LUC proceeding. On February 5, 2004, the LUC issued an order, with which HELCO concurred, that an environmental impact statement (EIS) be prepared in connection with its reclassification petition. Work on the EIS was already in progress before the ruling was issued. The entire reclassification process could take several years.

The probability that HELCO will be allowed to complete the installation of CT-4 and CT-5 during 2004 has been substantially enhanced by the Settlement Agreement, the Third Circuit's November 2003 Final Judgment, and the decisions of the BLNR to extend the construction deadline by 19 months from December 31, 2003 and to grant to HELCO a revocable permit to use brackish water for the plant. Although additional steps must be completed under the Settlement Agreement to satisfy its remaining conditions and HELCO must obtain the further permits necessary to complete installation of CT-4 and CT-5 (and, eventually ST-7), HELCO believes that the prospects are good that those conditions will be satisfied and that any further necessary permits will be obtained. Nevertheless, Waimana has continued its efforts to stop or delay the construction and there could be further delays in completing construction.

It is expected that CT-4 and CT-5 will go online in the second quarter 2004 and will be fully operational by year-end. HELCO retired diesel units D18-19 in February 2004 and will retire D20 at Keahole in accordance with the air permit requirements for CT-4 and CT-5.

3.6 Transmission Issues

In any electrical transmission system, it is crucial that the current flowing through the system and the voltage on the system are maintained within certain limits. Based on HELCO generating units on the system as of November 2002, 85% of HELCO's generating capacity resides on the east side of the island. Based on a normal economic commitment order with all of HELCO's transmission lines operating normally, HELCO, on a daily basis, transports the energy generated on the east side over to the load center on the west side. Only during some portions of the on-peak period, including the priority-peak period, is west side generation (via Keahole or Waimea) on-line to serve the load demand in West Hawaii.

Under normal conditions, with all transmission system components in service, HELCO's transmission system can still meet all line loading and voltage level requirements. However, under certain contingency conditions, such as a transmission line being out of service, conductor overloading and/or undervoltage conditions could occur. The most problematic area is in the northwest part of the island where the Keamuku-Keahole (6800) line, the Waimea-Keamuku (7200) line and the Waimea-Ouli (7300) line serve the Kona area. The current flowing through these lines carrying power from east side generators to meet the load demand in West Hawaii will exceed the current carrying capacity of the line under certain line contingency situations. Low voltage situation may also occur during certain line contingencies including the three mentioned above.

The overload and undervoltage situations can be alleviated either by decreasing the amount of power transported from the east side generators to the west side loads or by upgrading the transmission system to accommodate the increased current flow (that results from the increased power flow) and mitigate against low voltage conditions. For example, installing a baseload generation such as ST-7 at Keahole would allow the west side load to be served primarily by the efficient west side unit and decrease the amount of power required from east side generators. Another alternative is to upgrade the existing transmission system by reconductoring existing transmission lines and installing capacitors for voltage support.

HELCO's IRP preferred plan, as filed in HELCO's IRP-2 filing, planned for the completion of a base-loaded Keahole unit (ST-7) in 2006. The date of installation for ST-7 is no longer 2006 and there is some uncertainty in forecasting the exact installation date for ST-7. Improvements to the transmission system are now being planned for the near-term because of the increasing load in West Hawaii and the uncertainty of installing a baseload generating unit at Keahole. These improvements include the following projects:

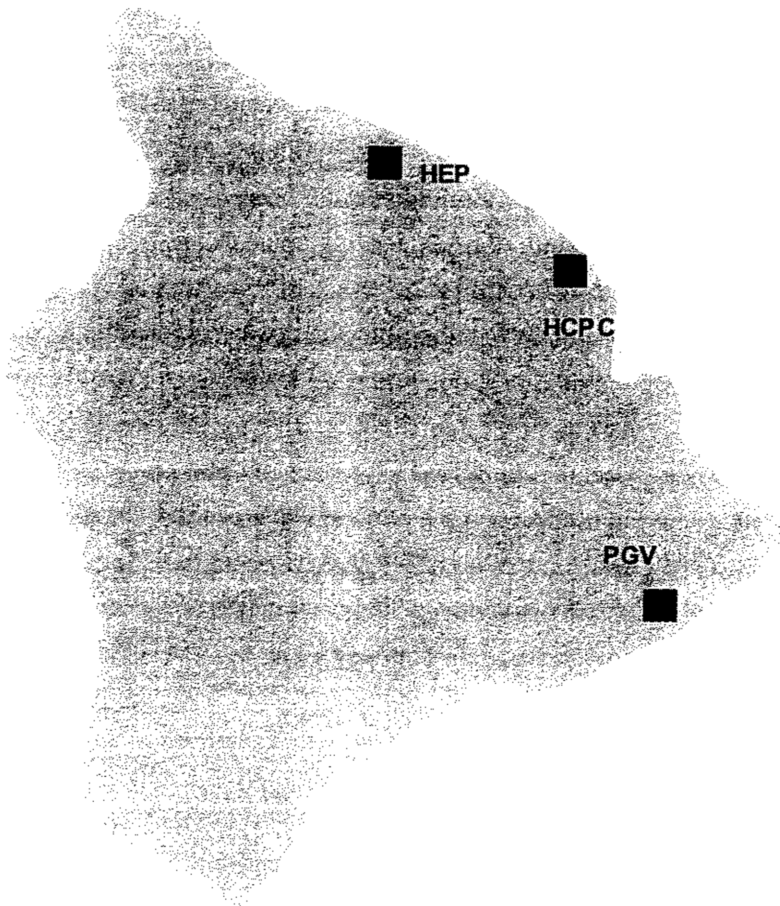
- Kailua Capacitor Bank Installation (Docket No. 03-0388)
- 7300 Transmission Line Reconductoring (targeted for 2004)
- 7200 Transmission Line Reconductoring (targeted for 2005-2006)

Transmission plans can differ depending on the location of where future generating units are located. Transmission issues will be considered in HELCO's IRP-3 process. See Section 2.3 of this report for additional discussion of transmission capital projects and their relationship to the IRP process.

3.7 Independent Power Producer Issues

HELCO purchases firm capacity from three Independent Power Producers (IPPs): Puna Geothermal Ventures, Hamakua Energy Partners, and Hilo Coast Power Company. Refer to Figure 3.7-1 for location of these IPPs.

Figure 3.7-1
Location of Firm Capacity IPPs



3.7.1 Puna Geothermal Ventures (PGV)

PGV's PPA specifies that 30 MW be exported to HELCO during the on-peak period. From April to December 2002, PGV exported an average of 5.6 MW due to blockage of one of their source wells. PGV has drilled a new source well and has been slowly increasing their export since the beginning of 2003. As of early February 2004, PGV has been able to export roughly 27 MW on a consistent basis. PGV is a renewable resource that provides a large contribution towards the HECO Companies Renewable Portfolio Standard. However, in 2002 HELCO learned first-hand that geothermal resources are not immune to production difficulties. PGV anticipates that it will be fully restored to 30 MW by late 2004.

3.7.2 Hamakua Energy Partners (HEP)

In June 2001, HEP demonstrated 60 MW of output from the facility. Subsequently, the output deteriorated due to technical problems in the steam turbine. HEP has since resolved its nozzle plugging problems, but due to high nitrogen oxide emissions and high steam turbine vibration problems, the output had been limited to 55-57 MW in early 2003. HEP requested maintenance outages to correct the problems and returned to providing HELCO with 60 MW later in 2003. In September 2003, the parent company of the managing general partner and a limited partner of HEP, Jones Capital Corporation, filed for reorganization in bankruptcy in North Carolina. Jones is one of the two co-guarantors of the HEP project. Jones has stated that the bankruptcy filing will have no impact on HEP's ability to meet its contractual commitments. Jones has been attempting to sell its interest in HEP under the supervision of the bankruptcy court. An auction among the qualified bidders was held on February 23, 2004 and the court held a hearing on February 24, 2004. By Order dated March 2, 2004, the court approved a motion to sell substantially all of the assets of Jones to United States Power Fund L. P. (USPF) and directed the appropriate parties to implement the sale. HELCO will be working with Jones and USPF to evaluate the terms and conditions of the sale and any implications of the sale on the PPA with HEP.

3.7.3 Hilo Coast Power Company (HCPC)

HCPC has helped HELCO's generation situation by switching from a 5 day per week schedule, as specified in the Second Amended and Restated PPA, to a 7 day per week schedule as needed, to prevent generation shortfalls. Weekend operations occurred frequently in 2002 after PGV's output was drastically reduced. Weekend operation was required less frequently in 2003, reflecting less frequent periods of tight capacity on the HELCO system.

The five-year term of HCPC's Second Amended and Restated PPA will end on December 31, 2004. After 2004, the PPA can continue on a year-to-year basis with either HCPC or HELCO able to terminate the contract by providing written notice by May 30th of the termination year. Any decision to give notice of termination would be based on the facts and circumstances at the time. The decision of whether or not to terminate the HCPC PPA will be reflected in HELCO's IRP-3 supply-side resource update.

4. UPDATED PLANNING INFORMATION

4.1 Sales and Peak Forecast

HELCO's May 2003 short-term sales and peak forecast included updates for changes in local economic conditions. A comparison of the May 2003 forecast (extrapolated to 2018) and the IRP-2 forecast (September 1997) shows that the system peak demands in the May 2003 forecast are higher, as a result of updated economic assumptions. A new updated long-term Sales & Peak Forecast is being developed for HELCO's IRP-3 process, which is currently in progress.

The following table compares the base scenario peak load values (in system net megawatts) included in the May 2003 forecast with those from the IRP-2 forecast. Actual recorded system peak demands for the years 2000, 2001, 2002, and 2003 are also provided. The May 2003 forecast was extrapolated from 2009 to 2018 in order to provide a comparison with the IRP-2 forecast. Only the May 2003 forecast contains non-utility CHP impacts as discussed in Section 3.2.5. Both forecasts contain DSM impacts.

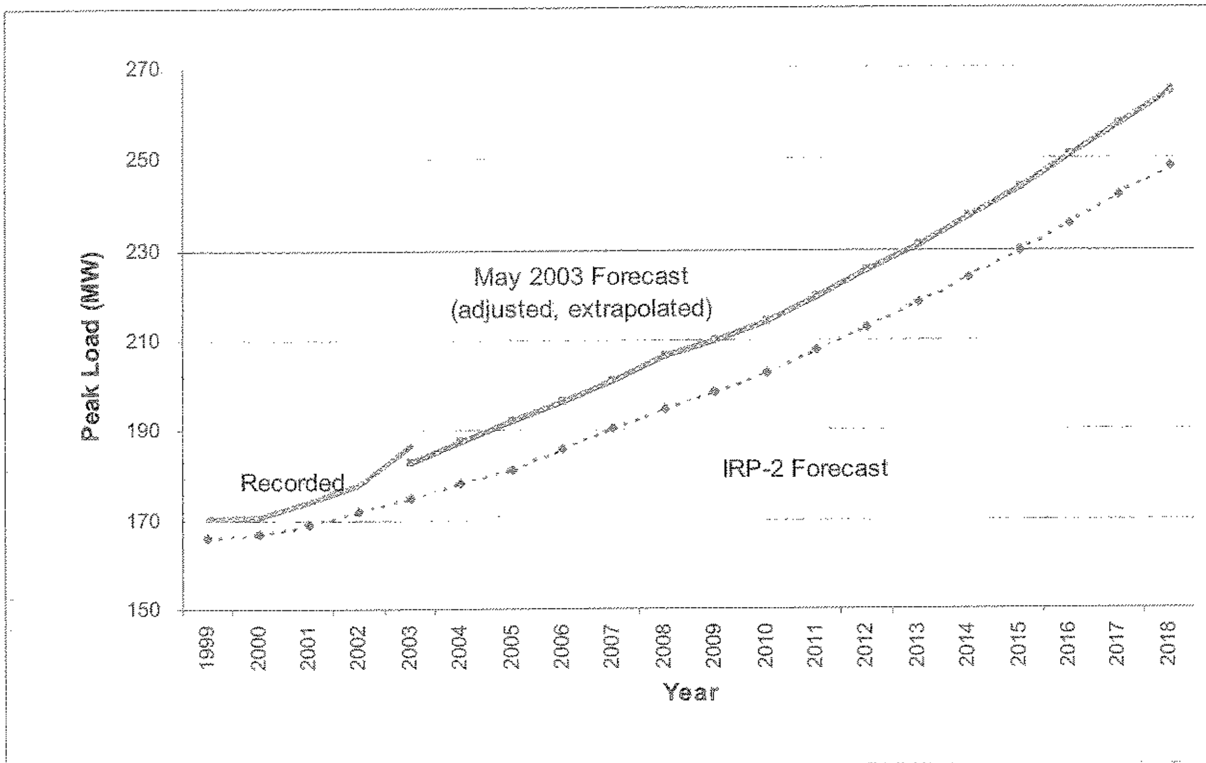
Table 4.1-1
Peak Load Forecast Comparison (Net MW)
May 2003 vs. IRP-2 Forecast

Year	May 2003 * Peak Load Net MW	IRP-2 Peak Load Net MW	Recorded Peak Load Net MW
1999		166	170
2000		167	171
2001		169	174
2002		172	178
2003	183	175	187
2004	188	178	
2005	192	181	
2006	197	186	
2007	201	190	
2008	207	195	
2009	210	199	
2010	214	203	
2011	220	208	
2012	225	213	
2013	231	218	
2014	237	224	
2015	244	230	
2016	251	236	
2017	258	242	
2018	265	248	

* May 2003 Forecast adjusted for DSM (after 2008) and 3rd Party CHP impacts
May 2003 Forecast extrapolated to 2018

The following graph illustrates the difference between the base scenario system peak load forecasted in the May 2003 forecast and the IRP-2 forecast.

Figure 4.1-1
IRP-2 Forecast vs. May 2003 Peak Forecast (Net MW)



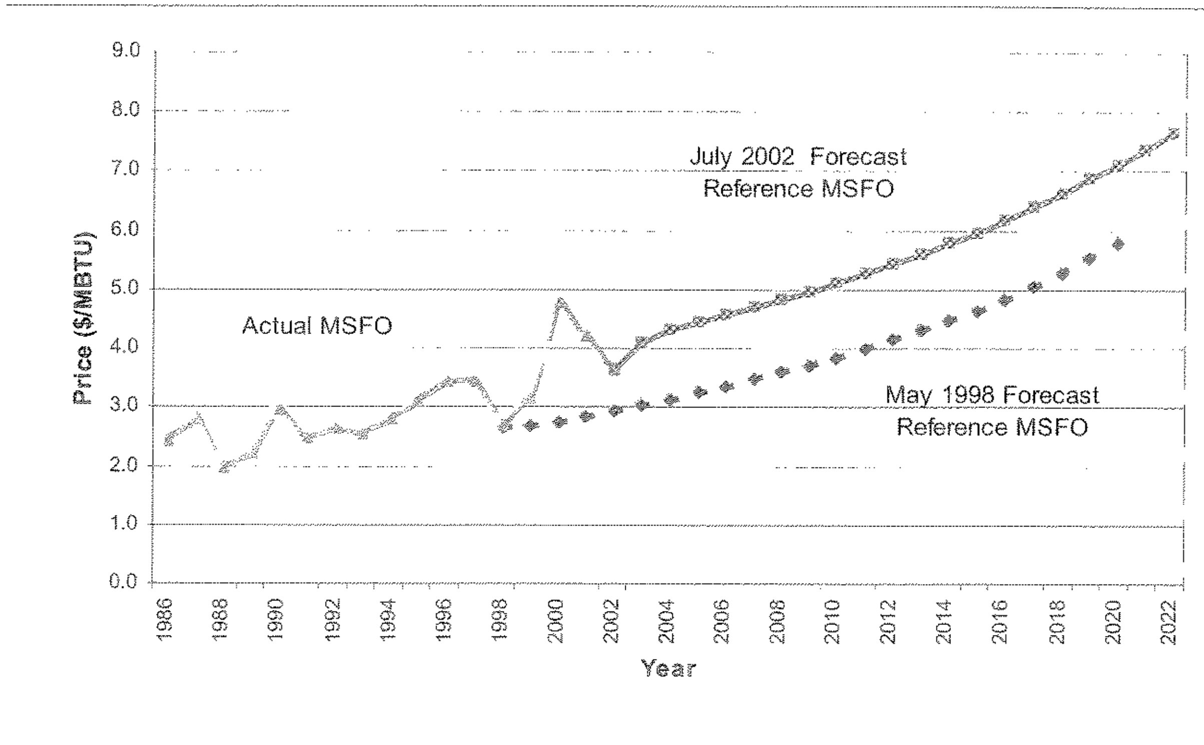
4.2 Fuel Price Forecast

Using widely used government forecasts, HELCO prepared and adopted a new fuel price forecast in July 2002. In the years between the 1998 Fuel Price Forecast used in the IRP-2 Supplement and the 2002 Fuel Price Forecast, the actual price of crude oil declined to record lows in 1998, spiked in 2001, and has since gone down.[16] A comparison of the July 2002 Fuel Price Forecast versus the May 1998 Fuel Price Forecast is shown in Table 4.2-1.

[16] The IRP-2 issued in September 1998 used the May 1995 Fuel Price Forecast. A Supplement, issued in March 1999, used the May 1998 Fuel Price Forecast. The 1995 reference forecast is generally higher than the 1998 reference forecast for both MSFO and diesel fuels.

The prices for both medium sulfur fuel oil (MSFO) and diesel are higher in the July 2002 Fuel Price Forecast than in the May 1998 Fuel Price Forecast.

Figure 4.2-1
MSFO Fuel Price Forecast Comparison
May 1998 versus July 2002



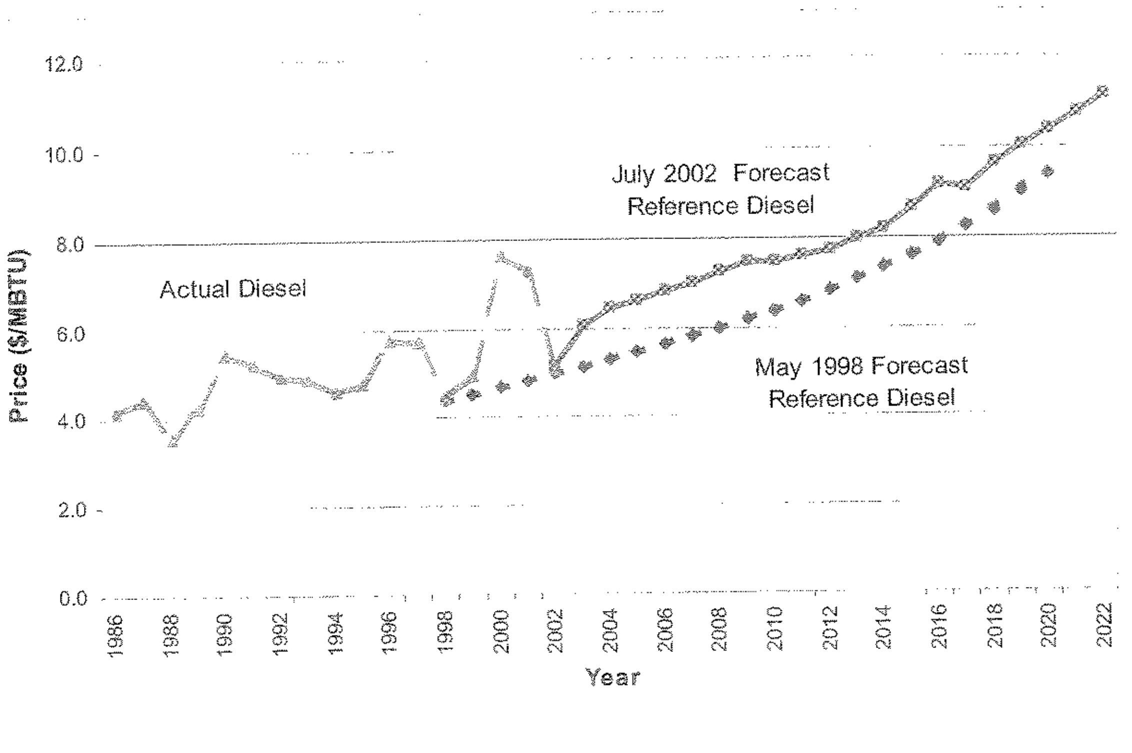
The price differentials or "spreads" between MSFO fuel forecasted prices in the July 2002 Fuel Price Forecast remained fairly consistent with the differentials in the May 1998 Fuel Price Forecast.

Table 4.2-1
MSFO and Diesel Price Forecast Comparison
May 1998 versus July 2002

Year	(A) May 1998 MSFO $/MBTU	(B) July 2002 MSFO $/MBTU	(A) - (B) Difference MSFO $/MBTU	(C) May 1998 Diesel $/MBTU	(D) July 2002 Diesel $/MBTU	(C) - (D) Difference Diesel $/MBTU
2002	2.93	3.66	-0.7	4.98	5.17	-0.20
2003	3.03	4.10	-1.1	5.13	6.08	-0.94
2004	3.13	4.32	-1.2	5.29	6.44	-1.14
2005	3.26	4.44	-1.2	5.47	6.63	-1.16
2006	3.37	4.56	-1.2	5.64	6.85	-1.21
2007	3.49	4.70	-1.2	5.81	7.01	-1.20
2008	3.61	4.84	-1.2	5.99	7.26	-1.27
2009	3.73	4.98	-1.2	6.17	7.47	-1.30
2010	3.86	5.13	-1.3	6.36	7.48	-1.11
2011	4.00	5.27	-1.3	6.59	7.61	-1.01
2012	4.15	5.45	-1.3	6.83	7.74	-0.91
2013	4.31	5.62	-1.3	7.07	8.00	-0.92
2014	4.47	5.79	-1.3	7.33	8.21	-0.88
2015	4.64	5.96	-1.3	7.59	8.65	-1.06
2016	4.85	6.18	-1.3	7.91	9.16	-1.25
2017	5.06	6.40	-1.3	8.25	9.11	-0.86
2018	5.29	6.62	-1.3	8.60	9.64	-1.04
2019	5.54	6.89	-1.4	8.99	10.04	-1.05
2020	5.79	7.12	-1.3	9.40	10.37	-0.97
2021	-	7.38		-	10.76	
2022	-	7.64		-	11.17	

Figure 4.2-2 below illustrates the difference between the base price of diesel forecasted in the July 2002 Fuel Price Forecast and in the May 1998 Fuel Price Forecast, and highlights the change in the forecasted price spreads.

Figure 4.2-2
Diesel Price Forecast Comparison
May 1998 versus July 2002



4.3 Alternative Planning Guideline

Despite the adequacy of the amount of generating capacity with respect to HELCO's capacity planning criteria, on November 8, 2002, HELCO experienced a shortfall of power generation that made rolling blackouts necessary. The cause of the shortfall was a coincidence of simultaneous outages of HELCO and IPP units. During the period of generation shortfall, PGV, which has a normal rating of 30 MW, was operating at an average normal top load rating of about 5.6 MW; HEP, which has a rated capacity of 60 MW, had tripped off-line; and several of HELCO's diesel engines were unable to start. On November 13, 2002, HELCO briefed the PUC and the Consumer Advocate (CA) on its generation situation. At the briefing the PUC requested that HELCO provide weekly reports on its expected generation margins for each day of the coming week and the actual margins for each day of the previous week. These reports continued until early May 2003, when the

PUC no longer required the weekly reports due to improved generation margins from increased output from PGV. However, these reports are filed periodically, whenever generation margins are projected to be low.

The November 8, 2002 incident illustrates that, although HELCO may meet its capacity requirements with respect to its capacity planning criteria, there may be times during which generation shortfalls can occur due to multiple, simultaneous unplanned (forced) outages of generating units. System reliability can be improved by increasing the amount of generation margin on the system or by increasing the reliability of the generating units on the system. With PGV exporting roughly 27 MW on a consistent basis, and the addition of new central station generation this year with CT-4 and CT-5, the reliability of the system should be significantly improved. HELCO will monitor the level of reliability of its system to determine if further investigation into an alternate capacity planning criteria is warranted.

5. UPDATED RESOURCE PLAN

Sections 3 and 4 of this report contain the updated resource and planning information used in this Evaluation Report. This section of the report explains the updated IRP-2 plan developed by HELCO based upon the updated resource and planning information.

- Given the amount of time that has elapsed and the numerous events that have occurred since the filing of HELCO's IRP-2 plan, the focus of this evaluation report is on the near-term (2004 – 2006). A thorough evaluation of the resources in the later years of the planning period will be made in the next major review of the IRP plan.

5.1 Comparison of Assumptions

Table 5.1-1 compares the assumptions used in HELCO's IRP-2 filed with the PUC on September 1, 1998 against the assumptions used in this evaluation report.

Table 5.1-1
Comparison of Assumptions: IRP-2 and 2003 IRP-2 Evaluation Report

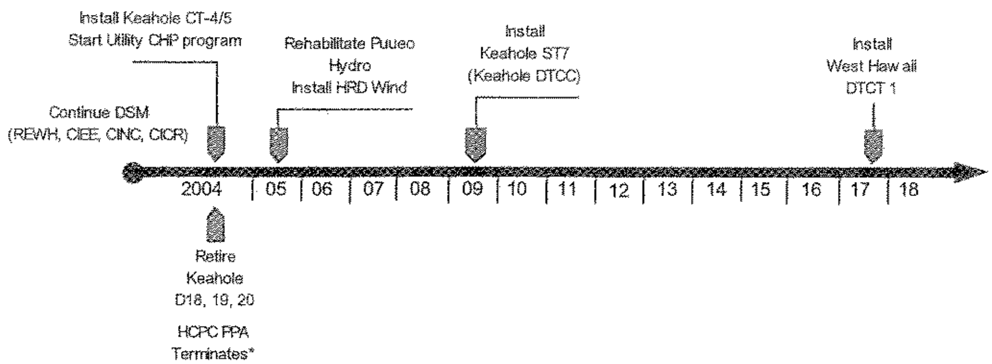
IRP-2	*2003 IRP-2 Evaluation Report*
• September 1997 Sales and Peak Forecast	• May 2003 Sales and Peak Forecast
• May 1998 Fuel Price Forecast (IRP Supplement)	• July 2002 Fuel Price Forecast
• Acquired DSM program impacts for 1996	• Acquired DSM program impacts from 1996 to 2003
• DSM impact estimates for 1998 – 2018 as of August 1997	• DSM impact estimates for 2004 – 2018 as of April 2003
• No Utility or 3rd Party CHP	• Includes Utility and 3rd Party CHP
• Keahole CT-4 and CT-5 operational in 1998	• Keahole CT-4 and CT-5 operational in 2004
• HEP (formerly Encogen) operational in 1999	• HEP operational in 2000
• 13 HELCO diesel units, Kanoelehua CT-1, and Shipman 1 retired after HEP and Keahole CT-4 and CT-5 are operational	• Waimea D8-10 and Shipman 1 retired in 2002. Keahole D18-19 were retired in February 2004 and D20 to be retired in accordance with Keahole CT-4 and CT-5 air permit requirements
• Puna steam unit placed on cold standby after HEP and Keahole CT–4 and CT–5 are operational	• No units placed on cold standby
• Expiration of HCPC PPA on December 31, 1999	• Uncertainty of HCPC PPA termination on December 31, 2004
	• Installation of a new Hawi Renewable Energy wind farm in 2005
	• Rehabilitated Puueo Hydro returned to service in 2005

5.2 Updated IRP-2 Plan

Given the assumptions for this Evaluation Report as shown in Table 5-1 and the considerations and circumstances previously discussed, HELCO's updated IRP-2 plan is shown in Figure 5.2-1. HELCO will use the updated IRP-2 plan as its based plan for future planning activities.

Figure 5.2-1
HELCO Updated IRP-2 Integrated Resource Plan

HELCO IRP-98 MODIFIED PREFERRED INTEGRATED RESOURCE PLAN (2004-2018)



Legend:

DTCC - Dual Train Combined Cycle	REWH - Residential Efficient Water Heating
DTCT - Combustion Turbine	CIEE - Commercial and Industrial Energy Efficiency
DTST - Steam Turbine with conversion of DTCTs to Combined Cycle	CINC - Commercial and Industrial New Construction
	CICR - Commercial and Industrial Customized Rebate

*NOTE: The five year term of HCPC's Second Amended and Restated PPA will end on December 31, 2004. After 2004, it the PPA can continue on a year-to-year basis with either HCPC or HELCO able to terminate the contract by providing written notice by May 30th of the termination year..

In terms of DSM resources, the Modified Preferred Plan includes:

- Four energy efficiency programs implemented over the period covered by this Evaluation Report, 2003-2018, including one residential program and three commercial and industrial programs. These programs provide incentives to customers to install energy efficiency measures such as solar water heating (for residential customers) or high efficiency lighting, air-conditioning or motors (for commercial and industrial customers) therefore reducing the overall demand for electricity on the HELCO system.

These demand-side components in the Updated IRP-2 Plan remain consistent with those given in the HELCO's IRP-2 Preferred Plan.

In terms of supply-side resources, the Modified Preferred Plan includes:

- Restoration of PGV output to 30 MW in 2004;
- Installation of Keahole CT-4 and CT-5 in 2004;
- Retirement of Keahole D18-20 in accordance with CT-4 and CT-5 air permit requirements;
- Continued operation of all other existing HELCO generating units[17];
- Consideration of HCPC PPA termination;
- Implementation of utility CHP projects beginning in 2004;
- Installation of Keahole ST-7 with selective catalytic reduction (SCR) in 2009, converting CT-4 and CT-5 to a dual train combined cycle;
- Installation of additional generating capacity at a West Hawaii site beginning in 2017;
- Installation of HRD wind farm in 2005[18]; and
- Rehabilitation of Puueo hydro in 2005.

The results of this evaluation report indicate four significant resource considerations in the near-term before the next IRP major review is completed.

First, CT-4 and CT-5 are expected to be on-line in the second quarter of 2004 and fully operational by year-end 2004.

Second, the five-year term of HCPC's Second Amended and Restated PPA will end on December 31, 2004. After 2004, the PPA can continue on a year-to-year basis with

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[17] Shipman 1 and Waimea D8-10 were retired in 2002.

[18] The Apollo repowering/expansion project is not yet included, because a PPA has not been finalized.

either HCPC or HELCO able to terminate the contract by providing written notice by May 30th of the termination year. Any decision to give notice of termination would be based on the facts and circumstances at the time. The decision of whether or not to terminate the HCPC PPA will be reflected in HELCO's IRP-3 supply-side resource update.

Third, HELCO anticipates installing ST-7 in the 2009 timeframe rather than in 2006, which necessitates that various older generating units that were previously targeted for retirement will no longer be retired. These older units are already permitted and grid-connected so that they can mitigate some of the uncertainty in the schedule for adding new generation. Also, a 5-year generation asset management program has been implemented in 2003.

Fourth, HELCO plans to pursue maintaining its current level of commitment to DSM and analyzing new DSM as part of IRP-3, while developing the new and emerging CHP market. Both the DSM and CHP programs have the potential to mitigate some of the uncertainty in the schedule for adding new generation, depending on how fast they can be ramped up.

6. UPDATED ACTION PLANS

HELCO's IRP-2 action plans were filed in 1998 and described the process by which HELCO's long-range resource program plans were scheduled for implementation over the five-year period 1999 to 2003. As shown in Table 5-1, a substantial number of planning assumptions have changed. This section provides an update to HELCO's five-year action plans for the period 2004 to 2008 that appropriately account for the changes in planning assumptions.

6.1 Updated Demand-Side Action Plan

HELCO recognizes that substantial work must be done to successfully continue the implementation of its four existing energy efficiency DSM programs in order to provide ample opportunities to ratepayers to better manage their electricity usage through energy efficiency, and to develop new programs for future implementation if warranted, including the development of applications for load management programs.

Specific tasks and activities associated with this scope of work include the following:

1. Examine the future of the current DSM programs and continue the programs until the end of HELCO's DSM Temporary Continuation Period.[19]

2. Continue implementation, evaluation, and reporting for the currently approved energy efficiency DSM programs. This includes meeting forecasted goals and budgets, making modifications as required, conducting an impact evaluation for program years 2000-2004, and preparing and filing annual Modification and Evaluation and Accomplishments and Surcharge reports.

3. Consider and evaluate new DSM programs as a part of its next full review of the IRP.

The estimated energy and demand savings, and forecasted expenditures are shown in the following tables. Table 6.1-1 shows the system level energy savings. Table 6.1-2

[19] Until one year after the commission makes a determination in Hawaiian Electric Company, Inc.'s (HECO) next rate case of HECO's revenue requirements in an interim decision and order or a final decision and order, whichever comes first (HELCO's DSM Temporary Continuation Period). Docket No. 95-0176 (Consolidated) Order No. 19094.

shows the system level demand savings. Table 6.1-3 shows the expected expenditures for the DSM action plan period:

Table 6.1-1
Summary of Future DSM Annualized System-Level Energy Savings (MWH)

Program	2004	2005	2006	2007	2008
Commercial & Industrial Energy Efficiency (CIEE)	1,780	1,834	1,889	1,946	2,004
Commercial & Industrial New Construction (CINC)	1,333	1,373	1,414	1,456	1,500
Commercial & Industrial Customized Rebate (CICR)	1,351	1,391	1,433	1,476	1,520
Residential Efficient Water Heating (REWH)	972	972	972	972	972
TOTAL	5,436	5,570	5,708	5,850	6,178

Table 6.1-2
Summary of Future DSM Annualized System-Level Demand Savings (KW)

Program	2004	2005	2006	2007	2008
Commercial & Industrial Energy Efficiency (CIEE)	257	264	275	283	292
Commercial & Industrial New Construction (CINC)	150	155	160	165	170
Commercial & Industrial Customized Rebate (CICR)	179	184	190	196	202
Residential Efficient Water Heating (REWH)	217	217	217	217	217
Annual TOTAL	803	820	842	861	881
Cumulative TOTAL	1,619	2,439	3,281	4,142	5,023

Table 6.1-3
Summary of Future DSM Expenditures
(In Thousands of Dollars)

Program	2004	2005	2006	2007	2008	Total
Commercial & Industrial Energy Efficiency (CIEE)	413	351	359	366	**374**	**1,863**
Commercial & Industrial New Construction (CINC)	219	197	200	208	**211**	**1,035**
Commercial & Industrial Customized Rebate (CICR)	218	196	204	207	**215**	**1,040**
Residential Efficient Water Heating (REWH)	802	687	697	707	**717**	**3,610**
TOTAL	**1,652**	**1,432**	**1,460**	**1,488**	**1,517**	**7,548**

6.2 Updated Supply-Side Action Plan

This five-year supply-side action plan update provides a schedule of planned supply-side activities and expenditures scheduled for implementation over the five-year period 2004 to 2008.

The Supply-Side Action Plan for the action plan period 2003 to 2008 is divided into:

- Renewable energy activities, and
- Keahole DTCC, and
- HELCO CHP Program

A summary of the estimated annual expenditures is included in Table 6.2-1 below:

Table 6.2-1
Summary of Supply-Side Action Plan Expenditures ($000)

	2004	2005	2006	2007	2008	Total
Renewable energy activities[A]	3,297	53	33	19	9	3,411
Keahole DTCC	18,315	689	415	5,342	23,700	48,461
Utility CHP program[B]						0
Totals by Year	18,501	732	448	5,251	22,189	47,121

[A] Total project budgets. Includes extramural funding, planning, and preliminary engineering. NOTE: Budgets for 2005-2008 are dependent on results of 2004 activities.

[B] In Order No. 20831, Docket No. 03-0366, the Commission suspended HECO, MECO, and HELCO's application for the Utility CHP program. It is anticipated that CHP projects will continue on an individual project basis rather than a program basis until the final decision regarding Docket No. 03-0366 is made. However, this will increase the uncertainty of timely project implementation due to the nature of doing individual project applications.

In its HELCO IRP-2 action plan, Section 9.2.2, part 3, HELCO stated:

> *"...HELCO plans to conduct studies to identify sites which can be prime candidates for distributed generation. This will allow HELCO to better define site-specific costs such as permitting, interconnection, fueling, and overall design. Once sites are identified, specific T&D and other system benefits can also be assessed. These costs and benefits could then be compiled and analyzed against the costs used in the IRP planning analysis to determine if distributed generation should be implemented. The study is planned to be initiated in 2002 and completed by 2003 such that the results of the study can be used in HELCO's 2004 IRP. Evaluation in the 2004 IRP should allow sufficient time for possible implementation of distributed diesels in the 2009 timeframe."*

Because of the extent of activities with DG, and in particular CHP that have occurred in the past two years, HELCO did not conduct a separate, stand-alone study for distributed generation. Project economics and the marketing of available technologies are actively driving actual DG and CHP projects and HELCO believes that a separate study is not needed. HELCO will conduct individual DG or CHP analyses as needed on a case-by-case basis. HELCO will also examine DG and CHP resource options within the context of integrated resource planning in its IRP-3 process.

6.2.1 Renewable Energy Activities

Substantial effort will be required to complete the work in HELCO's renewable energy strategy described previously in Section 3.3.2. The following are the activities in HELCO's Supply-Side Action Plan for renewable energy. Please note the activities related to HELCO seeking commercial-scale renewable energy projects with Renewable Hawaii possibly providing passive equity funding are still being developed and are not reflected in the following Supply-side Action Plan.

Facilitate Commercialization of Renewable Energy Technologies:

Renewable Hawaii Inc.

- Renwable Energy Request for Project Proposal

Wind Program

- Hawi Renewable Development (pending PPA approval)
- Apollo Repower and expansion at Kamaoa (pending agreement on and PUC approval of a PPA)
- Lalamilo Repower

Hydroelectric

- Puueo Hydroelectric Plant Rehabilitation Project
- Union Mill
- County of Hawaii Water Dept Demonstration Project

Facilitate Integration of Intermittent Resources

- Electronic Shock Absorber
- Intermittent Generation Assessment Protocol Study
- Grid Quality Assessment Project
- Distributed Resources Management as Microgrid
- Battery Energy Storage System Study

Facilitate Development of Renewable Energy Technologies:

Hydroelectric Resources

- Hydrogen Power Park Study

Distributed Energy System

- Natural Energy Laboratory of Hawaii Authority (NELHA) Gateway Project

Solar Thermal/Cooling

- Solar Thermal/Cooling Pilot Demonstration at Outrigger Waikoloa

Photovoltaics

- Sun Power for Schools program extension
- Team leader for Island of Hawaii Million Solar Roofs Partnership

The aforementioned activities will continue throughout the IRP five-year action plan time period. Follow-on work for 2005-2008 is dependent on results of 2004 activities.

6.2.2 Keahole Dual Train Combined Cycle

HELCO is currently proceeding with the construction of CT-4 and CT-5. It is estimated that these units will be placed into service in the 2004 timeframe. HELCO has also filed a Petition For Land Use District Boundary Amendment with the State of Hawaii Land Use Commission to amend the land use classification of certain lands at Keahole from the Conservation District to the Urban district. Once the Keahole land is reclassified from the "Conservation District" to the "Urban District", HELCO will file a request with the County of Hawaii Planning Commission and County Council to rezone the property from "Urban" to "Industrial". The total reclassification and rezoning process is expected to take four to six years to complete. This, however, would provide HELCO with the land use approval necessary to install ST-7 with selective catalytic reduction emission control equipment.

6.2.3 Distributed Generation/Combined Heat and Power

Customer demand and economic factors are driving the installation of DG and CHP projects. With the PUC application suspended at this time, HELCO anticipates pursuing individual CHP projects. Section 3.2.2 shows HELCO's estimate of the size of the utility-CHP market and addresses its implementation.

APPENDICES

Appendix A Generating Unit Ratings

Table A – 1
Generating Unit Ratings (February 2004)

	(in Gross MW)		(in Net MW)	
Unit ID	Reserve Rating (MW)	NTL Rating (MW)	Reserve Rating (MW)	NTL Rating (MW)
Shipman 1	0.00 (1)	0.00 (1)	0.00 (1)	0.00 (1)
Shipman 3	7.50	7.50	7.10	7.10
Shipman 4	7.70	7.70	7.30	7.30
Hill 5	14.10	14.10	13.50	13.50
Hill 6	21.40	21.40	20.20	20.20
Waimea d8	0.00 (1)	0.00 (1)	0.00 (1)	0.00 (1)
Waimea d9	0.00 (1)	0.00 (1)	0.00 (1)	0.00 (1)
Waimea d10	0.00 (1)	0.00 (1)	0.00 (1)	0.00 (1)
Kanoelehua d11	2.00	2.00	2.00	2.00
Waimea d12	2.75	2.50	2.75	2.50
Waimea d13	2.75	2.50	2.75	2.50
Waimea d14	2.75	2.50	2.75	2.50
Kanoelehua d15	2.75	2.50	2.75	2.50
Kanoelehua d16	2.75	2.50	2.75	2.50
Kanoelehua d17	2.75	2.50	2.75	2.50
Keahole d18	2.75 (2)	2.50 (2)	2.75 (2)	2.50 (2)
Keahole d19	2.75 (2)	2.50 (2)	2.75 (2)	2.50 (2)
Keahole d20	2.75 (2)	2.50 (2)	2.75 (2)	2.50 (2)
Keahole d21	2.75	2.50	2.75	2.50
Keahole d22	2.75	2.50	2.75	2.50
Keahole d23	2.75	2.50	2.75	2.50
Kanoelehua ct1	11.50	11.50	11.50	11.50
Keahole ct2	13.00	13.00	13.00	13.00
Puna ct3	20.80	20.80	20.40	20.40
Puna	15.50	15.50	14.10	14.10
Keahole ct4	19.90 (2)	19.90 (2)	19.90 (2)	19.90 (2)
Keahole ct5	19.90 (2)	19.90 (2)	19.90 (2)	19.90 (2)
Panaewa D24	1.00	1.00	1.00	1.00
Ouli D25	1.00	1.00	1.00	1.00
Punaluu D26	1.00	1.00	1.00	1.00
Kapua D27	1.00	1.00	1.00	1.00
HELCO total	190.30	187.30	185.90	182.90
HCPC	22.00 (2)	22.00 (2)	22.00 (2)	22.00 (2)
PGV	30.00 (3)	30.00 (3)	30.00 (3)	30.00 (3)
HEP Phase 2	60.00	60.00	60.00	60.00
IPP Total	112.00	112.00	112.00	112.00
System total	302.30	299.30	297.90	294.90

Notes
(1) Shipman 1, Waimea D8-10 retired in February 2002
(2) Keahole CT4 and CT5 ratings when installed
Keahole D18-20 are to be retired in accordance with the CT4 and CT5 air permit requirements
The five-year term of HCPC's Second Amended and Restated PPA will end on December 31, 2004
(3) PGV rating when fully restored

Appendix B Glossary of Acronyms

Acronym	Full Name
AEC	Apollo Energy Corporation
BESS	Battery Energy Storage System
BLNR	Board of Land and Natural Resources
C&I	Commercial and Industrial
CA	Consumer Advocate
CFL	Compact Fluorescent Light
CHP	Combined Heat and Power
CICR	Commercial and Industrial Customized Rebate
CIEE	Commercial and Industrial Energy Efficiency
CINC	Commercial and Industrial New Construction
CT	Combustion Turbine
D&O	Decision and Order
DBEDT	Department of Business, Economic Development, and Tourism
DER	Distributed Energy Resources
DG	Distributed Generation
DHHL	Department of Hawaiian Home Lands, State of Hawaii
DLNR	Department of Land and Natural Resources
DOH	Department of Health
DSM	Demand Side Management

Acronym	Full Name
DTCC	Dual Train Combined Cycle
DTCT	Combustion Turbine (Phase 1 or 2 of a DTCC)
DTST	Steam Turbine (Phase 3 of a DTCC)
EIS	Environmental Impact Statement
ESA	Electronic Shock Absorber
HCPC	Hilo Coast Power Company
HECO	Hawaiian Electric Company, Inc.
HELCO	Hawaii Electric Light Company, Inc.
HEP	Hamakua Energy Partners
HNEI	Hawaii Natural Energy Institute
HRD	Hawi Renewable Development
IGAP	Intermittent Generation Assessment Protocol
IPP	Independent Power Producer
IRP	Integrated Resource Plan
KDC	Keahole Defence Coalition
KPP	Kahua Power Partners
KW	Kilowatt
LED	Light Emitting Diode
LUC	Land Use Commission
MECO	Maui Electric Company, Ltd.

Acronym	Full Name
MSFO	Medium Sulfur Fuel Oil
MSR	Million Solar Roofs
MW	Megawatt
MWH	Megawatt hour
NELHA	Natural Energy Laboratory of Hawaii Authority
NEM	Net Energy Metering
NEMA	National Electrical Manufacturer Association
PEA	Preliminary Energy Assessment
PGV	Puna Geothermal Venture
PPA	Power Purchase Agreement
PSH	Pumped Storage Hydroelectric
PUC	Public Utilities Commission
RE RFPP	Renewable Energy Request for Project Proposal
REWH	Residential Efficient Water Heater
RHI	Renewable Hawaii Incorporated
RPS	Renewable Portfolio Standards
SCR	Selective Catalytic Reduction
ST	Steam Turbine
T&D	Transmission and Distribution
USPF	United States Power Fund

Acronym	Full Name
UTC	United Technologies Company
UWIG	Utility Wind Interest Group

A REVIEW OF ALTERNATIVE RESOURCES DISCUSSED IN THE IRP

INTRODUCTION

Alternative resources are examined during a full review of Hawaii Electric Light Company, Inc.'s (HELCO) Integrated Resource Plan (IRP). The objective of the IRP process is to identify the resources or mix of resources for meeting near- and long-term consumer energy needs in an efficient and reliable manner at the lowest reasonable cost. While alternative resources are formally evaluated during the IRP process, developments in alternative technologies are continuously monitored through a wide variety of activities. This report, prepared by HELCO staff, summarizes HELCO's ongoing efforts to develop alternative resources. Recent examples of these activities include:

RENEWABLE HAWAII, INC.

Hawaiian Electric Company, Inc. (HECO) created in December 2002 a non-regulated subsidiary called Renewable Hawaii, Inc. (RHI). The purpose of RHI is to seek passive investment opportunities that provide a reasonable return for cost-effective, commercial, renewable energy projects in the State. With an initial approval to invest up to $10 million, RHI's formation augments the company's ongoing commitment to increase Hawaii's use of renewable energy.

The primary objectives of RHI are to (1) stimulate the addition of cost-effective, commercial, renewable energy in Hawaii; (2) promote viable projects that will integrate positively with the utility grid; and (3) encourage renewable energy generation activity where there is a lack in targeted categories. To meet this objective, renewable projects must utilize cost-effective, commercial technologies with a proven track record, established costs, and be 1 megawatt (MW) or greater. Technologies requiring research and design, prototype development, or demonstration would not be considered.

RHI attempts to stimulate the renewable energy market by releasing a series of island-specific *Renewable Energy Request for Project Proposals* (RE RFPP). A RE RFPP for the island of Oahu was released on May 22, 2003 and closed on August 22, 2003. Three of the eight proposals submitted in response to the RE RFPP have passed initial screening and are being evaluated. A RE RFPP for the islands of Maui, Molokai, and Lanai, service territory of Maui Electric Company, Ltd (MECO), was released on September 4, 2003 and closed on December 4, 2003. Three of the five proposals received by RHI are currently in the screening process. A RE RFPP for the Big Island of Hawaii, service territory of HELCO, was released on January 22, 2004 and closed on April 22, 2004. The five proposals were submitted to RHI and are currently being screened.

HIGH RESOLUTION WIND RESOURCE MAPS

A project funded by HECO, MECO, the State of Hawaii Department of Business, Economic Development and Tourism (DBEDT), and the U.S. Department of Energy's National Renewable Energy Laboratory (NREL) was conducted to update the State's wind resource maps. High-resolution wind resource maps, which graphically show wind-power densities and wind speed, for the islands of Oahu, Hawaii, Maui, Molokai, and Lanai have been developed to help identify new wind sites that could lead to commercial wind development.

HAWAII WIND WORKING GROUP

HECO and DBEDT co-chair the federal-sponsored Hawaii Wind Working Group (HWWG) as part of the Department of Energy's Wind Powering America program. The functions of the HWWG are to provide a forum for information exchange on wind energy among member organizations, the public, and decision makers and to encourage the development of technically and economically feasible wind projects. Formed in 2002, the HWWG has held several meetings to exchange information that benefits all islands.

BIOENERGY PROGRAM

HECO is working with the Hawaiian Commercial and Sugar Company and the University of Hawaii at Manoa to develop the Hawaii Biomass Program. This proposed multi-year program would take a collaborative approach in developing a policy and technology framework that would lead to commercialization of an economically viable way to make full use of the total sugarcane material (including the use of cane trash) as a biomass energy resource (i.e., implement a comprehensive dual-use crop strategy to economically produce both sugar and energy).

The potential utilization of biofuels (e.g., biodiesel, ethanol, and biofuel blends) in existing and new utility power generation units is being explored under HECO's Biofuels Program. The use of biofuels in electric power generating units represents a promising renewable energy option. Before biofuels can be used on a commercial basis, however, the technical feasibility of firing stationary power generating units will need to be evaluated and demonstrated. HECO is funding a study (Phase 1 of a planned multi-phase, multi-year biofuels assessment project) to obtain information on biofuel properties, supply, availability, and pricing. Efforts to initiate Phase 2 of the program (obtain performance and emissions data of stationary power generation units fueled by biofuels) are underway.

ELECTRONIC SHOCK ABSORBER

To help stabilize operation of grid-connected wind turbines and minimize power fluctuations on an electric grid, which is connected to a number of wind farms, HECO, HELCO, and MECO teamed with a private company to conduct a Phase 1 study that confirmed a device can be developed from commercial products for installation between a wind farm and the utility grid. The purpose of the device, called the Electronic Shock Absorber (ESA), is to help the electric utility ride through short duration power fluctuations (frequency, voltage, etc.) from the wind farm caused by the variable nature of wind. HECO has received a patent for the ESA. A Phase 2 demonstration project is currently in progress and scheduled for installation in late 2005.

INTERMITTENT GENERATION ASSESSMENT PROTOCOL (IGAP)

To improve existing planning and evaluation tools, HECO and HELCO are working with a consultant on the IGAP study to address the technical and cost impacts of relatively high levels of intermittent renewable energy generation on small, isolated electric utility systems. This issue is already being experienced by HELCO on the Big Island of Hawaii.

The study will develop improved modeling to quantify the impacts of high levels of intermittent generation, establish appropriate power quality standards, and identify specific measures that can be taken by intermittent generation operators and utility operators to mitigate power quality fluctuations.

GRID QUALITY ASSESSMENT

Through its membership with the Utility Wind Interest Group (UWIG), HECO and HELCO plan to participate in a project to develop assessment tools related to grid quality. The purpose of this project is to determine and characterize the voltage fluctuations caused by wind farms on distribution feeder lines.

IN-LINE HYDRO AND PUMPED STORAGE HYDRO

Under a partnership with HECO, HELCO, DBEDT, County of Hawaii, and the State Department of Agriculture (DOA), a study is being funded by DBEDT and HECO/HELCO to identify the potential for in-line hydroelectric and pumped storage hydroelectric (i.e., use of wind during off-peak hours to pump water to a higher elevation and generating power through in-line hydro units during on-peak hours) in existing County, State, and private water systems.

In addition, HELCO has committed funding to cost-share with the County of Hawaii Department of Water Supply (DWS) for an in-line hydroelectric generator project.

HAWAII FUEL CELL TEST FACILITY

HECO has partnered with the Hawaii Natural Energy Institute (HNEI) of the University of Hawaii, U.S. Department of Defense (DOD), and UTC Fuel Cells to build and operate a hydrogen fuel cell test facility in Hawaii. The Hawaii Fuel Cell Test Facility, operational since April 2003, is housed in approximately 4,000 square feet of warehouse space at HECO's Ward Avenue facility and is used to evaluate the performance and reliability of production-sized, single-celled, fuel cell stack designs, materials, and fuels. Benefits to HELCO customers can be realized from the efforts at this facility.

HYDROGEN POWER PARK STUDY

One of the key components necessary for commercial utilization of hydrogen is a safe and reliable hydrogen storage and distribution system. HELCO is partnering with DBEDT, HNEI, Sentech, Sunline, Stuart Energy, UTC Fuel Cells, and HECO in a project to introduce and demonstrate hydrogen-based infrastructure in Hawaii. Integrated hydrogen-based infrastructure, including hydrogen production via electrolysis, hydrogen storage, fuel cell power production, and combined heat and power production, are planned for installation at the City and County of Honolulu's Kapolei Hale facility. Projects are to occur in phases through 2005.

NELHA GATEWAY PROJECT

HELCO is partnering with NELHA, DBEDT, HNEI, and Sentech in a project to construct distributed energy systems at the Gateway Center located at the entrance to NELHA's Hawaii Ocean Science and Technology (HOST) Park. This project aims to demonstrate renewable distributed energy resources and technology. A 20 kW photovoltaic (PV) system, funded and owned by HELCO, was installed at the Gateway Visitor Center in 2004.

Kona Base Yard Grid-Connected Photovoltaic System

To demonstrate a net energy metered photovoltaic system that would be similar to what a small commercial or residential customer might consider, HELCO has installed a 5.4 kW photovoltaic system along with battery back up and an educational display at its Kona base yard.

Solar Thermal/Cooling Pilot Project

HELCO has partnered with Pacific Energy Services, Solel, and the Waikoloa Beach Marriott, and Outrigger Resort, on a pilot-scale project to evaluate and demonstrate the feasibility for full-scale solar thermal and solar cooling installations for West Hawaii hotels and resorts. The purpose of the project was to gather and record operational data from the high temperature, solar thermal panel for an engineering feasibility study to evaluate the economics of full-scale production of domestic hot water, and production of chilled water by an absorption chiller process. The pilot project has been in operation and recording operational data since May 2003, and has been used to demonstrate the technology to interested hotel customers and engineers.

Bulk Energy Storage to Relieve Transmission Congestion on the Big Island

Under a partnership between HELCO, DBEDT, and Sentech, a study is being funded by the U.S. Department of Energy to investigate new forms of energy storage that could alleviate the issue of overloading transmission lines when transporting renewable electricity to end uses, fostering the increased use of distributed energy and renewable energy systems.

Distributed Energy Resources Management as a Microgrid

HECO and DBEDT have received funding under a U.S. Department of Energy competitive grant program to evaluate the combination of hybrid, controllable distributed energy resources (DER) systems that will encourage development of renewable and distributed resources.

EPRI Offshore Wave Energy Project

HECO is participating in a multi-phase, multi-state collaborative project headed by the Electric Power Research Institute (EPRI) to demonstrate the feasibility of wave power. The project will yield a conceptual design, including performance and cost estimates, for an offshore wave power device at a target location in each of six states (Hawaii, Maine, Massachusetts, California, Oregon, and Washington). Environmental and permitting issues will also be assessed.

HELCO Photovoltaic Area Lighting Projects

To promote the use of off-grid photovoltaic applications, HELCO has partnered with various entities to install photovoltaic area lighting systems:

- HELCO, the County of Hawaii, and the U.S. Department of Energy Million Solar Roofs (MSR) program teamed up to design and install a solar lighted educational kiosk and solar lighting for the Hilo bay front public restrooms.
- Two solar-powered lights provide dusk-to-dawn security and improve the safety of the parking lot at the Catholic Charities Community and Immigrant Services transitional shelter Ka Hale `O Kawaihae.

- A partnership between HELCO and the County of Hawaii was formed to provide improved lighting for two County parks located in Puna (Ahalanui Beach Park and Pohoiki Beach Park).

Sun Power for Schools Program

Through the Sun Power for Schools program, HECO, HELCO, and MECO install photovoltaic systems at Hawaii public schools using voluntary customer contributions and by providing in-kind utility contributions, including engineering, project management, administration, advertising, and marketing. To date, 19 public schools have received photovoltaic systems totaling over 23 kW (nine on Oahu, four on the island of Hawaii, and six in Maui County).

Background on Alternative Energy Resources

The subsections below provide background information on the alternative resources that may be considered by some to have the most promising prospects for long-term energy supply. This includes biomass conversion, municipal solid waste, geothermal energy, hydroelectric energy, solar energy, wind energy, ocean thermal energy conversion, coal, distributed generation and combined heat and power, and fuel cell technology.

Biomass Conversion

Biomass conversion involves cultivating and harvesting plants as a natural energy alternative to fossil fuels. Biomass can be used as a fuel for combustion to produce thermal energy, which is then converted to electrical power.

Before the decline of the sugar industry in the County of Hawaii, the fibrous waste associated with sugar cane processing, referred to as "bagasse," was burned to produce electricity. While bagasse is still available on Maui and Kauai and used for electricity generation on Maui, it is unavailable on the Big Island. Until a significant volume of combustible plant by-product becomes available at a reasonable cost, the economics of a biomass conversion operation discourage both the utility and IPPs from pursuing this technology.

Using a by-product to fuel a boiler has cost advantages over cultivation and harvesting of a dedicated energy crop. To date, there are no known commercially dedicated-biomass-to-electricity facilities in the United States. All existing biomass-to-electricity plants use waste products (i.e., wood waste, agricultural wastes, etc.) to power their facilities as part of a cogeneration process.

It is estimated that about 250-330 acres per MW is required for a dedicated biomass-to-electricity power plant. A 56 MW plant would require about 14,000-18,500 acres, and at a biomass crop yield of 22 dry tons per acre, approximately 308,000-407,000 dry tons of biomass would be available for energy conversion. The availability of suitable lands and irrigation water to support such a facility, as well as the operational and economic viability, requires a statewide initiative across private and public sectors.

HEI provided venture capital funding to Worldwide Energy Group, Inc., a Hawaii-based company developing a technology that converts sugarcane bagasse or other biomass resources into ethanol. Ethanol is a potential alternative fuel produced from locally available renewable sources that can be used to generate electricity.

HELCO and HECO were participants with the Pacific International Center for High Technology Research (PICHTR), the County of Hawaii, State, and other parties on a NREL study to examine biomass to ethanol and electricity applications for the Big Island. The parties determined that a biomass facility would be too costly at this time and the technology was still developing.[1]

HECO and HELCO also followed the progress of the PICHTR and State project development of a biomass gasifier demonstration at the Paia Sugar Mill on Maui. The purpose of the federal- and state-funded project to build and operate a 100-ton per-day facility was to demonstrate the latest gasifier technology, which could improve the efficiency of current biomass technologies. Despite gaining design and operational experience, technical problems and the corresponding lack of continued funding prevented further project phases to investigate hot gas cleanup and power production. Biomass gasification remains to progress beyond the demonstration stage.[2]

MUNICIPAL SOLID WASTE

Municipal solid-waste facilities such as HPOWER on Oahu use refuse derived fuel to create steam. The primary objective of municipal solid waste facilities is to reduce the volume of trash headed for landfills, with the generation of electricity being a by-product of the operation. While the County of Hawaii has explored various alternatives for disposal of its solid wastes, a municipal solid-waste facility has not been identified at this time. Therefore, HELCO is currently unable to speculate on: (1) the likelihood that a facility would be built in the next 5-7 years; (2) its location; and (3) its operating specifications (size in MW, hours of operation, maintenance outage requirements, dispatchability, etc.).

The performance of such plants is dependent on the quantity and characteristics of the available waste fuel as well as the design of the plant systems and equipment. Since waste-to-energy plants are designed primarily for waste reduction, and typically must compete for materials with other government-sponsored programs, such as recycling and composting, such plants cannot be dispatched to meet load demand and cannot be considered as firm power within the resource generation plans. Since the primary issue is waste disposal, the development of a waste-to-energy facility on the Big Island is dependent on State and County actions.

GEOTHERMAL ENERGY

Geothermal energy is natural heat energy from the earth that can be harnessed for electrical power generation. This energy may be found as steam, hot water, magma, or hot, dry rock.

HELCO has a long-term power purchase agreement with PGV for 30 MW of firm capacity. However, in April 2002 PGV encountered significant well problems, limiting its capacity to approximately 5.6 MW. This was due to depleting steam resource (production well changed characteristics from steam-dominate to water-dominate resource) and reinjection well problems. The average capacity for all of 2002 was 8.5 MW. By April 2003, capacity was restored to 25

1 PICHTR Sustainable Biomass Energy Program—NREL LOI—Hawaii Project. June 1996.

2 HECO Technology Division, personal communication, 2004.

MW, and during the 2003 system peak on December 30th, PGV supplied HELCO with 27 MW.[3] In 2000, the U.S. EPA granted PGV final approval to expand its operation on the Big Island.

HELCO is concerned with the operational compatibility of additional geothermal on the system due to the unknown reliability of the resource over the long term. Longevity of the steam resource from each supply well varies on a case-by-case basis, and steam production could decline unexpectedly. In addition, HECO is concerned with the changing geothermal resource characteristics (resource changing from steam to brine) over time, which could impede electrical production. Problems could also arise with reinjection wells. As described above, PGV experienced severe operational problems for portions of 2002 and 2003. At times, this jeopardized HELCO's ability to serve load, as the margin between demand and firm capacity was reduced.

HELCO is also concerned about the limited operational characteristics of geothermal facilities. Geothermal production wells should not be throttled down during daily minimum system load periods because this can jeopardize the well casing integrity.

Lastly, development of geothermal resources has caused considerable controversy among local residents and the general cultural community. This is the result of both health and safety concerns, especially concerns about noise, sulfuric acid emissions, and religious objections.

As the peak demand increases, off-peak demand increases or energy storage is added to the electrical grid, additional geothermal facilities could be added to the HELCO system. The current geothermal operator has expressed interest in increasing their geothermal capacity.

HYDROELECTRIC ENERGY

Hydroelectric power uses water from streams or rivers for generating electrical energy. On the Big Island, hydroelectric power provides only a small portion of the County's electrical energy because of limited hydropower generation opportunities. The rivers are relatively short, and few valleys or gorges can be dammed effectively. Because of the intermittent nature of the hydroelectric resource on the Big Island, hydroelectric power is purchased "as-available" rather than as firm capacity.

HELCO has an as-available contract with the Wailuku River Hydroelectric Power Company for up to 12 MW of energy.

HELCO had four hydroelectric units on the Wailuku River in Hilo that could generate up to 3.35 MW, depending on the river flow. In September 2002, the largest of the four units — the 1,500 kW unit at the Puueo Hydroelectric Plant — was severely damaged. In November 2003, HELCO received PUC approval to rehabilitate the Puueo Hydroelectric Plant. It is estimated that a 2.3 MW to 2.4 MW turbine would be installed in the 2005 timeframe, increasing HELCO's production of as-available hydroelectric power.

Under a partnership with HECO, HELCO, DBEDT, County of Hawaii, and the State DOA, a study is being funded by DBEDT and HECO to identify the potential for in-line hydroelectric and pumped storage hydroelectric (i.e., use of wind during off-peak hours to pump water to a higher

[3] Newspaper articles for EPA permit, 2003 AOS for 2002 performance, and Production Reports for 2003 performance.... "end of 2003" estimate for 30 MW restoration removed based on information regarding possible sale of facility, and corresponding lack-of-activity in restoring capacity.

elevation and generating power through in-line hydro units during on-peak hours) in existing County, State, and private water systems.

In 1995, a study by Christensen Associates, Inc. was conducted to provide preliminary resource potential and cost information on the most-promising pumped storage hydroelectric sites on the Big Island of Hawaii. Twelve sites were screened with respect to technical merit and potential environmental issues. Of these twelve sites, three potential sites (Puu Waawaa, Puu Anahulu, and Puu Enuhe) were selected to develop resource and cost information. It was determined that Puu Anahulu is the most promising site based on location, estimated cost, and potential environmental issues.

SOLAR ENERGY

Solar energy comes from the radiation of the sun, and it can provide thermal energy or produce electrical power directly via photovoltaic cells or solar electric systems. Solar energy is a power source that could be used to meet customer load demand in the future. However, to be a reliable source of electricity at night and during extended cloudy periods, it must be coupled with an energy storage system.

At this time, the most cost-effective approach for utilizing energy from the sun is solar water heating. One of the attractive features of solar water heating is the storage capability provided by the large capacity hot water tank, which allows water that was heated during the day to be used at night, when there is no sun. Currently, the combined HECO utilities have the highest per capita use of solar water heating in the nation. HELCO's energy efficiency DSM programs provide incentives for customers to install solar water heating systems, which help to defer the installation of generating units.

A large-scale photovoltaic plant consists of a number of photovoltaic modules mounted on structures known as arrays. Between 5 to 10 acres of land (depends if the panels are fixed or stationary or if they track the sun) are estimated as necessary to house the arrays for each 1 MW of power production. This land must be relatively flat and should be located in an area receiving a high degree of sunlight and away from shading, clouds, volcanic haze (VOG), dust, and salt spray. The cost of such a photovoltaic system is currently estimated at $9 to $13 million per installed MW. Although such large-scale, photovoltaic facilities have been shown to be technically feasible, they are not currently economical.

Photovoltaic systems are characterized as as-available resource (i.e., the photovoltaic system will operate only when the sun is shining). Shading from trees or other building can reduce the electrical output of this type of system. Passing clouds, volcanic haze, dust, water spray can also reduce electrical output.

HELCO has installed a 15 kW photovoltaic system on the County of Hawaii gymnasium in Kona, a 5.4 kW net-metered photovoltaic system at its Kona Base Yard, and a 20 kW photovoltaic system at the new Gateway Building at NELHA. HELCO has also installed smaller photovoltaic systems as part of the Sun Power for Schools program and numerous installations on and off the utility grid. Private owners such as the Mauna Lani Hotel and Parker Ranch have chosen to install large photovoltaic systems on their property as well.

The current net energy metering law in place allows residential and small commercial customers to install photovoltaic and other renewable technologies that are 50 kW or less and to exchange retail electricity with HELCO. Thus far, over 10 Big Island customers are net energy metered with HELCO.

In 1992, the State DBEDT conducted an assessment of solar thermal electric generating systems for Hawaii. The results of this study revealed that Hawaii's direct insolation (i.e., the amount of direct sunlight) is lower than anticipated and that land costs are too high to make solar thermal electric power cost effective. In addition, HECO has been following the development of solar dish/Stirling engine technology for potential use. This technology is still being developed. High cost and reliability are maintenance issues that still need to be addressed.

WIND ENERGY

Wind energy can be used to generate electricity through wind turbine generators. Currently, there are two wind farms that provide energy on an as-available basis to the HELCO grid. Apollo Energy Corporation exports up to 7 MW from its wind farm at Kamaoa, and the HELCO-owned Lalamilo wind farm in the Waimea area exports up to 2.28 MW.

Energy generated by the wind farms is typically intermittent and is considered "as-available" energy. HELCO is concerned with the operational compatibility of wind energy on the system due to the intermittent and gusty nature of wind, which can negatively affect the quality of power, especially on the small island-based electric grid systems. Existing wind farms on the Big Island have a measurable impact on system frequency deviations, especially during periods of low system load.

HELCO is currently in discussions with wind farm developers, and it is estimated that 10 to 20 MW of wind turbines could be added to the HELCO system in the coming years. The additional energy provided by these wind farms would decrease the use of fossil fuels. However, because wind farms do not supply firm capacity, the addition of wind turbines to the system does not defer the need for firm generating units like ST-7 at Keahole.

In the long term, to help stabilize grid operation and maintain power quality on a grid system with a high penetration of wind farms, HECO, HELCO, and MECO have teamed with a private company to examine whether a device can be developed from commercial products for installation between a wind farm and the utility grid. The ESA described above is to help the electric utility ride through short duration power fluctuations (frequency, voltage, etc.) from the wind farm caused by the variable nature of wind. HECO was awarded a patent for the ESA, and a study has been conducted to identify available technologies. An assessment study concluded that an ESA device using commercial products could be fabricated. A demonstration unit is scheduled for installation in late 2005.

HELCO is also concerned about the limited operational characteristics of wind facilities. Wind facilities cannot be throttled down during daily minimum system load periods. Thus, there are times when wind energy must be curtailed because demand is too low. To be a reliable source of electricity during low-wind periods, it must be coupled with an energy storage system.

OCEAN THERMAL ENERGY CONVERSION

An ocean thermal energy conversion (OTEC) plant uses the temperature difference between warm surface water and cold deep water to generate electricity. A minimum temperature difference of about 36° F is necessary to generate electricity. The movement of massive amounts of both deep cold and warmer surface waters is required. Depending on the onshore and offshore topography, infrastructure, and environmental considerations, OTEC plants can be designed as shore-based or offshore plants. Shore-based plants are appropriate for locations with steep offshore slopes and sufficient land area for infrastructure and generation equipment. Offshore plants can be floating platforms or tower-mounted structures. The electricity generated by offshore plants can be transmitted to shore through underwater cables.

Currently, OTEC technology is in the research and development stage. No commercial OTEC plants are currently operating. However, experimental plants demonstrating the OTEC concept have been constructed and tested in both the U.S. and Japan and are planned for India and Japan.

NELHA, off Keahole Point on Hawaii, operated an open-cycle OTEC demonstration project which produced approximately 210 kW of gross power. A closed-cycle 50-kW plant has also been operated at NELHA. However, the closed-cycle project had problems with ammonia leakage in the flat-plate aluminum heat exchangers.

Costs for OTEC facilities are high, with the capital costs of a 50-MW land-based facility estimated at over $300 million. Besides the high cost, other barriers must be overcome before commercial operation is realized. Reliable operation must be demonstrated and maintenance costs must be fully understood. The environmental impacts associated with intake and discharge of large volumes of warm and cold seawater must also be evaluated.

The U.S. Navy is in the preliminary stages of investigating the use of OTEC at one of its installations. In addition, the Honolulu Board of Water Supply (BWS) is evaluating the feasibility of developing a deep ocean water facility to produce potable water, generate power via OTEC, and provide chilled water for air conditioning and other applications. HECO is serving on the study's technical advisory group.

An IPP is proposing a 100 MW OTEC facility to be anchored off Kahe Point, Oahu. The proposal received in late December 2003 specifies a July 2008 in-service date. If the project proves to be technically and economically feasible, the facility would be the first commercial OTEC facility in the world. HECO and the IPP are at the preliminary stages of discussions.

WAVE ENERGY

The mechanical energy of waves can also be used to generate power. There are three basic types of wave energy conversion systems. Float systems drive hydraulic pumps, channel systems funnel waves into reservoirs, and oscillating water column systems use the waves to compress air within a sealed container. The mechanical power that is produced by these systems either drives an electrical generator directly or transfers energy to a working fluid that drives a turbine generator.

In addition to participating in the EPRI multi-state offshore wave power project, HECO provided engineering support regarding electric grid interconnection and serves as a Navy technical advisor for a wave buoy demonstration project on Oahu. An at-sea demonstration of a 20-kW buoy wave energy system will be conducted at Kaneohe Marine Base. Under a DOD Small Business Innovation Research (SBIR) grant, the Navy is partnering with Ocean Power Technologies (OPT) to assess the technical and economic feasibility of ocean wave energy.

Coal

Coal can be used as a fuel for thermal generating units. The primary fuel of the HCPC is coal, and it currently exports approximately 22 MW to the HELCO system. Coal-fired thermal units help to diversify the mix of fuel sources.

During HELCO's IRP-2 process, three alternatives for using coal as a fuel were considered. A screening process was used to select the best candidate on the basis of capital costs, operation and maintenance costs, fuel costs, and appropriateness for the size of the HELCO system. A 30 MW coal unit was found to be the most financially attractive coal choice, and was used in the next tier of analysis. However, the resource plan that incorporated this coal unit was still more expensive overall than a resource plan containing other options, such as dual-train combined-cycle technology.

HELCO will again consider coal units during its next IRP process. If the costs of implementing coal-fired alternatives are reduced relative to non-coal alternatives, it is possible that HELCO will incorporate a coal unit into its future resource plans.

Distributed Generation & Combined Heat and Power

Distributed generation ("DG") includes the application of small generators, typically ranging in capacity from a dozen to several thousand kWs scattered throughout a power system, to provide the electric power needed by electric consumers. As ordinarily applied, the term "distributed generation" includes the use of small electric power generators, whether utilizing fossil fuels or renewable energy resources, located on the utility system at a utility site or at a customer site, which is either connected to the utility's power grid or off-grid (not connected).

As an example, customers with large heating or air-conditioning loads may benefit from the use of waste heat generated by a DG resource located at a customer site. The waste heat could be used to heat water or, through an absorption chiller, to drive an air-conditioning system, reducing the energy that would otherwise be needed for these functions. These applications, referred to as Combined Heat and Power ("CHP") applications, can be economical given the right customer site and project. Generally, most of the current CHP systems remain connected to the utility grid as back up or to obtain the additional power needed beyond what is produced on site.

The HECO utilities have recently analyzed the economics of utility-owned, customer-sited CHP systems and have found them to be an attractive resource when certain criteria can be met. An application for a CHP Tariff was filed with the PUC on October 10, 2003. Under the terms of this Tariff, the HECO utilities will install and maintain CHP units in the HECO, HELCO, and MECO service territories. Additional details regarding the CHP Tariff are available in PUC Docket 03-0366.

On October 21, 2003, the Commission filed Order 20582 in Docket No. 03-0371, which instituted a proceeding to investigate DG in Hawaii. The stated purpose of the investigation was to examine the potential benefits and impacts of DG on Hawaii's electric distribution systems and market. The objective is to develop policies and a framework for DG projects deployed in Hawaii. At this time, the regulatory schedule for proceedings has not been established.

FUEL CELL TECHNOLOGY

Fuel cell development is a promising energy technology that produces electricity from hydrogen and oxygen. Fuel cells are highly efficient because there is no combustion in the production of the electricity. Though today's fuel cells use primarily fossil fuel to create hydrogen, the hope is that the fuel source can be renewable in the future. Fuel cell technology can be applied to the transportation industry as well as the electric utility industry. The primary barriers to the development of fuel cells are the high cost of the fuel cell technology, reliability and longevity.

In general, fuel cell power plants are characterized by high efficiency, minimal emissions, little noise, and small land requirements. A very clean fuel is required to avoid contamination and degradation of the fuel cell stack performance. An 11-MW phosphoric acid fuel cell plant would require approximately 1 acre of land and have a capital cost of between $28 and $34 million. A 200-kW phosphoric acid fuel cell plant would require approximately 1,200 square feet with a capital cost of approximately $1 million.

Megawatt-scale fuel cell demonstration projects using phosphoric acid as the electrolyte and natural gas as the fuel source are operating in Japan. Applications of this technology within the U.S. are still limited and testing is still being conducted using various liquid and gaseous fuels.

Other types of fuel cells are also being demonstrated in the United States. The proton exchange membrane fuel cell (PEMFC) is under research, development, and demonstration. A 200-kW PEMFC was demonstrated in Indiana and residential sized PEMFC units have been installed and demonstrated at various locations. No commercial units are available. Molten carbonate fuel cells (MCFC) are being tested at various locations. FuelCell Energy, the only manufacturer of MCFC in the U.S., has built a factory capable of manufacturing 50 MW of fuel cells per year and has installed about 30 units worldwide. System sizes between 250 kW and 1 MW have been designed, built, and tested. FuelCell Energy is currently demonstrating its 250 kW unit for combined heat and power applications at various field test sites. The solid oxide fuel cell (SOFC) is under research, development, and demonstration. Siemens Westinghouse Power Corp. is developing and demonstrating a tubular SOFC design with several demonstration projects (up to 250 kW) underway.

The Big Island only has propane available as a fuel source. In general, the fuels cell stacks are very sensitive to contamination by certain chemicals (e.g., sulfur, chloride, etc.) that can poison or drastically reduce the life of the fuel cell stack. Certain fuel cell stacks, such as the proton exchange membrane, are also sensitive to carbon monoxide. The majority of fuel cell demonstrations used natural gas as the fuel source. Only a small number of fuel cells have been tested using propane.

In addition to HECO's membership with the Electric Power Research Institute and the pooled efforts by the electric utility industry in fuel cell developments for electricity production, HECO is participating in partnerships to incorporate hydrogen and fuel cell technology into Hawaii's long-term energy future.

Local activities include the construction and operation of the Hawaii Fuel Cell Test Facility at HECO's Ward Avenue complex. The fuel cell test facility was developed though a partnership of the University of Hawaii, DOD, UTC Fuel Cells and HECO. HECO's Ward Avenue complex is the site of a new hydrogen fuel cell test facility operated by the University of Hawaii School of Ocean & Earth Science & Technology's Hawaii Natural Energy Institute (HNEI). Utilizing approximately 4,000 square feet of HECO warehouse space, the objective of the Hawaii Fuel Cell Test Facility is to accelerate the development of fuel cells for commercial and military applications through the testing of proton exchange membrane fuel cell designs, materials, fuels and components to evaluate endurance, reliability and efficiency. (See Appendix E, HELCO IRP-2 Evaluation Report.)

In June 2002, HEI provided venture capital funding to Hoku Scientific, Inc., a Hawaii-based fuel cell R&D company that is developing proprietary fuel cell membrane technology. HEI's investment, which was part of a $1+ million round of funding, is viewed as critical to the further development of Hoku Scientific and its technology

HECO and HELCO are partnering with the DBEDT, HNEI, Sentech, Sunline, Stuart Energy, and UTC Fuel Cells in a Hydrogen Power Park project to introduce and demonstrate hydrogen-based infrastructure in Hawaii.

The Department of Defense (DOD) Residential Proton Exchange Membrane (PEM) Demonstration Program was initiated in 2001 to demonstrate fuel cell units at military facilities across the U.S. Data performance monitoring will be conducted for each PEM unit. The Marine Corp Base Hawaii at Kaneohe was selected as a demonstration site; however, a PEM fuel cell unit has not yet been installed.

Through its participation in and monitoring of fuel cell research activities, HECO has determined that utility-scale application of fuel cells is not a viable alternative to installing ST-7 at Keahole. HECO cannot predict exactly when significant technology breakthroughs may occur or if suitable fuels will be available. However, the lack of commercially available fuel cells for utility generation does indicate that it may take some time before fuel-cell alternatives become cost effective.

HFP
Acoustical Consultants
Inc.

NOISE STUDY for
DRAFT ENVIRONMENTAL IMPACT STATEMENT

Hawaii Electric Light Company, Inc.
Keahole Generating Station & Keahole Airport Substation
North Kona, Hawaii

Belt Collins

Submitted by:

HFP Acoustical Consultants Inc.

HFP File 5535-1

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Table of Contents

1. Background and Introduction

1.1. Background

HFP Acoustical Consultants Inc. (HFP) of Houston, Texas was contracted by Belt Collins of Honolulu, Hawaii to conduct the acoustical portion of an environmental impact study for the Hawaii Electric Light Company, Inc. (HELCO), Keahole Generating Station & Keahole Airport Substation, North Kona, Hawaii (Plant).

1.2. Introduction

The purpose of the study was to (1) quantitatively describe the existing acoustical environment surrounding the plant, (2) predict the future changes in sound level due to plant expansion and changes in traffic, and (3) predict the overall cumulative sound level impact of the proposed power plant expansion.

An environmental sound level survey was performed to characterize and quantify the existing acoustical environment in the area surrounding the plant. This data was processed to separate (to the extent possible) the noise contributions from existing traffic, aircraft, and insects.

A computer noise model was constructed of the existing plant facility based on field measurements of the existing plant equipment. A separate model was constructed of the proposed plant expansion, including all proposed noise control treatments. The measurement data from the environmental sound level survey was combined with these computer noise model predictions to calculate the potential future environmental sound levels in the area surrounding the plant.

1.3. Glossary

A glossary of basic environmental noise parameters, metrics, and definitions is included in **Appendix A**.

2. Applicable Noise Regulations

The only known applicable noise regulation for this site is the State of Hawaii's regulation regarding industrial facility noise. This regulation requires that industrial facilities generate less than the specified noise levels at the industrial facility property line. The specified noise levels depend on the area classification of the land surrounding the industrial area. The area classification of the land surrounding this HELCO plant is unclear. Without commitment or admission, HELCO has voluntarily decided to meet the residential property line regulation of 55 dBA during the daytime (7:00 a.m. to 10:00 p.m.) and 45 dBA during the nighttime (10:00 p.m. to 7:00 a.m.).

3. Environmental Sound Level Survey

An environmental sound level survey was performed in the area surrounding the plant by Mr. David M. Jones of HFP from June 25th through June 29th, 2004.

3.1. Survey Methodology

Nine measurement locations were chosen to characterize the acoustical environment surrounding the plant. Seven of these locations were in the residential neighborhoods to the south and west of the plant, with the remaining locations placed in the undeveloped lava fields to the north and east of the plant. Each measurement location was chosen to ensure equipment security while remaining on public street rights-of-way or public lands.

Measurements were taken at each of the seven neighborhood locations for two 24 hour (approximately) non-contiguous measurement periods. The intent was to measure a large enough sample of sound levels to fairly characterize the existing acoustical environment.

Only one measurement was taken at each of the lava field locations to the north and east of the plant. The measurement at the north location was approximately 17 hours in duration. The measurement at the east location was approximately 48 hours in duration.

3.2. Equipment

The equipment used in the survey was field calibrated, and has current laboratory certification. The precision sound level meter standards met are ANSI S1.4, Type 1; IEC 651, 804, Type 1; and DIN IEC 651, 804, Type 1. The precision filters in the sound level meter met ANSI S1.11, Type 0-AA; IEC 225, and DIN IEC 225.

3.3. Measurement Locations

A map showing the approximate location of the neighborhood monitoring equipment is attached as **Map 1**. Measurement Locations 8 and 9 are not shown on this map but are described below.

Map 1 also shows the approximate structure locations and designations used in this report. These structures have been designated as residences, though they may be businesses. Not all structures are shown on **Map 1.** Where there were multiple structures grouped together, only one of the structures has been indicated on **Map 1**.

3.3.1. Location 1: West of Pukiawe Street, at Kupaloke Street

Location 1 is west of Pukiawe Street at the intersection with Kupaloke Street. The monitor was placed approximately five feet northwest of telephone pole number 7. This location has a clear line of sight to the plant. The exhaust stacks for CT-2, the reciprocating units, and CT-4 and 5 are clearly visible.

3.3.2. Location 2: North side of Kupaloke Street, driveway to Residence C

Location 2 is at the west edge of the driveway to Residence C, on the north side of Kupaloke Street. The monitor was placed approximately 5 feet east-northeast of telephone pole number 3. The location has a direct line of sight to the plant, and the exhaust stacks for CT-2, the reciprocating units, and CT-4 and 5 are clearly visible.

3.3.3. Location 3: East side of Lau'i Street at Kupaloke Street

Location 3 is at the east edge of Lau'i street, at the north edge of the intersection with Kupaloke Street. The monitor was placed approximately 6 feet north of the telephone pole located east of the north edge of Kupaloke Street. The top of the plant stacks are barely visible from this location. The other plant equipment is not visible.

3.3.4. Location 4: West Plant Fence line, east of Residence A

Location 4 is just inside the west plant fence line, east of the centerline of the residence / business located to the west of the plant. The monitor was located approximately 4 feet inside the fence, directly east of the television aerial on the business / residence. This location is shielded from the plant by the maintenance building and topography. None of the equipment stacks are visible due to the building and the large elevation change.

3.3.5. Location 5: East side of Lau'i Street, one block south of Kupaloke Street

Location 5 is at the east edge of Lau'i Street, approximately one block south of Location 3. The monitor was placed approximately 6 feet north of telephone pole number 9 on Lau'i Street. The plant is not visible from this location.

3.3.6. Location 6: North of Kupaloke Street, north of Residence B

Location 6 is on the north side of Kupaloke Street, north of Residence B. The monitor was placed approximately 3 feet west north-west of telephone pole number 2. The location has a direct line of sight to the plant, and the exhaust stacks for CT-2, the reciprocating units, and CT-4 and 5 are clearly visible.

3.3.7. Location 7: West of Pukiawe Street, one block south of Kupaloke Street

Location 7 is on the west side of Pukiawe Street, approximately one block south of Location 1. The monitor was placed approximately 8 feet south of telephone pole number 10. The plant is partially visible from this location, though most of the equipment is shielded by ground vegetation or the residences to the north.

3.3.8. Location 8: Approximately 2000 feet northeast of the Plant

Location 8 is approximately 2000 feet northeast of the plant in the middle of the lava field. This location was approximately 1500 feet north northwest of the northwest corner of the two water tanks located at the east end of the access road north of the plant. This location has a direct line of sight to the plant equipment. This location is representative of the existing sound levels to the north and northeast of the plant. There are currently no residences or other structures in this undeveloped area.

3.3.9. Location 9: Approximately 2500 feet southeast of the Plant

Location 9 is approximately 2500 feet east southeast of the plant in the middle of the undeveloped lava field. The monitor was located directly east of Residence E and north of telephone pole number 11 on Ka'iminani road. The location has a direct line of sight to the CT-4 and CT-5 exhausts but most other of the plant noise sources were hidden by terrain and foliage. This location is representative of the sound levels to the east and southeast of the plant. There are currently no residences or other structures in this undeveloped area.

3.4. Plant Operating Conditions

CT-4 was in peaking mode operation during the measurement periods. CT-5 was undergoing performance testing. One or both of these units were in operation during each measurement period. An equipment operational summary is shown in **Table 1: Operational Log of Plant Equipment.** CT-2 was not operated during any measurement period and D-23 was the only reciprocating unit that was operated. D-23 ran from 11:26 am until 2:16 pm on June 24th.

3.5. Weather Conditions

The weather conditions during the survey period were appropriate for an environmental sound level survey. A summary of the weather conditions is shown in **Table 2: Summary of Weather Conditions**. This weather data was collected from the records of the Kona International Airport, which is less than a mile west of the plant site.

There were a few brief periods of rain during the measurement survey. The only significant rain occurred on the morning of June 26th.

3.6. Field Observations

3.6.1. Traffic Noise Sources

The dominant noise sources in the vicinity of the plant are traffic on Queen Kaahumanu Highway, aircraft traffic from the Kona International Airport, local traffic on Ka'iminani Drive and other neighborhood streets, and insect and bird sounds. There are several agricultural facilities in and around the neighborhood, and there is significant truck and farm machinery activity associated with the facilities.

3.6.2. Insect and Bird Sounds

Insects and birds are the most significant nighttime noise sources in the area surrounding the plant. These sources can reasonably be considered part of the normal acoustical environment.

3.6.3. Plant Contribution

During field observations the plant was inaudible at Locations 3, 5, 7, and 9. The plant was barely audible at measurement Locations 1, 2, 4, and 6. The plant was clearly audible at Location 8.

3.7. Survey Results

3.7.1. Graphical Results

The raw results of the environmental survey are presented in **Appendix B: Figures 1A through 9**. The figure numbers correspond to the measurement locations. The letter suffixes indicate the measurement period for locations with more than one measurement period. In those cases "A" represents the first period and "B" represents the second period.

Each figure shows the results from a single 16 to 24 hour period of measurements at a single location. The top section of each graph shows the one-minute Leq, represented by a solid blue line; the fifteen-minute Leq, a stepped red line; the fifteen-minute L90, a stepped green line; and the fifteen minute L10, a stepped orange line.

The bottom section of each figure shows the frequency-based data. Sound frequency is plotted on the vertical axis and time on the horizontal axis. The color indicates the A-weighted sound pressure level at each frequency for each one-minute Leq. The frequency data is useful for determining the presence of any tonal frequencies and helps to characterize the presence of specific noise emissions. For example, the presence of insect noise is clearly visible during the night time periods as high sound levels in the 4,000 to 10,000 Hz frequencies.

3.7.2. Tabular Results

A table showing a summary of the measured fifteen-minute sound level metrics at each measurement location for each period is included in **Appendix C: Tables C1A through C9.** Each table presents the fifteen-minute interval data measured and displayed graphically in **Appendix B**.

3.7.3. Statistical Results

Table 3: Summary of Measurement Period Data shows the calculated Ld, Ln, and Ldn at each measurement location and period. Also shown is the logarithmic average of the 15 minute L90s measured for the day and night periods.

4. Existing Acoustical Environment

The existing acoustical environment surrounding the plant is dominated by noise from traffic on Queen Kaahumanu Highway, aircraft traffic from the Kona International Airport, and local traffic on Ka'iminani Drive and other neighborhood streets. There are several agricultural facilities in and around the neighborhood, and there is significant truck and farm machinery activity associated with the facilities. The plant was inaudible at most of the measurement locations during the daytime hours because of the other environmental noise sources.

4.1. Types of Environmental Noise

4.1.1. Time-Based Filtering

The environmental noise sources surrounding the plant can be divided into short term and steady state categories. Short term sources include aircraft overflights and local neighborhood traffic. Steady state sources include insects and birds (while they are active), traffic on Queen Kaahumanu Highway and Ka'iminani Drive, the power plant, and wind noise. The steady state sources vary with time, but their variation takes place over tens of minutes rather than one or two minutes like the short term sources.

The difference in noise contribution from the short term and steady state sources can be seen in **Appendix B: Figures 1A through 9**. The one-minute Leq shows the influence of a single loud short term event such as an aircraft overflight or neighborhood traffic passby. To separate the noise contributions of short term and steady state noise sources, a peak level filtering technique was used to process the one-minute measurement samples. In this technique, a peak cutoff value was determined for each measurement location. All one-minute measurement samples that exceeded this level were considered to be short term peak events and all other measurement samples were considered as part of the steady state noise environment. The sound levels chosen as the peak cutoff values were chosen from visual inspection of **Figures 1A through 9**, and are therefore a best-judgment selection. The selected values for the peak cutoff are listed in the results tables discussed below.

4.1.2. Frequency-Based Filtering

Insects and birds are significant sound sources in the area surrounding the plant. They are often the single most significant noise source, especially during the evening and early morning.

Insect noise is generally limited to the 5000 Hz and higher third octave bands. Bird noise is dependent on the species and situation, but in this case bird noises were generally seen in the data as strong tonal components between 1500 and 5000 Hz. The contributions of the insects and birds are quite apparent on the bottom (sonograph) portion of **Figures 1A through 9**. Labels have been applied to many of the most obvious examples of insect and bird noises.

4.2. Traffic Noise

4.2.1. Current Traffic Noise

Vehicles on Queen Kaahumanu Highway and Ka'iminani Road are the dominant noise sources at all locations surrounding the plant during the daylight hours. The traffic noise contribution can be seen on **Figures 1A through 9** as high amplitude mid-frequency (125 to 2000 Hz) sound energy that begins at approximately 6:00 a.m. and tapers off at approximately 10:00 p.m.

The steady state traffic noise contribution was calculated at each measurement location from the one-minute Leq measurements by first eliminating the contribution of insects (by filtering out the high frequency third octave bands) and then by eliminating aircraft overflights and local neighborhood car passbys (by using a peak cutoff level). The peak cutoff level used to filter out the short term events was dependent on the location, and was selected by inspection of **Figures 1A through 9**.

Table 4: Measured and Predicted Traffic Contributions shows the calculated traffic Ld, Ln, Ldn, and period Leq at each measurement location. The table also shows the peak cutoff level used at each measurement location to separate the short term events from the steady state traffic contribution.

4.2.2. Projected Traffic Noise

Belt Collins has generated a preliminary traffic noise study for the area surrounding the plant. The sound level contribution of traffic will increase logarithmically with traffic volume if all other variables are held constant. In this case, it was assumed that the percentage of heavy and medium weight trucks will remain relatively constant, and that the width and surface materials of Queen Kaahumanu Highway and Ka'iminani Road would remain unchanged.

Using the projected increase in traffic volume outlined in the traffic study, the sound level increase was estimated for the worst case morning and afternoon hours. Three different traffic cases were evaluated. However, the variation in predicted traffic volumes between the three cases was so slight that the calculated sound level increase for each case was identical, with a 1.9 dB increase for the worst-case afternoon hour and 1.7 dB for the worst-case morning hour.

A summary of the measured traffic sound levels along with the predicted future traffic contributions is shown in **Table 4: Measured and Predicted Traffic Contributions**. A summary of the current and predicted future traffic volumes and the associated worst case predicted traffic sound level increase is shown in **Table 5: Traffic Study Summary and Traffic Sound Level Increase Calculation.**

4.3. Aircraft and Local Traffic Noise

The highest short term sound levels at each measurement location generally resulted from events such as aircraft overflights or local neighborhood traffic passbys. These events are visible on **Figures 1A through 9** as sharp peaks in the one-minute Leq. These short term peaks in sound level can have a significant effect on the long term Leq. The effect is visible on **Figures 1A through 9**, where it is apparent that just one or two high level short term events can radically alter the 15 minute interval metrics for the corresponding measurement period.

As discussed above, a peak cutoff value was used to separate the contribution of the short term noise sources from the other environmental noise sources in the area surrounding the plant. **Table 6: Measured Aircraft Contributions** shows the calculated Ld, Ln, and Leq derived from the one-minute measurement samples that were equal to or greater than the peak cutoff value. These represent the Leq for the daytime or nighttime period with aircraft and local traffic noises as the only noise source present.

4.4. Insect and Bird Noise

As discussed above, one technique that can be used to quantify the contribution of insect and bird noise is to use frequency based filtering to separately evaluate the high frequency components of the environmental noise measurements. **Table 7: Measured Insect and Bird Contributions** shows the calculated Ld, Ln, Ldn and period Leq for the measurement locations based solely on the high frequency third-octave frequency bands. This effectively isolates the insect and bird sound level contribution at each measurement location.

Two different third octave ranges were used in the calculation, as appropriate (based on the characteristics of the insect and bird sounds found in the individual measurements): either 4,000 to 10,000 Hertz or 2,500 to 10,000 Hertz. The ranges varied from location to location because the mix of insect and bird noise differed by location. The one-third octave frequency range used in the calculation is shown on **Table 7: Measured Insect and Bird Contributions**.

4.5. Existing, Untreated Plant Contribution

Table 8: Comparison of CT-5 in Operation and Shutdown shows a comparison between early morning sound levels at four measurement locations with CT-5 operating (Period 7) and with it shut down (Period 16). The value for the 4:00 a.m. to 5:00 a.m. hour is shown because this is the quietest single hour at these measurement locations, and therefore minimizes all non-powerplant noise sources, such as traffic, aircraft, and insects. Use of the L90 metric also reduces the effect of short-term noise peaks.

Table 8: Comparison of CT-5 in Operation and Shutdown shows that the existing sound level contributions from CT-5 are insignificant. CT-5 was in operation for the entire On period at 40% or greater load. As shown, the period L90 actually increased at Locations 1 and 4 (moving from On to Off). The period L90 does drop by a small amount at Locations 2 and 3. Calculations indicate a sound level contribution from CT-5 of no more than 30 dBA at Locations 2 and 3.

It was not possible to simultaneously operate all of the existing plant equipment, therefore no measurements could be made for this condition. A computer noise model was developed to evaluate this scenario. The details of the computer model are discussed in **Section 5**. The results for the existing, untreated plant are shown in **Table 9: Predicted Existing Plant Contributions**. This table shows the calculated environmental sound level contributions with two combinations of existing equipment in operation: (1) nighttime operation of the three combustion turbines (CT-2, CT-4, and CT-5) and (2) daytime operation of three combustion turbines and three reciprocating units (D-21, D-22, D-23).

4.6. Summary of All Existing Noise Sources

Table 10: Calculated Total Existing Environmental Sound Levels, with Plant shows a summary of all existing environmental noise sources as separated and calculated in the tables above along with the computer model prediction of the existing plant. The "Combination of All Sources" column shows the logarithmic sum of the noise from the different environmental noise sources.

5. Prediction of Noise Impact

5.1. Computer Noise Model

5.1.1. Model Introduction

A computer noise model was constructed of the existing and the proposed plant. The model was developed using SoundPLAN, a commercial noise modeling package developed by Braunstein and Berndt, GmbH. This standards–based software takes into account spreading losses, ground and atmospheric effects, shielding from barriers and buildings, and reflections from surfaces. The ISO 9613 standard protocol was used for air absorption and the "General Prediction Method for Noise from Industrial Facilities" was used for other noise propagation factors.

5.1.2. Existing Plant

A computer noise model of the *existing* plant equipment was constructed. The model includes Units D-21, D-22, D-23, and CT-2, plus Units CT-4 and CT-5 in their present Simple Cycle configuration without any additional noise control. Also included are all auxiliary sources such as air conditioning units, utility pumps, etc. All sources included in the model are listed by category in **Appendix D**.

5.1.3. Future Plant

A computer noise model of the future plant was also constructed. This model includes all existing equipment at the site along with the proposed Combined Cycle plant equipment, including the CT-4 and CT-5 Heat Recovery Steam Generators (HRSGs), the new Unit ST-7 located inside an insulated metal building, and the ST-7 air-cooled condenser fans. As discussed below, the model includes all planned noise control for the existing plant equipment as well as planned noise control for the Combined Cycle equipment. All sources included in the model are listed by category in **Appendix D**.

5.1.4. Source Data for Computer Model

Sound pressure level and sound power level data were obtained from several different sources for use as the existing and future noise sources in the computer noise model. A table summarizing all noise sources in the computer model, their sound power level, location, and organization is attached as **Appendix D.**

5.1.4.1. CT-2

CT-2 was not in operation during the sound level survey period, so measurements provided by HELCO from a previous field sound level measurement survey were used to calculate the sound power level of the CT-2 components.

5.1.4.2. CT-4 and CT-5 Simple Cycle

The original Request for Quote Specification for the Simple Cycle noise control project contained several noise measurements of the various plant noise sources. This original information was supplemented with actual field sound level measurements performed by HFP of the operating CT-4 and CT-5 noise sources during the environmental survey.

5.1.4.3. CT-4, CT-5, ST-7 Combined Cycle

Sound power levels for the HRSG and associated ductwork were taken from the Sound Technologies Incorporated predictions made during the Simple Cycle noise control project. The ST-7 turbine and air-cooled condenser information was taken from manufacturer data, proposed purchase specifications, and HFP field measurements of similar equipment.

5.1.4.4. Reciprocating Diesel Units

Original information for the reciprocating diesel unit sound power level was provided by HELCO based on a previous field sound level measurement survey. Supplementary measurements of D-23 were performed by HFP during the environmental survey.

5.1.5. Noise Model Assumptions

The noise model is intended to represent a conservative calculation of the sound level due to the existing and future plant. Terrain elevations were modeled from photos and estimated terrain heights and verified with available topographic data. No foliage or vegetation was included in the calculations. The ground was modeled as being only 30% absorptive to estimate the generally reflective nature of the broken lava fields surrounding the plant.

5.1.6. Modeled Weather Conditions

Temperature and humidity have an influence on sound propagation. Statistical data from June 27, 2003 to June 27, 2004 was used as the basis for the computer model weather data. The average daily low temperature of 68°F was used as the night time period temperature and the average daily high temperature of 84°F was used for the daytime period. The average mean temperature of 78°F and average dew point of 67°F were used to calculate an overall average relative humidity of 69% for the year.

Wind and atmospheric stability are significant factors in sound propagation calculations. The average annual wind speed of 7 mph was used along with a very conservative omnidirectional wind. In the computer noise model, the wind direction is designated as blowing from the plant to each evaluated receiver position.

The atmospheric stability class for the daytime was estimated at Class B, which represents mostly-sunny moderate wind conditions, and is a conservative representation of the typical day time conditions for the area. The nighttime stability class was estimated at Class F, which represents a low cloud cover moderate wind speed condition.

5.2. Future Noise Control and Property Line Targets

Significant future noise control treatments are planned for the existing plant equipment. Each treatment project will specify property line sound level targets for the subject equipment. These targets will vary by with an overall goal of meeting HELCO's overall property line targets of 55 dBA during daytime operation and 45 dBA during nighttime operation for all plant equipment. A summary of the property line targets for each treatment project are shown in **Table 11: Summary of Property Line Noise Control Targets**.

5.2.1. CT-4 and CT-5 Simple Cycle Noise Control Project

HELCO has already contracted for the installation of noise control equipment that will limit the noise contributions of the CT-4 and CT-5 Simple Cycle equipment to less than 42 dBA at all plant property lines.

5.2.2. CT-2 Noise Control

HELCO has performed an engineering analysis of the required noise control for CT-2 so that all plant equipment in simultaneous operation would produce less than 45 dBA at the plant property line. HELCO plans to issue a Request for Quote to a design-build contractor that will implement noise control such that the property line sound level targets shown in **Table 11: Summary of Property Line Noise Control Targets** are met for CT-2 operating alone.

These property line targets have been developed to allow the operation of CT-2, CT-4, CT-5 and ST-7 simultaneously while meeting the nighttime property line target of 45 dBA.

5.2.3. Reciprocating Diesel Unit Noise Control

The initial review of the noise control treatments necessary to reduce the reciprocating diesel unit (D-21, D-22, and D-23) property line noise contributions to less than the nighttime 45 dBA target found that the predicted cost per megawatt hour would exceed HELCO's target. Since these units are used primarily as peaking power units and are small compared to the other equipment on site, HELCO has decided to restrict their use to daytime operation only. The daytime property line target chosen by HELCO is 55 dBA.

The noise-control targets necessary for all three of these units to meet the 55 dBA property line target while in simultaneous operation are shown in **Table 11: Summary of Property Line Noise Control Targets**.

5.2.4. CT-4, CT-5, and ST-7 Combined Cycle Noise Control

Generally, the noise control required for the Simple Cycle CT-4 and CT-5 will be sufficient for the Combined Cycle expansion to meet a 45 dBA property line target with all equipment in operation.

A Heat Recovery Steam Generator (HRSG) will be added to both the CT-4 and CT-5 exhaust ductwork. These are large devices, and they will function as additional barriers for the exhaust ductwork and other plant noise sources. The HRSGs will also provide significant additional exhaust silencing.

The most significant noise sources added with the Combined Cycle project will be the ST-7 unit and the associated ST-7 air cooled condenser bank.

The ST-7 unit will be located in an insulated metal building to the west of the existing control building. The air cooled condensers will be located southwest of the ST-7 building. **Table 12: Combined Cycle Equipment and Noise Control Assumptions** shows the estimated sound level inside the ST-7 building, the required building wall and ventilation acoustical performance, along with the required 200-foot sound level criterion for the air cooled condensers in order to meet HELCO's 45 dBA nighttime property line target with all equipment in operation.

5.3. Predicted Sound Levels

Because of the limitations of computer noise modeling accuracy, the results from the computer model have been rounded to the nearest whole decibel. Any calculations based on the computer model results have also been rounded to the nearest whole decibel.

5.3.1. Existing Plant Levels

The sound level contribution of the existing plant is shown in **Table 9: Predicted Existing Plant Contributions**. This table shows the predicted levels for two combinations of existing equipment in operation with (1) nighttime operation of three combustion turbines, one steam turbine, and all associated equipment (CT-2, CT-4, CT-5, and ST-7) and (2) daytime operation of the night time equipment along with three reciprocating units (D-21, D-22, D-23) and associated equipment.

5.3.2. Predicted Plant Sound Levels

Table 13: Predicted Future Plant Contribution shows the predicted daytime and nighttime sound level contributions of the plant with all future planned equipment in operation and all noise control treatments installed. The daytime operation assumes that all plant equipment is in operation while meeting the individual property line targets as outlined in **Table 11: Summary of Property Line Noise Control Targets**. The plant contribution includes the effects of wind from the plant to all receivers, as discussed in **Section 5.1.6**.

The predicted future sound level contribution from the plant is significantly lower than the current measured and predicted sound levels. This is due to the fact that even though equipment will be added during the combined cycle expansion, noise control treatments will be added to many of the existing noise sources during the Simple Cycle noise control project and the CT-2 noise control project. The Combined Cycle equipment will also be chosen and installed with HELCO's property line noise targets in mind.

Table 14: Predicted Total Future Environmental Sound Levels, with Plant shows a summation of all future environmental noise sources. The traffic levels are the predicted future traffic sound levels calculated using the volume adjustment discussed earlier. The aircraft and insect sound levels are the measured sound levels from the environmental survey. No information was available for projected increases in aircraft traffic and there is no expected change in the insect noise contribution. The Predicted Future Plant levels are as discussed above. The "Combination of All Sources" column shows the logarithmic sum of the noise from the different environmental noise sources.

5.3.3. Predicted Increase in Plant Contribution

Table 15: Predicted Increase in Plant Contribution shows the difference between the predicted existing plant equipment and all future equipment. Significant decreases in sound level are predicted at all measurement locations due to HELCO's planned noise control projects, as indicated by negative table values. These reductions range from 11 to 20 dB, with the most significant reductions occurring during nighttime operation.

Table 16: Predicted Overall Increase in Sound Level shows a comparison between the predicted future overall environmental levels with the measured existing levels and the predicted existing levels with all plant sources in operation. The "Increase over Measured Existing" column shows that the predicted future environmental sound levels (including all traffic increases, insects, aircraft, and all plant sources) will be very similar to the existing measured environmental sound levels. The "Increase over Measured Existing" ranges from 0.0 to +1.7 dB. Negative numbers are the result of cumulative rounding errors, and should be considered equal to zero. The increases are due exclusively to the predicted increase in traffic noise of +1.9 dB.

6. Ground Vibration

The current equipment produces no perceptible ground vibration at the fence line, and no vibration is perceptible at any of the measurement locations. It is extremely unlikely that there will be any perceptible ground vibration at the plant fence line due to any power plant equipment, existing or future.

Ground borne vibration requires extremely high exciting forces in order to travel distances such as those from the plant to the residences. Such powerful exciting forces might be expected during pile driving, explosive blasting, or demolition, but would not be consistent at all with modern internal combustion and steam turbine technology.

Units D-21, D-22, and D-23 are reciprocating units that have been installed and operated at the Keahole site for many years. They are maintained in good operating order and balance, and would not be operated if they generated excessive vibration. They will not be modified in any way that might increase the vibration produced.

Gas and steam turbines are, by necessity, extremely well balanced. Because of their high rotational speeds any small out-of-balance condition would cause operational problems or damage to the equipment components. Auxiliary equipment associated with the combustion and steam turbines, such as the various centrifugal pumps skids and electrical transformers are also, by the nature of their designs, highly unlikely to produce any significant ground vibration.

7. Tables and Maps

Table 1: Operational Log of Plant Equipment

Percentage indicates approximate unit loading during the time period from the start time to the next period start time.

Date	Operational Period	Start Time	CT4	CT5	D23
6/24/2004	1	0:00	0%	0%	0%
6/24/2004	2	8:22	0%	80%	0%
6/24/2004	3	11:26	0%	80%	81%
6/24/2004	4	14:16	0%	85%	0%
6/24/2004	5	20:39	51%	67%	0%
6/24/2004	6	22:57	0%	79%	0%
6/25/2004	7	0:00	0%	40%	0%
6/25/2004	8	9:27	90%	40%	0%
6/25/2004	9	9:47	90%	0%	0%
6/25/2004	10	11:42	83%	102%	0%
6/25/2004	11	12:16	0%	102%	0%
6/25/2004	12	23:24	0	0	0
6/26/2004	13	8:11	100%	0	0
6/26/2004	14	12:14	61%	27%	0
6/26/2004	15	13:00	100%	0	0
6/26/2004	16	23:03	0	0	0
6/27/2004	17	8:20	100%	0	0
6/27/2004	18	21:30	0	0	0
6/28/2004	19	8:35	87%	0	0
6/28/2004	20	23:22	0	0	0
6/29/2004	21	8:42	0	75%	0

Table 2: Summary of Weather Conditions

Day	Max Temp (deg F)	Mean Temp (deg F)	Min Temp (deg F)	Max Humidity (%)	Mean Humidity (%)	Min Humidity (%)	Mean Atm. Pressure (In.)	Mean Wind Speed (mph)
6/20/2004	84	78	73	89	75	62	30	4
6/21/2004	84	78	72	84	69	60	29.98	5
6/22/2004	84	80	75	82	72	61	29.98	5
6/23/2004	86	80	75	79	64	51	29.94	5
6/24/2004	82	78	75	82	72	65	29.95	9
6/25/2004	82	78	73	84	71	62	29.96	3
6/26/2004	86	82	78	79	68	58	29.96	8
6/27/2004	82	78	73	94	81	62	29.95	9
6/28/2004	84	78	73	84	70	58	29.99	7
6/29/2004	82	78	73	91	76	67	30	7
6/30/2004	84	80	75	87	74	60	30.01	4
7/1/2004	86	80	75	76	64	53	30.04	8
7/2/2004	84	78	73	82	71	60	30	10
7/3/2004	84	80	75	84	69	56	29.98	8

Table 3: Summary of Measurement Period Data

						Average of 15 Minute L90s		
Start Date	Location	Ld	Ln	Ldn	Leq	L90 day	L90 night	L90 Period
6/24/2004	1A	55.5	48.7	57.0	54.0	45.0	42.1	44.1
6/26/2004	1B	54.0	50.0	57.2	52.8	46.1	42.8	45.2
6/24/2004	2A	56.0	54.5	61.2	55.5	44.3	44.8	44.5
6/26/2004	2B	53.3	53.9	60.2	53.5	44.1	40.9	43.2
6/24/2004	3A	61.7	50.4	61.3	59.8	54.8	35.7	52.7
6/26/2004	3B	59.6	53.8	61.7	58.2	51.5	34.9	49.5
6/24/2004	4A	55.0	49.6	57.3	53.6	48.4	44.9	47.4
6/26/2004	4B	54.3	48.7	56.5	52.9	49.0	44.0	47.7
6/25/2004	5A	51.5	48.9	55.8	50.7	40.8	40.2	40.6
6/27/2004	5B	50.7	44.2	52.3	49.2	38.8	37.7	38.4
6/25/2004	6A	53.3	48.3	55.9	52.1	44.2	41.4	43.4
6/27/2004	6B	53.9	53.5	60.0	53.7	42.2	43.0	42.5
6/25/2004	7A	57.8	50.4	59.0	56.2	46.1	42.3	45.0
6/27/2004	7B	57.3	52.1	59.7	55.9	44.9	41.6	44.0
6/25/2004	8	51.9	49.7	56.5	51.2	46.2	44.6	45.7
6/27/2004	9	48.3	47.4	54.0	48.0	39.2	39.3	39.2

Table 4: Measured and Predicted Traffic Contributions

Position	Peak Cutoff	Steady State Traffic Contribution, Measured Existing				Increase (Calc'd Below)	Predicted Future Traffic Contribution			
		Ld	Ln	Ldn	Leq		Ld	Ln	Ldn	Leq
1A	58	50.6	46.1	53.5	49.4	+1.9	52.5	48.0	55.4	51.3
1B	58	50.8	44.7	52.7	49.2		52.7	46.6	54.6	51.1
2A	58	47.7	43.2	50.7	46.5		49.6	45.1	52.6	48.4
2B	58	46.9	40.0	48.3	45.3		48.8	41.9	50.2	47.2
3A	55	45.8	40.1	48.0	44.4		47.7	42.0	49.9	46.3
3B	55	44.6	38.3	46.3	43.0		46.5	40.2	48.2	44.9
4A	58	52.3	46.4	54.3	50.9		54.2	48.3	56.2	52.8
4B	58	52.7	46.1	54.3	51.1		54.6	48.0	56.2	53.0
5A	53	45.7	42.5	49.6	44.8		47.6	44.4	51.5	46.7
5B	53	44.7	40.7	48.0	43.5		46.6	42.6	49.9	45.4
6A	55	48.1	45.3	52.3	47.2		50.0	47.2	54.2	49.1
6B	55	46.5	43.0	50.1	45.4		48.4	44.9	52.0	47.3
7A	58	51.0	47.6	54.7	49.9		52.9	49.5	56.6	51.8
7B	58	49.7	45.6	52.9	48.5		51.6	47.5	54.8	50.4
8	56	49.3	47.9	54.6	48.6		51.2	49.8	56.5	50.5
9	50	41.8	40.2	46.9	41.2		43.7	42.1	48.8	43.1

Table 5: Traffic Study Summary and Traffic Sound Level Increase Calculation

Traffic Case	Worst-Case Hour	Queen Kaahumanu Highway		Ka'iminani Drive		TOTAL	
		Number of Passbys	Increase (dB)	Number of Passbys	Increase (dB)	Number of Passbys	Increase (dB)
Existing	AM	1408	-	660	-	2068	-
	PM	1770	-	752	-	2522	-
Case 2	AM	2206	2.0	830	1.0	3036	1.7
	PM	2916	2.2	985	1.2	3901	**1.9**
Case 3, Alt A	AM	2209	2.0	843	1.1	3052	1.7
	PM	2917	2.2	993	1.2	3910	**1.9**
Case 4, Alt B	AM	2216	2.0	830	1.0	3046	1.7
	PM	2923	2.2	985	1.2	3908	**1.9**

Table 6: Measured Aircraft Contributions
These are calculated period contribution of only the one-minute samples that exceeded the Peak Cutoff level, dBA.

Location	Peak Cutoff	Ld	Ln	Ldn	Leq
1A	58	52.9	41.6	52.4	51.0
1B	58	48.5	41.3	49.8	46.9
2A	58	49.3	36.1	48.4	47.4
2B	58	46.0	34.5	45.5	44.1
3A	55	56.2	39.6	54.7	54.2
3B	55	50.0	35.5	48.8	48.0
4A	58	51.5	42.1	51.8	49.8
4B	58	48.8	39.2	48.9	47.0
5A	53	50.0	46.3	53.5	48.9
5B	53	49.2	40.5	49.7	47.5
6A	55	51.4	41.9	51.6	49.6
6B	55	51.7	41.9	51.8	49.9
7A	58	55.4	44.3	55.0	53.5
7B	58	54.3	47.2	55.6	52.8
8	56	48.7	42.7	50.6	47.3
9	50	45.1	42.5	49.4	44.3

Table 7: Measured Insect and Bird Contributions
Averages for all one-minute measurement data in the given third-octave band frequency range, dBA.

Location	Frequency Range (Hertz)	Ld	Ln	Ldn	Leq
1A	4k - 10k	48.8	42.8	50.8	47.3
1B	4k - 10k	48.1	47.6	54.1	47.9
2A	2.5k - 10k	54.0	48.9	56.5	52.7
2B	2.5k - 10k	51.0	53.7	59.8	52.2
3A	4k - 10k	60.2	49.8	60.1	58.4
3B	4k - 10k	59.1	53.7	61.4	57.7
4A	4k - 10k	43.0	45.0	51.2	43.9
4B	4k - 10k	42.1	44.2	50.4	43.1
5A	4k - 10k	40.8	42.7	48.9	41.6
5B	4k - 10k	40.0	35.4	42.9	38.8
6A	4k - 10k	42.9	43.0	49.4	42.9
6B	4k - 10k	47.8	53.0	58.9	50.6
7A	2.5k - 10k	51.7	44.3	52.9	50.0
7B	2.5k - 10k	52.8	48.4	55.8	51.6
8	4k - 10k	32.0	42.7	48.5	40.3
9	2.5k - 10k	43.5	44.5	50.8	43.9

Table 8: Comparison of CT-5 in Operation and Shutdown

	4:00 to 5:00a.m. Hour, L90, A-weighted	
Location	CT-5 On (Period 7)	CT-5 Off (Period 16)
1	40.8	41.6
2	33.8	31.1
3	32.4	28.8
4	43.9	44.6

Table 9: Predicted Existing Plant Contributions
All existing equipment operating, as currently installed
D-21, D-22, D-23, CT-2, CT-4, CT-5

Location	Calm			With Wind		
	Ld	Ln	Ldn	Ld	Ln	Ldn
1	53	53	60	56	54	61
2	54	54	60	57	55	62
3	41	43	49	45	44	50
4	55	56	62	56	56	63
5	46	49	55	51	50	56
6	55	55	61	58	56	62
7	46	49	55	51	50	56
8	46	51	57	52	52	58
9	40	45	50	47	46	52

Table 10: Calculated Total Existing Environmental Sound Levels, with Plant

Loc.	Traffic			Aircraft			Insects			Predicted Plant			Combination of All Sources		
	Ld	Ln	Ldn	Ld	Ln	Ldn	Ld	Ln	Ldn	Ld	Ln	Ldn	Ld	Ln	Ldn
1A	50.6	46.1	53.5	52.9	41.6	52.4	48.8	42.8	50.8	56	54	61	59	55	62
1B	50.8	44.7	52.7	48.5	41.3	49.8	48.1	47.6	54.1	56	54	61	58	55	62
2A	47.7	43.2	50.7	49.3	36.1	48.4	54.0	48.9	56.5	57	55	62	60	56	63
2B	46.9	40.0	48.3	46.0	34.5	45.5	51.0	53.7	59.8	57	55	62	59	58	64
3A	45.8	40.1	48.0	56.2	39.6	54.7	60.2	49.8	60.1	45	44	50	62	51	62
3B	44.6	38.3	46.3	50.0	35.5	48.8	59.1	53.7	61.4	45	44	50	60	54	62
4A	52.3	46.4	54.3	51.5	42.1	51.8	43.0	45.0	51.2	56	56	63	59	57	64
4B	52.7	46.1	54.3	48.8	39.2	48.9	42.1	44.2	50.4	56	56	63	58	57	63
5A	45.7	42.5	49.6	50.0	46.3	53.5	40.8	42.7	48.9	51	50	56	54	53	59
5B	44.7	40.7	48.0	49.2	40.5	49.7	40.0	35.4	42.9	51	50	56	54	51	58
6A	48.1	45.3	52.3	51.4	41.9	51.6	42.9	43.0	49.4	58	56	62	59	57	64
6B	46.5	43.0	50.1	51.7	41.9	51.8	47.8	53.0	58.9	58	56	62	59	58	65
7A	51.0	47.6	54.7	55.4	44.3	55.0	51.7	44.3	52.9	51	50	56	59	53	61
7B	49.7	45.6	52.9	54.3	47.2	55.6	52.8	48.4	55.8	51	50	56	58	54	61
8	49.3	47.9	54.6	48.7	42.7	50.6	32.0	42.7	48.5	52	52	58	55	54	61
9	41.8	40.2	46.9	45.1	42.5	49.4	43.5	44.5	50.8	47	46	52	51	50	56

Table 11: Summary of Property Line Noise Control Targets

Equipment	Property Line Limit			
	North	East	South	West
CT-4 and CT-5 Simple Cycle	42 dBA, 70 dBC			
CT-2 Simple Cycle	36 dBA	40 dBA	34 dBA	40 dBA
Diesel Units, per Unit	48 dBA			

Table 12: Combined Cycle Equipment and Noise Control Assumptions

	Overall	Linear Sound Power or Pressure Level at Octave Center Frequency								
	dBA	31.5	63	125	250	500	1000	2000	4000	8000
Air Cooled Condenser										
Original bid specification at **300'**, per HELCO	95	134	108	77	48	21	2	0	6	
Maximum allowable sound pressure level at **200'**, per HFP	91	130	104	73	43	16	-3	-12	-3	5
Steam Turbine Building										
Given sound pressure level at 3' from turbine	85.0	63	78	83	78	81	80	75	78	75
Calculated sound pressure level inside steam turbine building	82.4	63	77	80	75	78	77	73	76	73
Required Building Wall TL		12	12	11	16	26	34	41	44	46
All building ventilation openings will require at least 3' ventilation silencers.										
HRSG Duct Calculated Sound Power Levels (from Sound Technologies calculations of May 13, 2003)										
Turbine Exh Duct: Enclosure to HRSG	67.8	104.4	90.1	70.6	58.6	43.5	27.5	17.5	7.6	-2.4
HRSG Body	59.9	96.0	83.0	62.0	40.6	18.7	3.4	1.5	7.7	15.5
Turbine Exh Duct: After HRSG	61.4	97.1	84.9	63.1	41.1	19.1	3.1	-6.0	2.0	6.0
CT-4 and CT-5 Exhaust Sound Power Level										
Single Turbine Exhaust with HRSG, directivity, silencer	66.6	98	91	74	59	51	46	33	28	16

Table 13: Predicted Future Plant Contribution

Location	Calm			With Wind		
	Ld	Ln	Ldn	Ld	Ln	Ldn
1	39	36	43	41	37	44
2	42	37	44	46	38	47
3	31	25	33	34	27	35
4	41	39	46	42	40	46
5	35	32	39	40	33	41
6	42	38	45	46	39	47
7	33	31	38	37	32	39
8	32	31	37	38	32	40
9	30	26	33	35	28	36

Table 14: Predicted Total Future Environmental Sound Levels, with Plant

Loc.	Predicted Future Traffic			Aircraft			Insects			Predicted Future Plant			Combination of All Sources		
	Ld	Ln	Ldn	Ld	Ln	Ldn	Ld	Ln	Ldn	Ld	Ln	Ldn	Ld	Ln	Ldn
1A	52.5	48.0	55.4	52.9	41.6	52.4	48.8	42.8	50.8	41	37	44	57	50	58
1B	52.7	46.6	54.6	48.5	41.3	49.8	48.1	47.6	54.1	41	37	44	55	51	58
2A	49.6	45.1	52.6	49.3	36.1	48.4	54.0	48.9	56.5	46	38	47	57	51	59
2B	48.8	41.9	50.2	46.0	34.5	45.5	51.0	53.7	59.8	46	38	47	54	54	61
3A	47.7	42.0	49.9	56.2	39.6	54.7	60.2	49.8	60.1	34	27	35	62	51	61
3B	46.5	40.2	48.2	50.0	35.5	48.8	59.1	53.7	61.4	34	27	35	60	54	62
4A	54.2	48.3	56.2	51.5	42.1	51.8	43.0	45.0	51.2	42	40	46	56	51	59
4B	54.6	48.0	56.2	48.8	39.2	48.9	42.1	44.2	50.4	42	40	46	56	50	58
5A	47.6	44.4	51.5	50.0	46.3	53.5	40.8	42.7	48.9	40	33	41	53	50	57
5B	46.6	42.6	49.9	49.2	40.5	49.7	40.0	35.4	42.9	40	33	41	52	45	53
6A	50.0	47.2	54.2	51.4	41.9	51.6	42.9	43.0	49.4	46	39	47	55	50	57
6B	48.4	44.9	52.0	51.7	41.9	51.8	47.8	53.0	58.9	46	39	47	55	54	61
7A	52.9	49.5	56.6	55.4	44.3	55.0	51.7	44.3	52.9	37	32	39	58	52	60
7B	51.6	47.5	54.8	54.3	47.2	55.6	52.8	48.4	55.8	37	32	39	58	53	60
8	51.2	49.8	56.5	48.7	42.7	50.6	32.0	42.7	48.5	38	32	40	53	51	58
9	43.7	42.1	48.8	45.1	42.5	49.4	43.5	44.5	50.8	35	28	36	49	48	55

Table 15: Predicted Increase in Plant Contribution

Loc.	Predicted Existing Plant			Predicted Future Plant			Predicted Increase		
	Ld	Ln	Ldn	Ld	Ln	Ldn	Ld	Ln	Ldn
1A	56	54	61	41	37	44	-15	-17	-17
1B	56	54	61	41	37	44	-15	-17	-17
2A	57	55	62	46	38	47	-11	-17	-15
2B	57	55	62	46	38	47	-11	-17	-15
3A	45	44	50	34	27	35	-11	-17	-15
3B	45	44	50	34	27	35	-11	-17	-15
4A	56	56	63	42	40	46	-14	-16	-17
4B	56	56	63	42	40	46	-14	-16	-17
5A	51	50	56	40	33	41	-11	-17	-15
5B	51	50	56	40	33	41	-11	-17	-15
6A	58	56	62	46	39	47	-12	-17	-15
6B	58	56	62	46	39	47	-12	-17	-15
7A	51	50	56	37	32	39	-14	-18	-17
7B	51	50	56	37	32	39	-14	-18	-17
8	52	52	58	38	32	40	-14	-20	-18
9	47	46	52	35	28	36	-12	-18	-16

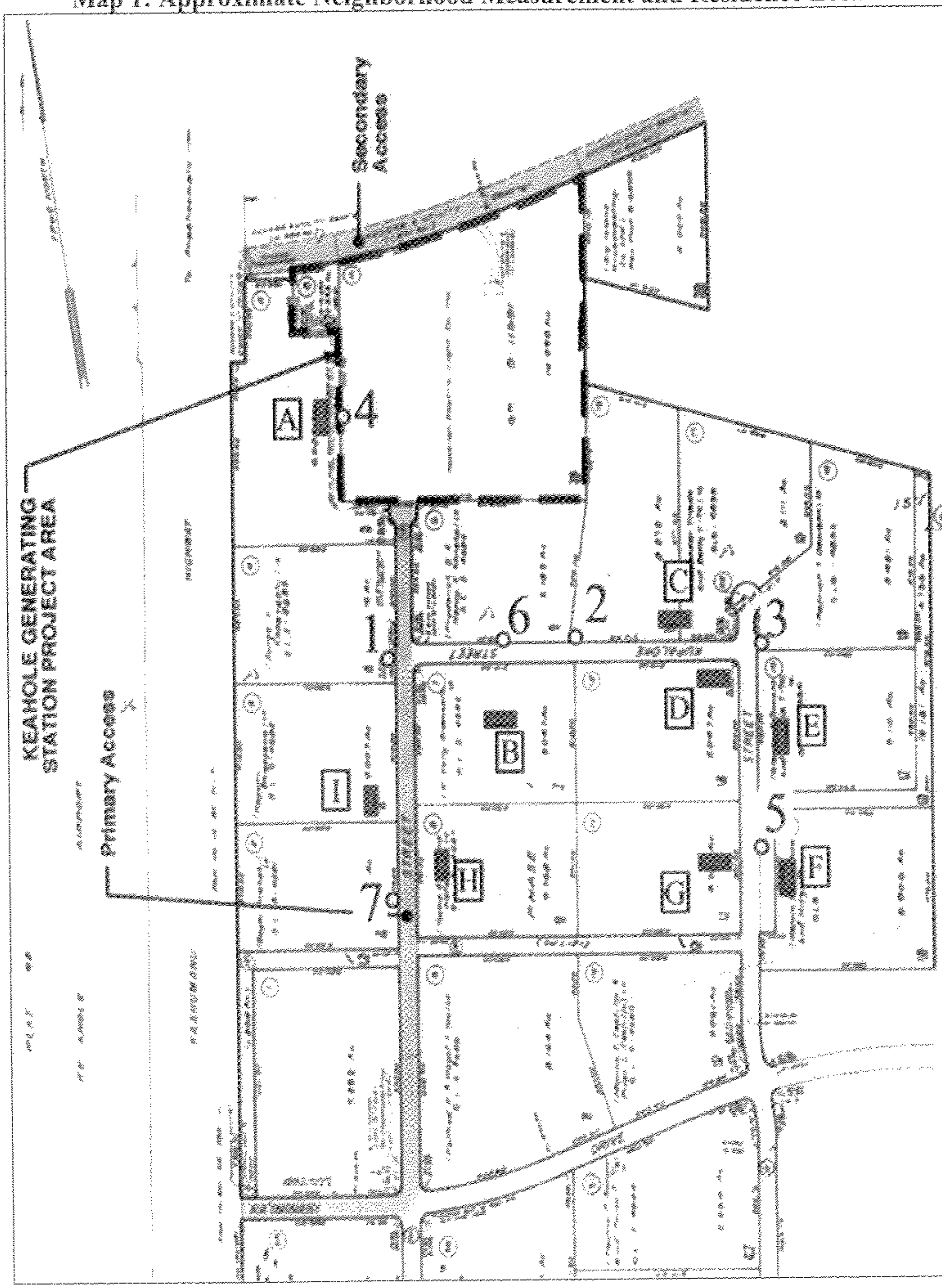
Table 16: Predicted Overall Increase in Sound Levels

	Measured Existing			Predicted, All Sources, Existing			Predicted, All Sources, Future			Increase over Measured Existing*			Increase over Predicted Existing		
Loc.	Ld	Ln	Ldn	Ld	Ln	Ldn	Ld	Ln	Ldn	Ld	Ln	Ldn	Ld	Ln	Ldn
1A	55.5	48.7	57.0	59	55	62	57	50	58	1.1	1.4	1.0	-2	-5	-4
1B	54.0	50.0	57.2	58	55	62	55	51	58	1.3	0.9	0.8	-3	-5	-4
2A	56.0	50.1	58.0	60	56	63	57	51	59	0.8	0.8	1.0	-3	-5	-4
2B	53.3	53.9	60.2	59	58	64	54	54	61	1.1	0.3	0.8	-4	-3	-3
3A	61.7	50.4	61.3	62	51	62	62	51	61	0.2	0.4	-0.3**	0	-1	-1
3B	59.6	53.8	61.7	60	54	62	60	54	62	0.2	0.2	0.3	0	0	0
4A	55.0	49.6	57.3	59	57	64	56	51	59	1.5	1.4	1.7	-2	-6	-5
4B	54.3	48.7	56.5	58	57	63	56	50	58	1.7	1.6	1.5	-2	-6	-5
5A	51.5	48.9	55.8	54	53	59	53	50	57	1.0	0.7	1.2	-2	-3	-2
5B	50.7	44.2	52.3	54	51	58	52	45	53	1.0	1.3	0.7	-2	-6	-5
6A	53.3	48.3	55.9	59	57	64	55	50	57	1.4	1.5	1.1	-5	-7	-7
6B	53.9	53.5	60.0	59	58	65	55	54	61	1.2	0.5	1.0	-4	-4	-4
7A	57.8	50.4	59.0	59	53	61	58	52	60	0.6	1.2	1.0	0	-2	-1
7B	57.3	52.1	59.7	58	54	61	58	53	60	0.6	0.5	0.3	0	-2	-1
8	51.9	49.7	56.5	55	54	61	53	51	58	1.4	1.6	1.5	-2	-3	-3
9	48.3	47.4	54.0	51	50	56	49	48	55	0.8	0.6	1.0	-2	-2	-1

* This increase is due almost exclusively to the predicted traffic increase of 1.9 dB.

** This negative number is due to cumulative rounding errors and should be regarded as 0.0 dB.

Map 1: Approximate Neighborhood Measurement and Residence Locations



Appendix A: Overview of Environmental Acoustics Definitions and Concepts

Noise is generally defined as "unwanted sound." Annoyance due to noise is a highly subjective matter, which makes it difficult to predict or explain public response to a given noise condition. Sensitivity to noise varies widely in any population, with a few highly noise-sensitive individuals, a few that are very non-sensitive, and the majority somewhere in between.

Sound Pressure Level:

A logarithmic parameter describing the quantity of sound relative to a reference pressure value, expressed in units of decibels, or dB.

A-weighting:

A sound level weighting scale in which the sound levels in individual frequency bands are adjusted to match the response of the human ear. The reference adjustment is 0 dB at 1000 Hz. The human ear is much less responsive at low frequencies. An A-weighted overall sound level is the total contribution from all sound frequencies, with the appropriate weighting factors applied.

C-weighting

A sound level weighting scale that is relatively flat from 31.5 Hz to 8k Hz with a roll-off higher and lower than those frequencies. The adjustment is 0 dB from 200 Hz to 1250 Hz. A C-weighted overall sound level is the total contribution from all sound frequencies, with the appropriate weighting factors applied.

Leq

The equivalent continuous A-weighted sound level. It is defined as the logarithmic average of the sound levels for a specified time period. It is the most commonly used form of sound level averaging.

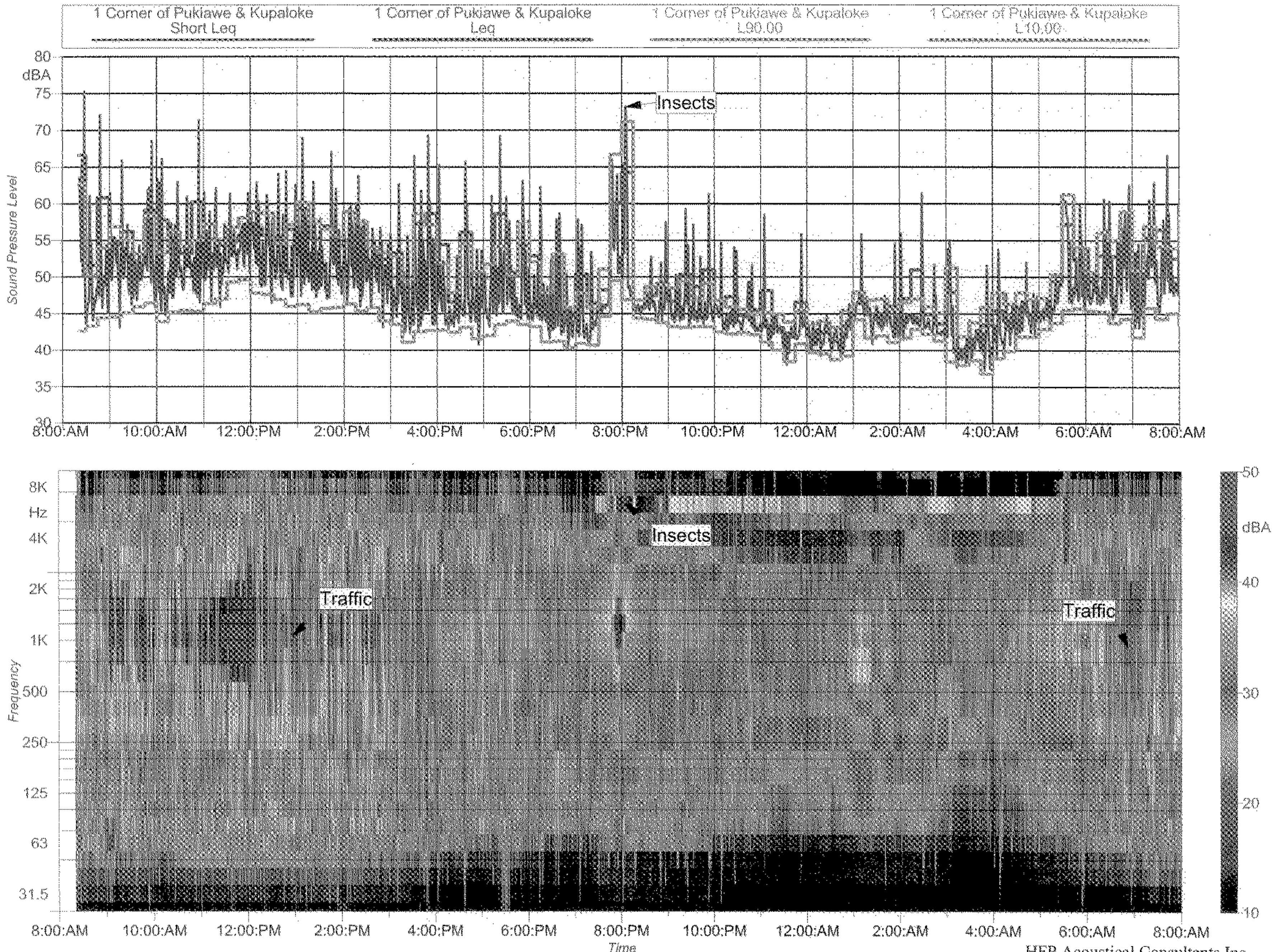
L90

A statistical parameter representing the sound level exceeded 90 percent of the sampled time period. The L90 is often used as an indicator of the background or ambient sound level, because short term higher-level noise events have limited effects on the L90 value.

Sound Power Level

A logarithmic parameter describing the power characteristics of a noise source, relative to a reference power value. It is expressed in units of decibels, dB. The sound *power* level should not be confused with the sound *pressure* level. The sound *power* level is a characteristic of a noise source analogous to the wattage rating of a light bulb, and is independent of the surroundings. It is calculated from measurements of the sound *pressure* level. The sound *pressure* level is the quantity measured with a sound level meter, and is dependent upon the surroundings of the noise source.

Figure 1A: Corner of Pukiawe and Kupaloke; June 24 - 25, 2004



Appendix B: Figures 1A - 9

Figure 1B: Corner of Pukiawe and Kupaloke; June 26 - 27, 2004

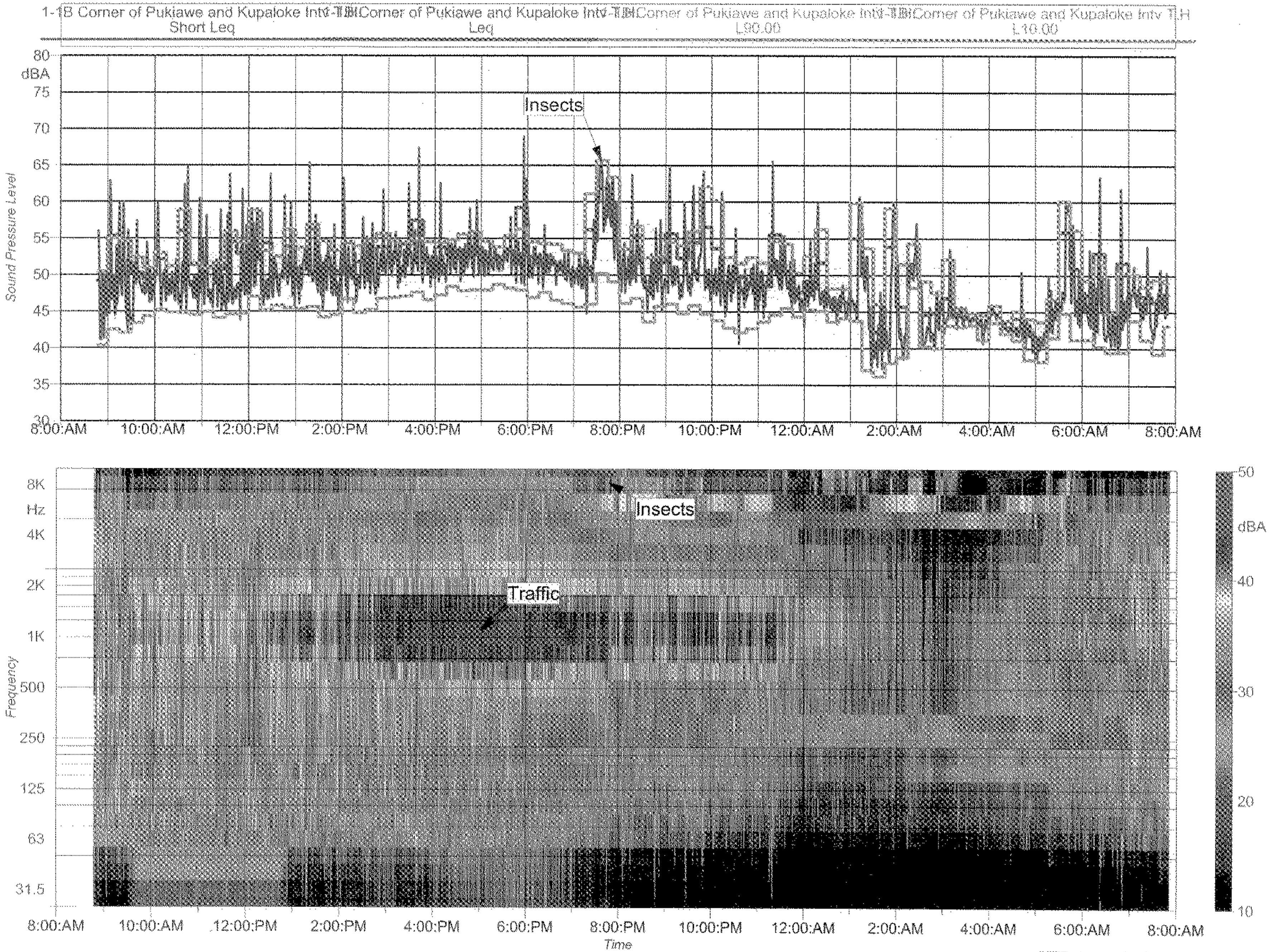


Figure 2A: Middle of Kupaloke; June 24 - 25, 2004

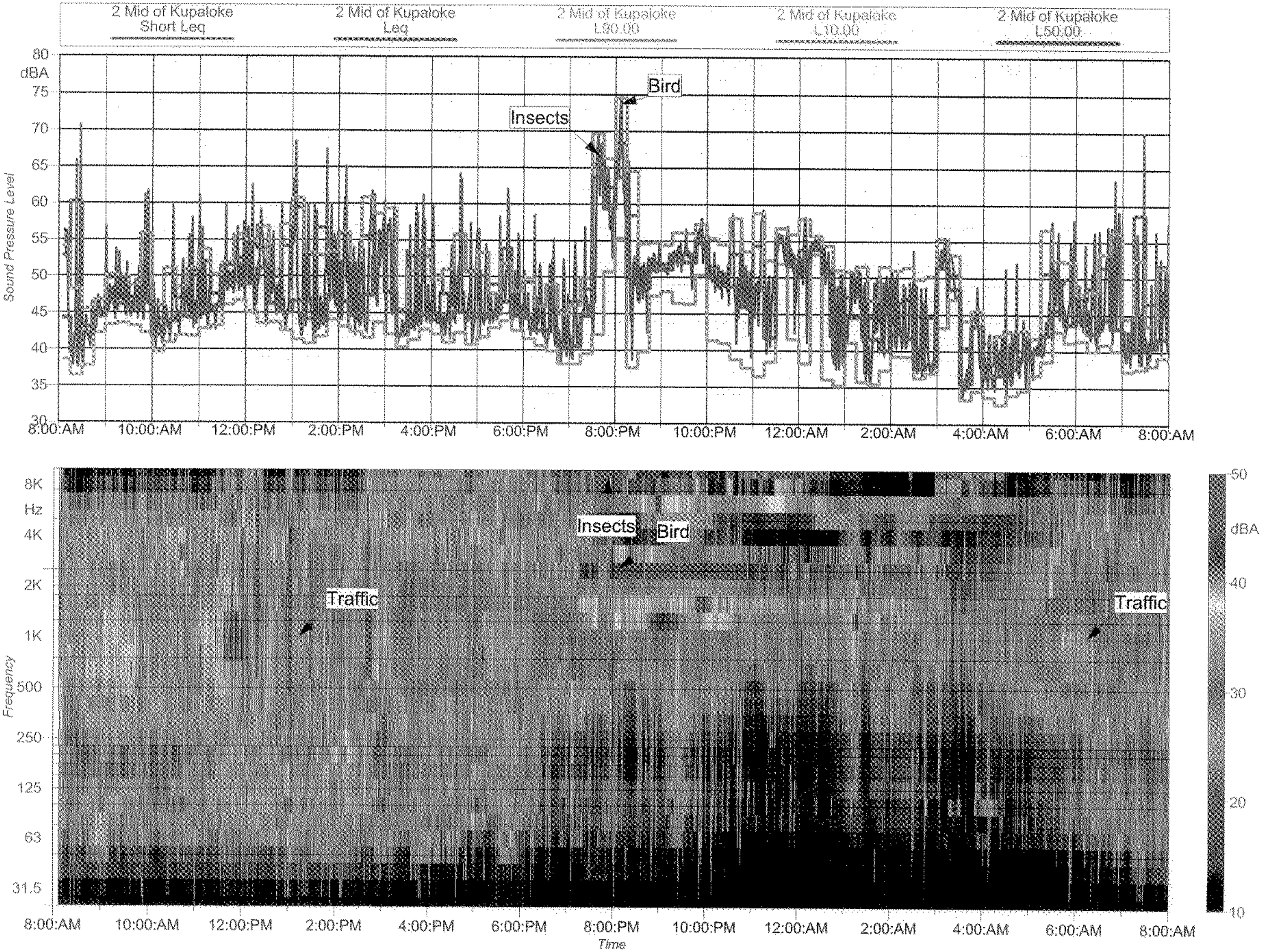


Figure 2B: Middle of Kupaloke; June 26 - 27, 2004

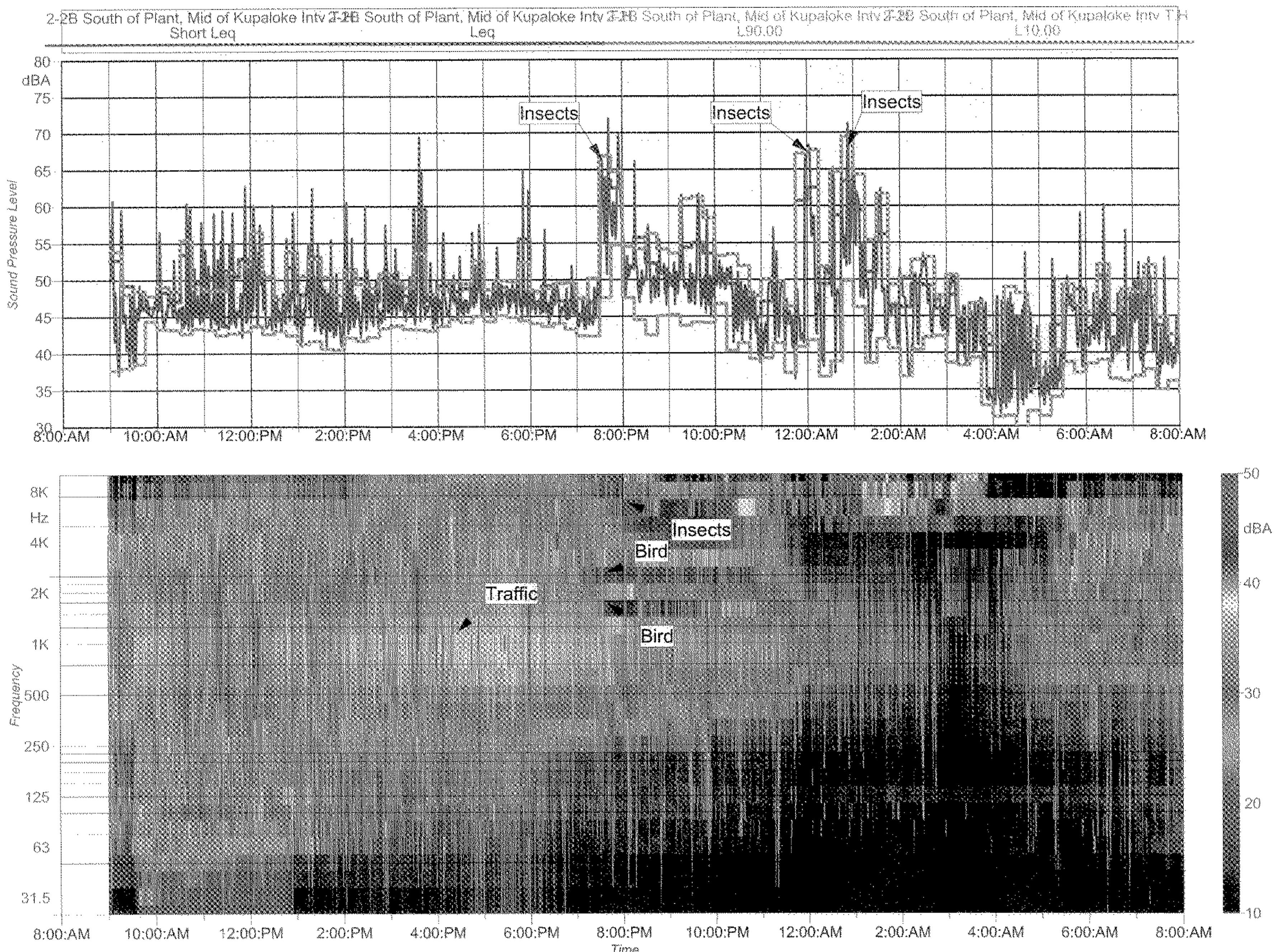
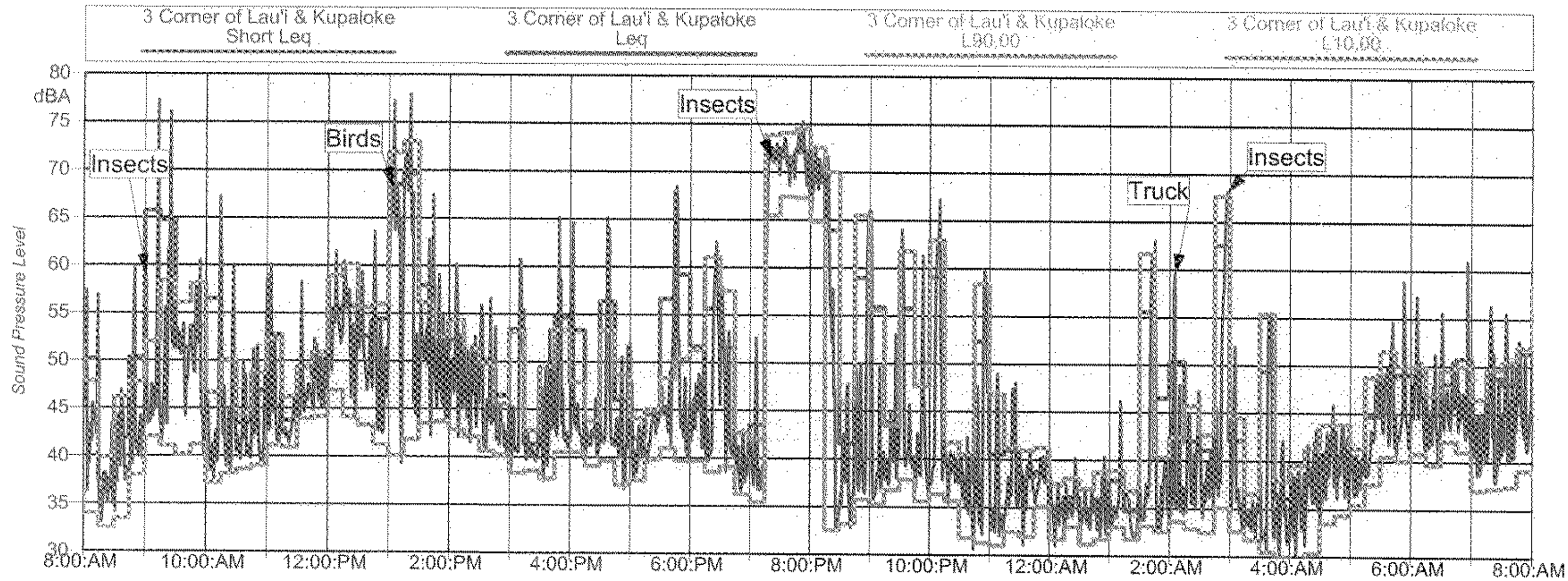
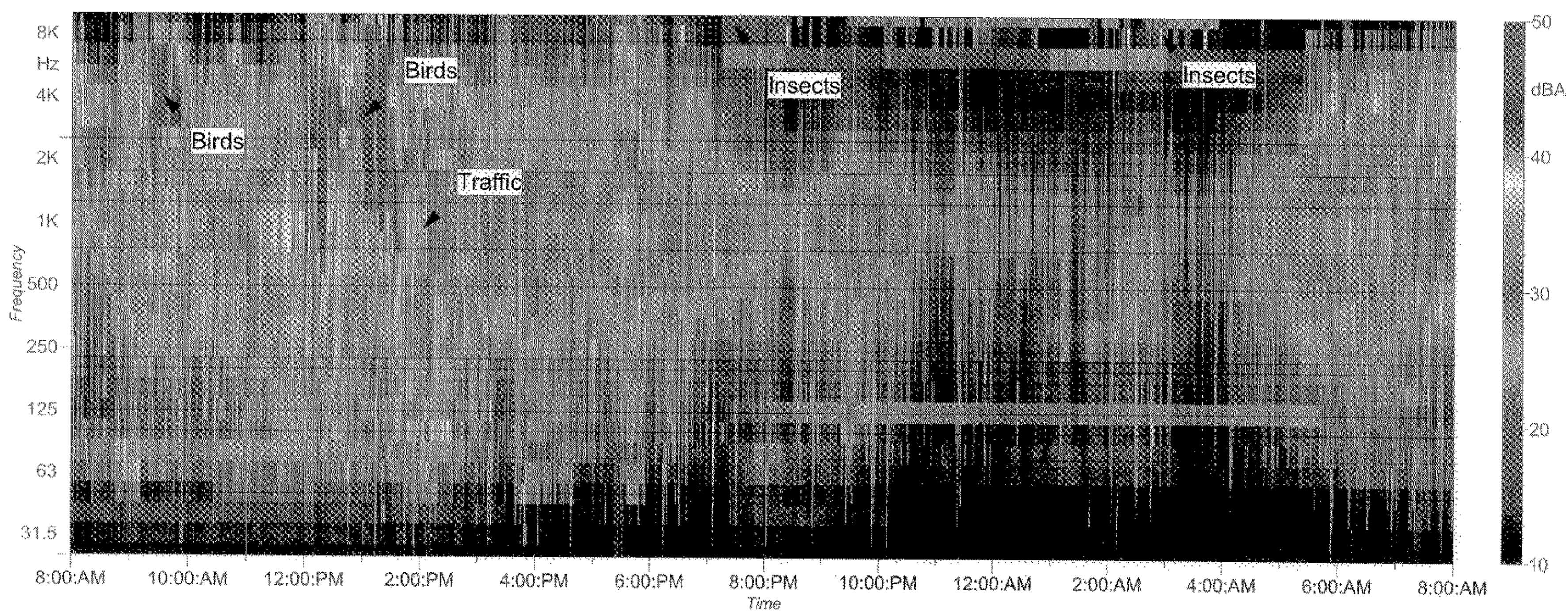


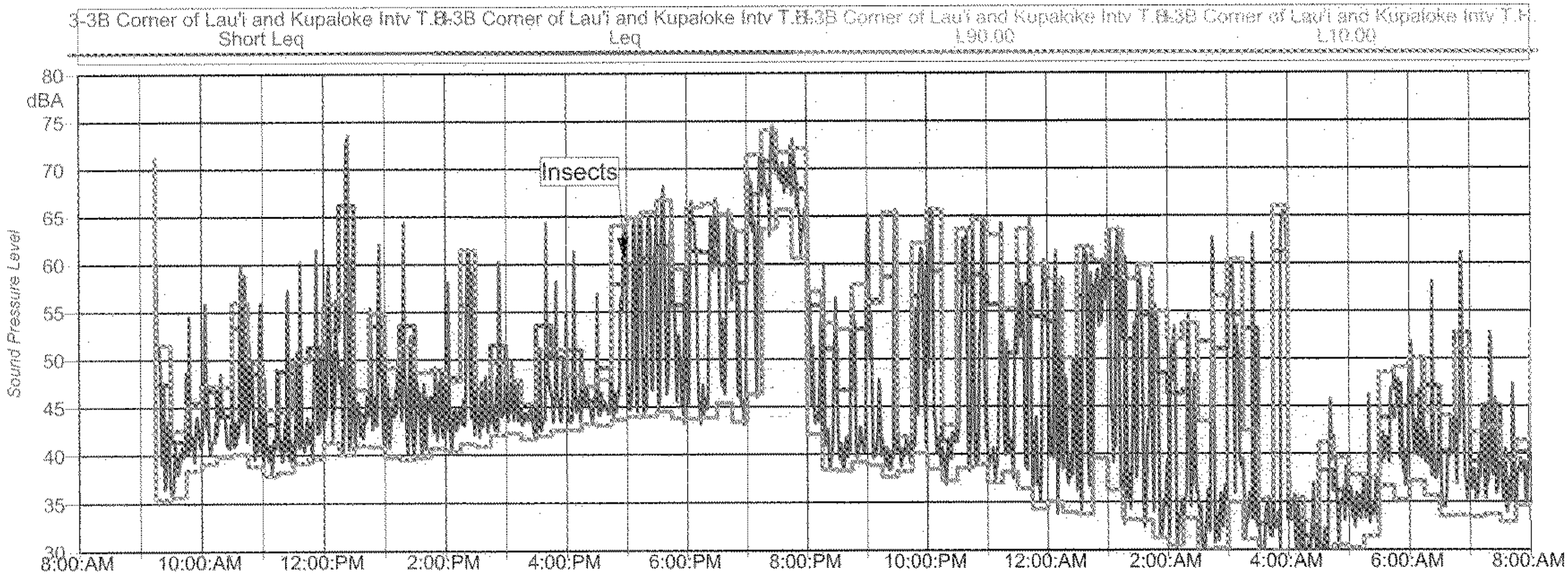
Figure 3A: Corner of Lau'i and Kupaloke; June 24 - 25, 2004





Appendix B: Figures 1A - 9

Figure 3B: Corner of Lau'i and Kupaloke; June 26 - 27, 2004



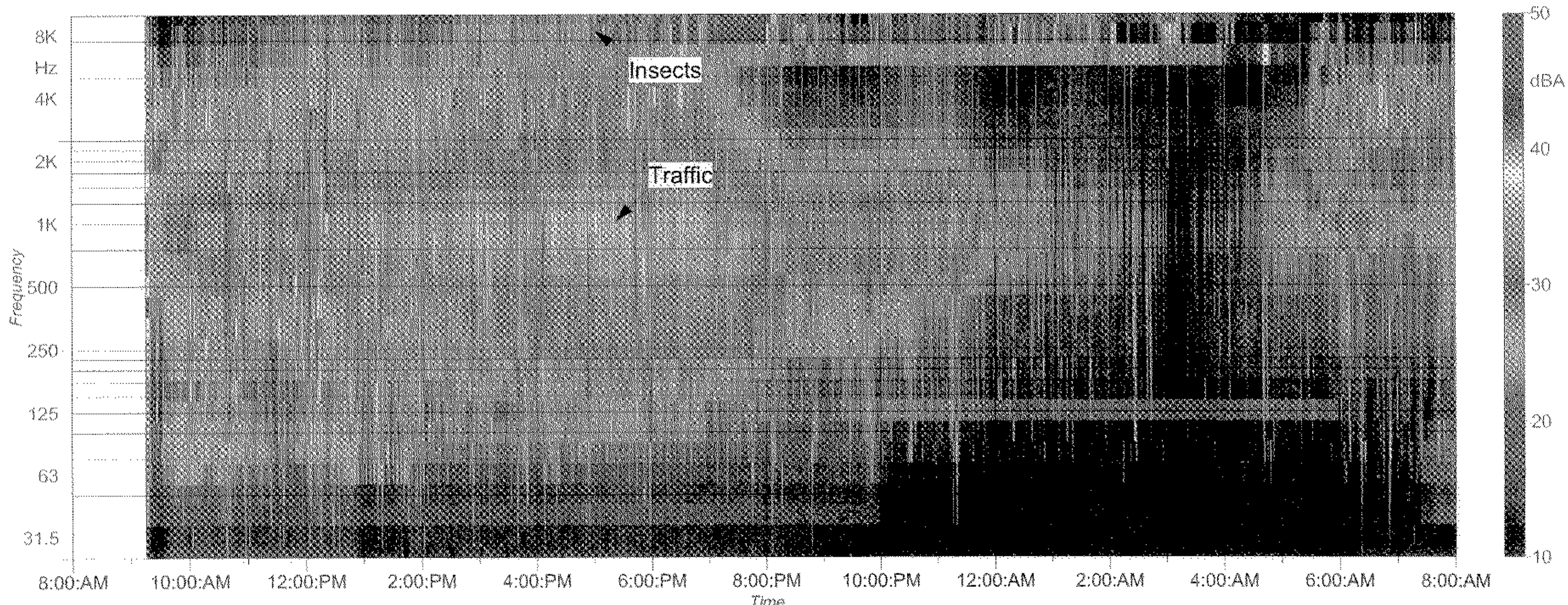
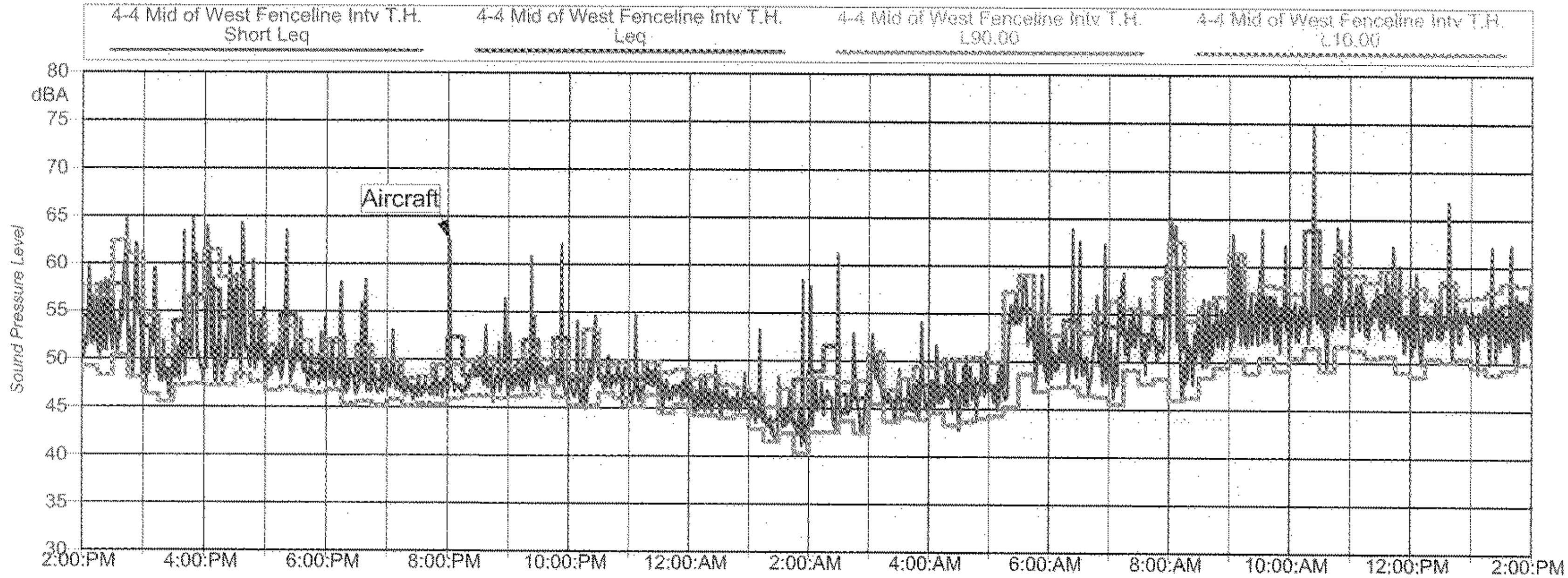
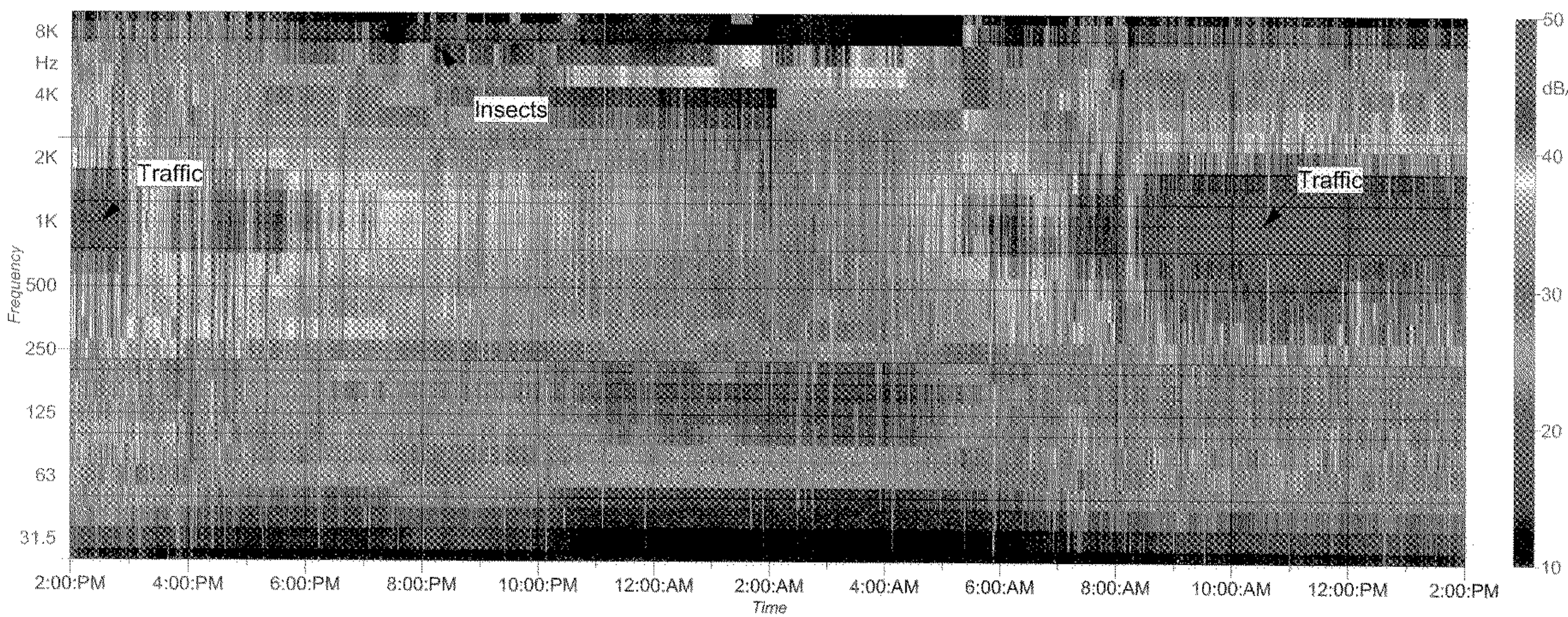


Figure 4A: West Plant Fenceline; June 24 - 25, 2004





Appendix B: Figures 1A - 9

Figure 4B: West Plant Fenceline; June 26 - 27, 2004

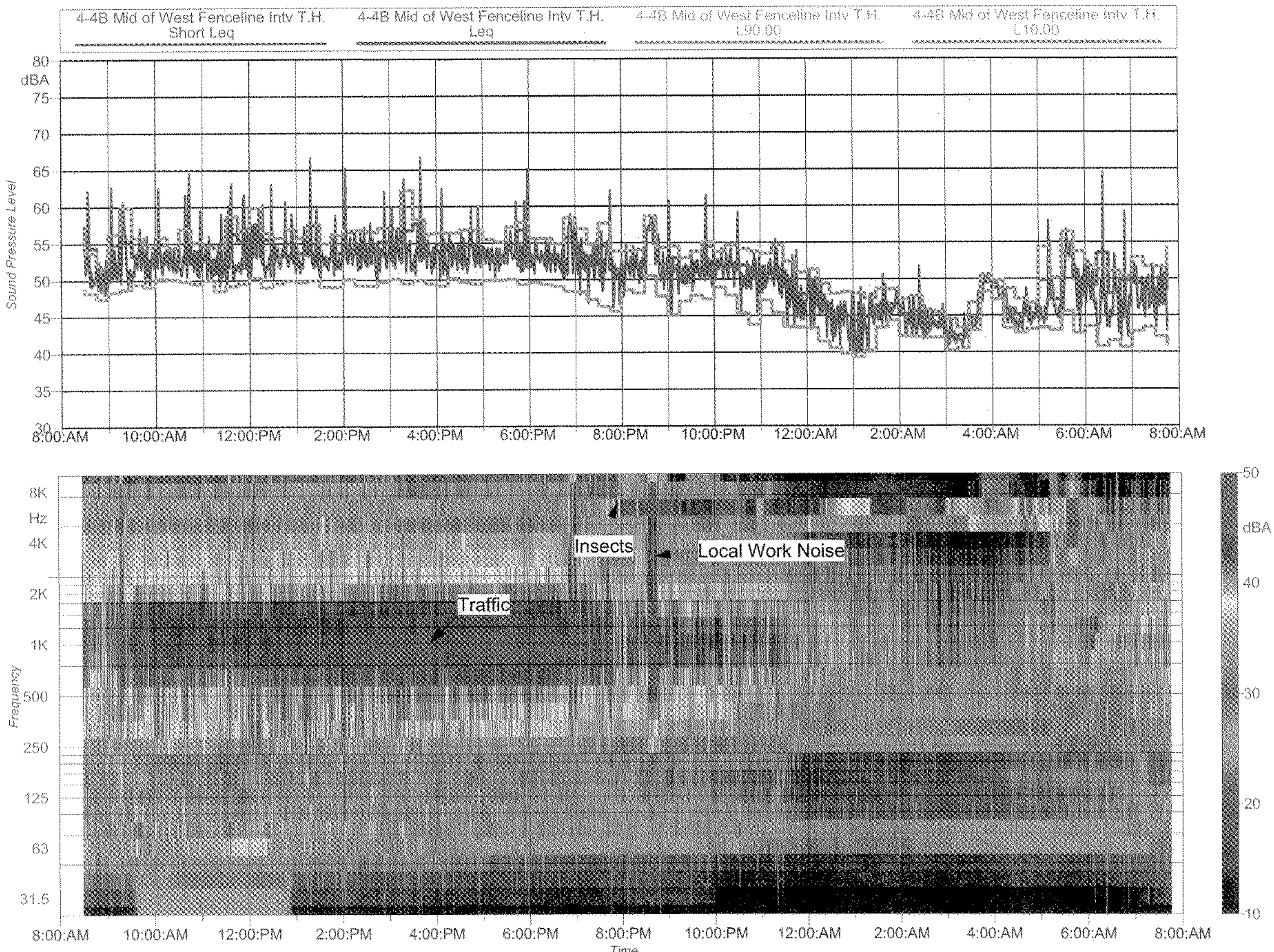


Figure 5A: South on Lau'i; June 25 - 26, 2004

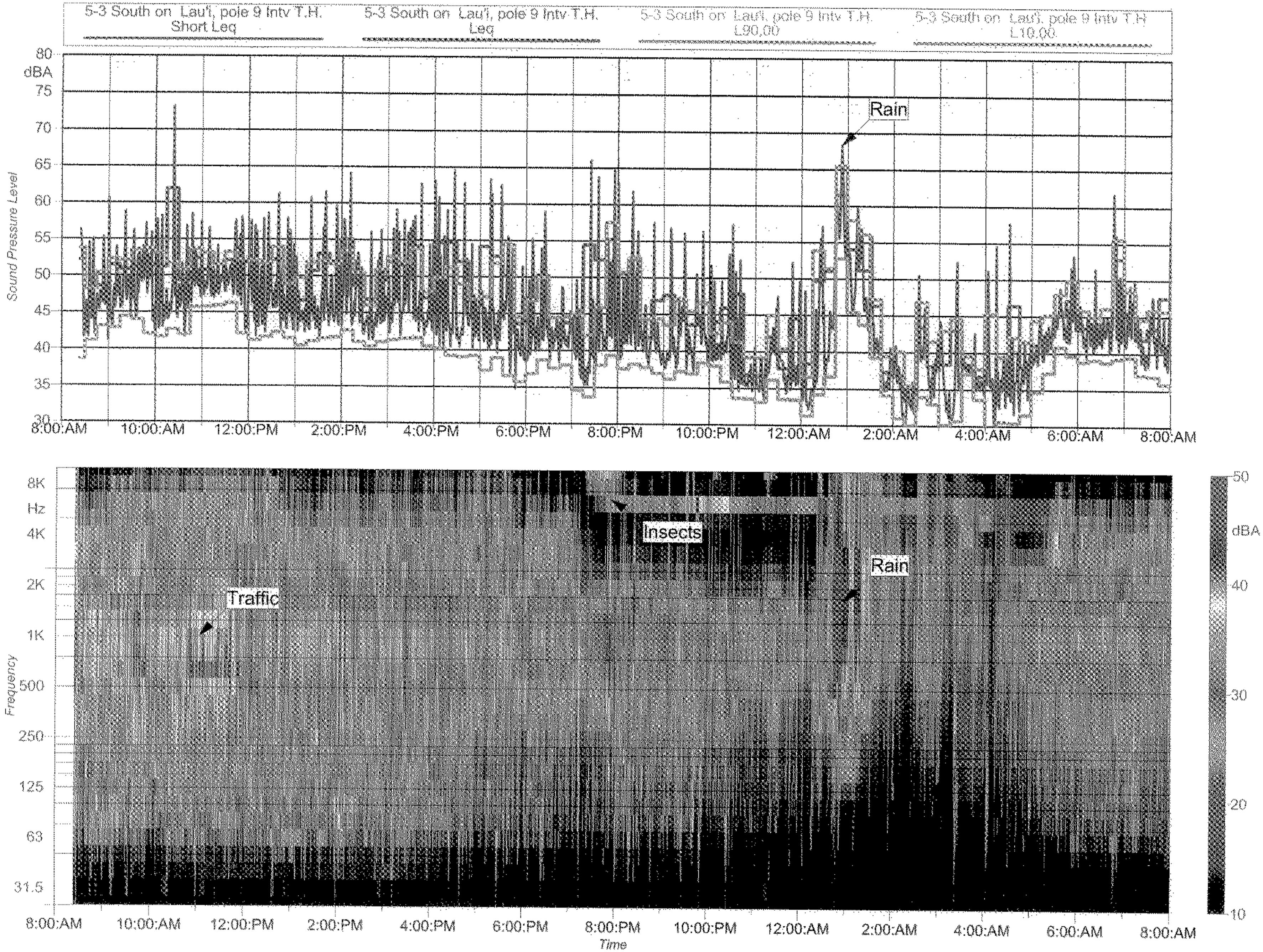
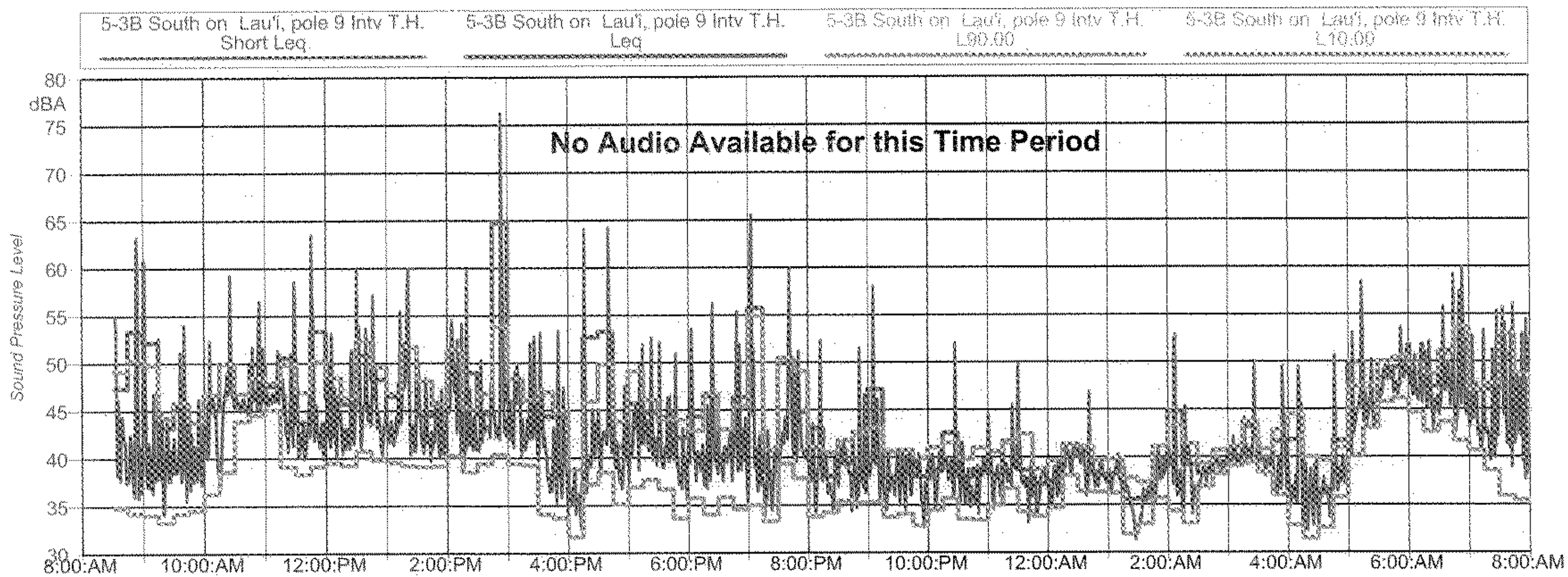


Figure 5B: South on Lau'i, June 27 - 29, 2004



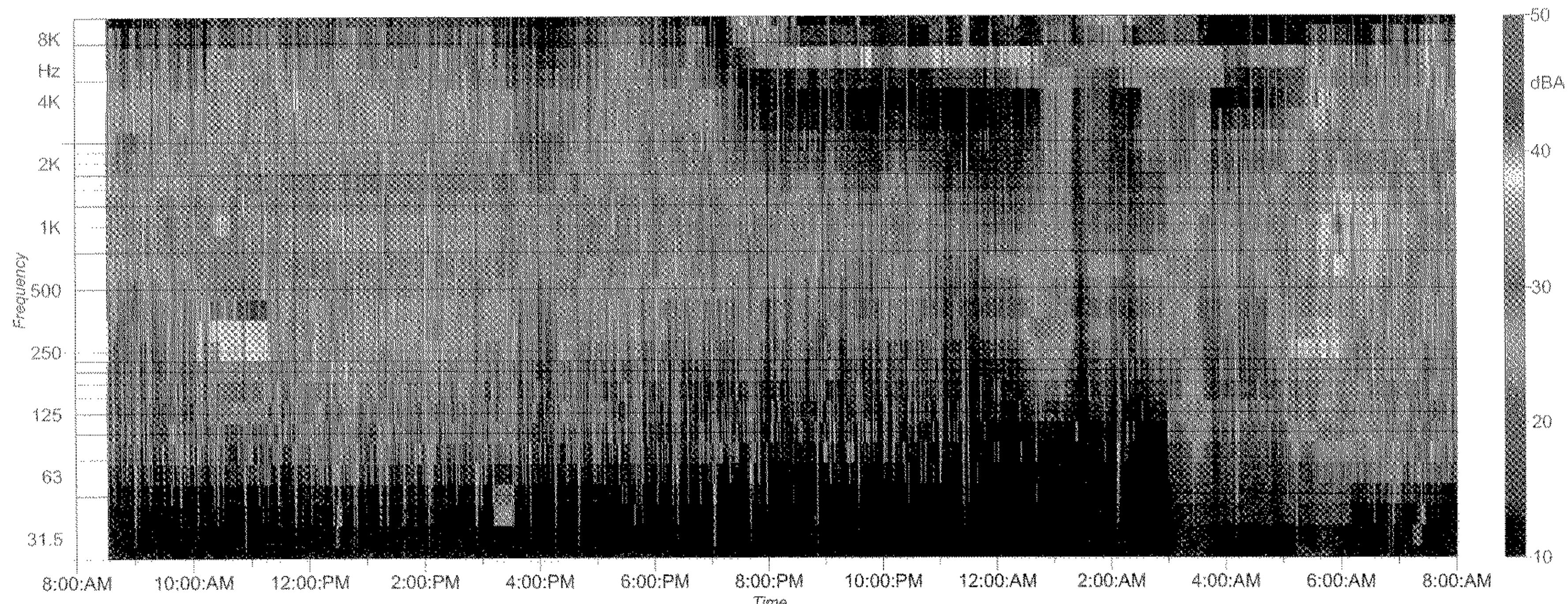
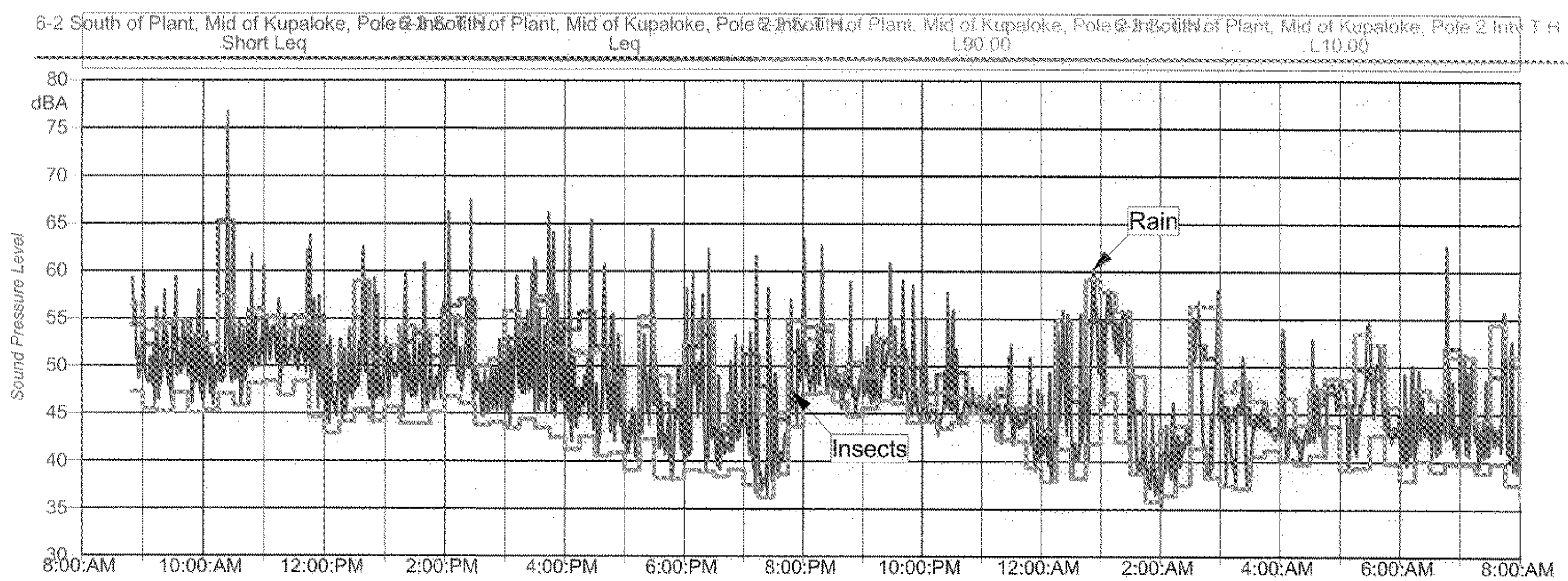


Figure 6A: South of Plant, Middle of Kupaloke, June 25 - 26, 2004



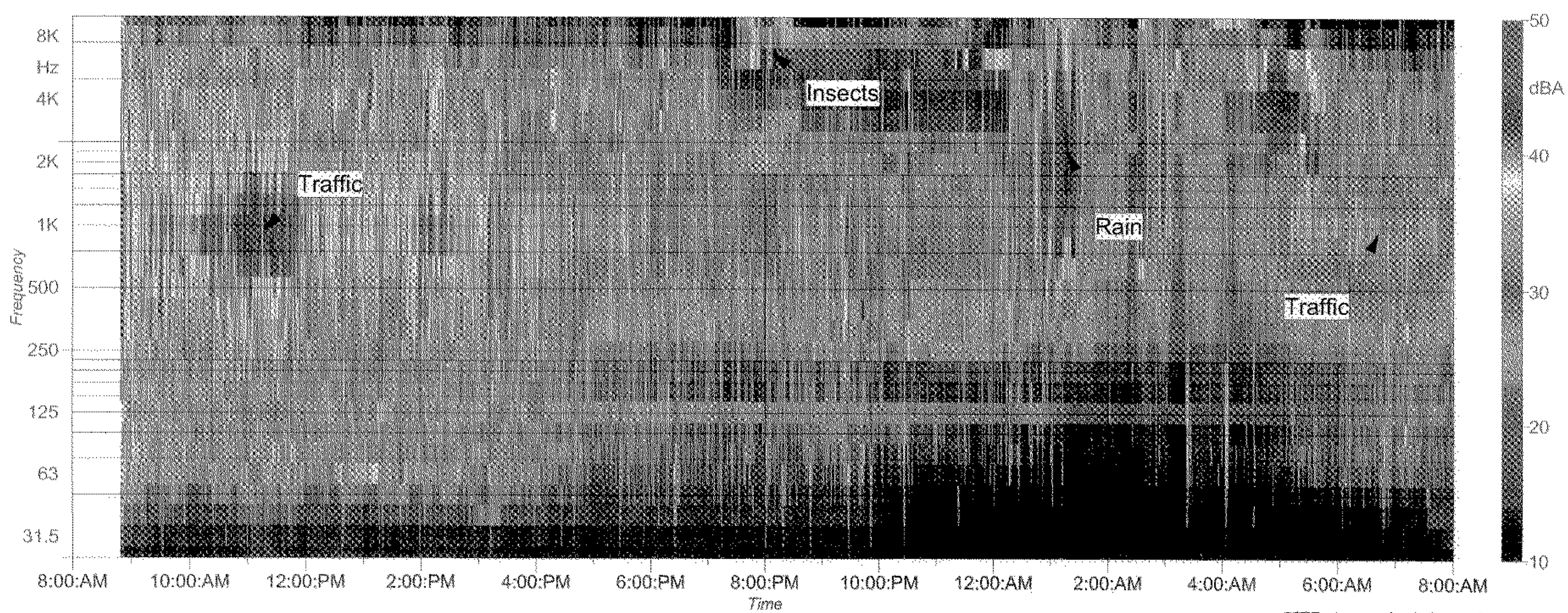


Figure 6B: South of Plant, Middle of Kupaloke, June 27 - 29, 2004

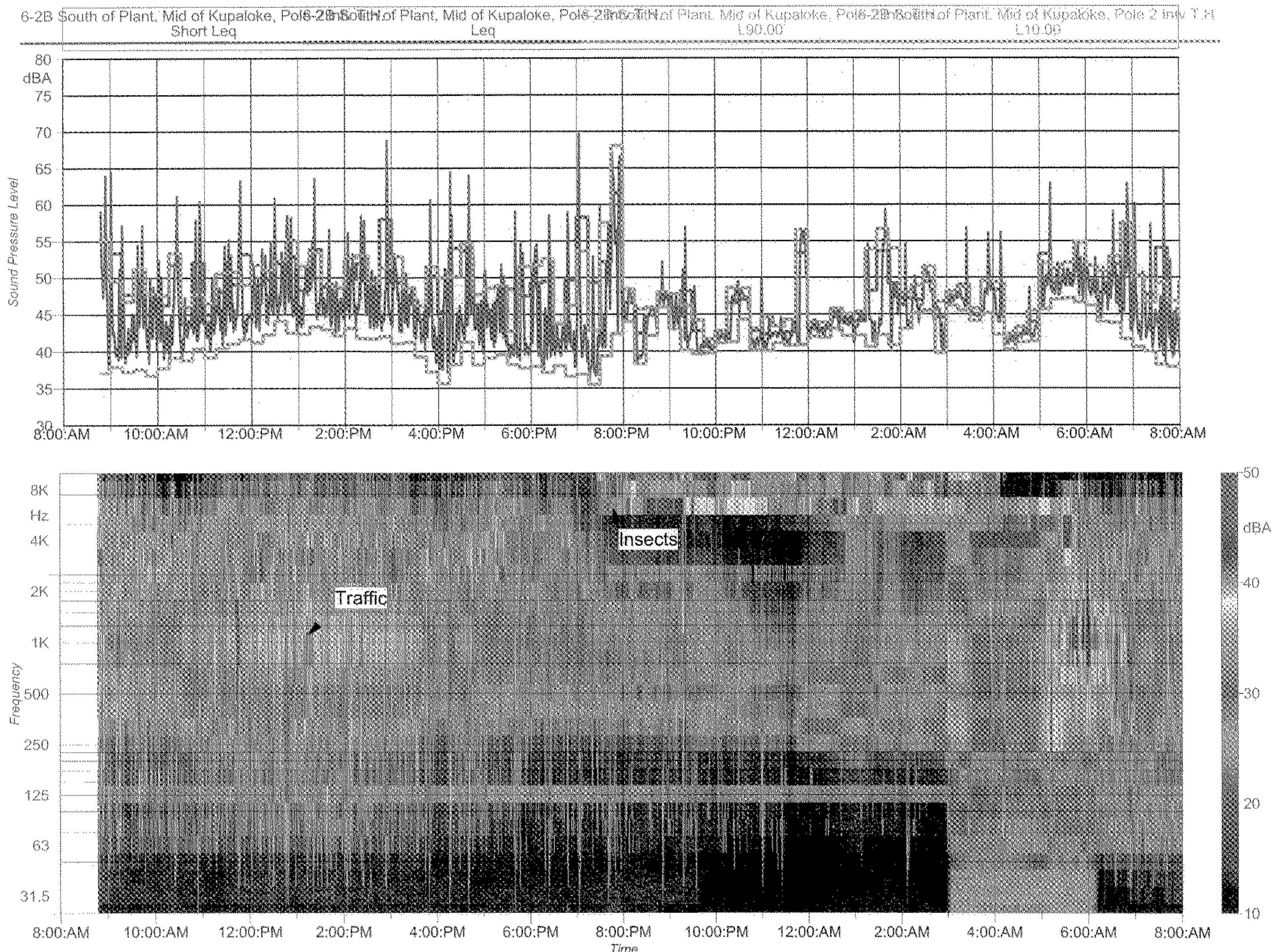
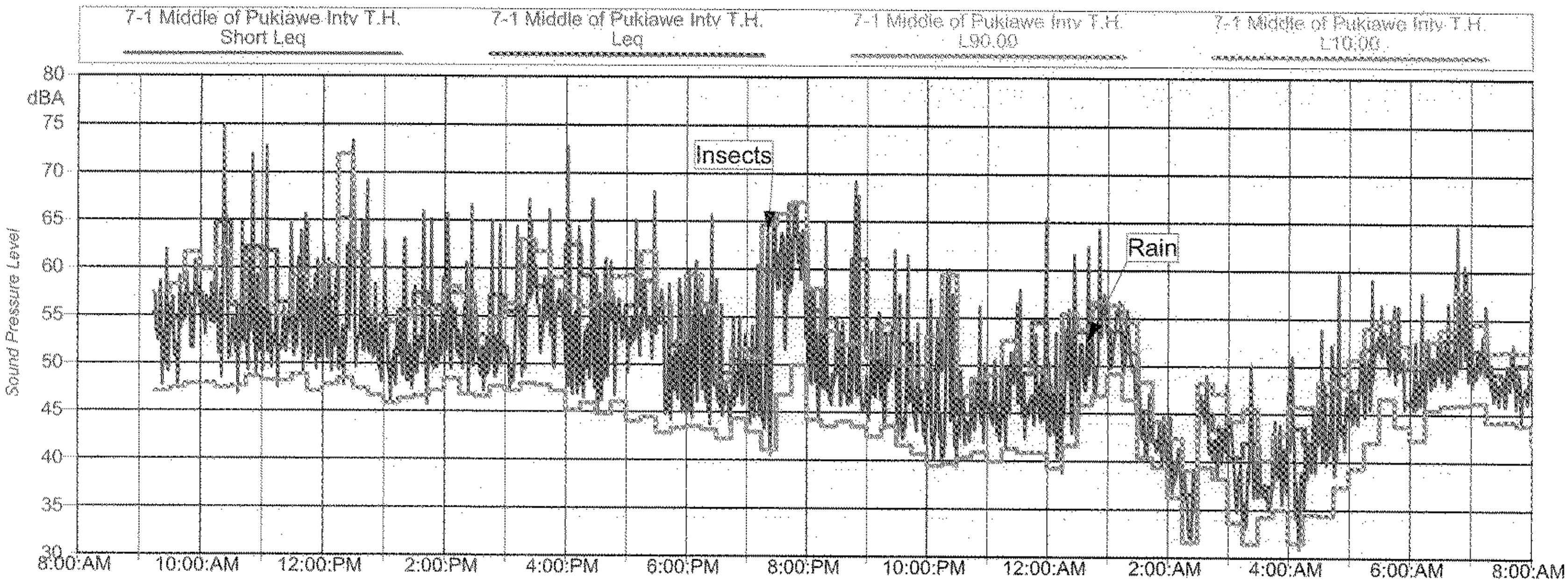
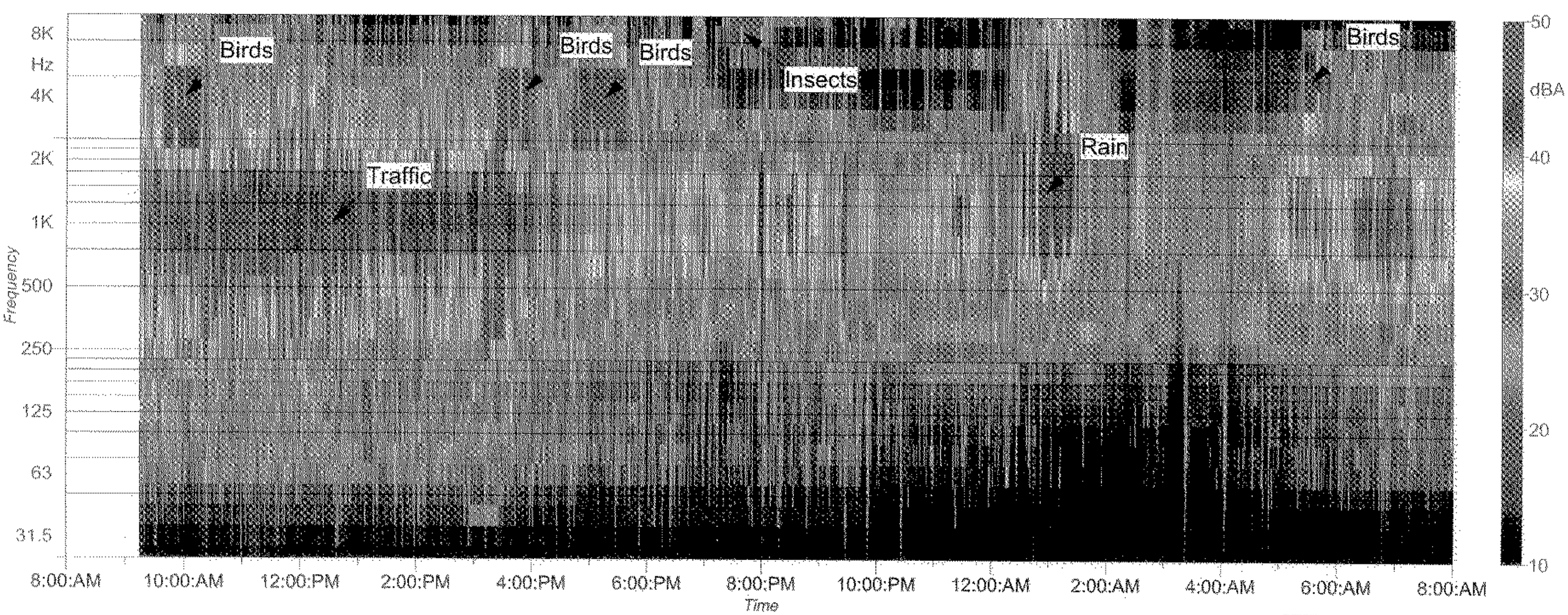


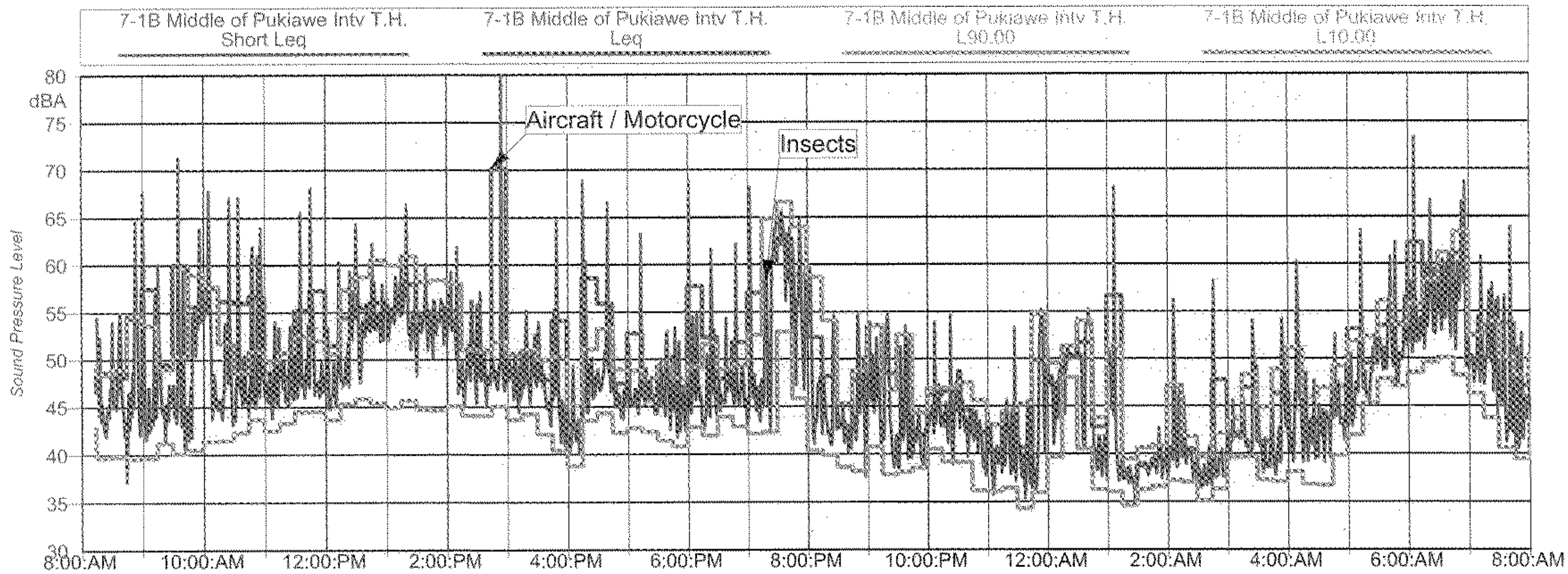
Figure 7A: South of Plant, Middle of Kupaloke, June 25 - 26, 2004





Appendix B: Figures 1A - 9

Figure 7B: South of Plant, Middle of Kupaloke, June 27 - 29, 2004



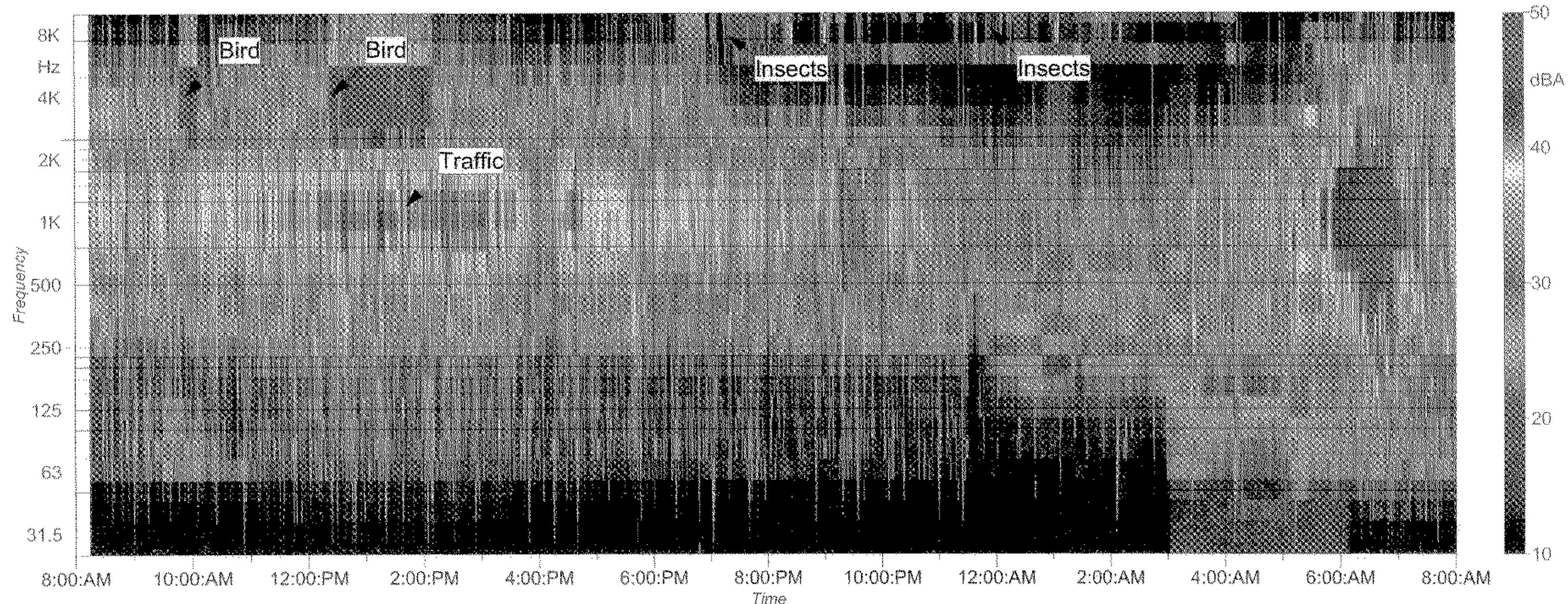
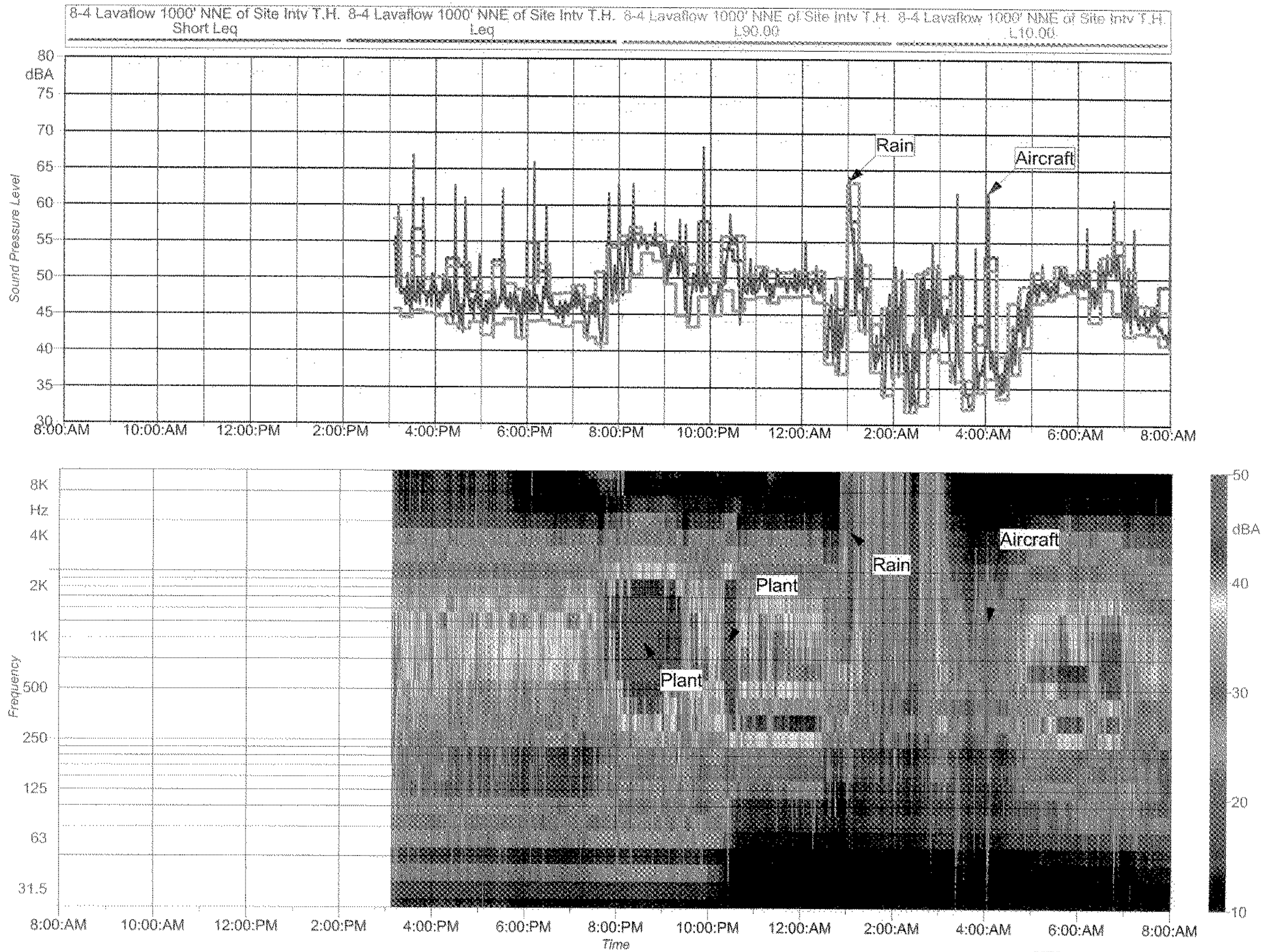
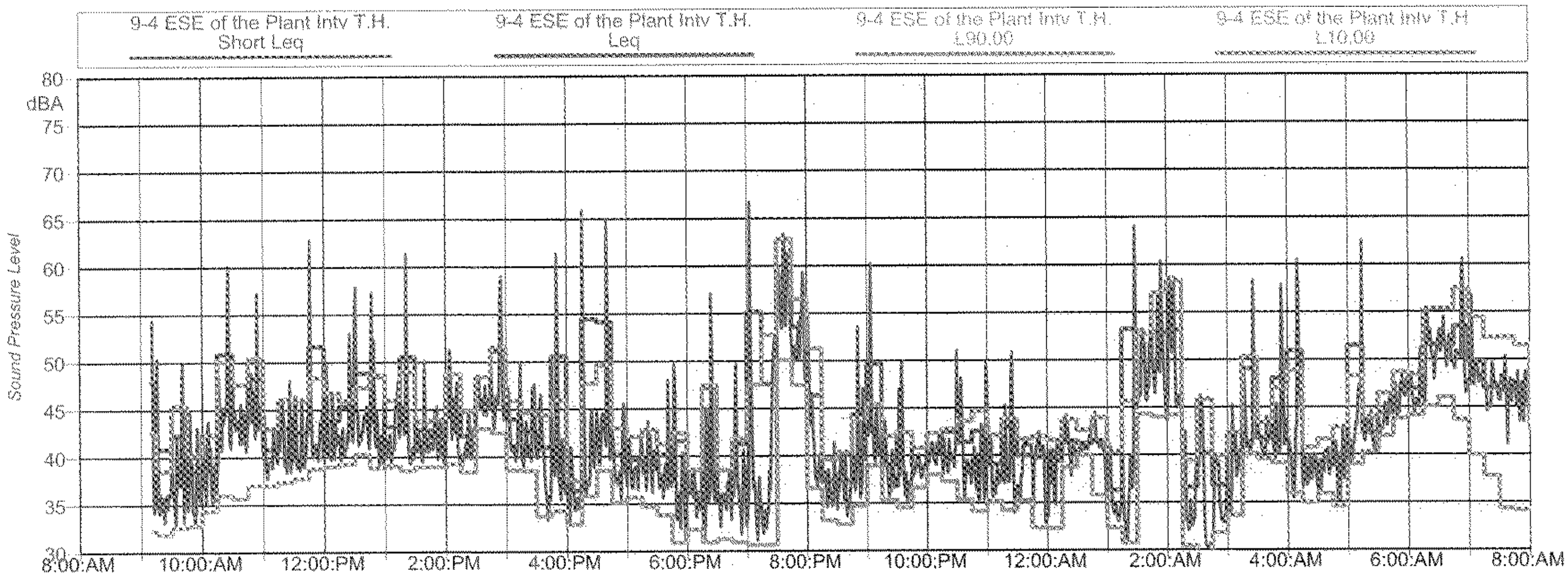


Figure 8: Approximately 2500' Northeast of Plant, June 25 - 26, 2004



Appendix B: Figures 1A - 9

Figure 9: East South-east of the Plant, June 27 - 29, 2004



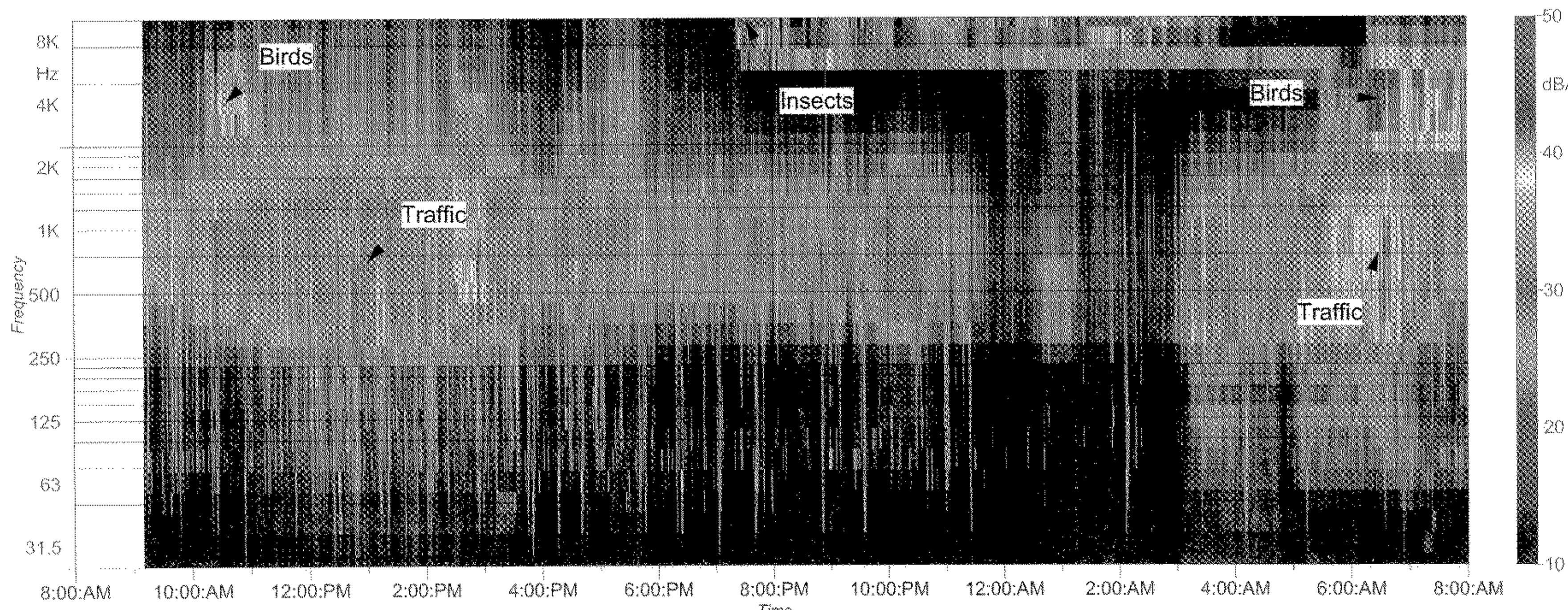


Table C1A: Sound Level Results at Measurement Location 1

Start Date and Time	Day / Night	Duration (seconds)	Leq (dB(A))	L1.00 (dB(A))	L10.00 (dB(A))	L50.00 (dB(A))	L90.00 (dB(A))	L95.00 (dB(A))	31.5 dB	63 dB	125 dB	250 dB	500 dB	1000 dB	2000 dB	4000 dB	8000 dB
6/24/2004 8:21	DAY	537.625	66.6	78.7	62.6	48.3	42.6	41.9	64.4	67.9	63.4	67.5	58.9	61.8	60.3	52.2	45.4
6/24/2004 8:30	DAY	900	51.6	63.3	50.3	46.3	43.3	42.7	59.6	62.2	57.5	52.5	49.1	45.8	41.6	38.7	32.5
6/24/2004 8:45	DAY	900	60.8	71.2	54	48	44.4	43.8	60.4	66.1	61.2	63.3	59.7	55.0	51.3	46.7	42.3
6/24/2004 9:00	DAY	900	54.3	64.9	56.8	51.7	44.5	43.2	61.8	71.9	59.3	54.4	50.1	48.6	44.3	40.7	32.6
6/24/2004 9:15	DAY	900	56.2	68.6	55.1	49.6	45.1	44.2	59.5	65.6	57.9	53.1	50.1	50.7	48.1	47.6	46.8
6/24/2004 9:30	DAY	900	51.8	61	53.2	49.4	45.9	45.2	60.2	61.5	55.6	50.8	48.0	47.1	43.8	38.8	32.5
6/24/2004 9:45	DAY	900	59.1	73.4	58.3	50.7	46.4	45.4	67.3	64.2	63.5	60.0	58.1	53.2	48.6	42.9	37.8
6/24/2004 10:00	DAY	900	57.7	72.7	53.3	46.9	43.9	42.8	59.0	62.2	62.9	58.2	54.7	51.8	49.0	47.0	39.0
6/24/2004 10:15	DAY	900	54.9	67.1	56.1	49.3	45.2	44	60.4	64.4	61.5	56.9	52.3	48.9	44.3	40.4	32.7
6/24/2004 10:30	DAY	900	53.2	64	54.1	49.8	45.4	44.5	59.6	60.3	55.8	51.6	48.7	48.3	44.7	44.3	38.5
6/24/2004 10:45	DAY	900	60.2	73.5	55	49.4	45.3	43.8	61.1	63.2	63.2	60.4	56.6	55.2	51.8	48.8	43.1
6/24/2004 11:00	DAY	900	55.1	67.2	57.2	50.6	46.4	45	63.7	64.2	60.4	56.6	52.6	49.7	45.1	40.9	30.1
6/24/2004 11:15	DAY	900	54.3	64.8	54.6	50.7	47	45.8	60.6	61.4	57.9	51.5	48.5	50.1	47.9	41.1	33.7
6/24/2004 11:30	DAY	900	54.9	65.3	56.7	52.4	49.3	48.6	63.0	62.6	59.4	53.8	51.8	50.8	45.8	39.9	33.1
6/24/2004 11:45	DAY	900	55.6	64.4	58	53.5	49.6	48.9	60.8	62.9	58.1	51.9	51.0	52.1	48.1	41.2	35.0
6/24/2004 12:00	DAY	900	56.7	68.2	58.9	52.7	47.8	47	62.0	63.7	64.3	56.6	53.0	51.5	47.9	45.1	40.6
6/24/2004 12:15	DAY	900	55.6	66.7	58.6	51.3	47.6	46.4	61.3	63.1	58.2	52.4	50.5	50.1	48.5	46.5	44.0
6/24/2004 12:30	DAY	900	55.4	69.2	54.5	49.9	46.9	46	59.9	63.2	57.9	58.1	52.4	49.3	45.5	43.3	36.2
6/24/2004 12:45	DAY	900	56.4	69.3	57.1	49.9	45.9	45.2	62.3	64.4	62.2	56.7	54.0	50.7	48.0	41.4	37.6
6/24/2004 13:00	DAY	900	59.3	70.6	60.2	50.2	46.2	45.3	64.5	65.2	63.2	60.9	55.4	54.5	50.8	47.5	43.3
6/24/2004 13:15	DAY	900	55.1	66.5	57.5	48.5	45.2	44.6	62.3	63.5	61.2	57.3	51.8	49.1	45.3	41.9	34.7
6/24/2004 13:30	DAY	900	56.9	69.8	56.5	48.4	45.7	45.1	62.7	64.2	61.9	59.6	55.9	50.5	43.8	39.3	31.9
6/24/2004 13:45	DAY	900	54.2	66.9	55.5	49.7	45.8	45	64.1	64.2	60.0	53.6	51.0	50.2	43.3	39.9	33.2
6/24/2004 14:00	DAY	900	54.9	65.5	58.9	49.4	46.3	45.5	62.5	66.3	59.5	55.9	51.9	49.9	45.6	41.7	35.1
6/24/2004 14:15	DAY	900	55.7	65.9	57.5	48.6	45.4	44.7	61.4	61.4	60.3	55.0	52.4	50.9	47.3	42.9	37.7
6/24/2004 14:30	DAY	900	52	61.5	54	49.4	45.8	45	59.6	63.8	57.8	51.0	47.6	47.3	43.5	39.3	33.4
6/24/2004 14:45	DAY	900	52.3	65.1	53.3	47.3	44	43	60.2	61.3	58.3	53.7	47.9	46.7	44.1	39.9	36.8
6/24/2004 15:00	DAY	900	53.2	67.5	52.8	46.2	43.5	42.9	61.6	64.4	62.0	56.7	50.9	45.2	40.2	37.5	29.9
6/24/2004 15:15	DAY	900	48.4	60.3	49.3	43.1	41.1	40.6	59.3	60.4	55.6	48.1	44.0	43.5	39.0	36.8	30.5
6/24/2004 15:30	DAY	900	57.2	68.5	58.6	45.8	42.5	42.1	61.3	64.3	67.9	57.6	53.3	51.4	46.7	43.2	37.7
6/24/2004 15:45	DAY	900	58.6	73.5	57.1	45.4	42.7	42.1	63.5	65.9	65.5	62.8	57.2	50.8	43.3	37.1	29.7
6/24/2004 16:00	DAY	900	54.4	69.8	51.8	45.3	42.8	42.4	60.2	63.4	62.3	58.1	52.5	46.3	40.0	39.3	28.8
6/24/2004 16:15	DAY	900	46.6	55.8	47.8	44.4	42.4	42.1	56.7	57.5	53.4	45.1	42.2	41.0	36.5	37.8	28.0
6/24/2004 16:30	DAY	900	56.1	70.6	54.5	45.8	43.1	42.5	61.0	64.1	65.0	59.2	54.1	48.8	41.7	36.2	26.0
6/24/2004 16:45	DAY	900	48.4	58.3	50.6	45.4	41.6	40.6	56.6	57.6	54.9	49.6	44.9	42.7	37.8	37.8	29.2
6/24/2004 17:00	DAY	900	51.7	64.8	51.7	44.9	42	41.1	57.3	57.5	57.1	49.5	46.4	47.0	43.2	42.7	35.3
6/24/2004 17:15	DAY	900	58.6	71	54.1	46.3	43.5	43	63.7	58.1	66.4	63.8	54.7	49.0	46.7	44.1	38.1
6/24/2004 17:30	DAY	900	50.6	62.4	50.2	46.3	44	43.3	64.1	57.0	52.0	46.5	46.6	46.8	42.2	39.4	34.0
6/24/2004 17:45	DAY	900	54.2	66.6	57.5	45.7	43.5	43	58.9	56.4	53.7	46.4	45.8	43.6	40.0	51.4	46.3
6/24/2004 18:00	DAY	900	52.9	65.7	52	45.5	43.2	42.5	60.9	62.0	61.2	57.4	49.9	44.0	39.5	38.4	30.2
6/24/2004 18:15	DAY	900	46.3	55.2	47.8	43.6	41.1	40.4	58.0	55.1	53.8	46.6	40.7	40.5	36.2	38.6	31.5
6/24/2004 18:30	DAY	900	51.8	64.1	53.1	43.5	41.2	40.6	57.6	57.4	54.8	49.0	49.0	47.7	43.6	38.7	29.8
6/24/2004 18:45	DAY	900	44.7	53.7	45.9	42.9	40.3	39.9	55.6	52.5	48.8	42.0	40.2	40.8	36.5	33.0	23.4
6/24/2004 19:00	DAY	900	50.3	62.8	47.8	42.6	40.9	40.4	59.0	59.4	60.2	51.5	46.3	44.2	40.7	35.9	32.0
6/24/2004 19:15	DAY	900	46.4	58.6	45.8	43.2	40.7	40.3	57.3	53.7	58.5	46.7	40.2	39.9	36.0	29.1	31.8
6/24/2004 19:30	DAY	900	48.2	55.8	51.1	46.1	44.6	44.3	58.9	56.9	49.9	45.1	40.6	40.8	38.1	30.4	46.5
6/24/2004 19:45	DAY	900	60	68.1	66.7	52.8	49.5	49.1	58.9	57.9	52.1	47.4	44.9	44.9	42.0	34.9	60.9
6/24/2004 20:00	DAY	900	64.2	74.6	71.2	49	46.9	46.2	61.7	63.4	62.0	58.1	52.7	46.6	41.2	32.1	64.3
6/24/2004 20:15	DAY	900	45.8	48.2	46.9	45.6	44.4	44.1	58.6	55.8	50.1	42.6	38.1	38.6	36.4	28.5	42.2
6/24/2004 20:30	DAY	900	47.5	55.8	48.6	46.2	44.2	43.6	58.4	55.1	49.8	45.9	42.6	40.7	36.8	27.8	43.4
6/24/2004 20:45	DAY	900	49.1	60.8	48.9	45.7	43.7	43.3	59.5	57.5	53.5	48.2	45.9	43.8	39.8	31.5	40.9
6/24/2004 21:00	DAY	900	46.7	54.8	48.5	44.8	43.2	43.1	57.6	59.0	49.4	44.4	41.7	39.7	37.4	30.6	41.8
6/24/2004 21:15	DAY	900	50.3	63.3	49.5	45	43.1	42.7	59.0	58.1	57.9	53.2	48.1	43.6	38.6	29.6	37.5
6/24/2004 21:30	DAY	900	48.7	60.7	47	44.6	43.2	43	57.4	53.4	54.4	43.5	43.4	44.2	41.0	36.2	38.8
6/24/2004 21:45	DAY	900	50.9	64.3	49.1	44.9	43.2	43	60.1	61.2	59.8	54.5	48.3	42.7	37.7	27.4	39.3
6/24/2004 22:00	NIGHT	900	46.8	58	46.8	44.7	42.5	42.1	59.8	57.1	53.3	47.3	42.9	40.3	36.1	26.0	40.0
6/24/2004 22:15	NIGHT	900	47.3	59.1	45.9	43.7	42.2	42	55.9	56.3	49.6	43.4	42.4	42.6	38.9	33.9	39.2
6/24/2004 22:30	NIGHT	900	44.8	50.4	45.6	43.9	42.4	42.1	54.9	51.8	51.6	44.6	39.6	38.3	33.0	27.8	39.5
6/24/2004 22:45	NIGHT	900	45.5	55.9	44.9	43.1	42.2	42	54.6	51.0	50.2	45.4	40.4	40.2	34.9	28.4	39.2
6/24/2004 23:00	NIGHT	900	48.2	57	45.2	43	41.1	40.4	54.4	53.2	58.9	50.0	46.9	38.6	34.2	27.8	38.9
6/24/2004 23:15	NIGHT	900	43.1	48.1	45	42.7	40	39	53.6	49.2	45.8	41.2	37.2	37.4	33.8	26.6	37.9
6/24/2004 23:30	NIGHT	900	41.9	46	43.9	41.6	38.5	37.7	53.4	49.8	46.4	41.4	37.3	36.4	31.8	26.0	34.7
6/24/2004 23:45	NIGHT	900	46.6	53.9	45.5	42.7	40.9	40.4	54.8	52.8	54.8	45.1	41.6	41.7	37.4	32.7	37.2
6/25/2004 0:00	NIGHT	900	41.9	46.6	43.6	41.4	39.7	39.4	54.1	49.7	46.5	41.9	36.0	35.5	31.5	28.2	36.2
6/25/2004 0:15	NIGHT	900	42.5	47.8	44	41.9	39.5	39.2	54.1	49.9	47.3	41.7	36.2	36.4	31.6	29.8	36.9
6/25/2004 0:30	NIGHT	900	41.3	45.5	43.2	40.8	38.8	38.1	53.7	49.1	46.1	40.9	35.1	35.3	30.7	28.5	35.4
6/25/2004 0:45	NIGHT	900	43.3	48.4	45.5	43	39.2	38.6	54.5	50.5	48.4	44.0	38.7	38.6	33.2	26.7	33.2
6/25/2004 1:00	NIGHT	900	47.9	59.8	47.9	45.9	44.2	43.8	55.4	52.7	56.6	53.1	43.1	41.6	35.9	28.1	31.1
6/25/2004 1:15	NIGHT	900	44.9	50	46.9	44.6	41.7	40.9	55.0	52.3	50.0	45.5	40.5	39.1	33.9	28.0	37.7
6/25/2004 1:30	NIGHT	900	44.8	50.5	47	43.9	42	41.2	58.2	55.4	47.8	44.0	38.0	40.1	34.8	27.6	38.6
6/25/2004 1:45	NIGHT	900	46	58.8	45.7	43.2	41.1	40.6	55.3	51.2	51.1	48.6	41.5	40.7	35.5	28.8	35.0
6/25/2004 2:00	NIGHT	900	47.1	60.8	46.5	44	41.7	41.3	55.6	51.4	50.2	48.9	42.6	42.3	37.0	30.7	36.3

Appendix C: Tabular Sound Level Measurement Results

Table C1A: Sound Level Results at Measurement Location 1

Start Date and Time	Day / Night	Duration (seconds)	Leq (dB(A))	L1.00 (dB(A))	L10.00 (dB(A))	L50.00 (dB(A))	L90.00 (dB(A))	L95.00 (dB(A))	31.5 dB	63 dB	125 dB	250 dB	500 dB	1000 dB	2000 dB	4000 dB	8000 dB
6/25/2004 2:15	NIGHT	900	51	65.6	47	43.8	42.9	42.4	56.1	55.8	59.8	54.9	47.2	44.2	37.1	30.7	34.8
6/25/2004 2:30	NIGHT	900	44.9	54.1	46	43.3	42.2	42.1	55.1	53.6	52.0	45.6	40.5	38.2	33.9	30.5	37.8
6/25/2004 2:45	NIGHT	900	43.7	51.8	45.2	42.6	41.3	40.9	54.8	51.4	50.6	45.4	36.3	36.7	33.6	30.5	37.9
6/25/2004 3:00	NIGHT	900	47.9	59.4	51.3	41.7	38.4	37.8	53.8	49.2	46.4	44.8	40.7	44.3	41.4	31.1	35.7
6/25/2004 3:15	NIGHT	900	40.1	46.8	41.9	39	38	37.5	52.3	46.5	42.4	37.8	32.8	33.9	30.9	28.7	34.9
6/25/2004 3:30	NIGHT	900	41.6	46.9	43.8	40.8	38.6	38.2	52.5	48.2	44.5	39.5	35.4	35.2	31.2	31.9	35.9
6/25/2004 3:45	NIGHT	900	43.5	52.9	45.9	39.4	36.8	36	52.1	47.5	46.9	44.0	38.3	38.3	35.5	29.9	33.4
6/25/2004 4:00	NIGHT	900	45.4	57	47.9	41.3	38.9	38.4	56.4	58.2	56.8	48.4	38.6	36.4	32.1	28.9	35.9
6/25/2004 4:15	NIGHT	900	44	52.3	46.4	42.4	39.9	39.4	52.5	50.2	46.1	40.5	37.9	39.5	35.0	31.8	36.9
6/25/2004 4:30	NIGHT	900	45.9	53.6	47.9	43.8	41.9	41.4	52.7	51.0	50.5	44.3	41.5	40.5	36.8	34.4	38.3
6/25/2004 4:45	NIGHT	900	44.9	51.8	47	43.7	41.9	41.4	53.4	52.7	48.3	43.6	40.6	39.7	36.1	32.4	35.6
6/25/2004 5:00	NIGHT	900	45.3	49.4	47.2	44.7	42.9	42.4	54.1	52.5	51.2	43.7	40.0	40.3	36.4	32.5	35.8
6/25/2004 5:15	NIGHT	900	49.4	60.5	50.4	47	43.7	43.1	55.1	56.5	48.5	43.8	41.9	41.4	40.6	44.2	41.8
6/25/2004 5:30	NIGHT	900	57.2	62.9	61.2	51.6	45.5	45	55.1	54.8	50.5	45.9	42.4	43.3	41.9	54.4	51.9
6/25/2004 5:45	NIGHT	900	52.4	63.8	54.1	47.8	45.7	45.2	62.4	62.7	59.4	53.5	49.0	46.7	43.0	39.1	34.0
6/25/2004 6:00	NIGHT	900	49.4	59.5	50.7	47.2	45.4	45.1	56.3	58.3	54.8	47.5	44.8	45.3	41.2	37.8	30.4
6/25/2004 6:15	NIGHT	900	52.9	64.8	56	47.3	45.3	45	56.6	58.1	57.3	51.1	49.9	48.5	43.0	40.3	36.7
6/25/2004 6:30	NIGHT	900	52.8	65.6	55	45.7	43.8	43.3	59.2	59.5	57.0	51.9	49.8	48.5	44.3	38.6	30.7
6/25/2004 6:45	NIGHT	900	55.3	67	59	47.7	44.3	43.6	60.3	64.9	62.0	56.6	52.9	49.8	45.3	40.9	34.4
6/25/2004 7:00	DAY	900	49.7	62.1	50.9	44.6	41.8	41.3	57.7	59.5	54.9	47.9	45.9	45.2	41.0	38.6	33.6
6/25/2004 7:15	DAY	900	55.3	68.2	57	49.7	45.8	44.8	60.9	66.7	61.0	55.0	51.4	49.9	47.0	43.9	40.2
6/25/2004 7:30	DAY	900	56.5	67.9	54.2	47.4	44.3	43.7	60.0	60.8	61.6	57.5	52.7	51.3	48.4	44.2	40.4
6/25/2004 7:45	DAY	900	52.5	62.7	54	48.3	45.1	44.1	60.7	62.3	59.7	53.1	49.2	47.5	42.9	38.3	31.1
6/25/2004 8:00	DAY	900	59.9	73.6	58.2	47.6	43.5	42.6	60.1	61.5	65.7	63.5	57.1	52.5	50.5	45.5	39.0
6/25/2004 8:15	DAY	900	50.9	61.7	52.9	47.7	43.5	42.5	60.7	58.8	54.2	50.2	45.9	45.5	42.2	41.2	39.8
6/25/2004 8:30	DAY	900	54.1	64.2	53.6	48.7	45.6	45.1	58.9	61.0	58.4	53.3	50.5	49.4	45.9	41.7	34.8
6/25/2004 8:45	DAY	619.125	56.5	68	55.4	51.1	46.8	45.5	60.6	61.9	59.8	55.0	52.6	51.4	49.3	44.7	39.1

Table C1B: Sound Level Results at Measurement Location 1

Start Date and Time	Day / Night	Duration	Leq	L1.00	L10.00	L50.00	L90.00	L95.00	31.5	63	125	250	500	1000	2000	4000	8000
		(seconds)	(dB(A))	(dB(A))	(dB(A))	(dB(A))	(dB(A))	(dB(A))	dB	dB	dB	dB	dB	dB	dB	dB	dB
6/26/2004 8:47	DAY	759.75	49.2	60.5	50.5	43.5	40.4	39.6	60.0	56.7	52.9	46.9	45.7	44.9	40.7	36.7	30.2
6/26/2004 9:00	DAY	900	55.3	68.1	55	46.7	42.6	42	60.5	62.2	62.2	59.7	54.0	48.0	41.3	36.4	29.5
6/26/2004 9:15	DAY	900	51.9	63.9	54.7	45.7	42.1	41.4	59.6	59.3	56.5	49.5	44.8	45.1	44.8	44.5	40.3
6/26/2004 9:30	DAY	900	50.4	60.5	52.4	47.8	43.5	42.5	65.6	64.2	57.2	50.2	47.5	45.0	42.0	34.7	26.0
6/26/2004 9:45	DAY	900	49.4	54.7	51	47.7	44.3	43.5	67.8	60.5	54.4	46.9	44.1	45.8	41.7	34.6	26.9
6/26/2004 10:00	DAY	900	52.1	63.5	53	48.8	45.2	44	68.2	62.6	59.7	53.6	49.6	46.8	41.3	33.9	25.9
6/26/2004 10:15	DAY	900	49	56.9	51.2	47.6	44.9	44.1	67.8	60.6	56.2	49.2	44.0	44.3	39.9	34.8	28.3
6/26/2004 10:30	DAY	900	56.1	67.9	58.9	47.7	44.8	44.2	68.5	62.5	61.9	58.8	54.5	50.1	43.3	36.4	28.2
6/26/2004 10:45	DAY	900	51.4	64.3	51.6	47.8	44.5	43.9	68.8	63.4	59.9	53.9	48.3	45.0	40.7	36.7	28.4
6/26/2004 11:00	DAY	900	51.1	60.7	50.9	47.3	45	44.1	68.0	59.5	55.9	48.7	46.6	47.2	43.1	37.0	31.5
6/26/2004 11:15	DAY	900	50.8	63	51.7	46.7	44.2	43.6	67.8	60.2	56.7	50.1	46.6	46.1	42.5	37.8	30.5
6/26/2004 11:30	DAY	900	54.5	67.3	56	47.2	44.6	44.1	68.4	64.7	62.2	57.8	52.9	47.6	41.0	33.7	27.2
6/26/2004 11:45	DAY	900	53	66.2	54.5	47.9	44.7	43.5	67.6	60.6	59.2	54.8	50.7	47.8	41.9	35.3	29.3
6/26/2004 12:00	DAY	900	55.1	64.3	59	50.4	47	46.3	68.1	61.6	59.1	55.4	53.1	50.4	45.3	38.0	28.9
6/26/2004 12:15	DAY	900	54.4	66.8	53.3	48.1	45.2	44.6	68.2	61.7	60.9	57.1	52.4	48.2	42.5	39.0	29.0
6/26/2004 12:30	DAY	900	49.8	55.6	52.5	48.6	45.8	45.1	68.2	62.8	56.7	48.7	44.6	45.4	40.7	34.3	29.3
6/26/2004 12:45	DAY	900	53.9	64.3	56.2	49.7	45.4	44.6	64.8	66.0	60.4	55.2	50.3	48.4	44.1	36.8	29.1
6/26/2004 13:00	DAY	900	50.8	56.7	53.7	49.6	45.4	44.2	61.3	63.4	57.1	50.2	46.3	46.1	41.5	37.1	28.2
6/26/2004 13:15	DAY	900	56.2	69.4	56.9	49.9	45.6	44.8	62.4	64.7	63.3	58.2	54.2	49.8	45.0	39.5	32.7
6/26/2004 13:30	DAY	900	51.1	60.2	54.7	48	44.2	43.2	61.0	66.1	58.0	50.3	45.8	46.0	41.6	37.5	30.4
6/26/2004 13:45	DAY	900	50.5	59.9	53.4	48.3	44.6	43.7	62.0	57.8	54.6	51.0	46.7	46.1	41.5	37.2	28.9
6/26/2004 14:00	DAY	900	54.4	66.6	54.5	50	46.7	45.7	62.9	60.2	59.4	54.8	52.6	49.8	43.7	36.8	28.8
6/26/2004 14:15	DAY	900	51.8	62.3	54	49.7	44.8	43.7	61.2	58.0	56.8	51.1	46.9	47.7	43.2	37.8	30.3
6/26/2004 14:30	DAY	900	52.2	61.4	54.6	49.7	45.3	44.1	63.6	59.0	58.4	50.3	46.9	48.5	43.7	37.8	31.8
6/26/2004 14:45	DAY	900	53.8	64.9	55.6	51.1	46.8	45.5	65.5	60.7	58.5	53.7	51.4	49.5	43.9	37.0	32.6
6/26/2004 15:00	DAY	900	52.5	61.2	54.7	51.3	46.9	45.6	64.9	58.4	56.7	49.7	47.6	49.4	43.9	37.1	31.1
6/26/2004 15:15	DAY	900	54.2	62.9	54.4	51.2	47.1	45.6	61.7	58.8	55.7	50.6	48.5	50.6	47.6	40.2	34.6
6/26/2004 15:30	DAY	900	57.5	72.1	55	51.1	47.6	46.9	63.2	62.1	62.5	57.9	56.7	52.1	45.9	38.8	34.6
6/26/2004 15:45	DAY	900	51.8	56	54.5	51.5	46.6	44.6	63.8	58.0	53.9	47.5	45.7	49.1	43.9	35.9	30.4
6/26/2004 16:00	DAY	900	53.8	65.1	54.5	50.6	47.3	46.4	65.6	61.0	59.6	53.0	51.7	49.4	43.6	36.5	31.3
6/26/2004 16:15	DAY	900	52.8	59.4	54.9	52	48.4	47.4	65.8	62.5	56.2	47.9	46.6	50.0	44.6	37.7	32.8
6/26/2004 16:30	DAY	900	53.4	62.3	55.6	51.3	47.8	47	66.6	58.8	56.5	54.8	48.7	49.6	45.0	39.3	32.9
6/26/2004 16:45	DAY	900	53.9	63.4	56	52	48	46.9	67.2	60.0	59.2	53.2	50.2	50.2	44.2	38.8	33.6
6/26/2004 17:00	DAY	900	52.3	57.9	54.7	51.5	47.9	47.1	66.1	57.6	56.8	48.0	45.9	49.6	43.8	36.9	32.4
6/26/2004 17:15	DAY	900	52.1	57.7	53.9	51.6	48.7	47.7	67.8	58.7	57.2	49.0	46.2	49.1	43.5	37.6	33.3
6/26/2004 17:30	DAY	900	53.3	58.4	55.4	52	48.2	46.9	67.9	59.4	55.7	47.7	47.2	50.7	45.0	39.0	33.6
6/26/2004 17:45	DAY	900	59.2	70.6	56.3	52	47.9	46.7	69.0	60.9	62.2	62.0	59.7	51.4	48.4	43.2	39.2
6/26/2004 18:00	DAY	900	52.6	59.5	54.6	51.2	46.9	45.9	67.2	57.9	56.4	47.5	47.1	49.8	44.2	37.7	33.1
6/26/2004 18:15	DAY	900	52.1	56.8	54.3	50.9	47.6	46.7	67.4	58.2	53.9	46.1	45.0	49.3	45.0	38.7	33.6
6/26/2004 18:30	DAY	900	51.5	55.7	54.2	51	46.5	45.5	65.7	56.0	53.2	44.0	45.4	49.1	43.1	36.8	32.0
6/26/2004 18:45	DAY	900	50.7	56.9	53.4	49.6	46.1	45.3	65.4	55.7	51.2	44.0	44.6	48.1	42.5	36.8	31.3
6/26/2004 19:00	DAY	900	50.5	56.4	53	49.9	45.6	44.5	63.2	54.7	50.6	43.2	43.9	48.3	42.4	34.6	28.7
6/26/2004 19:15	DAY	900	56.2	66.5	61.2	50.3	46	44.2	62.5	55.3	53.5	44.7	45.1	48.3	42.2	33.8	56.2
6/26/2004 19:30	DAY	900	61.8	67.8	65.7	59.8	50.2	47.3	60.7	56.8	58.8	52.7	51.6	49.7	43.3	34.6	62.5
6/26/2004 19:45	DAY	900	58.7	65	63.4	55.4	49.1	48	60.8	56.1	55.9	48.4	44.8	46.4	41.1	32.6	59.0
6/26/2004 20:00	DAY	900	50.8	56.6	53.6	50.1	46.1	45.3	59.9	55.0	52.4	45.8	44.3	46.4	40.8	32.6	47.0
6/26/2004 20:15	DAY	900	55.3	66.2	56.7	51.7	46.8	46.1	58.2	60.0	64.6	50.3	48.4	49.5	44.2	37.2	51.5
6/26/2004 20:30	DAY	900	49.1	55.8	52.4	47.4	43.6	43.1	58.0	51.5	49.1	44.5	42.2	46.0	41.0	31.5	41.0
6/26/2004 20:45	DAY	900	51.7	62.7	52.6	48.9	45.7	44.3	60.8	58.6	57.2	52.5	48.9	46.5	41.2	32.7	43.3
6/26/2004 21:00	DAY	900	55.7	65.8	54.6	49.7	46	44.8	57.5	52.1	48.0	42.2	41.6	46.2	41.5	33.1	55.8
6/26/2004 21:15	DAY	900	52.3	62.6	54.1	48.2	44.7	44.2	59.1	55.0	53.3	46.5	42.5	45.5	40.9	32.8	51.2
6/26/2004 21:30	DAY	900	54.5	63.9	56	49.9	45.9	44.6	57.0	53.1	52.0	42.8	42.9	46.7	41.8	33.0	54.7
6/26/2004 21:45	DAY	900	56.6	66.2	62.2	50.1	44.7	43.4	56.8	56.0	58.5	55.5	51.4	49.6	43.0	32.9	54.6
6/26/2004 22:00	NIGHT	900	53.7	62.7	60.2	48.4	43.8	42.6	53.2	51.1	55.2	42.0	41.1	46.0	40.8	32.8	53.4
6/26/2004 22:15	NIGHT	900	49.1	54.4	52.5	48	42.8	41.7	56.4	51.5	53.2	44.0	43.0	46.5	40.4	33.0	36.4
6/26/2004 22:30	NIGHT	900	49.8	55.4	51.6	47.6	42.1	40.7	56.3	51.4	50.4	45.2	43.7	46.8	42.0	36.2	35.0
6/26/2004 22:45	NIGHT	900	49	55.3	52.5	47.4	42.7	42.2	57.2	51.0	47.3	40.0	43.3	46.1	40.1	35.2	39.1
6/26/2004 23:00	NIGHT	900	48.7	53.7	51.7	47.6	43.6	42.9	56.3	49.7	47.9	40.4	41.8	45.9	40.1	35.1	38.8
6/26/2004 23:15	NIGHT	900	55.6	66.1	54.7	49.5	44.6	42.7	60.0	68.7	64.9	56.8	49.9	49.3	43.9	39.2	45.0
6/26/2004 23:30	NIGHT	900	50.6	57.5	54.3	48.4	45.5	44.9	51.1	50.5	49.9	41.4	40.1	43.8	38.6	31.2	49.5
6/26/2004 23:45	NIGHT	900	47.7	55.4	50.3	46	44.3	41.7	50.5	46.7	44.3	38.6	39.8	43.1	37.5	30.6	44.0
6/27/2004 0:00	NIGHT	900	49.2	56.1	52.7	47.1	45.3	45.1	49.3	48.8	44.8	39.4	36.8	41.9	36.6	31.2	48.4
6/27/2004 0:15	NIGHT	900	51.7	60.9	56.3	46.7	45.1	44.7	49.4	47.1	46.8	41.1	34.4	40.0	36.2	30.9	52.6
6/27/2004 0:30	NIGHT	900	46.2	50.5	48.2	45.7	43.6	42.6	49.5	46.4	43.1	38.9	34.7	38.6	35.2	31.1	44.4
6/27/2004 0:45	NIGHT	900	46.4	52	48.2	45.6	44.1	43.6	49.3	46.6	44.6	39.5	37.8	39.5	34.8	30.9	44.3
6/27/2004 1:00	NIGHT	900	55	61.6	59.9	46.6	43.7	43.1	49.2	47.5	45.4	38.5	34.5	37.8	32.8	31.0	56.1
6/27/2004 1:15	NIGHT	900	50	57.8	53.8	46.8	37.1	36.5	49.7	45.2	43.3	37.7	34.7	37.1	32.3	31.0	50.9
6/27/2004 1:30	NIGHT	900	42.3	50.9	46.1	38.7	36.2	35.8	49.5	45.7	42.5	38.1	34.9	39.0	33.6	29.1	33.4
6/27/2004 1:45	NIGHT	900	53.9	60.7	59.2	49.5	38	36.7	49.5	45.8	43.7	37.6	33.9	37.2	32.7	29.9	55.2
6/27/2004 2:00	NIGHT	900	45.8	53.8	51.6	41	38.8	38.3	49.1	49.2	42.1	37.6	31.7	35.9	31.7	30.3	46.0
6/27/2004 2:15	NIGHT	900	51.6	60	54.4	49.8	48.3	47.5	49.5	46.5	50.6	49.0	39.0	35.8	30.8	30.8	52.2

Appendix C: Tabular Sound Level Measurement Results

Table C1B: Sound Level Results at Measurement Location 1

Start Date and Time	Day / Night	Duration (seconds)	Leq (dB(A))	L1.00 (dB(A))	L10.00 (dB(A))	L50.00 (dB(A))	L90.00 (dB(A))	L95.00 (dB(A))	31.5 dB	63 dB	125 dB	250 dB	500 dB	1000 dB	2000 dB	4000 dB	8000 dB
6/27/2004 2:30	NIGHT	900	44.6	50.3	49.2	41.6	40.3	40.1	49.4	44.9	44.7	41.5	34.5	31.9	25.7	30.8	44.6
6/27/2004 2:45	NIGHT	900	44.9	48.9	47.7	44.4	40	39.4	48.7	47.8	41.3	37.7	29.5	31.5	27.8	30.9	45.2
6/27/2004 3:00	NIGHT	900	46.9	54.9	52.2	44.4	43.2	42.3	48.7	45.1	41.7	38.4	28.7	27.2	24.5	32.6	47.1
6/27/2004 3:15	NIGHT	900	44.5	46.6	45.7	44.5	43	42.4	49.7	46.3	43.8	40.1	31.9	30.3	25.3	34.1	43.2
6/27/2004 3:30	NIGHT	900	44.2	46.1	45	44.1	43.2	43	49.9	47.7	44.8	40.3	32.4	31.5	26.7	36.2	42.0
6/27/2004 3:45	NIGHT	900	43.3	45.5	44.6	43.3	41.2	39.8	49.3	48.2	44.8	41.5	33.0	30.3	25.4	33.7	41.3
6/27/2004 4:00	NIGHT	900	44.9	47	45.9	44.8	43.5	43.2	49.4	47.2	43.6	40.8	33.5	32.1	27.4	32.8	43.7
6/27/2004 4:15	NIGHT	900	42.9	44.9	43.8	42.9	42	41.4	50.7	49.8	45.3	41.2	34.2	32.5	28.1	32.5	40.3
6/27/2004 4:30	NIGHT	900	44.2	50.6	45.2	42.4	41.1	40.8	50.1	49.9	49.6	45.1	38.8	36.4	32.6	31.6	39.3
6/27/2004 4:45	NIGHT	900	41.8	46.2	44.1	41.4	38.5	38	49.2	49.7	48.1	40.2	35.8	34.9	31.6	30.6	36.6
6/27/2004 5:00	NIGHT	900	41.4	45.2	43.7	40.9	38.2	37.6	49.4	47.5	43.8	40.3	36.4	35.4	32.8	28.6	34.4
6/27/2004 5:15	NIGHT	900	45.5	54.3	46.8	43.9	41.5	41	54.3	51.4	48.9	44.4	39.3	39.9	38.4	34.2	35.5
6/27/2004 5:30	NIGHT	900	55.9	62.4	60.2	48.3	44.8	44.2	51.5	50.1	48.0	43.6	41.0	42.1	39.5	52.7	51.8
6/27/2004 5:45	NIGHT	900	51	60.5	56.2	44.3	41.2	40.5	51.0	50.5	46.6	43.1	37.8	37.6	38.0	47.3	46.6
6/27/2004 6:00	NIGHT	900	47.4	58.3	49.4	44.2	41.2	40.4	51.9	52.9	54.9	50.6	41.7	40.9	38.2	38.9	28.2
6/27/2004 6:15	NIGHT	900	53.1	68.5	51.8	42.9	40.3	39.7	60.2	58.4	50.8	48.5	47.8	48.7	47.0	42.7	33.4
6/27/2004 6:30	NIGHT	900	45.1	57.7	44.8	41.2	39.5	39.2	52.7	53.6	51.2	46.8	39.1	37.0	35.7	38.2	26.5
6/27/2004 6:45	NIGHT	900	51.8	65.5	50.4	42.4	39.5	39.1	56.9	60.0	59.6	55.9	50.0	41.8	37.8	36.5	26.3
6/27/2004 7:00	DAY	900	47.7	55.1	50.1	46.6	43.8	42.8	52.6	53.1	51.9	49.0	41.0	42.9	40.8	35.1	24.6
6/27/2004 7:15	DAY	900	47.2	56.1	48.5	44.3	41.2	40.4	55.4	53.6	53.7	44.8	41.1	42.5	39.4	38.4	28.9
6/27/2004 7:30	DAY	900	46.4	55	49.5	44	39.3	38.4	55.4	53.4	51.5	44.0	39.4	41.7	39.4	37.0	28.7
6/27/2004 7:45	DAY	377.5	47.5	56.9	49.1	45.7	43.2	42.5	55.3	52.2	48.3	44.6	43.6	43.2	40.1	35.3	29.9

Table C2A: Sound Level Results at Measurement Location 2

Start Date and Time	Day / Night	Duration (seconds)	Leq (dB(A))	L1.00 (dB(A))	L10.00 (dB(A))	L50.00 (dB(A))	L90.00 (dB(A))	L95.00 (dB(A))	31.5 dB	63 dB	125 dB	250 dB	500 dB	1000 dB	2000 dB	4000 dB	8000 dB
6/24/2004 8:06	DAY	501.375	52.8	65.4	54.1	44.3	38.6	37.6	60.2	57.0	52.7	48.3	46.1	46.0	46.1	44.2	42.6
6/24/2004 8:15	DAY	900	60.2	75.4	48.2	39.5	36.4	35.6	63.2	69.7	61.0	55.0	54.6	55.7	54.1	49.5	41.8
6/24/2004 8:30	DAY	900	43.1	50.1	45.6	42.2	37.7	36.9	57.9	55.5	47.9	38.5	39.5	38.2	33.2	34.2	24.0
6/24/2004 8:45	DAY	900	45.1	50.1	46.8	44.5	42.2	41.6	58.0	62.6	47.7	39.3	41.1	40.4	34.9	35.3	26.1
6/24/2004 9:00	DAY	900	49.7	61.9	50.2	46.3	43.3	42.6	59.0	64.3	57.2	49.7	46.2	42.9	41.6	37.0	28.7
6/24/2004 9:15	DAY	900	48.7	59.7	50	46.1	43.6	43.1	57.2	54.9	51.0	44.2	43.9	42.6	43.5	37.8	29.8
6/24/2004 9:30	DAY	900	47	55.8	48.8	45.7	43.2	42.4	58.0	54.9	45.4	40.5	44.7	43.5	37.3	34.1	26.2
6/24/2004 9:45	DAY	900	54.5	67.5	55.9	46.3	42.3	41.4	64.4	60.0	58.2	55.7	53.0	49.1	43.6	39.7	30.7
6/24/2004 10:00	DAY	900	44.1	52.4	45.9	42	39.6	39.1	56.9	52.8	48.6	41.3	38.5	38.4	35.8	36.8	26.7
6/24/2004 10:15	DAY	900	50.1	63.5	51.1	43.8	40.9	40.3	58.5	59.1	59.3	52.1	48.5	42.4	36.0	37.9	26.9
6/24/2004 10:30	DAY	900	47	56.9	48.5	44.5	41.9	41.3	57.7	55.2	50.2	41.9	41.7	42.0	38.6	39.7	29.3
6/24/2004 10:45	DAY	900	50.6	63.3	51	44.3	41.8	41.4	58.4	56.4	56.6	48.0	46.9	45.5	42.9	40.4	34.1
6/24/2004 11:00	DAY	900	52	65.1	53.6	45.3	42.8	42	62.5	60.6	59.6	53.8	50.7	45.1	40.1	35.6	23.9
6/24/2004 11:15	DAY	900	47.5	55	50.2	45.8	43.2	42.3	57.9	54.1	49.1	41.0	42.2	42.7	39.8	39.5	33.6
6/24/2004 11:30	DAY	900	51.5	62.8	51.8	48.7	46.1	45.4	59.6	59.5	59.1	51.2	49.1	46.0	40.5	39.0	33.5
6/24/2004 11:45	DAY	900	52.4	62.5	55.7	49.3	46.7	45.9	58.8	57.7	53.6	47.9	48.6	48.3	44.4	41.5	38.5
6/24/2004 12:00	DAY	900	54.3	66.2	55	49	45.2	44.4	60.0	61.6	63.9	56.4	51.4	48.3	44.4	40.8	37.2
6/24/2004 12:15	DAY	900	53.8	63	56.9	51.1	43.5	42.8	59.0	58.0	54.0	47.6	48.5	47.1	47.1	45.9	44.2
6/24/2004 12:30	DAY	900	49.9	62.4	50.9	46.2	43.7	43.3	57.8	58.1	54.0	49.1	47.7	44.6	39.9	38.8	29.6
6/24/2004 12:45	DAY	900	54.1	65.3	57.1	45.1	42.6	42	61.6	62.5	61.1	53.6	49.1	45.7	47.7	45.1	35.8
6/24/2004 13:00	DAY	900	59.4	73	60.7	46.6	41.3	40.7	61.8	70.2	62.6	59.5	55.4	52.3	52.8	49.3	42.5
6/24/2004 13:15	DAY	900	52.9	65.9	53.3	44.2	40.8	40.2	61.0	59.4	60.1	53.0	49.9	47.0	44.7	39.5	33.4
6/24/2004 13:30	DAY	900	56.6	70.7	52.9	43.9	41.8	41.3	60.9	63.5	62.2	58.6	56.9	49.0	42.5	38.3	31.7
6/24/2004 13:45	DAY	900	52.5	65.4	53.4	47.4	44.1	43.2	62.0	62.4	59.8	54.4	49.2	48.0	41.8	36.8	31.1
6/24/2004 14:00	DAY	900	55.9	67.4	56.1	46.5	43.1	42.5	66.1	67.5	59.0	54.8	52.1	50.8	48.2	44.6	36.4
6/24/2004 14:15	DAY	900	48.9	59	52.1	44.7	42.4	41.8	58.9	57.7	56.1	50.0	46.6	43.8	39.0	33.8	24.7
6/24/2004 14:30	DAY	900	55.5	65.1	60.9	47.4	41.6	41.1	58.2	58.2	56.8	49.0	51.3	51.6	47.1	45.1	39.8
6/24/2004 14:45	DAY	900	55.8	65.1	58.6	52.7	43.7	42.1	59.2	58.5	63.2	61.2	50.5	47.5	45.0	44.0	44.0
6/24/2004 15:00	DAY	900	54.2	63.4	59.3	47.9	42.1	41.3	59.3	61.1	63.7	60.8	49.4	43.1	40.4	40.2	35.0
6/24/2004 15:15	DAY	900	45.2	52.4	45.5	42	40.3	40	57.6	55.1	49.8	42.4	39.7	39.9	36.4	37.6	32.2
6/24/2004 15:30	DAY	900	52.8	66.5	50.8	43.6	41.3	40.8	58.8	59.9	55.5	51.4	50.0	48.4	43.6	40.6	35.2
6/24/2004 15:45	DAY	900	52.8	66.5	53.7	44.7	42.8	42.3	61.6	64.8	62.8	55.4	50.5	44.3	37.4	39.3	31.8
6/24/2004 16:00	DAY	900	50.1	62.6	49.5	44.1	42.1	41.6	59.0	63.8	60.3	53.6	46.6	40.8	36.4	36.9	31.3
6/24/2004 16:15	DAY	900	47.6	56.6	51	44.3	41	40.4	55.3	63.4	53.9	46.5	40.2	40.6	37.2	40.2	32.6
6/24/2004 16:30	DAY	900	55.8	69.6	55.7	45.3	42.3	41.5	59.9	66.2	65.8	59.2	53.8	46.2	41.1	38.5	37.8
6/24/2004 16:45	DAY	900	50.8	64.4	50.6	44.4	40.7	39.6	57.9	59.1	54.1	51.8	47.0	45.3	40.8	41.0	34.0
6/24/2004 17:00	DAY	900	50.1	59.9	53.3	44.4	41.7	40.7	57.4	53.7	53.3	46.2	44.9	47.2	40.4	39.1	34.0
6/24/2004 17:15	DAY	900	48.9	57.4	47.7	44.9	43	42.2	58.9	54.7	54.3	47.0	44.1	43.3	40.6	40.0	36.0
6/24/2004 17:30	DAY	900	53.9	67.2	51.9	46.6	43.9	43.4	59.6	60.7	52.8	44.0	43.5	42.6	50.2	45.1	43.8
6/24/2004 17:45	DAY	900	49.2	62.5	48	44.7	42.6	42.2	59.2	60.8	54.9	46.4	44.1	44.2	41.8	38.6	34.9
6/24/2004 18:00	DAY	900	49.3	62	49.9	44.4	41.5	41	59.9	58.0	59.7	51.5	44.6	40.4	37.6	39.1	34.4
6/24/2004 18:15	DAY	900	46.2	56.2	45.9	42.7	40.6	40.1	56.0	52.8	49.8	40.7	37.0	35.7	36.2	42.5	36.2
6/24/2004 18:30	DAY	900	47.9	58.8	48.9	42.5	39.8	39.2	56.5	54.3	53.1	44.2	44.8	43.4	38.9	37.8	32.8
6/24/2004 18:45	DAY	900	45.3	57.9	44.9	40.5	38.1	37.5	54.1	50.1	45.4	36.6	39.1	39.1	39.3	38.3	30.5
6/24/2004 19:00	DAY	900	46.6	58.2	46.1	40.5	38.1	37.5	56.5	59.6	52.8	45.3	41.1	41.5	38.4	33.7	29.3
6/24/2004 19:15	DAY	900	48.3	60.5	49.8	44.7	39.5	38.9	55.9	53.9	59.7	44.7	39.4	39.8	43.3	32.5	30.1
6/24/2004 19:30	DAY	900	65.5	70.9	69.6	63.6	42.1	40.5	57.2	52.0	43.8	36.4	35.0	37.5	41.9	29.8	66.3
6/24/2004 19:45	DAY	900	62.3	69.4	66.2	59.4	50.7	48.6	56.9	52.0	46.7	40.0	39.8	39.8	43.3	38.6	63.1
6/24/2004 20:00	DAY	900	68.4	75.4	74.5	63.7	55.3	53.7	59.2	60.4	60.9	52.2	47.6	41.3	48.7	37.4	69.3
6/24/2004 20:15	DAY	900	58.4	67.4	64.5	49.9	37.6	37.1	56.3	49.7	40.9	30.3	30.3	38.6	47.4	36.3	58.5
6/24/2004 20:30	DAY	900	50.5	57.2	54.6	48.5	39.8	39.1	56.6	50.4	47.6	43.8	40.2	40.4	48.0	36.7	37.1
6/24/2004 20:45	DAY	900	52	57.9	54.7	51	47.4	46	57.5	53.2	51.0	43.7	41.5	42.5	49.4	35.7	39.0
6/24/2004 21:00	DAY	900	51.8	56.7	54.4	51.1	48	47	55.8	55.5	44.2	37.6	38.3	42.0	49.6	32.9	38.9
6/24/2004 21:15	DAY	900	53	57.9	56.1	52.2	46.4	44.8	57.7	56.6	53.4	46.2	42.1	41.9	50.7	31.5	39.2
6/24/2004 21:30	DAY	900	53.1	58.3	56	52	46.3	43.3	55.9	51.8	47.9	41.0	40.0	42.7	51.1	35.0	39.3
6/24/2004 21:45	DAY	900	55.4	63.1	57.3	54.7	50.3	49	58.7	60.5	61.2	51.6	46.2	41.3	49.9	31.1	51.2
6/24/2004 22:00	NIGHT	900	51.5	57.5	55.3	50	41.3	39.8	58.0	54.5	50.6	43.5	37.5	38.6	48.2	29.0	45.9
6/24/2004 22:15	NIGHT	900	50.4	56.7	54.5	48.8	41	40	53.7	46.7	42.1	34.0	35.5	38.5	47.7	28.5	44.2
6/24/2004 22:30	NIGHT	900	53.2	60	58.1	48.8	38.8	36.9	52.0	48.9	50.8	38.2	38.5	39.5	46.7	33.2	52.2
6/24/2004 22:45	NIGHT	900	49.5	57.9	53.6	46	37.6	36.8	51.9	51.0	49.3	43.2	39.0	40.0	47.0	30.5	36.9
6/24/2004 23:00	NIGHT	900	54.3	60.9	58.8	48.6	36.5	35.7	51.5	44.5	38.6	27.9	27.9	33.6	45.9	26.6	54.6
6/24/2004 23:15	NIGHT	900	47.5	56	52.4	41.8	38.5	38.2	51.6	43.7	39.0	31.8	32.8	35.0	44.8	27.7	41.6
6/24/2004 23:30	NIGHT	900	55	58.2	56.8	54.9	51.8	51.4	50.7	44.3	41.4	32.9	33.9	34.9	45.3	27.3	55.2
6/24/2004 23:45	NIGHT	900	52.6	58	55.9	51.6	41.6	39	51.5	46.4	41.8	32.0	33.2	34.7	44.7	29.9	52.5
6/25/2004 0:00	NIGHT	900	53.8	59.3	58	52.3	38.2	35.9	51.2	42.0	36.7	29.0	28.9	32.0	43.5	26.2	54.2
6/25/2004 0:15	NIGHT	900	54.3	57.8	55.7	53.9	53.2	53.1	51.3	43.4	38.7	30.2	30.4	32.6	44.0	29.4	55.5
6/25/2004 0:30	NIGHT	900	51	57	54.4	50.6	36.1	34.3	50.7	42.6	36.0	28.8	29.2	30.8	44.4	30.5	50.7
6/25/2004 0:45	NIGHT	900	46	55.7	51	39.3	35.2	34.6	51.1	43.0	38.8	32.3	32.5	35.1	44.0	31.8	31.6
6/25/2004 1:00	NIGHT	900	47.4	56.4	50.9	44.6	41.1	40.3	51.9	45.7	49.6	45.5	39.6	41.5	43.1	32.2	32.3
6/25/2004 1:15	NIGHT	900	47.5	55.4	51.6	44.7	35.7	35.4	51.7	45.6	41.9	35.9	36.9	41.4	44.4	31.0	32.6
6/25/2004 1:30	NIGHT	900	44.6	55.2	46.9	41.6	35.4	35	54.6	48.5	39.9	33.4	34.8	38.2	41.0	31.3	33.1
6/25/2004 1:45	NIGHT	900	46.5	56.4	51.5	40	37.3	37.1	52.5	45.6	41.8	38.7	40.0	37.5	43.6	32.4	32.6

Appendix C: Tabular Sound Level Measurement Results

Table C2A: Sound Level Results at Measurement Location 2

Start Date and Time	Day / Night	Duration	Leq	L1.00	L10.00	L50.00	L90.00	L95.00	31.5	63	125	250	500	1000	2000	4000	8000
		(seconds)	(dB(A))	(dB(A))	(dB(A))	(dB(A))	(dB(A))	(dB(A))	dB	dB	dB	dB	dB	dB	dB	dB	dB
6/25/2004 2:00	NIGHT	900	46.6	56.3	51	42.4	39.3	38.4	52.6	45.6	41.0	39.4	40.1	38.3	43.4	32.6	34.0
6/25/2004 2:15	NIGHT	900	47.1	57.4	51.4	41.7	39.2	38.1	53.0	50.1	47.8	44.3	43.4	38.2	43.0	33.0	33.4
6/25/2004 2:30	NIGHT	900	44.9	55.5	49.8	37.6	36.3	36.1	52.4	48.9	46.4	40.3	35.6	33.3	42.0	31.5	33.6
6/25/2004 2:45	NIGHT	900	44.6	51	50.3	38.1	36.9	36.5	52.9	50.9	48.9	40.8	32.5	32.7	31.1	27.2	44.7
6/25/2004 3:00	NIGHT	900	52.6	57.9	55.4	51.4	43.2	34.9	51.8	45.3	39.6	42.7	38.4	40.2	44.3	36.5	52.2
6/25/2004 3:15	NIGHT	900	50.4	55	53.2	48.4	47	46.6	50.7	45.6	42.5	30.0	29.1	29.8	33.6	25.3	51.7
6/25/2004 3:30	NIGHT	900	40.5	48.5	44.2	35.6	33.3	33.1	51.0	43.8	38.5	29.2	31.3	30.2	25.8	24.0	39.9
6/25/2004 3:45	NIGHT	900	43.5	51.5	45.5	43.4	34.5	33.9	50.5	47.5	43.1	37.5	37.2	35.4	30.8	25.8	41.4
6/25/2004 4:00	NIGHT	900	38.2	46	41.2	36.6	33.7	33.1	53.2	51.8	46.7	37.8	33.9	32.8	27.3	22.7	30.3
6/25/2004 4:15	NIGHT	900	42.2	50.5	42.2	36.7	32.7	31.6	50.6	46.6	44.5	38.1	38.0	38.2	34.2	28.9	32.1
6/25/2004 4:30	NIGHT	900	42.7	49	42.8	37.6	34	33.2	50.3	45.5	43.3	40.0	39.5	39.0	34.1	28.4	25.2
6/25/2004 4:45	NIGHT	900	40.1	46.9	42.8	39	34.6	34	50.7	47.9	40.4	34.9	36.8	36.5	29.9	29.1	27.6
6/25/2004 5:00	NIGHT	900	39.9	43.5	41.8	39.7	36.7	35.8	51.2	45.8	41.9	33.3	34.8	35.7	29.5	32.3	30.3
6/25/2004 5:15	NIGHT	900	50.6	60	56.6	42.2	38.6	38	51.6	48.9	40.7	35.9	37.1	37.4	36.5	44.9	48.3
6/25/2004 5:30	NIGHT	900	49.4	58.6	52.4	45.6	42.7	42	51.9	49.1	43.1	35.5	37.7	38.3	35.3	45.1	45.6
6/25/2004 5:45	NIGHT	900	49.9	61.5	52.2	43.7	41.2	40.6	60.5	59.4	55.3	49.2	43.6	39.9	42.3	44.1	35.5
6/25/2004 6:00	NIGHT	900	47.2	55.8	47.8	44.3	41.4	40.5	53.3	55.7	48.0	40.3	41.2	42.0	38.8	40.3	35.0
6/25/2004 6:15	NIGHT	900	48.6	62.3	48.1	42.4	40	39.3	55.5	51.5	50.7	45.6	47.3	43.3	39.7	36.8	29.1
6/25/2004 6:30	NIGHT	900	51.5	62.9	53.3	44.4	41	40.2	56.3	54.4	50.1	49.5	47.8	46.2	42.8	43.7	34.1
6/25/2004 6:45	NIGHT	900	55	67.9	56.2	43.2	40.1	39.5	57.4	60.6	59.2	53.6	51.0	48.5	47.5	46.8	38.7
6/25/2004 7:00	DAY	900	42.6	52.8	44.5	40.1	37.3	36.9	55.0	53.6	49.1	40.8	38.5	37.0	33.6	34.1	26.4
6/25/2004 7:15	DAY	900	58.7	72.9	52.5	40.4	37.6	37.1	61.3	63.6	63.4	54.5	53.9	54.0	51.7	47.6	43.5
6/25/2004 7:30	DAY	900	46.6	57.6	43.5	40.6	38	37.4	56.3	54.4	51.5	44.9	41.9	41.8	37.9	37.7	32.3
6/25/2004 7:45	DAY	900	51.7	65.7	51.4	41.8	39.2	38.6	59.1	57.4	55.1	50.8	48.9	47.4	42.7	38.2	31.8
6/25/2004 8:00	DAY	900	57.5	72	51.2	42.5	38.6	37.8	58.9	57.3	56.9	57.8	56.1	52.2	48.6	43.1	37.6
6/25/2004 8:15	DAY	900	51.2	63.5	52.9	46.1	44.6	44.3	59.0	54.2	48.7	46.5	47.3	45.2	44.7	42.2	38.1
6/25/2004 8:30	DAY	13.875	62.4	71	68.5	54	51.4	51	57.5	51.1	51.5	52.7	54.9	58.1	57.8	48.5	38.8

Table C2B: Sound Level Results at Measurement Location 2

Start Date and Time	Day / Night	Duration (seconds)	Leq (dB(A))	L1.00 (dB(A))	L10.00 (dB(A))	L50.00 (dB(A))	L90.00 (dB(A))	L95.00 (dB(A))	31.5 dB	63 dB	125 dB	250 dB	500 dB	1000 dB	2000 dB	4000 dB	8000 dB
6/26/2004 9:00	DAY	896.625	52.7	65.9	53.9	43.4	37.7	37	59.0	59.1	59.2	55.2	51.1	45.7	42.4	39.1	36.3
6/26/2004 9:15	DAY	900	49.3	63.7	48.1	41.3	38	37	56.9	53.7	54.4	54.9	46.7	40.8	37.7	39.7	30.3
6/26/2004 9:30	DAY	900	46	52.9	48.5	45.4	38.6	37.9	65.5	61.6	54.5	42.9	41.1	40.2	37.8	36.3	28.6
6/26/2004 9:45	DAY	900	46.2	50.9	47.9	45.7	44.4	44.1	67.4	62.7	54.6	44.2	40.8	40.7	37.3	35.5	29.9
6/26/2004 10:00	DAY	900	48.3	58.9	49.1	45.3	43.3	42.8	66.7	60.7	55.3	48.5	46.2	42.7	37.0	34.9	27.6
6/26/2004 10:15	DAY	900	47.1	53.2	48.5	45.4	43.2	42.7	66.4	60.2	54.8	47.7	42.1	41.3	37.6	35.6	31.4
6/26/2004 10:30	DAY	900	53.5	66.6	55.4	44.5	42.7	42.3	66.7	60.8	59.7	56.2	52.2	47.2	41.1	34.9	27.2
6/26/2004 10:45	DAY	900	49.6	62.5	48.9	45.2	43.4	43	67.2	61.0	57.8	51.9	46.3	42.7	38.6	37.2	31.2
6/26/2004 11:00	DAY	900	50.5	62.9	48.6	44.8	43.3	42.9	65.9	59.7	56.0	48.1	45.3	45.8	42.8	39.8	33.3
6/26/2004 11:15	DAY	900	51.3	65.1	48.6	44.2	42.5	42.2	66.1	60.2	57.9	49.2	47.9	46.5	43.0	38.7	32.5
6/26/2004 11:30	DAY	900	50.5	63.4	51	44.6	42.7	42.3	66.5	61.0	58.8	52.6	48.8	43.7	37.6	33.8	30.9
6/26/2004 11:45	DAY	900	52.9	67.6	51.9	45	43	42.1	65.8	59.7	58.3	53.7	51.9	47.7	39.1	35.8	30.6
6/26/2004 12:00	DAY	900	53.7	65	56.5	47.7	43.7	43.3	66.2	59.6	57.9	54.4	52.1	49.0	42.9	37.2	30.3
6/26/2004 12:15	DAY	900	50.5	63.7	50.6	44.5	42.6	42.2	66.0	60.0	59.3	53.3	48.9	43.2	37.3	34.5	30.5
6/26/2004 12:30	DAY	900	45.7	52.7	47.4	44.8	43.1	42.5	65.8	60.2	52.8	43.5	41.8	40.6	35.7	33.2	30.3
6/26/2004 12:45	DAY	900	51.7	63.7	53.9	45.8	42.5	41.6	62.9	62.7	56.8	53.1	48.8	45.3	42.6	38.4	31.2
6/26/2004 13:00	DAY	900	48	56.3	50.6	44.5	41.3	40.2	57.9	60.1	53.1	47.8	44.5	42.8	38.0	36.7	30.6
6/26/2004 13:15	DAY	900	53.1	67.8	52.9	44.6	41.7	41	58.4	61.3	60.6	55.3	52.6	45.5	39.8	35.9	29.9
6/26/2004 13:30	DAY	900	47.9	57	50.4	43.3	40.6	39.8	57.8	61.8	52.4	45.5	44.6	43.3	37.3	34.8	31.0
6/26/2004 13:45	DAY	900	45.4	54.1	47.9	43.1	40.5	39.9	59.0	54.3	49.9	46.0	42.7	39.9	34.4	33.0	32.9
6/26/2004 14:00	DAY	900	51.4	64.2	51.2	44.6	42.1	41.4	59.3	56.0	53.8	51.3	48.7	45.5	42.1	41.9	33.7
6/26/2004 14:15	DAY	900	50.2	63.9	49.4	44.6	41.7	41.2	59.2	57.6	54.8	49.6	46.6	45.4	40.9	37.4	30.9
6/26/2004 14:30	DAY	900	47.1	57.4	48.9	44.9	42.2	41.6	60.7	52.7	49.8	43.0	42.0	41.6	40.0	37.7	34.8
6/26/2004 14:45	DAY	900	50.1	61.9	50.9	45.7	43.4	42.9	61.5	57.3	57.7	49.6	47.9	44.2	39.6	38.2	33.3
6/26/2004 15:00	DAY	900	49.1	59.3	49.7	46.6	43.8	43.2	58.9	52.5	50.4	45.7	45.7	44.2	39.8	40.1	35.3
6/26/2004 15:15	DAY	900	47.9	58.9	48.9	45.7	43.3	42.7	58.4	52.7	49.4	45.6	43.3	44.0	39.8	35.8	32.2
6/26/2004 15:30	DAY	900	59.6	71.9	53.5	45.5	43.2	42.7	59.8	59.3	61.3	55.3	54.0	47.7	56.7	44.0	39.1
6/26/2004 15:45	DAY	900	47.2	57.5	48.1	45.8	43.1	42.3	60.7	54.0	51.2	44.8	42.9	43.5	38.4	34.7	32.3
6/26/2004 16:00	DAY	900	49.2	60.8	48.8	46.1	43.7	43.2	62.2	57.7	57.1	49.2	47.4	43.3	37.8	36.1	34.1
6/26/2004 16:15	DAY	900	48.4	56.4	49.7	47.1	44.6	44.1	62.0	54.9	48.8	42.0	43.2	43.5	40.5	40.1	36.5
6/26/2004 16:30	DAY	900	48.8	60.2	49.5	46.4	44.2	43.6	62.5	53.6	51.4	52.7	45.7	43.0	39.3	36.8	35.5
6/26/2004 16:45	DAY	900	50.7	61.1	52.7	47.6	45.1	44.4	66.0	59.3	58.2	50.2	48.5	44.1	39.2	40.9	36.9
6/26/2004 17:00	DAY	900	47.2	54.4	48.7	46.2	44.3	43.7	62.4	52.2	51.4	44.7	43.1	42.7	38.4	36.7	34.3
6/26/2004 17:15	DAY	900	49	59	49.9	47	45.1	44.4	64.7	54.1	52.5	44.9	43.7	43.2	43.0	38.7	36.7
6/26/2004 17:30	DAY	900	48.5	55.1	49.8	47.2	44.9	44.1	64.9	55.2	48.1	41.8	43.3	42.9	42.6	38.4	36.0
6/26/2004 17:45	DAY	900	55.6	69.9	52.3	47	44.4	43.4	65.0	59.9	59.1	52.5	53.0	50.2	48.8	41.1	37.7
6/26/2004 18:00	DAY	900	46.7	51.4	48.4	46.4	44.1	43.4	64.1	53.0	45.4	39.5	42.1	42.2	38.3	38.3	34.8
6/26/2004 18:15	DAY	900	49.2	60.5	48.8	46	43.6	43.1	62.1	51.6	45.9	40.0	44.6	45.4	42.2	37.6	33.8
6/26/2004 18:30	DAY	900	47.1	51.8	49.5	46.3	44	43.3	62.6	51.3	44.9	38.4	41.0	41.7	38.5	40.9	36.4
6/26/2004 18:45	DAY	900	47.2	54.9	49.6	45.5	43.3	42.7	59.9	49.8	43.3	39.3	41.4	41.1	39.1	41.5	34.9
6/26/2004 19:00	DAY	900	45.3	51.1	47.5	44.4	42.4	41.7	58.1	48.6	42.6	37.2	39.8	41.0	39.0	34.8	30.9
6/26/2004 19:15	DAY	900	46.9	54.3	50.2	44.8	42.3	41.4	57.9	49.0	44.5	41.7	42.8	41.3	41.7	34.1	33.9
6/26/2004 19:30	DAY	900	63.6	73.8	66.9	59	47.6	46	58.3	51.3	50.9	46.7	47.7	43.3	45.9	35.0	63.8
6/26/2004 19:45	DAY	900	62.5	72.9	64.7	58.2	54.7	52.8	57.7	57.0	57.3	45.8	41.9	40.9	47.5	32.3	62.7
6/26/2004 20:00	DAY	900	51.9	57.3	54.6	51.1	47.6	47.1	57.0	52.3	49.4	42.6	41.6	40.3	46.5	32.2	49.2
6/26/2004 20:15	DAY	900	55.7	64.2	54.2	48.9	44.5	42.8	56.5	55.6	67.5	55.3	51.0	47.6	47.7	39.7	46.6
6/26/2004 20:30	DAY	900	52.3	58.7	56.3	49.7	42.5	41.8	55.7	47.4	45.4	41.9	39.5	41.0	47.3	36.5	48.6
6/26/2004 20:45	DAY	900	51	58.7	54.2	49	45.1	44.2	58.0	55.1	52.8	46.1	44.6	40.7	47.3	35.7	42.9
6/26/2004 21:00	DAY	900	50.4	56.1	53.6	48.6	45.2	44.6	55.3	47.0	40.6	35.1	37.4	39.7	46.8	35.0	45.4
6/26/2004 21:15	DAY	900	54.4	62	61	49.2	43.8	41.4	56.4	49.4	48.5	42.7	41.1	39.8	45.0	31.6	53.9
6/26/2004 21:30	DAY	900	55	62.7	61.4	47.9	44.2	43.4	54.9	47.4	43.1	36.6	38.7	40.0	45.7	33.9	54.7
6/26/2004 21:45	DAY	900	53.6	62.3	58.4	47.5	44.1	43.6	54.1	49.7	49.3	46.4	49.2	45.1	46.1	35.4	50.2
6/26/2004 22:00	NIGHT	900	50.5	59.1	53.3	49.1	46.7	44.5	49.7	45.9	44.3	34.4	37.3	39.4	44.3	35.1	48.2
6/26/2004 22:15	NIGHT	900	49.5	56.7	53.5	48.1	40.3	39.4	49.1	45.7	50.5	38.9	38.9	39.6	44.9	37.1	44.5
6/26/2004 22:30	NIGHT	900	47.7	55.7	52	44.6	41.4	40.7	50.8	47.0	46.8	37.5	38.7	39.6	44.0	36.6	38.4
6/26/2004 22:45	NIGHT	900	45	53.5	47.8	43	39.2	38.3	49.0	44.6	38.5	33.9	38.9	39.6	39.0	34.2	36.8
6/26/2004 23:00	NIGHT	900	47	51.5	50.1	44.5	39.3	38.5	49.1	43.9	39.0	34.9	38.6	39.6	33.2	28.5	45.6
6/26/2004 23:15	NIGHT	900	49.6	59	49.8	46.8	41.4	40.3	57.8	59.7	54.0	47.0	46.2	42.9	36.4	31.2	45.4
6/26/2004 23:30	NIGHT	900	44	48.4	46.4	44.2	37.3	35.9	47.4	44.3	40.7	34.7	36.7	37.7	31.2	24.9	41.9
6/26/2004 23:45	NIGHT	900	60.7	67.9	67.2	44.1	40.8	38.9	46.5	42.0	36.7	31.0	35.3	37.1	29.7	23.7	61.7
6/27/2004 0:00	NIGHT	900	62.6	69.4	67.7	58.1	41.7	40.8	45.8	42.1	37.3	30.4	32.7	36.0	28.8	23.4	63.5
6/27/2004 0:15	NIGHT	900	49.4	52.3	51.8	50.6	36.8	35.4	45.8	40.9	39.2	33.4	31.4	34.2	28.5	23.5	49.4
6/27/2004 0:30	NIGHT	900	58.8	67	64.7	48.1	38.8	36.4	46.1	41.7	37.5	32.0	31.7	32.9	27.3	21.3	59.7
6/27/2004 0:45	NIGHT	900	63.4	71.8	69.5	55.6	49.8	48.5	45.8	41.8	38.2	30.9	32.5	33.3	27.8	23.8	64.3
6/27/2004 1:00	NIGHT	900	59.5	65.9	64.3	55	46.3	45.5	45.4	41.4	38.0	30.8	30.6	31.7	25.6	23.0	60.6
6/27/2004 1:15	NIGHT	900	51.1	56.8	55.4	48.8	38.6	37.6	45.3	39.5	39.5	28.4	30.3	31.0	25.2	23.6	52.0
6/27/2004 1:30	NIGHT	900	56.2	63	61.7	48.6	41.9	41.3	45.7	40.1	36.0	28.8	30.4	32.6	25.8	22.9	57.4
6/27/2004 1:45	NIGHT	900	46.5	52.3	49.4	46.2	40.6	40.3	45.4	40.2	39.6	28.7	30.2	31.1	25.9	23.6	47.3
6/27/2004 2:00	NIGHT	900	46.3	51.4	50.4	44	36.8	36.3	45.1	42.7	36.2	26.4	27.2	29.4	24.9	25.0	46.9
6/27/2004 2:15	NIGHT	900	49.4	54.6	52.7	49	40.5	39.7	45.5	40.7	47.5	44.2	35.1	30.9	22.7	30.6	49.9
6/27/2004 2:30	NIGHT	900	49.2	54.5	53.1	48.1	42.2	41.7	45.9	40.3	40.8	34.3	30.9	28.4	21.7	23.2	50.3

Appendix C: Tabular Sound Level Measurement Results

Table C2B: Sound Level Results at Measurement Location 2																		
Start Date and Time	Day / Night	Duration	Leq	L1.00	L10.00	L50.00	L90.00	L95.00	31.5	63	125	250	500	1000	2000	4000	8000
		(seconds)	(dB(A))	(dB(A))	(dB(A))	(dB(A))	(dB(A))	(dB(A))	dB	dB	dB	dB	dB	dB	dB	dB	dB
6/27/2004 2:45	NIGHT	900	46.1	51.1	47.9	46.2	42.3	42.1	45.6	41.8	35.1	25.5	25.1	26.0	35.8	32.3	45.7
6/27/2004 3:00	NIGHT	900	47.9	54.2	50.7	48.2	38.6	37.9	44.9	37.3	34.6	24.0	21.4	22.2	40.0	29.9	47.8
6/27/2004 3:15	NIGHT	900	43	53	44.9	39.8	38.3	38.1	45.3	38.7	37.5	26.3	23.7	24.4	38.8	25.0	41.2
6/27/2004 3:30	NIGHT	900	44.6	53.5	46.8	42.1	39.4	39	45.7	40.2	35.8	26.3	25.4	26.8	39.4	25.5	43.7
6/27/2004 3:45	NIGHT	900	41.1	53.1	42.6	34.6	32.9	32.4	44.9	44.3	36.2	29.2	26.2	24.8	37.6	24.4	37.2
6/27/2004 4:00	NIGHT	900	41.4	54.2	41.4	33.5	31.3	30.9	45.1	39.9	35.0	27.8	27.3	28.4	39.0	28.9	31.0
6/27/2004 4:15	NIGHT	900	43.7	54.9	49	33.4	31.4	31	45.7	42.0	35.7	26.8	26.3	27.2	42.0	28.6	29.3
6/27/2004 4:30	NIGHT	900	44.7	53.7	48.2	34.7	29.3	28.6	45.9	42.5	43.6	39.8	38.5	37.9	41.0	28.6	29.5
6/27/2004 4:45	NIGHT	900	40.2	52	41.7	36.1	32.1	31.3	45.4	44.4	38.3	28.6	31.3	31.8	36.7	25.4	32.0
6/27/2004 5:00	NIGHT	900	35.6	42.4	38	34.5	31.4	30.9	45.6	42.1	37.3	29.4	32.1	32.1	26.1	22.9	24.8
6/27/2004 5:15	NIGHT	900	43.8	58.5	40.4	36.3	34	33.4	51.0	48.8	46.6	40.5	39.9	39.1	36.9	32.3	27.7
6/27/2004 5:30	NIGHT	900	46.5	53.1	49.4	45.7	38.7	37.4	46.8	40.9	37.7	30.9	30.5	32.1	38.7	43.6	36.8
6/27/2004 5:45	NIGHT	900	48.7	58.3	46.5	40.8	37.3	36.6	46.8	42.5	37.1	32.1	31.3	34.6	46.2	40.0	34.3
6/27/2004 6:00	NIGHT	900	43.3	52.5	45.6	41.4	38.5	37.7	48.3	46.9	50.1	42.8	35.7	37.7	35.9	36.0	27.3
6/27/2004 6:15	NIGHT	900	50.6	65.1	52.1	42.8	39.1	38.1	59.3	54.4	45.3	44.4	43.0	45.6	44.3	43.2	35.1
6/27/2004 6:30	NIGHT	900	42.1	50.7	45.3	39.5	36.5	35.8	48.9	46.3	39.3	32.7	32.0	34.5	31.1	38.7	31.1
6/27/2004 6:45	NIGHT	900	47.3	60.5	48.7	41	36.2	35.3	53.6	57.1	57.7	48.6	43.0	39.5	31.1	39.2	31.8
6/27/2004 7:00	DAY	900	46.6	59.1	48.2	40.2	36.9	36.3	49.3	49.8	45.9	38.4	36.3	40.1	40.8	40.6	31.2
6/27/2004 7:15	DAY	900	47.6	56.7	52	43	37.7	36.7	53.5	44.9	39.2	30.9	32.0	35.2	37.8	44.8	39.3
6/27/2004 7:30	DAY	900	43.7	53	44.8	38.1	35.1	34	53.2	49.3	49.7	39.4	37.2	38.5	34.6	37.4	28.3
6/27/2004 7:45	DAY	900	40.6	49.7	42.5	38.7	36.2	35.6	53.5	47.8	41.1	36.2	33.7	34.0	30.6	34.9	31.8
6/27/2004 8:00	DAY	900	48.8	60.3	52.3	39.7	34.5	33.8	55.0	49.1	47.4	40.4	40.4	42.4	36.4	44.6	39.8
6/27/2004 8:15	DAY	900	61.6	75.7	59.6	39.6	35.8	35.1	54.3	47.2	41.5	35.0	33.4	36.7	48.4	59.3	54.8
6/27/2004 8:30	DAY	265.375	74.2	85.6	78.7	55.5	40	38.6	56.1	50.6	46.5	42.9	42.5	42.4	62.1	71.9	66.7

Table C3A: Sound Level Results at Measurement Location 3																	
Start Date and Time	Day / Night	Duration	Leq	L1.00	L10.00	L50.00	L90.00	L95.00	31.5	63	125	250	500	1000	2000	4000	8000
		(seconds)	(dB(A))	(dB(A))	(dB(A))	(dB(A))	(dB(A))	(dB(A))	dB	dB	dB	dB	dB	dB	dB	dB	dB
6/24/2004 7:54	DAY	349.375	48.1	56.5	51.4	45.6	36.4	35.4	64.6	58.8	54.3	47.4	44.7	42.2	38.6	37.5	33.9
6/24/2004 8:00	DAY	900	50.1	60.9	47.8	41.2	34	33.1	57.1	50.4	49.3	44.4	46.0	43.7	45.4	39.8	32.0
6/24/2004 8:15	DAY	900	37.5	45.3	39.9	35.1	32.5	32.1	57.3	52.8	41.2	34.0	31.2	33.6	25.2	29.2	20.2
6/24/2004 8:30	DAY	900	41.9	50.9	46.2	37.8	33.4	32.5	57.4	52.5	44.7	38.7	33.8	40.3	25.9	25.9	19.6
6/24/2004 8:45	DAY	900	50.3	63.1	47.8	41	38	37.2	58.4	61.4	54.5	45.9	46.1	44.9	42.6	38.9	38.5
6/24/2004 9:00	DAY	900	65.7	79.7	52	44.5	42	41.3	59.4	63.7	57.1	53.8	46.2	44.8	62.9	58.1	53.3
6/24/2004 9:15	DAY	900	64.7	75.8	58.3	44.6	41	40.4	58.2	53.2	49.6	45.4	42.8	44.3	62.2	56.3	50.7
6/24/2004 9:30	DAY	900	51.3	62	56	44.4	40.2	39.4	58.3	51.9	43.2	41.5	41.5	39.0	39.4	48.4	42.0
6/24/2004 9:45	DAY	900	53.5	65.3	58.1	44.9	41.2	40.1	62.5	58.6	58.2	54.3	51.0	47.7	42.2	43.8	36.6
6/24/2004 10:00	DAY	900	56.4	69.5	46.6	39.5	37.2	36.7	57.7	51.4	46.0	41.8	35.7	37.7	54.6	44.2	40.1
6/24/2004 10:15	DAY	900	50	63.5	50	41.2	38.1	37.4	59.0	57.8	58.7	55.3	46.5	41.2	33.4	33.8	22.6
6/24/2004 10:30	DAY	900	43.4	52.8	44.3	40.5	38.6	38.1	59.1	54.0	45.6	41.8	38.4	37.8	33.0	36.5	29.6
6/24/2004 10:45	DAY	900	46.9	58.6	48.7	41.7	39	38.3	58.7	55.6	51.9	48.2	43.9	41.0	36.7	35.7	33.1
6/24/2004 11:00	DAY	900	52.7	66.2	52.2	43.7	41.1	40.6	63.2	62.2	60.9	55.8	49.9	44.6	41.1	37.2	25.8
6/24/2004 11:15	DAY	900	43.7	48.3	46.2	42.8	40.9	40.4	58.9	54.3	46.8	42.4	39.9	39.7	33.0	32.3	24.1
6/24/2004 11:30	DAY	900	49.3	61	49.3	45.9	43.9	43.3	60.1	58.2	57.2	52.8	45.7	43.0	36.6	34.4	28.1
6/24/2004 11:45	DAY	900	48.2	56.4	50.9	45.8	44.1	43.5	59.5	56.4	53.5	47.1	44.8	44.0	38.9	34.0	27.6
6/24/2004 12:00	DAY	900	55.3	64.9	58.8	52	46.9	46.4	59.9	57.6	59.2	54.4	51.2	47.4	46.5	48.9	43.2
6/24/2004 12:15	DAY	900	55.7	63	60.1	52.8	44.1	43.2	58.3	56.3	54.3	49.2	47.2	48.5	49.4	49.1	45.7
6/24/2004 12:30	DAY	900	52.6	62.4	55.6	46.6	43.3	42.7	58.4	56.7	53.8	48.2	43.8	42.3	45.4	48.2	37.8
6/24/2004 12:45	DAY	900	54.3	68	55.9	43.9	41.2	40.6	59.8	60.1	61.2	57.5	49.1	45.4	42.0	47.2	37.7
6/24/2004 13:00	DAY	900	68.4	81.7	71.8	53.3	40.1	39.3	61.6	58.9	55.2	49.0	44.5	46.4	66.0	59.7	56.2
6/24/2004 13:15	DAY	900	69.6	81	73	48.8	41.8	41.2	59.1	57.9	58.8	54.6	47.5	48.2	67.7	58.8	52.9
6/24/2004 13:30	DAY	900	57.9	72.7	56.1	49.7	43.4	41.9	61.1	63.3	65.7	58.4	56.3	49.9	49.7	41.5	36.7
6/24/2004 13:45	DAY	900	51.1	63.3	52.5	45.8	43.6	43	62.0	60.5	59.2	52.5	46.3	45.5	40.9	40.7	35.4
6/24/2004 14:00	DAY	900	52.2	65.1	54.3	46.2	42.8	42.1	61.9	61.8	59.2	52.8	49.3	46.8	43.2	38.5	25.9
6/24/2004 14:15	DAY	900	48.2	56.8	51.2	45.3	42.1	40.9	59.1	56.3	57.6	48.6	44.1	41.8	39.2	37.3	26.7
6/24/2004 14:30	DAY	900	50.1	63.3	49.8	43.7	40.6	39.9	58.3	57.6	57.3	48.7	44.5	42.1	41.8	43.0	36.2
6/24/2004 14:45	DAY	900	46.4	60.2	45.6	42.4	40.2	39.4	57.8	54.0	51.0	47.8	42.0	40.8	37.9	33.7	27.3
6/24/2004 15:00	DAY	900	53.3	66.6	53.1	41.4	38.3	37.7	59.3	59.9	61.0	56.5	49.9	45.6	44.0	40.6	34.6
6/24/2004 15:15	DAY	900	41.3	50.3	42.8	40.3	38.5	38.2	56.6	51.3	43.4	38.2	37.9	35.6	32.6	31.0	31.1
6/24/2004 15:30	DAY	900	46.4	57.5	49.4	41.1	37.7	37	57.0	58.4	51.7	46.2	42.7	40.6	38.7	33.2	27.4
6/24/2004 15:45	DAY	900	54.7	68.7	53.3	42.5	40.5	40.1	61.7	64.6	63.2	59.1	52.9	45.2	36.5	36.0	25.7
6/24/2004 16:00	DAY	900	53.3	69	47.8	42.5	40.5	39.8	59.5	63.6	61.5	58.1	51.9	42.2	34.5	28.6	25.1
6/24/2004 16:15	DAY	900	42.2	49.9	43.8	40.9	39.1	38.3	54.8	58.7	47.7	40.6	37.8	37.2	30.8	31.6	25.4
6/24/2004 16:30	DAY	900	56.3	71.2	53.2	42.2	39.6	39.1	59.8	63.5	65.6	60.1	54.0	46.4	41.6	39.2	30.0
6/24/2004 16:45	DAY	900	46	57.9	48.6	41	37.1	36.2	54.5	56.3	52.7	45.8	42.3	40.2	36.1	35.7	26.2
6/24/2004 17:00	DAY	900	42	50.4	44.1	40.3	37.6	36.7	57.6	52.1	47.9	42.0	37.4	36.7	31.8	30.4	27.0
6/24/2004 17:15	DAY	900	44.5	54.3	45.1	42.8	39.8	39.1	59.0	52.7	48.2	41.5	39.4	40.2	36.1	34.1	29.1
6/24/2004 17:30	DAY	900	56.6	63.1	48.3	44.2	41	40.3	58.1	58.1	48.4	42.0	40.2	40.4	54.7	43.8	40.0
6/24/2004 17:45	DAY	900	59.2	74.7	50.3	42.4	39.7	38.7	56.7	56.4	50.5	45.4	42.9	42.7	50.1	56.3	50.9
6/24/2004 18:00	DAY	900	51.6	64.7	51.3	43	39.7	38.9	57.9	58.8	60.4	57.0	47.6	39.7	38.2	38.8	34.4
6/24/2004 18:15	DAY	900	55.6	63.8	61.1	42.5	38.5	37.8	54.8	52.8	49.9	43.9	37.3	35.1	30.2	27.7	55.8
6/24/2004 18:30	DAY	900	51.5	60.9	57.5	41.4	39.1	38.2	56.1	52.8	52.5	46.5	43.5	42.9	38.8	33.3	49.4
6/24/2004 18:45	DAY	900	40.1	48.3	42.7	38.3	36.2	35.6	54.0	46.6	42.0	36.8	35.4	35.3	31.4	32.1	23.2
6/24/2004 19:00	DAY	900	43.5	54.8	42	37.8	35.4	35	56.9	54.9	52.1	46.9	40.0	36.3	30.4	28.6	22.8
6/24/2004 19:15	DAY	900	71.3	74.8	73.9	71.3	65.4	63.6	55.6	47.9	42.0	35.4	35.4	34.7	28.6	25.0	71.7
6/24/2004 19:30	DAY	900	71.6	75.4	74.1	71.2	67.4	66.4	57.2	51.4	43.6	38.9	34.3	33.7	27.1	23.4	71.9
6/24/2004 19:45	DAY	900	72.2	77.1	74.5	72.1	67.3	64.3	58.6	53.2	45.6	39.0	38.6	34.8	29.3	25.0	72.5
6/24/2004 20:00	DAY	900	69.9	74	72.6	69.4	64.8	61.7	60.6	60.8	61.5	58.0	49.6	41.3	31.3	21.4	70.2
6/24/2004 20:15	DAY	900	63.9	72.7	70	48.5	32.5	32	57.5	50.0	40.5	31.4	28.7	28.9	23.3	18.2	64.4
6/24/2004 20:30	DAY	900	41.6	51.5	46	36.7	33.2	32.2	57.5	50.8	46.4	42.2	39.0	35.5	29.1	21.3	33.9
6/24/2004 20:45	DAY	900	58.9	66.5	65.5	40.5	35.8	35.2	58.2	52.9	51.2	45.8	39.5	38.6	32.7	23.3	59.4
6/24/2004 21:00	DAY	900	55.9	66.7	55.5	37.5	35.3	34.8	56.5	57.8	45.3	39.2	37.3	34.3	28.5	20.7	56.4
6/24/2004 21:15	DAY	900	43.9	56.8	43.5	39.2	36.8	36.2	56.2	56.4	53.6	47.4	40.1	36.8	29.9	23.3	24.7
6/24/2004 21:30	DAY	900	55.7	65.6	61.8	40.5	37.9	37.3	55.9	48.2	48.2	41.4	38.6	39.2	34.1	28.6	55.8
6/24/2004 21:45	DAY	900	50.1	64.1	47.7	39	35.6	34.8	58.3	59.6	60.8	53.9	48.0	41.0	31.2	21.0	26.7
6/24/2004 22:00	NIGHT	900	59	67.6	63	40.2	36.4	35.5	58.9	54.9	51.3	47.0	38.9	35.5	28.2	19.5	59.3
6/24/2004 22:15	NIGHT	900	39.3	44.7	41.8	38.5	35.6	34.7	53.2	44.7	42.1	36.6	34.8	35.9	28.5	21.4	31.1
6/24/2004 22:30	NIGHT	900	37.6	46.8	40.5	35.6	31.8	30.6	51.7	43.4	41.0	35.9	36.3	32.4	26.1	20.2	29.6
6/24/2004 22:45	NIGHT	900	52.3	60.4	58.4	37.7	31.3	30.6	52.1	44.0	42.3	36.5	32.9	36.8	28.7	20.7	52.9
6/24/2004 23:00	NIGHT	900	40.5	49.8	46.8	32.9	31	30.5	52.7	45.0	39.8	28.8	27.4	28.0	22.3	18.5	40.7
6/24/2004 23:15	NIGHT	900	41	54.2	41.3	35.9	32.5	31.7	56.4	49.1	43.7	39.7	36.2	36.8	32.7	26.9	30.0
6/24/2004 23:30	NIGHT	900	38.2	43.7	41	37.4	32	30.9	51.1	43.4	43.2	35.5	33.3	33.7	27.1	18.3	33.3
6/24/2004 23:45	NIGHT	900	38.7	45	41.3	37.5	35.2	34.5	52.0	45.9	42.4	35.8	33.6	34.4	27.3	18.4	33.6
6/25/2004 0:00	NIGHT	900	35.2	41.3	37.5	34.2	31.7	31	52.1	43.8	39.6	32.1	28.9	30.4	24.2	18.8	30.9
6/25/2004 0:15	NIGHT	900	36.1	43.3	38.1	34.9	33	32.5	53.0	45.8	40.8	32.4	30.3	30.9	25.0	18.3	32.0
6/25/2004 0:30	NIGHT	900	34.7	40.6	37	33.8	31.2	30.6	52.1	44.1	39.8	30.3	28.2	29.3	23.4	18.4	30.9
6/25/2004 0:45	NIGHT	900	35.8	43.9	38.7	33.7	31.7	31.3	52.3	44.3	40.5	35.3	30.5	31.3	24.4	18.3	29.1
6/25/2004 1:00	NIGHT	900	37.9	50.2	39	35	33	32.5	53.4	46.9	46.6	42.3	33.7	30.1	24.0	18.6	29.9
6/25/2004 1:15	NIGHT	900	34.8	41.3	36.9	33.3	31.8	31.4	53.6	47.3	40.9	34.0	29.3	28.0	23.3	19.1	29.7

Table C3A: Sound Level Results at Measurement Location 3

Start Date and Time	Day / Night	Duration	Leq	L1.00	L10.00	L50.00	L90.00	L95.00	31.5	63	125	250	500	1000	2000	4000	8000
		(seconds)	(dB(A))	(dB(A))	(dB(A))	(dB(A))	(dB(A))	(dB(A))	dB	dB	dB	dB	dB	dB	dB	dB	dB
6/25/2004 1:30	NIGHT	900	55.5	63.7	61.7	36.2	33.2	32.6	54.4	46.3	40.9	35.8	31.5	31.5	24.8	18.1	56.1
6/25/2004 1:45	NIGHT	900	46.5	62.6	40.3	34.7	32.6	32.1	53.5	46.1	41.3	35.6	31.3	27.4	24.1	18.8	46.7
6/25/2004 2:00	NIGHT	900	50.3	62	42.4	35.4	33.6	33.3	55.8	49.1	47.0	44.7	44.2	47.0	43.8	37.1	33.5
6/25/2004 2:15	NIGHT	900	42	50.4	45.8	36.7	32.9	32.2	54.2	50.9	49.1	42.4	38.2	34.3	27.2	21.6	38.0
6/25/2004 2:30	NIGHT	900	41.1	53.5	42.7	36.1	32.5	32.1	53.8	50.8	48.0	43.2	39.1	34.7	28.5	21.9	29.3
6/25/2004 2:45	NIGHT	900	62.5	68.9	67.7	55.3	35.1	34.5	54.4	50.5	50.2	45.7	40.8	40.9	40.8	37.2	62.9
6/25/2004 3:00	NIGHT	900	42.1	53.8	44.5	34.9	32.6	32.1	52.8	45.6	42.3	43.1	35.4	38.0	34.6	22.5	31.8
6/25/2004 3:15	NIGHT	900	34.8	42.7	36.6	33.7	31.7	31.3	50.7	42.0	39.4	30.7	28.7	29.5	22.8	17.4	31.4
6/25/2004 3:30	NIGHT	900	49.3	55.8	55.4	32.9	30.5	30.2	51.3	42.4	39.8	29.8	29.5	29.1	22.2	18.3	49.1
6/25/2004 3:45	NIGHT	900	36.1	46.5	38	33.4	30	29.3	51.2	43.5	41.5	36.6	32.8	31.7	24.9	18.0	26.3
6/25/2004 4:00	NIGHT	900	36.2	43.6	39.6	34.1	29.5	28.9	51.5	48.2	44.1	37.2	31.6	31.8	25.3	18.8	19.1
6/25/2004 4:15	NIGHT	900	38.7	49.2	41.4	35.2	30.4	29.7	50.4	43.2	41.9	36.9	34.6	35.9	28.5	20.7	19.4
6/25/2004 4:30	NIGHT	900	40.7	49.7	43.8	38.1	33.5	32.3	50.5	44.9	44.9	37.6	36.9	37.6	30.7	23.2	26.5
6/25/2004 4:45	NIGHT	900	40.5	48.5	43.9	38.5	34.3	32.9	51.0	46.6	42.6	38.9	36.9	37.4	30.9	21.8	19.8
6/25/2004 5:00	NIGHT	900	39.1	43.3	41.3	38.7	35.5	34.9	51.2	44.5	43.5	36.2	35.0	36.1	29.5	21.4	19.9
6/25/2004 5:15	NIGHT	900	44.7	52.1	48.8	42.2	37.6	36.8	51.5	47.1	42.7	38.6	36.8	37.9	32.6	40.2	36.6
6/25/2004 5:30	NIGHT	900	48.8	59.5	51.6	44.2	40.5	39.8	51.7	48.1	43.8	38.7	37.3	37.1	37.4	44.8	43.9
6/25/2004 5:45	NIGHT	900	49.1	60.5	50	42.9	40	39.5	60.7	60.2	57.1	53.4	45.1	41.2	34.2	37.5	28.3
6/25/2004 6:00	NIGHT	900	49	60.8	49.9	43.7	40.8	40.2	53.8	52.4	46.3	40.4	38.4	40.6	42.7	44.4	36.2
6/25/2004 6:15	NIGHT	900	45	55.5	46.9	42.3	39.6	38.8	54.2	51.0	48.8	45.2	42.3	40.7	34.3	31.9	28.0
6/25/2004 6:30	NIGHT	900	48.2	59.8	49.5	44.9	42.1	41.3	55.2	53.1	49.8	47.0	45.4	43.2	37.3	39.3	31.6
6/25/2004 6:45	NIGHT	900	50.7	64.7	50	43.7	41	40.2	56.3	58.1	59.4	54.5	48.5	43.1	35.4	35.9	29.7
6/25/2004 7:00	DAY	900	44.1	54.9	46.6	39.7	37	36.4	55.0	58.0	49.7	44.2	39.4	37.3	34.3	36.5	31.4
6/25/2004 7:15	DAY	900	48.8	61.1	49.6	40.6	37.2	36.7	57.9	55.9	53.6	48.2	44.1	42.7	39.8	40.7	34.3
6/25/2004 7:30	DAY	900	48.1	60.8	50.4	40.7	37.4	36.8	55.5	56.6	47.8	44.2	43.3	42.1	39.9	40.6	37.6
6/25/2004 7:45	DAY	900	51.4	64.8	51.9	43.2	39.1	38.3	58.7	56.5	54.2	50.6	48.3	46.5	41.2	42.3	30.9
6/25/2004 8:00	DAY	515.375	57.7	72.8	58.5	42.9	38.8	38	60.2	58.6	59.4	58.3	56.5	51.8	46.5	46.7	41.0

Table C3B: Sound Level Results at Measurement Location 3

Start Date and Time	Day / Night	Duration	Leq	L1.00	L10.00	L50.00	L90.00	L95.00	31.5	63	125	250	500	1000	2000	4000	8000
		(seconds)	(dB(A))	(dB(A))	(dB(A))	(dB(A))	(dB(A))	(dB(A))	dB	dB	dB	dB	dB	dB	dB	dB	dB
6/26/2004 9:14	DAY	7	69.2	71.3	71.3	69	65.1	64	60.0	60.6	74.2	76.4	66.7	58.2	52.9	47.1	36.4
6/26/2004 9:15	DAY	900	47.4	58.2	51.5	40.8	35.4	34.7	61.3	56.5	52.8	47.3	44.9	41.6	36.5	37.7	29.8
6/26/2004 9:30	DAY	900	41.4	51.5	42.6	38.8	35.7	35.1	62.0	52.9	45.6	37.7	35.2	34.2	29.3	37.0	22.1
6/26/2004 9:45	DAY	900	45.4	52.9	45.2	40.7	38.4	38	64.2	55.2	48.1	41.7	36.0	35.2	41.4	37.6	27.1
6/26/2004 10:00	DAY	900	46.7	57	47.3	41.3	39.1	38.5	64.4	57.3	53.1	50.0	43.8	41.0	32.7	31.6	23.8
6/26/2004 10:15	DAY	900	44.1	51	47.2	42.2	39.8	39.3	63.9	56.5	50.5	45.1	38.5	37.4	31.4	36.1	27.8
6/26/2004 10:30	DAY	900	53.3	65.6	56	43.2	40.1	39.5	65.3	58.5	58.9	56.3	51.4	47.3	40.6	33.4	25.9
6/26/2004 10:45	DAY	900	48.6	62.1	49.7	41.9	38.8	38.3	65.2	59.9	56.9	54.2	43.7	40.0	33.5	30.5	25.1
6/26/2004 11:00	DAY	900	43.2	54.1	44.8	40.4	37.9	37.3	64.0	54.6	47.7	42.6	38.9	38.5	34.4	30.8	26.8
6/26/2004 11:15	DAY	900	48.8	63.8	44.5	40.3	38.2	37.8	63.2	56.1	52.0	47.3	45.8	44.4	40.4	34.5	29.7
6/26/2004 11:30	DAY	900	50	62.8	49.8	41.6	39.1	38.5	64.0	60.4	58.8	54.8	47.3	41.1	33.6	30.2	27.0
6/26/2004 11:45	DAY	900	51.3	65.4	50.5	42.9	39.6	38.6	63.5	56.3	57.4	54.0	49.4	45.7	36.2	31.1	29.7
6/26/2004 12:00	DAY	900	53	64.7	55.9	45.9	41.3	40.6	64.4	58.6	57.2	54.3	49.7	47.5	42.0	43.3	34.0
6/26/2004 12:15	DAY	900	66.2	81.7	56.9	42.8	40	39.4	64.5	59.0	58.0	54.9	47.4	45.9	63.6	57.5	54.4
6/26/2004 12:30	DAY	900	44.3	49.9	46.9	43.3	41	40.4	64.5	57.8	49.4	43.4	39.4	39.4	33.4	33.5	30.5
6/26/2004 12:45	DAY	900	53.5	67	54.8	44.1	40.9	39.6	62.0	61.5	57.2	54.3	50.3	46.5	45.3	43.1	31.2
6/26/2004 13:00	DAY	900	45.8	54.9	49.2	42.8	39.8	39	60.2	58.9	52.6	48.9	42.0	39.6	33.8	30.1	27.0
6/26/2004 13:15	DAY	900	53.6	67.7	51.4	43.2	39.5	38.6	61.2	60.7	60.8	58.0	51.5	46.3	37.5	31.3	27.3
6/26/2004 13:30	DAY	900	44.9	53.5	48.6	42.1	39.7	39	60.6	60.1	51.4	45.6	41.3	38.8	32.8	31.5	31.0
6/26/2004 13:45	DAY	900	45.5	53.7	48.9	43	40.7	40.2	61.7	57.4	51.5	47.3	42.0	39.6	35.1	32.2	28.7
6/26/2004 14:00	DAY	900	48.1	61.8	47.8	42.8	40.4	40	61.2	54.8	52.6	49.5	46.4	43.3	36.1	31.7	27.2
6/26/2004 14:15	DAY	900	55.7	63	61.5	44.2	41.1	40.4	60.8	55.7	54.7	49.5	45.5	43.8	36.9	35.0	54.5
6/26/2004 14:30	DAY	900	44.5	51.1	47	43.4	40.9	40.3	61.0	50.6	49.1	44.6	39.7	39.2	33.4	35.9	31.4
6/26/2004 14:45	DAY	900	51.5	65	49.7	44.3	42	41.3	62.7	57.8	61.1	54.7	49.9	42.8	35.8	33.8	31.4
6/26/2004 15:00	DAY	900	46.5	55.1	47.8	44.1	42.3	42	61.8	52.5	50.7	46.4	42.8	41.1	35.6	37.5	33.5
6/26/2004 15:15	DAY	900	43.7	48.2	45.3	43.3	41.6	41.2	61.0	50.9	44.4	41.9	39.2	39.7	34.3	32.4	31.8
6/26/2004 15:30	DAY	900	53.6	68.1	51.1	43.9	42	41.3	62.4	58.8	61.5	58.9	50.2	45.8	38.7	37.2	31.8
6/26/2004 15:45	DAY	900	50.2	63.3	51.1	44.8	42.5	42.1	61.9	59.1	50.7	45.9	43.6	44.1	44.9	40.2	36.3
6/26/2004 16:00	DAY	900	51	66	48.4	44.4	42.6	42.2	62.5	58.7	60.4	54.5	48.7	43.1	35.7	34.6	30.6
6/26/2004 16:15	DAY	900	45.7	51.8	47.2	44.9	43.2	42.9	62.3	54.1	49.0	44.2	41.3	40.9	35.5	36.6	31.2
6/26/2004 16:30	DAY	900	49.1	61.5	47.9	44.8	43.1	42.5	62.3	53.9	54.8	48.9	44.3	41.0	42.8	39.4	36.1
6/26/2004 16:45	DAY	900	57.9	65.9	64.1	46.7	43.7	42.9	63.3	56.5	58.3	52.5	45.6	42.4	37.8	35.3	57.3
6/26/2004 17:00	DAY	900	60	67.8	64.9	47.5	44	43.3	62.7	52.4	51.5	46.5	41.4	40.8	45.1	40.9	59.5
6/26/2004 17:15	DAY	900	60.7	66.9	65.5	56.1	44	43.3	63.1	52.3	49.8	46.9	41.6	40.6	35.8	34.4	60.9
6/26/2004 17:30	DAY	900	62	69.8	66.7	57.5	44.5	43.4	62.8	55.2	52.3	48.3	44.5	43.6	43.9	38.8	61.7
6/26/2004 17:45	DAY	900	55.7	66.5	59.5	47.5	43.8	43.1	63.0	57.6	57.6	52.2	48.6	44.3	41.3	36.8	54.3
6/26/2004 18:00	DAY	900	61.4	68	66	53.4	43.7	43	62.2	51.4	46.7	44.3	41.1	40.7	36.8	37.9	61.3
6/26/2004 18:15	DAY	900	61.2	68.4	66.4	56.5	43.9	43.3	62.6	52.0	47.4	44.8	41.2	40.8	36.5	35.5	61.5
6/26/2004 18:30	DAY	900	59.9	67.4	65.2	53.7	45.4	44.7	62.4	51.7	48.3	44.8	42.2	40.7	36.4	37.0	59.8
6/26/2004 18:45	DAY	900	58	67.3	63.5	47.4	43.5	42.9	62.1	51.3	46.7	44.0	41.8	40.4	35.2	32.3	58.1
6/26/2004 19:00	DAY	900	67.4	73.6	71.5	65.1	46.4	45	61.4	51.0	45.1	43.6	42.1	41.0	35.5	31.1	67.6
6/26/2004 19:15	DAY	900	70.8	75.8	74.1	70.1	63.7	59.5	61.3	54.9	47.9	44.7	42.0	40.3	34.9	30.5	71.0
6/26/2004 19:30	DAY	900	69.6	73.2	71.8	69.4	65.7	64	61.1	52.8	53.4	50.0	45.7	41.9	34.0	27.1	69.6
6/26/2004 19:45	DAY	900	67.9	73.9	72.2	65.9	60.6	59.1	61.1	54.9	56.1	49.6	41.9	37.8	33.9	27.2	68.0
6/26/2004 20:00	DAY	900	55.6	66.8	57.1	44.9	42.1	41.5	61.0	53.0	50.5	45.0	40.2	37.5	31.0	25.6	55.4
6/26/2004 20:15	DAY	900	51.1	63.2	53.8	41	38.4	37.8	60.4	59.3	61.1	47.8	44.3	43.1	38.0	32.9	47.8
6/26/2004 20:30	DAY	900	46.8	57.3	53.1	40.2	38.3	37.9	60.1	49.6	42.3	38.9	36.0	36.0	29.2	24.1	46.4
6/26/2004 20:45	DAY	900	53.2	63.5	57.9	41	39.2	38.9	61.1	54.4	52.8	47.9	41.3	37.6	30.2	23.6	51.9
6/26/2004 21:00	DAY	900	56.2	67.7	55.9	41.2	38.9	38.3	59.6	49.5	42.4	38.7	36.2	36.3	29.0	22.1	56.4
6/26/2004 21:15	DAY	900	58.6	66.4	65.4	40.1	37.6	37.1	59.8	50.8	49.3	43.9	37.8	37.1	29.3	21.5	58.4
6/26/2004 21:30	DAY	900	40.5	44	41.9	40.2	38.2	37.6	59.0	49.5	45.0	39.2	36.6	37.0	29.5	23.4	27.3
6/26/2004 21:45	DAY	900	56.6	63.8	62.2	45.8	40.1	39.5	57.2	52.3	51.2	48.1	46.6	42.0	33.1	23.0	56.8
6/26/2004 22:00	NIGHT	900	59.2	67.6	65.8	43.2	38.5	38	51.7	45.9	44.5	39.0	37.4	38.0	31.8	25.7	59.8
6/26/2004 22:15	NIGHT	900	41.4	49	43.1	40.3	37.3	36.5	50.4	45.2	51.0	41.9	37.5	37.5	30.0	25.8	27.0
6/26/2004 22:30	NIGHT	900	58	65.8	63.7	43.6	38.6	37.7	50.3	46.4	47.5	38.6	36.5	37.0	29.8	25.6	58.2
6/26/2004 22:45	NIGHT	900	58.8	65.9	64.6	46.2	38.9	37.9	54.1	44.9	42.0	35.6	37.1	38.1	30.5	26.7	58.9
6/26/2004 23:00	NIGHT	900	55.7	66.1	63.1	39.9	37	36.3	51.1	43.7	43.0	37.0	37.1	37.2	30.1	25.7	56.4
6/26/2004 23:15	NIGHT	900	50.6	63.2	55.3	41.5	38.1	37.3	54.7	61.2	53.8	45.5	41.9	38.9	31.4	27.3	50.0
6/26/2004 23:30	NIGHT	900	57.8	65.8	63.7	52.4	36.4	33.2	47.0	41.7	42.3	36.4	35.0	35.0	28.1	23.2	58.2
6/26/2004 23:45	NIGHT	900	54.4	62	59.9	39.7	34.3	33.4	45.6	41.3	40.1	37.4	34.2	35.0	26.4	19.9	54.9
6/27/2004 0:00	NIGHT	900	53.9	62.8	58.5	40.5	35.1	33.2	44.2	40.0	40.3	32.9	32.4	34.7	26.7	22.6	54.6
6/27/2004 0:15	NIGHT	900	44.8	52.8	50.1	37.8	33.9	32.9	44.3	39.7	40.6	36.5	30.4	33.0	26.7	24.0	45.4
6/27/2004 0:30	NIGHT	900	56.6	64.8	61.9	39.1	33.7	32.7	43.9	40.0	39.5	35.8	32.2	32.2	25.6	19.2	57.2
6/27/2004 0:45	NIGHT	900	57.7	62.2	60.4	58	39.5	37.8	44.1	40.4	39.2	33.7	31.5	32.3	25.2	18.2	58.3
6/27/2004 1:00	NIGHT	900	58.4	65.4	63.6	44.2	36.3	35.7	44.1	40.3	39.7	32.9	30.1	30.0	23.1	19.6	58.9
6/27/2004 1:15	NIGHT	900	52.1	62.8	58.5	37.3	33.2	32.3	44.7	39.9	40.8	31.6	30.6	29.5	22.9	20.3	52.1
6/27/2004 1:30	NIGHT	900	54.6	61	59.9	43.3	33.1	32.4	44.4	38.8	38.6	31.7	30.1	31.6	23.3	19.0	55.1
6/27/2004 1:45	NIGHT	900	48.5	56.3	55	34.6	31.3	30.6	43.9	39.0	38.9	30.0	28.5	29.5	24.2	22.9	49.0
6/27/2004 2:00	NIGHT	900	46.4	54.9	52.1	34.5	30.5	29.8	43.9	41.0	38.3	28.8	27.3	28.1	21.8	17.9	47.0
6/27/2004 2:15	NIGHT	900	46.8	55.8	53.8	36.2	33.3	32.3	43.2	40.7	48.0	45.9	34.2	27.5	22.6	22.1	46.5
6/27/2004 2:30	NIGHT	900	51.8	63.7	43.5	32.4	29.8	29.4	42.8	37.4	43.6	36.8	29.3	25.8	19.7	17.6	51.9

Table C3B: Sound Level Results at Measurement Location 3

Start Date and Time	Day / Night	Duration	Leq	L1.00	L10.00	L50.00	L90.00	L95.00	31.5	63	125	250	500	1000	2000	4000	8000
		(seconds)	(dB(A))	(dB(A))	(dB(A))	(dB(A))	(dB(A))	(dB(A))	dB	dB	dB	dB	dB	dB	dB	dB	dB
6/27/2004 2:45	NIGHT	900	51.1	63.7	56.6	33.8	30.2	29.8	45.2	38.6	37.1	27.2	24.9	25.7	20.4	17.2	51.1
6/27/2004 3:00	NIGHT	900	54.6	61.7	60.5	47.3	35	33.7	42.3	36.5	36.3	24.6	20.4	19.0	20.6	22.2	54.9
6/27/2004 3:15	NIGHT	900	53.2	63.9	42.5	33.5	31.1	30.5	42.0	36.3	37.4	27.0	22.2	21.7	18.3	19.4	53.8
6/27/2004 3:30	NIGHT	900	32.7	38.5	35.3	31.5	28.3	27.8	42.6	37.2	37.0	28.1	23.7	23.6	18.4	17.4	30.4
6/27/2004 3:45	NIGHT	900	61.3	66.9	66.1	34.9	29.9	29.1	42.6	40.8	38.0	31.4	25.6	23.3	18.8	18.7	62.4
6/27/2004 4:00	NIGHT	900	33.2	39.5	35.5	32.2	28.2	27.7	42.9	39.2	37.6	30.5	26.1	25.8	20.1	20.3	30.1
6/27/2004 4:15	NIGHT	900	31.5	37.2	33	29.5	27.9	27.4	43.3	41.2	37.9	29.9	25.4	25.2	22.2	22.7	19.6
6/27/2004 4:30	NIGHT	900	38.3	48.6	41.3	32.1	27.8	27.2	43.1	41.9	44.1	37.0	32.4	32.1	26.0	21.1	33.7
6/27/2004 4:45	NIGHT	900	36.2	41.9	39.7	34.7	30.6	29.1	42.8	41.6	39.9	31.9	29.9	32.1	25.1	18.9	30.5
6/27/2004 5:00	NIGHT	900	34.9	40.3	37.9	33.9	30.3	29.4	42.9	37.9	37.7	31.3	30.1	31.9	25.1	19.6	20.0
6/27/2004 5:15	NIGHT	900	37.5	49.2	37.5	33.9	31.5	31	47.0	40.5	39.7	36.1	33.7	33.1	29.1	25.9	20.4
6/27/2004 5:30	NIGHT	900	43.8	50.7	48.6	40.7	36.7	35.7	43.7	38.2	38.7	30.7	28.9	30.6	34.4	40.8	36.2
6/27/2004 5:45	NIGHT	900	45	55.9	49.2	39.6	35.3	34.6	44.4	39.7	38.3	32.7	31.1	31.8	37.1	41.2	37.8
6/27/2004 6:00	NIGHT	900	46.1	57	50.1	40.2	37.2	36.4	45.2	44.9	49.3	44.0	35.8	34.9	36.5	41.5	39.4
6/27/2004 6:15	NIGHT	900	47.2	62.1	44.6	38.3	35.7	35	57.3	52.8	42.7	42.5	41.6	43.8	40.5	35.0	23.7
6/27/2004 6:30	NIGHT	900	40.3	48.5	44.1	37.3	33.6	33.1	45.9	42.4	37.3	32.3	29.6	31.0	28.6	37.6	27.8
6/27/2004 6:45	NIGHT	900	52.7	67.7	51.2	38.5	33.6	32.7	53.9	57.0	58.6	54.8	48.3	37.4	33.4	48.0	42.4
6/27/2004 7:00	DAY	900	39.3	48.6	42.3	36.6	33.5	33.1	47.7	43.4	37.5	34.2	30.5	29.1	28.6	36.0	27.1
6/27/2004 7:15	DAY	900	45.1	55.5	42.9	37.1	33.7	33.1	54.3	46.3	38.9	34.8	32.6	34.4	39.0	39.8	37.4
6/27/2004 7:30	DAY	900	39.6	52	39.3	35.2	32.9	32.4	55.4	49.7	40.3	33.8	29.9	31.0	28.1	36.5	20.4
6/27/2004 7:45	DAY	900	40.2	52.1	41.5	37.7	34.6	34.1	56.4	50.3	40.9	36.6	32.7	31.7	32.6	35.0	27.9
6/27/2004 8:00	DAY	900	49.5	60.5	53	39.7	33.1	32.3	57.4	50.2	46.2	39.9	36.0	38.3	45.6	43.5	31.3
6/27/2004 8:15	DAY	197.5	49.1	63.8	50.3	35.8	34	33.5	58.6	50.4	46.1	43.6	46.7	45.5	39.5	36.2	33.4

Table C4A: Sound Level Results at Measurement Location 4

Start Date and Time	Day / Night	Duration (seconds)	Leq (dB(A))	L1.00 (dB(A))	L10.00 (dB(A))	L50.00 (dB(A))	L90.00 (dB(A))	L95.00 (dB(A))	31.5 dB	63 dB	125 dB	250 dB	500 dB	1000 dB	2000 dB	4000 dB	8000 dB
6/24/2004 13:55	DAY	244.375	53.1	60	55.7	51.9	48.5	48	63.1	62.1	52.8	48.9	49.2	49.8	44.4	39.5	34.7
6/24/2004 14:00	DAY	900	54.4	62.4	57.7	52	49.2	48.5	63.5	64.4	55.6	53.4	51.4	50.3	45.3	39.6	37.5
6/24/2004 14:15	DAY	900	54.5	64.5	56.5	51.7	48.3	47.4	63.8	62.7	55.7	53.6	51.5	50.5	45.7	39.0	31.7
6/24/2004 14:30	DAY	900	57.8	66.1	62.4	53.3	50.4	50	65.2	66.4	57.8	51.3	51.0	52.7	50.4	49.1	48.9
6/24/2004 14:45	DAY	900	56.1	65.8	61.1	51.6	48.1	46.9	64.7	67.0	58.0	49.9	49.0	49.5	47.6	47.0	50.6
6/24/2004 15:00	DAY	900	53.3	65.6	54.5	50.1	46.3	45.5	65.1	68.8	59.4	56.0	51.3	45.6	41.6	37.4	32.5
6/24/2004 15:15	DAY	900	48.8	57.2	50.3	47.7	45.5	45	62.4	62.4	54.0	47.6	43.8	43.3	40.4	38.7	33.2
6/24/2004 15:30	DAY	900	53.9	67.8	52.3	49.2	47.3	46.9	63.6	62.2	56.7	53.8	50.8	49.0	45.7	39.6	31.4
6/24/2004 15:45	DAY	900	56.6	69.8	56.2	50	47.4	46.9	66.0	66.6	60.1	59.8	55.2	50.0	43.7	40.0	35.9
6/24/2004 16:00	DAY	900	57.2	67.8	61.5	50	47.2	46.7	67.1	69.3	67.6	57.4	55.4	49.1	43.7	44.7	42.9
6/24/2004 16:15	DAY	900	54.2	63.8	58.5	50	47.3	46.7	62.1	61.6	55.8	51.1	50.5	49.3	47.2	42.5	36.9
6/24/2004 16:30	DAY	900	57.2	70.9	58.1	50.6	48.4	47.4	62.4	63.3	60.8	59.9	56.5	50.2	44.8	38.5	31.5
6/24/2004 16:45	DAY	900	53.4	64.9	54	50.2	47.6	46.8	61.1	61.3	64.2	56.8	48.6	47.8	42.7	38.3	34.0
6/24/2004 17:00	DAY	900	49.5	53.9	51.4	49.1	46.7	46.1	59.7	58.9	50.6	46.3	45.6	46.1	40.6	35.3	28.9
6/24/2004 17:15	DAY	900	54.6	66.3	53.4	49.9	47.1	46.4	61.2	60.4	65.4	58.6	49.4	48.1	44.2	39.0	33.7
6/24/2004 17:30	DAY	900	50	56.4	51.9	49.2	46.6	46.1	60.1	57.6	49.2	46.5	45.9	46.2	41.0	33.7	40.4
6/24/2004 17:45	DAY	900	49.5	57.2	50.4	48.3	46.5	46.2	59.7	58.0	51.6	48.3	47.5	45.3	40.2	34.1	25.5
6/24/2004 18:00	DAY	900	51.8	63.1	52	49	46.8	46.2	61.2	61.3	56.5	54.1	49.8	46.0	40.6	33.1	23.6
6/24/2004 18:15	DAY	900	48.2	55.3	49.7	47.3	45.4	45	60.0	58.2	51.1	48.1	45.4	43.8	39.3	33.1	23.3
6/24/2004 18:30	DAY	900	51.4	63.4	51	47.6	45.6	45	60.1	58.5	52.2	50.5	48.4	47.4	42.8	36.0	25.2
6/24/2004 18:45	DAY	900	47.8	52.2	49.7	47.4	45.2	44.6	59.3	56.8	48.6	46.1	43.5	44.2	38.9	34.0	31.6
6/24/2004 19:00	DAY	900	48.4	56.8	49.8	47.5	45.8	45.3	61.3	58.5	50.9	47.9	44.7	44.3	39.5	32.8	24.4
6/24/2004 19:15	DAY	900	46.8	49.8	48	46.6	45.2	44.7	60.6	57.5	48.2	45.5	43.1	42.7	38.4	31.3	21.3
6/24/2004 19:30	DAY	900	46.9	51	48.2	46.6	45.4	45.2	61.6	59.7	50.0	45.5	44.0	42.1	38.0	31.6	32.3
6/24/2004 19:45	DAY	900	47.4	52	49.4	46.7	45.3	45.1	62.3	60.5	48.7	44.8	44.8	42.8	38.1	32.0	34.5
6/24/2004 20:00	DAY	900	52.3	66.2	49.5	47.1	45.9	45.4	63.4	61.9	55.4	55.4	51.5	43.8	37.2	31.8	41.0
6/24/2004 20:15	DAY	900	48.3	51.8	49.8	48.1	46.2	45.6	61.8	60.5	51.0	44.0	43.8	42.4	37.4	33.0	43.2
6/24/2004 20:30	DAY	900	49	56.4	50.3	48	46.3	45.8	62.0	59.8	49.7	46.5	45.2	43.4	37.5	30.8	43.7
6/24/2004 20:45	DAY	900	49.7	61	49.3	47.7	46	45.5	62.7	60.7	50.9	48.9	46.4	43.8	38.8	32.0	43.5
6/24/2004 21:00	DAY	900	48.4	53.8	49.3	47.5	46.1	45.8	61.4	61.5	49.6	45.4	44.4	42.9	38.0	32.9	42.2
6/24/2004 21:15	DAY	900	52	65.8	50.9	48.1	46.3	46	61.7	62.4	54.9	52.7	50.8	46.4	39.2	30.8	41.7
6/24/2004 21:30	DAY	900	48.9	52.5	50.1	48.7	47.2	47	61.2	60.4	49.8	43.7	43.5	43.7	38.0	33.2	44.0
6/24/2004 21:45	DAY	900	52.3	64	51.3	47.6	46.1	45.6	62.4	62.2	56.9	55.2	50.8	44.3	37.6	32.8	42.8
6/24/2004 22:00	NIGHT	900	47.9	57.3	48.5	46.6	45.2	44.8	62.2	59.0	50.3	47.6	45.0	41.8	36.0	30.9	41.0
6/24/2004 22:15	NIGHT	900	49.9	55.8	53.1	48.4	45.2	44.4	59.5	57.3	48.1	43.3	41.4	41.3	35.3	38.6	47.5
6/24/2004 22:30	NIGHT	900	48.2	53.2	49.5	47.7	46.6	46.2	57.9	56.1	48.1	43.6	42.1	39.9	32.8	36.1	45.4
6/24/2004 22:45	NIGHT	900	48.3	52.4	49.8	48	46	45.2	57.2	55.4	45.5	43.2	40.8	39.8	33.4	36.6	45.8
6/24/2004 23:00	NIGHT	900	48	58.9	48.5	46.4	45.1	44.8	57.9	59.5	58.1	46.1	40.2	39.3	34.5	34.8	43.7
6/24/2004 23:15	NIGHT	900	48.2	51.7	49.9	47.9	46.4	46.2	57.1	55.2	44.0	41.6	40.6	41.7	36.4	36.7	44.9
6/24/2004 23:30	NIGHT	900	46.7	50.5	48.7	46	44.4	44.2	57.1	55.4	44.8	42.0	40.2	40.3	35.0	35.3	42.6
6/24/2004 23:45	NIGHT	900	47.3	52.4	49	46.6	45.4	45.2	58.7	56.3	45.6	42.7	40.9	41.1	35.3	36.2	43.0
6/25/2004 0:00	NIGHT	900	46.2	51.5	48.1	45.4	44.2	44.1	57.0	55.7	44.8	41.9	38.7	39.3	34.2	35.6	42.4
6/25/2004 0:15	NIGHT	900	46.5	53.8	48.4	45.3	44.2	44.1	57.1	55.5	44.4	42.2	39.5	39.9	35.0	36.5	42.3
6/25/2004 0:30	NIGHT	900	45.6	49.1	47.5	45.1	43.9	43.5	57.0	55.2	43.3	40.8	38.0	38.1	32.8	37.1	41.7
6/25/2004 0:45	NIGHT	900	45.9	50.2	47.2	45.4	44.3	44.1	57.2	55.7	45.0	42.2	39.0	37.9	31.8	37.6	41.9
6/25/2004 1:00	NIGHT	900	46.1	57.1	46.5	44.3	42.8	42.4	57.3	56.0	48.5	48.2	42.6	37.1	31.7	35.2	39.5
6/25/2004 1:15	NIGHT	900	43.7	51	45.1	42.7	41.5	41.2	57.2	56.4	44.2	42.2	38.3	35.7	32.0	34.6	38.2
6/25/2004 1:30	NIGHT	900	44.7	50.5	47.1	43.7	42.4	42.2	60.0	58.9	43.7	41.6	38.7	38.6	33.1	35.8	38.7
6/25/2004 1:45	NIGHT	900	48	63.9	45.4	42.5	40.3	40.1	57.7	55.6	45.0	48.2	48.0	40.5	32.3	34.3	38.2
6/25/2004 2:00	NIGHT	900	48.9	61.7	48.3	45.7	42.5	42	57.5	55.8	44.6	47.2	47.8	41.6	35.6	35.3	42.1
6/25/2004 2:15	NIGHT	900	51.5	65.9	48.3	46.2	42.5	42.3	57.6	57.5	52.9	51.9	51.7	43.3	35.8	36.5	42.2
6/25/2004 2:30	NIGHT	900	46.5	56.2	47.8	44.7	43.7	43.3	57.5	56.6	47.8	45.8	42.3	38.6	34.8	36.6	40.6
6/25/2004 2:45	NIGHT	900	46.1	53.3	47.9	45.4	42.4	42.2	57.5	56.0	46.4	43.1	39.4	38.9	34.4	37.1	41.6
6/25/2004 3:00	NIGHT	900	49	57.8	50.9	47.5	45.5	45	57.3	55.6	43.6	44.3	43.5	43.2	38.2	39.7	43.5
6/25/2004 3:15	NIGHT	900	45.8	49.2	47	46	43.6	43.3	57.0	55.3	42.9	40.5	38.4	37.7	35.6	38.9	40.5
6/25/2004 3:30	NIGHT	900	45.9	51.4	48.2	44.9	44.1	43.8	57.1	55.7	43.3	40.9	40.9	39.2	35.3	38.1	39.7
6/25/2004 3:45	NIGHT	900	47.5	57.6	49.5	45	43.9	43.4	56.9	57.3	45.6	45.1	44.2	41.5	37.3	37.6	39.7
6/25/2004 4:00	NIGHT	900	47.4	55	49.4	46	44.6	44.1	59.0	60.0	55.4	46.4	41.8	39.8	36.0	37.6	40.5
6/25/2004 4:15	NIGHT	900	47.3	53.5	50.2	45.9	43.3	42.7	57.1	56.4	44.9	43.0	41.8	42.7	38.2	36.9	38.7
6/25/2004 4:30	NIGHT	900	47.5	53.9	50.2	46.2	43.6	43	57.2	56.4	44.5	42.6	43.7	43.4	39.3	35.5	35.3
6/25/2004 4:45	NIGHT	900	47.7	54.1	50.4	46.5	44	43.1	57.7	58.5	47.3	44.5	44.1	42.9	38.9	35.4	37.5
6/25/2004 5:00	NIGHT	900	47.4	52.9	49.9	46.6	44.3	43.8	57.6	57.5	49.0	43.9	43.1	43.6	39.2	35.0	32.5
6/25/2004 5:15	NIGHT	900	54.1	59.7	57.3	53.4	45.2	44.5	58.9	60.5	49.2	45.3	45.4	45.4	41.0	50.6	46.6
6/25/2004 5:30	NIGHT	900	55.5	61.5	59	54.2	48.7	47.5	58.2	58.5	49.2	44.4	44.2	44.7	40.3	52.4	49.5
6/25/2004 5:45	NIGHT	900	52.8	63.7	55	49.6	46.9	46.2	63.4	62.5	55.1	52.9	51.4	46.5	41.6	43.9	33.9
6/25/2004 6:00	NIGHT	900	50.5	56.1	52.8	49.7	47.3	46.8	58.8	59.7	52.7	46.5	46.7	47.3	41.3	37.9	25.8
6/25/2004 6:15	NIGHT	900	54.3	67.7	53.7	49.8	47.4	47	58.9	59.5	54.5	53.1	52.7	49.6	44.9	39.2	29.0
6/25/2004 6:30	NIGHT	900	53	66.7	52.9	48.9	46.5	45.8	61.0	61.1	55.5	52.7	51.2	48.0	43.6	39.2	34.3
6/25/2004 6:45	NIGHT	900	54	65.9	55.2	49.9	46.3	45.5	62.0	66.4	56.9	54.9	52.3	47.0	43.9	43.8	33.0
6/25/2004 7:00	DAY	900	53.7	64.1	56.3	50.1	45.5	44.7	63.0	66.1	56.5	46.7	48.9	47.8	44.1	42.7	48.0
6/25/2004 7:15	DAY	900	52.9	58.6	55.5	51.8	49.2	48.5	64.8	69.2	58.1	49.6	49.3	48.1	43.8	40.7	37.5

Appendix C: Tabular Sound Level Measurement Results

Table C4A: Sound Level Results at Measurement Location 4

Start Date and Time	Day / Night	Duration	Leq	L1.00	L10.00	L50.00	L90.00	L95.00	31.5	63	125	250	500	1000	2000	4000	8000
		(seconds)	(dB(A))	(dB(A))	(dB(A))	(dB(A))	(dB(A))	(dB(A))	dB	dB	dB	dB	dB	dB	dB	dB	dB
6/25/2004 7:30	DAY	900	52.9	61.5	55.3	50.8	47.7	46.8	61.0	62.9	54.1	48.1	48.3	48.3	44.4	42.9	42.0
6/25/2004 7:45	DAY	900	54.7	62.7	58.8	51.8	48.2	47.4	62.4	64.1	54.5	50.8	49.4	48.2	43.6	40.6	51.2
6/25/2004 8:00	DAY	900	59.8	69.2	62.5	52.7	46	45.2	64.2	65.6	66.6	59.1	54.5	54.9	53.0	47.6	39.3
6/25/2004 8:15	DAY	900	51.3	57.7	54.3	49.7	46.3	45.6	62.1	61.3	53.5	49.0	48.3	47.4	41.9	37.0	34.2
6/25/2004 8:30	DAY	900	53.2	60.1	55.7	51.9	48.4	47.4	62.2	64.4	54.8	49.2	50.2	49.8	44.0	36.8	28.3
6/25/2004 8:45	DAY	900	54	59.8	56.8	52.9	49.4	48.5	62.4	63.9	54.5	51.8	51.4	50.6	44.4	36.8	29.0
6/25/2004 9:00	DAY	900	58.1	66	61.4	55.5	50.3	49.3	67.0	70.7	61.3	56.4	54.2	54.0	49.6	44.0	35.4
6/25/2004 9:15	DAY	900	54.2	61.2	57.2	52.8	48.9	47.7	62.6	64.6	56.2	52.8	51.9	50.6	44.2	36.2	30.2
6/25/2004 9:30	DAY	900	56.8	68	58.1	53.7	50.5	49.5	66.5	67.4	57.9	56.5	55.3	52.5	45.8	38.0	34.1
6/25/2004 9:45	DAY	900	55.6	66.5	57.8	53.1	49.1	48.4	62.6	64.1	57.2	53.5	53.0	51.5	46.5	42.0	40.0
6/25/2004 10:00	DAY	900	54.5	60	57.2	53.7	50.5	49.9	61.6	62.0	52.8	50.8	51.5	51.5	44.7	40.0	37.2
6/25/2004 10:15	DAY	900	63.8	75.3	59.9	54.6	51.5	50.7	62.3	66.9	66.1	64.6	63.0	58.8	51.7	44.6	33.2
6/25/2004 10:30	DAY	900	55.4	62.6	58.2	54.2	49.1	48	63.8	67.7	58.9	53.3	52.9	51.5	45.7	37.8	30.0
6/25/2004 10:45	DAY	900	59	69.6	61.3	55.3	51.7	50.8	64.7	67.8	68.0	60.1	56.5	54.1	47.0	40.8	34.4
6/25/2004 11:00	DAY	900	56.1	61.5	59.1	55	51.3	50.5	63.5	64.4	55.5	53.8	53.7	52.5	46.3	39.3	33.6
6/25/2004 11:15	DAY	900	55.3	61.1	58.4	54.1	50.5	49.4	62.9	64.9	54.2	52.2	52.8	52.1	45.6	37.0	28.8
6/25/2004 11:30	DAY	900	57.1	66.5	59.6	55.3	50.7	49.9	63.9	65.0	57.3	57.3	55.0	52.8	46.7	38.4	29.9
6/25/2004 11:45	DAY	900	54.8	63.7	57.1	53.2	49	47.7	62.2	65.6	54.5	51.9	51.5	51.5	46.0	38.0	29.0
6/25/2004 12:00	DAY	900	54.5	62.1	57.9	52.5	48.5	47	62.3	63.1	53.5	51.7	51.7	51.3	44.9	37.7	31.0
6/25/2004 12:15	DAY	900	54.3	59.5	56.6	53.7	50.5	49.9	62.8	64.8	55.2	51.4	51.0	51.1	44.9	36.9	33.2
6/25/2004 12:30	DAY	900	58.2	70.9	58.5	53.5	50.1	49	67.4	67.8	59.9	59.3	57.5	52.7	45.8	39.4	29.4
6/25/2004 12:45	DAY	900	54.4	60	56.7	53.7	50.5	49.5	64.1	67.1	56.1	50.7	50.9	50.9	44.7	41.3	28.5
6/25/2004 13:00	DAY	900	54.1	60.4	56.9	52.9	49.5	48.1	62.0	61.5	53.1	51.6	51.4	51.1	44.3	34.2	24.6
6/25/2004 13:15	DAY	900	55.5	65.7	57.5	53.4	48.8	48	64.0	63.7	56.9	56.3	53.7	51.2	44.6	38.4	29.3
6/25/2004 13:30	DAY	900	56	65.2	58.3	53.4	49.3	47.7	64.0	67.7	59.6	58.2	54.0	50.9	44.1	35.6	29.2
6/25/2004 13:45	DAY	900	54.9	61.5	58	53.5	49.9	48.3	64.2	64.1	53.9	53.2	53.0	51.4	44.8	35.2	25.8
6/25/2004 14:00	DAY	900	55.8	63	58.4	54.7	49.8	48.5	62.7	64.2	57.3	53.2	53.1	52.4	45.9	36.6	24.7
6/25/2004 14:15	DAY	900	58	66	62.5	54.9	50.7	49.6	62.7	64.8	57.2	52.5	53.1	53.1	49.9	47.8	49.8
6/25/2004 14:30	DAY	86.375	56.9	65.1	57.8	56	53.4	52.8	66.1	67.1	58.6	55.2	54.4	53.1	47.2	42.0	32.0

Table C4B: Sound Level Results at Measurement Location 4

Start Date and Time	Day / Night	Duration (seconds)	Leq (dB(A))	L1.00 (dB(A))	L10.00 (dB(A))	L50.00 (dB(A))	L90.00 (dB(A))	L95.00 (dB(A))	31.5 dB	63 dB	125 dB	250 dB	500 dB	1000 dB	2000 dB	4000 dB	8000 dB
6/26/2004 8:29	DAY	49.875	55.4	65.7	57.3	52	48.8	48.3	62.5	62.5	57.3	50.4	50.5	50.2	48.1	45.5	43.3
6/26/2004 8:30	DAY	900	54.4	67.1	53.8	50.2	48.2	47.9	62.6	64.2	56.5	57.2	52.7	48.5	42.7	38.3	30.8
6/26/2004 8:45	DAY	900	50.2	54.8	51.9	49.4	47.4	47.1	61.2	60.8	52.6	46.9	46.0	45.6	42.7	38.4	31.8
6/26/2004 9:00	DAY	900	54.9	67.4	56.3	51	48.4	47.7	62.9	64.1	57.8	56.9	53.1	49.0	44.4	40.0	32.5
6/26/2004 9:15	DAY	900	55.3	63.7	59.9	51.5	48.7	48.2	62.9	63.0	58.7	52.3	49.6	49.6	47.6	46.8	46.1
6/26/2004 9:30	DAY	900	53.3	59.2	55.8	52.3	49.5	48.8	69.5	68.5	58.3	48.1	49.9	49.0	44.4	38.8	31.1
6/26/2004 9:45	DAY	900	52.7	58.8	54.5	52	49.1	48.6	71.3	63.9	54.6	47.9	48.1	49.3	44.6	39.0	32.9
6/26/2004 10:00	DAY	900	54.9	65.9	55.9	52.7	50.3	49.7	71.4	63.9	58.0	53.8	53.2	50.4	44.9	39.0	30.9
6/26/2004 10:15	DAY	900	52.5	57.2	54.4	52	50.1	49.6	71.3	63.0	54.8	49.3	48.8	48.6	44.0	40.1	32.0
6/26/2004 10:30	DAY	900	57	67.7	57	52	49.9	49.4	71.6	64.5	59.6	58.2	55.4	52.5	45.5	38.4	30.4
6/26/2004 10:45	DAY	900	53.6	62.6	55.2	52	49.5	49.1	71.9	64.7	56.8	53.7	50.6	49.0	44.1	38.1	31.2
6/26/2004 11:00	DAY	900	52.8	58.6	54.7	52.3	50	49.4	71.3	63.9	55.0	48.7	48.4	49.2	44.6	39.1	34.4
6/26/2004 11:15	DAY	900	52.8	62.6	54.4	51	48.5	48.2	71.5	64.3	53.9	49.8	49.3	48.9	44.6	38.9	30.3
6/26/2004 11:30	DAY	900	56.3	67.5	58.8	51.7	49.2	48.7	71.8	68.5	58.3	58.5	54.2	50.4	45.0	41.2	39.6
6/26/2004 11:45	DAY	900	55.5	67.6	56.8	51.8	49.6	49.1	71.3	65.8	58.7	56.5	52.3	50.2	45.5	42.7	39.0
6/26/2004 12:00	DAY	900	56.2	65.3	59.9	52.9	50.3	49.8	71.5	65.4	55.8	56.2	53.3	50.7	46.2	45.2	43.1
6/26/2004 12:15	DAY	900	55.6	67.6	56.4	51.8	49	48.4	71.4	65.4	57.2	56.9	53.9	50.1	45.5	40.2	32.8
6/26/2004 12:30	DAY	900	53.3	59.2	55.8	52.3	49.6	49.1	71.2	62.8	54.6	50.3	50.0	49.2	44.5	40.8	32.1
6/26/2004 12:45	DAY	900	55	64.9	56.9	52.7	49.9	49.3	67.2	63.1	57.8	54.2	51.9	50.7	46.5	39.9	31.8
6/26/2004 13:00	DAY	900	53.6	61.2	55.8	52.5	49.7	49.2	62.5	62.9	54.4	51.8	50.6	49.8	44.6	38.6	32.8
6/26/2004 13:15	DAY	900	57.5	70.2	57.7	52.4	50	49.3	62.6	62.6	58.1	59.6	56.3	51.8	46.4	40.4	32.0
6/26/2004 13:30	DAY	900	52.9	60.3	55	51.7	49.1	48.4	61.3	62.3	53.8	50.5	49.4	48.7	44.3	40.1	34.1
6/26/2004 13:45	DAY	900	53.6	61.7	56.1	51.8	49	48.3	62.7	61.0	53.2	51.4	50.5	49.5	45.4	39.7	33.7
6/26/2004 14:00	DAY	900	56.5	68.9	56.7	53	50.1	49.4	63.0	62.2	58.6	56.9	55.1	52.1	45.5	38.9	30.5
6/26/2004 14:15	DAY	900	54.2	61.4	56.8	53	49.3	48.5	61.4	60.0	55.5	51.1	50.4	50.5	45.4	40.7	33.5
6/26/2004 14:30	DAY	900	53.7	60.9	56.6	52.2	49.2	48.5	61.1	61.6	55.1	50.4	50.2	50.0	44.8	41.4	33.4
6/26/2004 14:45	DAY	900	55.2	65.3	57.1	52.9	49.7	49.2	62.5	60.8	55.0	55.4	53.0	50.9	45.2	39.5	32.2
6/26/2004 15:00	DAY	900	55.1	62.6	57	53.6	50.1	49.5	61.7	60.8	53.7	52.8	52.6	51.3	45.6	40.4	36.4
6/26/2004 15:15	DAY	900	56.8	64.9	62.3	53.5	49.5	48.9	63.3	62.3	52.1	49.2	51.0	53.7	49.9	43.8	33.4
6/26/2004 15:30	DAY	900	57.7	69.4	58.3	53.3	49.9	49.2	63.9	61.7	58.0	59.9	56.0	52.3	46.6	39.3	31.0
6/26/2004 15:45	DAY	900	53.6	57.9	56.3	52.8	49.5	49.1	61.5	60.6	53.9	49.3	50.2	50.3	44.8	38.5	30.9
6/26/2004 16:00	DAY	900	54.9	65.9	56.4	52.4	49.2	48.6	61.9	61.0	54.5	55.2	52.6	50.4	45.1	39.3	37.6
6/26/2004 16:15	DAY	900	54	58.3	56.4	53.5	50.2	49.7	61.2	58.5	52.5	48.9	50.5	51.0	45.2	38.1	30.5
6/26/2004 16:30	DAY	900	54.5	62.9	56.9	52.5	49.7	49.2	61.1	59.7	57.0	54.5	51.9	50.5	45.1	39.6	29.8
6/26/2004 16:45	DAY	900	54.5	61.9	56.7	53.4	49.4	48.8	61.7	59.5	53.9	54.7	51.8	50.6	45.0	38.2	30.6
6/26/2004 17:00	DAY	900	53.3	58.7	55.5	52.7	49.9	49.3	60.6	57.6	52.3	50.0	50.0	50.0	44.6	37.8	30.2
6/26/2004 17:15	DAY	900	53	57.7	55.2	52.5	50	49.3	60.4	58.4	52.9	50.4	49.5	49.6	44.5	37.8	30.9
6/26/2004 17:30	DAY	900	55	62.6	57.2	53.5	50.1	49.4	62.7	59.7	53.4	50.8	50.5	51.5	47.4	41.1	32.4
6/26/2004 17:45	DAY	900	56.8	66.9	57.8	53.1	49.4	48.7	62.3	61.8	63.5	58.7	54.5	51.2	45.9	40.7	35.3
6/26/2004 18:00	DAY	900	53.1	58.4	55.6	52.3	49.6	49.1	60.5	57.1	50.0	47.3	49.5	49.8	45.1	38.7	31.3
6/26/2004 18:15	DAY	900	53.2	58.4	55.6	52.4	49.4	48.8	60.7	57.7	51.4	48.1	49.1	49.9	45.4	39.2	31.5
6/26/2004 18:30	DAY	900	52.7	57.3	54.9	52	49.1	48.3	60.8	56.0	50.3	46.8	48.7	49.4	44.8	38.4	31.4
6/26/2004 18:45	DAY	900	55.7	60.6	58.5	56	48.4	47	60.8	58.9	51.3	49.4	51.1	52.7	46.7	43.6	43.0
6/26/2004 19:00	DAY	900	53.4	59.8	57	52.1	48.4	47.3	60.5	56.9	49.1	47.1	48.1	50.4	45.1	40.6	41.4
6/26/2004 19:15	DAY	900	52.4	59.1	54.8	51.2	47.3	46.5	60.5	56.9	50.6	48.4	49.3	49.0	43.8	38.0	32.4
6/26/2004 19:30	DAY	900	54.6	64.8	57.7	51.7	46.3	44.4	61.0	57.8	52.5	55.4	52.0	50.0	44.9	40.3	37.3
6/26/2004 19:45	DAY	900	51.4	60	53.9	49.9	45.7	44.4	61.3	57.9	51.7	50.1	47.2	47.0	41.3	33.2	43.9
6/26/2004 20:00	DAY	900	51.9	56.7	53.9	51	48.6	47.4	61.6	57.6	49.1	47.8	47.3	46.9	41.7	37.7	46.5
6/26/2004 20:15	DAY	900	51.8	55.9	54.1	51.3	48.2	47.4	61.2	56.5	48.1	44.7	46.2	47.3	43.3	40.1	45.2
6/26/2004 20:30	DAY	900	56.8	59.9	58.7	57	50.5	49.3	61.2	59.6	50.8	49.0	51.2	53.1	47.0	46.3	48.6
6/26/2004 20:45	DAY	900	52.1	60.3	54.4	50.6	47.7	47	62.6	59.1	55.2	50.9	48.6	47.6	41.2	33.2	44.5
6/26/2004 21:00	DAY	900	52.9	63.5	54.6	49.9	45.2	44.4	60.4	56.3	47.9	44.1	47.2	48.2	46.7	41.8	43.1
6/26/2004 21:15	DAY	900	50.6	56.2	53	49.7	47.1	46.4	61.5	56.9	49.7	47.8	46.4	46.8	40.5	31.3	42.6
6/26/2004 21:30	DAY	900	51.4	56.7	53.8	50.5	47.8	47.2	60.2	57.1	48.9	45.1	46.8	47.8	41.5	32.7	44.5
6/26/2004 21:45	DAY	900	54.5	66.5	55.2	50.8	47.3	46.6	59.3	59.3	55.3	53.8	53.7	49.2	42.4	32.7	43.8
6/26/2004 22:00	NIGHT	900	51.8	56.9	53.8	51.2	49	48.1	56.0	55.9	50.7	46.2	46.4	47.1	40.8	34.1	47.2
6/26/2004 22:15	NIGHT	900	52	56.5	54.7	51.2	47.8	46.2	55.7	55.3	49.7	46.9	46.6	47.3	41.3	35.5	47.1
6/26/2004 22:30	NIGHT	900	51.9	60.8	54.2	49.7	45.4	44.5	59.7	59.8	63.4	49.9	46.4	47.1	41.8	35.5	42.2
6/26/2004 22:45	NIGHT	900	50.7	58.8	53.8	49	43.8	42	54.9	53.9	46.5	44.5	47.4	47.4	41.1	32.4	41.3
6/26/2004 23:00	NIGHT	900	50.7	55.3	53.5	49.7	47.1	46.3	54.6	53.4	45.8	43.8	45.3	46.7	40.8	33.9	45.0
6/26/2004 23:15	NIGHT	900	51.3	58.3	54.6	49.4	45.5	44.8	59.0	56.8	50.2	49.5	47.6	47.3	41.3	35.1	42.5
6/26/2004 23:30	NIGHT	900	49	56.4	52.5	46.6	43.5	43.2	54.3	54.2	45.5	44.7	45.1	44.7	38.9	33.9	41.9
6/26/2004 23:45	NIGHT	900	48	56.1	51	45.8	43.4	43.2	54.3	52.8	43.1	41.3	42.8	43.8	37.2	33.9	42.3
6/27/2004 0:00	NIGHT	900	48.2	53.9	51.4	47.2	43.4	43	54.1	54.1	42.9	40.6	41.2	43.5	36.3	35.1	44.0
6/27/2004 0:15	NIGHT	900	46.6	53.4	49.5	45.2	41.5	40.7	54.1	53.0	45.1	40.9	39.7	42.0	36.4	31.8	41.8
6/27/2004 0:30	NIGHT	900	44.8	51.1	48.1	43	40.6	40.3	54.2	52.6	42.0	39.1	38.7	40.3	34.9	28.1	39.5
6/27/2004 0:45	NIGHT	900	45	51.7	48.3	43	39.8	39.4	54.3	52.8	43.6	39.7	40.5	41.0	35.1	28.0	38.2
6/27/2004 1:00	NIGHT	900	44.2	52.6	48.1	40.9	39.4	39.2	53.9	53.0	44.1	40.0	40.0	39.7	33.2	31.5	37.6
6/27/2004 1:15	NIGHT	900	44.9	52.6	47.4	43.8	40.2	40	54.0	52.5	42.3	39.3	39.4	38.3	32.3	32.4	41.3
6/27/2004 1:30	NIGHT	900	46.4	54.2	48.7	44.8	43.4	43.2	54.2	52.8	42.2	39.2	40.1	41.1	33.8	33.0	42.7
6/27/2004 1:45	NIGHT	900	46.6	52.7	48.7	45.6	44.4	44.1	54.1	52.8	43.0	38.4	38.5	39.5	33.3	33.7	44.1

Appendix C: Tabular Sound Level Measurement Results

Table C4B: Sound Level Results at Measurement Location 4

Start Date and Time	Day / Night	Duration (seconds)	Leq (dB(A))	L1.00 (dB(A))	L10.00 (dB(A))	L50.00 (dB(A))	L90.00 (dB(A))	L95.00 (dB(A))	31.5 dB	63 dB	125 dB	250 dB	500 dB	1000 dB	2000 dB	4000 dB	8000 dB
6/27/2004 2:00	NIGHT	900	45.2	50.5	47.4	44.9	42.2	41.9	54.0	53.4	42.4	37.9	36.9	38.0	32.4	31.8	42.7
6/27/2004 2:15	NIGHT	900	45.6	55.8	47.7	43	42.1	42	54.4	53.2	44.8	48.2	40.5	38.0	31.8	29.9	40.9
6/27/2004 2:30	NIGHT	900	44	50.6	45.9	43	42	41.4	54.4	52.7	42.6	39.9	37.8	35.2	31.5	31.4	41.2
6/27/2004 2:45	NIGHT	900	44	49.3	45.5	43.6	42	41.5	54.0	53.7	41.5	37.5	34.5	34.8	29.0	33.0	41.8
6/27/2004 3:00	NIGHT	900	42.1	46.3	44.6	41.5	40.2	39.9	54.4	53.0	41.8	38.3	33.5	30.5	24.8	28.2	40.4
6/27/2004 3:15	NIGHT	900	42.4	48.3	43.4	41.9	40.6	40.3	54.8	53.4	43.2	38.9	34.9	33.5	26.5	32.3	39.3
6/27/2004 3:30	NIGHT	900	44.7	50.5	46.8	43.8	43	42.6	55.0	54.2	43.4	39.4	36.3	36.4	29.3	38.2	40.9
6/27/2004 3:45	NIGHT	900	49.5	51.3	50.6	49.6	48.3	46.5	54.6	53.8	43.4	40.1	35.6	30.0	24.6	39.0	49.7
6/27/2004 4:00	NIGHT	900	48.8	50.7	49.8	49	47.3	47.1	54.6	53.6	42.5	39.3	35.8	34.2	28.5	39.1	48.6
6/27/2004 4:15	NIGHT	900	46	49.8	48.8	44.7	43.3	43.1	55.2	54.8	44.4	40.3	37.5	35.2	29.0	39.0	44.2
6/27/2004 4:30	NIGHT	900	45.2	51.2	47.4	44.2	42.6	42.1	55.4	54.6	44.3	41.2	39.7	39.0	32.6	33.7	40.8
6/27/2004 4:45	NIGHT	900	45.2	50.8	46.8	44.7	43.2	42.7	55.0	56.2	46.4	41.4	39.2	39.1	33.5	34.3	40.2
6/27/2004 5:00	NIGHT	900	49.9	59.5	54.4	45.1	43.4	43.1	55.0	54.1	43.4	40.8	41.1	44.4	43.9	40.7	41.3
6/27/2004 5:15	NIGHT	900	47.2	52.8	50.2	46	43	42.3	55.9	55.4	45.9	41.9	41.1	42.1	40.6	37.6	36.5
6/27/2004 5:30	NIGHT	900	53.4	59.4	56.5	52.8	45.6	44.4	55.3	54.8	46.5	41.7	40.5	44.3	39.2	50.3	46.6
6/27/2004 5:45	NIGHT	900	50	57.9	53.8	46.7	42.6	41.9	55.3	55.7	45.0	42.1	42.6	46.4	37.1	43.2	40.3
6/27/2004 6:00	NIGHT	900	49.1	57.6	51.8	47.2	43.5	42.4	57.1	57.2	48.0	46.7	43.6	46.8	37.3	34.6	34.6
6/27/2004 6:15	NIGHT	900	53.6	68.9	51.4	44.8	40.8	40.1	61.6	61.2	50.0	47.6	49.5	49.9	46.4	41.5	28.5
6/27/2004 6:30	NIGHT	900	48	58.5	51.1	44.5	41.6	41.1	56.1	57.9	48.9	43.0	40.9	43.6	39.1	41.1	30.7
6/27/2004 6:45	NIGHT	900	49.8	61.8	50.4	44.8	40.7	40.2	58.6	60.0	54.9	52.7	47.9	43.9	36.3	34.0	31.5
6/27/2004 7:00	DAY	900	49.5	57.2	53	47.6	42.9	41.8	57.1	57.8	48.5	45.8	45.8	45.5	40.3	40.4	28.6
6/27/2004 7:15	DAY	900	48.5	55.5	51.8	46.8	43.4	42.7	59.4	59.4	48.8	42.9	43.9	45.1	40.1	37.5	28.2
6/27/2004 7:30	DAY	900	48.5	55.8	51.7	46.8	42.1	40.7	59.4	59.2	50.0	42.5	43.8	45.7	39.6	35.6	24.3
6/27/2004 7:45	DAY	43.125	51.4	60.5	54.4	49.1	40.9	40.4	59.3	58.9	49.5	48.9	47.9	47.1	42.6	40.9	37.5

Table C5A: Sound Level Results at Measurement Location 5																
Start Date and Time	**Day / Night**	**Duration**	**Leq**	**L1.00**	**L10.00**	**L50.00**	**L90.00**	**L95.00**	**31.5**	**63**	**125**	**250**	**500**	**1000**	**2000**	**4000**	**8000**
		(seconds)	**(dB(A))**	**(dB(A))**	**(dB(A))**	**(dB(A))**	**(dB(A))**	**(dB(A))**	**dB**	**dB**	**dB**	**dB**	**dB**	**dB**	**dB**	**dB**	**dB**
6/25/2004 8:23	DAY	377.625	52.1	65.4	53.8	43.7	38.6	37.4	59.8	58.2	55.6	49.7	48.5	47.5	44.1	40.4	35.3
6/25/2004 8:30	DAY	900	48.2	58.9	48.2	44.1	41.1	40.5	53.5	54.7	52.7	46.1	44.4	44.5	39.3	34.9	28.5
6/25/2004 8:45	DAY	900	48.5	57.2	50.3	46.1	43.1	41.6	57.4	56.5	54.2	45.4	44.3	44.8	39.9	35.2	28.7
6/25/2004 9:00	DAY	900	51.4	64.5	52.3	46.5	42.9	41.8	66.8	58.9	58.6	54.0	48.1	45.1	40.4	37.4	34.2
6/25/2004 9:15	DAY	900	50.8	63.3	52	47.5	44.4	43.7	54.9	55.6	58.3	53.4	48.3	44.5	40.7	34.9	35.1
6/25/2004 9:30	DAY	900	51.1	60.4	53.5	48.7	44	43	59.4	57.3	55.0	49.1	48.8	46.4	42.9	35.8	32.8
6/25/2004 9:45	DAY	900	51.4	61.1	53.6	48.6	42	41.2	55.7	54.3	54.6	47.9	48.6	46.9	43.2	39.5	30.2
6/25/2004 10:00	DAY	900	51.2	60.4	53	44.1	41.6	41	54.4	50.6	53.8	47.4	45.2	44.5	40.5	46.6	33.7
6/25/2004 10:15	DAY	900	61.9	73.7	51.7	45.3	42.6	42.1	59.6	59.8	64.3	63.7	61.4	56.8	49.4	40.9	30.2
6/25/2004 10:30	DAY	900	49.3	58.8	50.8	45.1	41.9	40.8	55.7	55.9	54.4	48.7	46.2	44.9	39.8	34.8	34.2
6/25/2004 10:45	DAY	900	52.4	63.7	53.6	48.6	45.7	45.1	59.6	60.4	59.4	52.2	50.1	47.7	41.0	35.9	30.3
6/25/2004 11:00	DAY	900	50.7	59.5	53.1	48.6	45.7	45.1	57.8	54.4	51.3	46.9	47.7	44.7	41.4	43.7	29.8
6/25/2004 11:15	DAY	900	49.6	55.5	51.5	48.3	45.9	45.2	58.1	55.2	51.9	46.6	47.4	45.0	40.3	36.7	30.5
6/25/2004 11:30	DAY	900	52.1	63.8	53.2	49	46.2	45.6	57.0	60.6	59.5	52.5	49.9	46.1	41.4	35.7	33.8
6/25/2004 11:45	DAY	900	51.8	63.7	52.1	46.1	42.1	41.2	55.6	57.0	54.5	49.6	47.8	46.5	45.2	39.4	35.5
6/25/2004 12:00	DAY	900	51.9	65.6	52	43.9	41.2	40.5	56.1	58.7	56.8	51.2	47.3	46.7	44.8	40.0	36.0
6/25/2004 12:15	DAY	900	51.7	64.1	51.7	45.4	41.6	40.7	56.1	56.6	58.7	49.5	47.7	46.3	43.2	40.6	39.6
6/25/2004 12:30	DAY	900	52.2	63.5	53.9	45.7	42.3	41.4	59.9	59.8	62.4	54.6	49.1	45.1	38.4	35.8	36.5
6/25/2004 12:45	DAY	900	51	65.4	48.8	43.8	41.5	41.1	56.5	55.1	60.0	50.8	47.3	45.9	42.4	38.0	29.3
6/25/2004 13:00	DAY	900	46.6	54.7	49.7	44.4	40.5	39.9	62.6	56.4	52.8	51.4	42.2	40.5	33.7	32.2	25.0
6/25/2004 13:15	DAY	900	50.7	63.4	51.9	43.8	41.1	40.3	57.4	58.7	62.4	52.8	46.9	43.1	35.2	31.7	22.8
6/25/2004 13:30	DAY	900	53	66.6	52	44.6	41.5	40.8	57.2	59.2	63.7	56.1	49.4	45.1	39.6	35.0	28.8
6/25/2004 13:45	DAY	900	51.9	64.2	51.6	44.5	41.6	40.8	58.4	56.5	56.6	51.9	47.4	46.9	44.6	39.5	31.7
6/25/2004 14:00	DAY	900	55	66.5	53.4	45.4	42.6	42.1	57.8	61.8	61.4	55.0	50.5	49.5	45.8	41.5	40.4
6/25/2004 14:15	DAY	900	48.7	60.1	50.4	44.3	41	40.2	55.1	56.6	53.1	48.1	45.1	44.2	40.4	34.4	27.7
6/25/2004 14:30	DAY	900	46.8	53.4	46	42.7	40.4	40	54.3	52.8	51.7	45.6	41.4	42.8	39.1	34.2	27.7
6/25/2004 14:45	DAY	900	49.4	62	50.9	44.1	41.1	40.4	58.5	57.9	51.7	49.6	46.1	45.3	40.1	35.9	28.6
6/25/2004 15:00	DAY	900	51.9	64.7	52.7	45	41.3	40.7	59.3	61.9	59.5	53.6	49.6	45.8	40.7	37.7	30.4
6/25/2004 15:15	DAY	900	51.5	63.9	51.8	44.4	41.5	41	56.3	59.1	57.0	51.1	47.8	46.7	42.7	39.5	32.0
6/25/2004 15:30	DAY	900	54.1	68	53.8	44.2	41.6	41	57.1	55.3	56.7	54.3	52.8	49.1	43.9	37.0	29.8
6/25/2004 15:45	DAY	900	47.1	59.2	47.9	43.2	40.5	39.8	56.2	52.9	52.4	45.3	43.2	43.3	38.1	32.4	26.9
6/25/2004 16:00	DAY	900	54.6	68.1	49.8	43.3	40.2	39.5	54.7	60.1	59.1	55.4	50.7	50.1	45.1	40.1	34.4
6/25/2004 16:15	DAY	900	54.6	69.8	51.3	42.7	39.2	38.4	57.2	59.4	61.1	58.1	52.7	47.8	42.4	36.8	31.9
6/25/2004 16:30	DAY	900	52	66.8	49	42.9	39.1	38.1	58.7	59.0	62.2	55.7	48.3	44.7	38.2	34.0	29.9
6/25/2004 16:45	DAY	900	46.8	57.5	46.9	42.3	39.3	38.4	56.6	57.2	55.3	44.7	40.9	40.9	36.5	36.8	30.1
6/25/2004 17:00	DAY	900	54.1	68.7	47.3	40.9	37.3	36.3	55.0	51.9	61.9	51.4	52.6	47.4	44.0	42.1	35.3
6/25/2004 17:15	DAY	900	52.8	66.5	51.9	42.4	39	38.2	58.7	60.1	64.0	56.3	49.9	43.4	34.0	33.5	26.5
6/25/2004 17:30	DAY	900	50.1	61.1	54.4	43.4	36.5	35.5	54.9	56.7	49.3	42.3	39.5	40.0	45.5	43.7	37.0
6/25/2004 17:45	DAY	900	43.6	53.9	44.5	39.6	35.7	34.4	53.6	58.7	46.7	40.1	38.7	39.6	34.7	30.0	26.0
6/25/2004 18:00	DAY	900	47.1	59.2	46.8	40.4	36.8	35.9	53.7	51.7	49.4	46.5	45.9	42.4	36.4	31.9	25.3
6/25/2004 18:15	DAY	900	50.2	63.4	49.9	42.3	38.7	37.7	56.5	57.4	59.3	51.9	47.7	44.1	38.1	32.8	27.7
6/25/2004 18:30	DAY	900	41.8	47.5	44.5	41.1	37.6	37.1	53.2	50.8	46.6	38.6	36.1	37.7	32.8	33.1	23.6
6/25/2004 18:45	DAY	900	43.8	54.4	44.5	40.9	38	37.4	52.4	49.2	44.8	40.5	37.4	38.9	36.7	34.8	27.8
6/25/2004 19:00	DAY	900	44.5	57.7	44.9	38.5	34.6	33.9	53.8	52.9	50.2	45.0	41.1	39.4	35.8	30.7	21.2
6/25/2004 19:15	DAY	900	54.4	62	42.1	37.3	33.7	33	52.0	54.7	65.4	54.8	52.0	47.7	43.1	40.2	37.1
6/25/2004 19:30	DAY	900	52.4	67.4	45.9	41.3	38	37.2	52.9	48.6	47.6	39.2	36.6	35.3	27.9	17.9	52.1
6/25/2004 19:45	DAY	900	55.2	66.2	57.5	42.8	39.4	38.7	53.4	53.5	53.3	52.9	50.1	45.6	38.3	31.4	53.4
6/25/2004 20:00	DAY	900	50.5	63.5	50.7	40.9	37.6	37.1	56.6	60.0	61.9	53.1	47.1	42.5	36.7	29.8	33.3
6/25/2004 20:15	DAY	900	52.5	66.5	52.7	42	38.2	37.4	56.9	64.6	62.7	54.8	49.3	45.8	40.2	32.3	32.2
6/25/2004 20:30	DAY	900	41.8	49.7	44.3	40.4	37.7	37	52.7	51.6	49.5	41.3	38.5	36.9	29.8	19.5	32.2
6/25/2004 20:45	DAY	900	46.9	60	44.4	40.1	37	36.3	54.9	54.8	53.6	48.5	44.4	41.9	34.9	25.7	29.2
6/25/2004 21:00	DAY	900	47.6	60.5	43.5	38.8	36.2	35.6	53.3	53.3	48.4	46.9	44.8	43.9	37.9	31.6	27.8
6/25/2004 21:15	DAY	900	47	59.9	47.1	41.6	37.3	36.5	56.2	57.9	56.1	49.9	44.3	40.6	33.2	19.8	24.7
6/25/2004 21:30	DAY	900	43.6	54.8	45.4	40.6	36.9	36.2	52.9	54.1	52.5	45.4	40.4	35.7	28.5	23.7	36.1
6/25/2004 21:45	DAY	900	46.6	58.9	46.5	41.8	38.4	37.7	55.7	56.3	54.9	49.6	43.7	37.6	28.8	22.9	39.0
6/25/2004 22:00	NIGHT	900	44	55	42.4	39.3	38	37.4	50.7	46.2	46.3	41.5	39.2	39.0	35.9	28.3	36.5
6/25/2004 22:15	NIGHT	900	45.9	59.6	43.9	40.3	35.9	34.4	54.8	55.6	54.6	47.1	42.8	39.6	32.8	23.3	37.5
6/25/2004 22:30	NIGHT	900	47.8	61.4	41.2	35.9	33.7	33.1	47.5	51.1	49.5	44.1	44.7	43.7	39.7	33.2	30.4
6/25/2004 22:45	NIGHT	900	36.8	42.9	39.3	35.8	33.6	33.1	44.1	47.6	42.5	36.1	33.3	32.7	25.1	17.0	25.4
6/25/2004 23:00	NIGHT	900	36.7	41.8	39.2	35.7	33.1	32.5	47.8	45.7	40.0	34.5	32.9	32.9	26.2	18.4	26.6
6/25/2004 23:15	NIGHT	900	42	51.5	45	39.1	36.2	35.5	55.3	50.5	43.1	41.0	40.3	37.8	30.4	19.8	30.2
6/25/2004 23:30	NIGHT	900	37.8	43.6	40.4	36.9	33.6	33	44.7	47.7	41.9	35.8	33.5	34.3	27.8	18.5	23.6
6/25/2004 23:45	NIGHT	900	44.5	58.7	41.8	36.3	33.5	33	45.4	46.8	45.8	40.5	40.5	40.7	36.5	30.6	30.2
6/26/2004 0:00	NIGHT	900	38.4	46.9	36.6	33.3	31.3	31	44.4	54.1	39.1	34.8	33.7	33.9	30.1	26.4	27.7
6/26/2004 0:15	NIGHT	900	49.7	57.5	53.9	41.9	34.3	33.2	43.6	48.2	48.8	43.7	43.1	43.6	43.5	41.3	39.7
6/26/2004 0:30	NIGHT	900	51.1	62.9	51.4	42.1	36.7	35.6	50.1	42.3	41.9	39.1	43.0	45.5	45.5	42.2	41.2
6/26/2004 0:45	NIGHT	900	61.5	67.9	65.5	57.3	52.8	52.2	52.6	48.0	45.8	47.9	52.7	55.1	55.4	53.1	54.3
6/26/2004 1:00	NIGHT	900	54	60.8	58	51.6	45.4	44.8	42.7	46.2	41.9	41.8	44.0	46.7	48.4	46.3	46.5
6/26/2004 1:15	NIGHT	900	51.2	57.8	56.1	47.1	43.7	42.9	40.9	37.5	37.3	38.2	41.2	43.9	45.7	43.6	43.1
6/26/2004 1:30	NIGHT	900	46.3	55.9	47.2	41.1	39.3	38.8	41.3	39.4	38.6	36.9	39.1	40.6	40.4	37.8	36.5
6/26/2004 1:45	NIGHT	900	37.3	42.9	39.5	36.6	34.2	33.7	39.8	39.2	37.0	33.5	30.8	30.5	30.8	28.7	28.4

Appendix C: Tabular Sound Level Measurement Results

Table C5A: Sound Level Results at Measurement Location 5

Start Date and Time	Day / Night	Duration	Leq	L1.00	L10.00	L50.00	L90.00	L95.00	31.5	63	125	250	500	1000	2000	4000	8000
		(seconds)	(dB(A))	(dB(A))	(dB(A))	(dB(A))	(dB(A))	(dB(A))	dB	dB	dB	dB	dB	dB	dB	dB	dB
6/26/2004 2:00	NIGHT	900	36.9	42.8	40.1	35.9	31.1	30.3	40.1	36.1	38.6	31.9	30.1	30.3	30.7	28.2	27.6
6/26/2004 2:15	NIGHT	900	33.5	39.3	35.5	32.8	30.1	29.5	39.8	34.3	37.6	29.3	26.2	26.3	27.3	25.0	24.6
6/26/2004 2:30	NIGHT	900	43.4	51.4	46.9	40.1	34	30.6	39.1	39.3	38.3	34.2	33.8	36.5	38.0	35.5	34.6
6/26/2004 2:45	NIGHT	900	38.2	44.4	41.5	36.7	33	32.3	42.0	39.3	37.9	37.2	33.6	32.7	31.0	27.3	26.4
6/26/2004 3:00	NIGHT	900	38.4	45.8	43	35	30.2	29.5	38.7	35.5	33.3	32.0	29.9	31.4	32.8	30.5	29.6
6/26/2004 3:15	NIGHT	900	43	56.1	44.5	35.4	30.7	30.2	51.9	55.7	56.2	46.6	36.3	29.1	27.7	26.8	26.8
6/26/2004 3:30	NIGHT	900	38.4	42.4	39.6	37.9	37.1	37	41.8	38.3	37.4	33.9	29.2	30.8	33.5	30.7	26.7
6/26/2004 3:45	NIGHT	900	36.8	47.8	37.8	35.3	33.7	33.3	41.7	39.9	38.9	37.5	33.1	30.4	27.1	26.5	28.0
6/26/2004 4:00	NIGHT	900	45.1	54.8	45.3	35.7	29.4	28.1	49.7	51.7	51.1	45.2	40.7	39.8	37.6	31.0	30.0
6/26/2004 4:15	NIGHT	900	36.3	43.7	39.4	34.7	30.6	29.8	41.3	40.7	42.3	33.9	30.9	31.9	27.5	25.3	25.1
6/26/2004 4:30	NIGHT	900	46.4	53.8	42.1	34.9	30.5	29.7	43.2	45.8	43.8	43.3	40.2	42.8	40.5	30.2	24.7
6/26/2004 4:45	NIGHT	900	38.1	45.3	41.5	36.3	31.6	30.8	44.0	44.2	42.0	36.3	33.1	34.6	29.9	23.6	20.1
6/26/2004 5:00	NIGHT	900	41.1	47.9	44.4	39.5	34.7	33.9	44.4	43.0	44.1	38.5	35.8	38.5	32.0	23.4	20.2
6/26/2004 5:15	NIGHT	900	42.3	48	45.2	41.4	37.3	35.4	45.2	49.3	42.3	38.2	34.9	38.5	34.0	34.6	24.3
6/26/2004 5:30	NIGHT	900	45.2	51.7	48	44.1	40.8	39.8	46.6	47.5	47.5	39.2	37.4	38.0	34.0	41.2	34.7
6/26/2004 5:45	NIGHT	900	47.2	58.2	49.8	43.3	39.7	38.9	47.6	50.8	45.8	40.3	35.9	39.0	40.4	42.6	32.2
6/26/2004 6:00	NIGHT	900	43.5	51.3	45.8	42	38.8	38	49.8	50.3	48.0	41.4	37.5	38.5	32.9	36.8	22.2
6/26/2004 6:15	NIGHT	900	44.1	53	44.9	41.8	39.1	38.4	46.8	48.0	45.5	41.6	37.3	38.8	38.9	32.6	23.9
6/26/2004 6:30	NIGHT	900	43.4	50	46.1	42.1	38.8	37.7	48.0	49.7	48.1	42.4	38.6	39.8	33.8	30.7	24.3
6/26/2004 6:45	NIGHT	900	52.9	65.7	55.6	42.7	39.2	38.3	55.0	60.4	63.1	55.2	48.3	45.3	44.4	33.7	26.8
6/26/2004 7:00	DAY	900	45.5	52.8	48.5	43.4	39.5	38.4	47.4	54.4	55.4	46.9	40.4	39.5	34.6	33.6	22.4
6/26/2004 7:15	DAY	900	41.9	49.6	44.6	40.3	37.1	36	47.5	49.5	46.1	41.4	37.8	37.4	31.9	32.1	23.6
6/26/2004 7:30	DAY	900	43.3	52.8	45.9	40.9	36.9	36.1	50.1	49.0	47.9	39.2	36.2	38.3	32.8	37.1	30.7
6/26/2004 7:45	DAY	900	47.6	62.2	45.8	39.8	35.9	34.7	50.6	52.6	55.9	52.9	44.4	39.6	32.5	31.8	27.3
6/26/2004 8:00	DAY	900	50	63.6	45.3	39.3	34.9	33.8	53.0	51.5	52.7	49.0	45.3	45.7	42.5	37.5	33.1
6/26/2004 8:15	DAY	900	47.9	63.1	46.7	39.7	34.8	33.7	52.4	53.0	49.3	41.9	37.6	36.8	45.0	36.6	31.8
6/26/2004 8:30	DAY	900	52.2	68.4	47.1	39.6	35.1	34	55.6	58.6	59.9	57.0	49.9	44.1	34.8	33.0	29.0
6/26/2004 8:45	DAY	900	45.8	59.6	46.7	39	35.3	34.5	53.1	51.1	52.6	46.3	42.0	37.6	39.0	31.4	28.2
6/26/2004 9:00	DAY	232.625	57.3	68.9	61.4	42.5	37.2	36.6	60.0	63.1	62.7	60.0	56.4	50.6	43.9	37.3	29.7

Table C5B: Sound Level Results at Measurement Location 5																	
Start Date and Time	Day / Night	Duration	Leq	L1.00	L10.00	L50.00	L90.00	L95.00	31.5	63	125	250	500	1000	2000	4000	8000
		(seconds)	(dB(A))	(dB(A))	(dB(A))	(dB(A))	(dB(A))	(dB(A))	dB	dB	dB	dB	dB	dB	dB	dB	dB
6/27/2004 8:31	DAY	803.125	47.4	60.2	49.2	39.8	34.8	33.8	56.9	54.1	53.1	44.3	43.5	42.8	39.2	36.4	30.4
6/27/2004 8:45	DAY	900	53.4	67.8	50.3	38.4	34.3	33.3	51.2	47.7	60.8	54.7	50.9	48.0	40.7	32.8	27.0
6/27/2004 9:00	DAY	900	52.2	67.1	49.8	38.1	34.1	33.3	57.0	59.8	62.8	56.8	48.1	41.8	39.4	34.1	27.3
6/27/2004 9:15	DAY	900	43.2	56.8	44.3	38	33.3	32.4	55.3	53.3	47.7	40.2	37.9	38.8	34.4	33.7	25.5
6/27/2004 9:30	DAY	900	45.3	58.5	45.8	37.9	34.2	33.4	54.5	51.6	54.1	44.8	43.2	39.5	34.7	31.6	27.6
6/27/2004 9:45	DAY	900	40.7	50.3	43.9	37.8	34.5	33.9	53.6	52.8	46.1	40.4	34.9	34.7	32.8	29.8	25.3
6/27/2004 10:00	DAY	900	45.1	53.5	46.7	41.8	36.3	35.1	55.9	56.4	49.2	45.4	42.6	39.5	34.9	33.0	25.7
6/27/2004 10:15	DAY	900	50	62.9	49.9	46.3	38.6	36	54.5	56.1	56.8	54.3	48.3	42.3	32.8	32.9	28.6
6/27/2004 10:30	DAY	900	45.5	48.9	46.8	45.3	43.9	43.4	53.2	49.6	48.0	48.3	45.7	37.8	31.8	30.9	25.5
6/27/2004 10:45	DAY	900	50	63.4	48.4	45.8	44.5	44.2	59.0	59.4	57.1	52.6	48.9	40.9	40.5	35.1	28.0
6/27/2004 11:00	DAY	900	47.6	55	48	46.2	45.1	44.8	54.5	51.3	49.0	48.7	47.8	40.9	36.6	34.6	28.5
6/27/2004 11:15	DAY	900	50.6	63.5	49.8	43.6	39.1	38.3	55.3	58.7	54.9	49.3	46.6	44.9	43.7	39.0	33.4
6/27/2004 11:30	DAY	900	43.7	52.4	47	41.2	38.3	38	54.2	49.1	49.1	41.7	39.6	39.9	34.9	30.0	26.1
6/27/2004 11:45	DAY	900	53.4	68.1	50.2	42.1	39.1	38.3	55.8	57.8	62.5	55.4	51.6	46.3	39.6	38.0	31.1
6/27/2004 12:00	DAY	900	46.4	54.4	48.5	43.1	39.5	38.5	55.5	53.3	54.9	49.1	41.6	40.6	35.0	32.2	27.6
6/27/2004 12:15	DAY	900	45.7	58.3	46.3	42.1	39.2	38.5	59.0	56.2	53.2	47.1	43.3	40.0	33.0	31.2	26.3
6/27/2004 12:30	DAY	900	50.9	63.8	52.4	44.3	40.7	39.9	60.8	57.5	60.3	51.8	47.4	43.1	37.1	42.3	31.8
6/27/2004 12:45	DAY	900	48.3	59.9	49.6	43.6	39.8	39.1	57.8	58.7	57.9	49.8	45.8	41.3	33.5	34.6	34.3
6/27/2004 13:00	DAY	900	46.5	58.5	46.8	42.4	39.5	38.9	54.8	53.1	52.1	47.6	42.7	41.7	36.4	33.5	28.9
6/27/2004 13:15	DAY	900	51.7	65.5	51.7	43.2	39.2	38.3	55.7	58.1	61.0	53.0	50.1	45.2	37.9	35.9	28.3
6/27/2004 13:30	DAY	900	44.5	52.4	48.2	42.1	39.1	38.1	56.4	54.4	50.0	45.8	37.5	38.4	32.5	38.3	27.1
6/27/2004 13:45	DAY	900	44.6	53.4	45.6	41.6	39.1	38.5	54.4	52.0	48.0	43.4	40.2	40.2	34.7	34.1	28.7
6/27/2004 14:00	DAY	900	49.7	61.6	51.4	43.9	40.3	39.5	57.9	57.6	55.4	50.7	47.2	44.0	40.1	36.7	28.0
6/27/2004 14:15	DAY	900	49	60	45.3	40.9	38.5	37.8	53.4	50.1	49.3	44.1	45.1	44.0	42.5	37.9	30.5
6/27/2004 14:30	DAY	900	44.7	50.8	46.8	42.6	39.4	38.6	53.2	51.4	47.1	41.9	38.9	40.1	35.8	36.8	29.6
6/27/2004 14:45	DAY	900	64.8	70.5	53.9	43.2	40.4	39.8	58.9	65.0	67.6	66.3	63.6	58.5	52.9	47.6	46.8
6/27/2004 15:00	DAY	900	45.9	57	48.3	42.4	39.4	38.9	58.2	56.6	51.8	43.0	39.8	38.5	39.8	35.0	35.9
6/27/2004 15:15	DAY	900	46.1	57	46.1	41.6	39.2	38.7	62.1	61.1	52.5	45.5	41.1	41.2	38.0	33.5	26.8
6/27/2004 15:30	DAY	900	44.4	55.2	46.9	39.8	34.1	33.4	56.9	57.2	51.9	46.4	40.2	38.7	34.6	30.2	26.7
6/27/2004 15:45	DAY	900	44.3	56.7	44.9	37.6	33.7	32.8	54.5	55.8	53.1	47.6	40.9	34.7	31.4	33.6	23.9
6/27/2004 16:00	DAY	900	36	42	38.8	34.7	31.8	31.3	51.1	46.0	41.6	34.3	32.3	31.0	25.0	26.7	20.9
6/27/2004 16:15	DAY	900	52.7	69.1	45.9	40.6	37.3	36	56.1	59.7	62.0	57.4	50.3	43.9	33.3	28.7	21.8
6/27/2004 16:30	DAY	900	53.3	67.8	49.9	41.6	38.5	37.5	57.2	59.7	62.4	56.4	52.2	45.0	36.9	32.2	26.6
6/27/2004 16:45	DAY	900	41.2	49.9	43.8	39.3	35.1	34.3	53.2	48.4	48.2	43.7	34.6	35.6	31.3	30.7	25.8
6/27/2004 17:00	DAY	900	45.7	54.1	49.1	41.1	36.9	36	53.0	49.0	45.6	42.5	39.3	39.1	35.2	40.8	31.5
6/27/2004 17:15	DAY	900	44.7	53.2	46.1	41.2	37.7	36.6	53.1	56.9	52.1	42.4	39.2	39.4	33.9	33.8	35.6
6/27/2004 17:30	DAY	900	44.3	55.8	44	39.7	36.7	35.9	54.9	51.0	51.4	46.9	39.2	38.4	34.3	32.1	31.6
6/27/2004 17:45	DAY	900	42.1	53	44	38	33.6	32.6	53.3	53.9	46.9	43.5	39.6	35.7	29.9	30.6	27.4
6/27/2004 18:00	DAY	900	44.3	54.4	42.8	39	35.8	35.1	51.3	49.2	48.1	43.7	38.2	40.5	35.0	34.4	27.3
6/27/2004 18:15	DAY	900	46.5	59.5	46.7	38.6	34.1	33.2	55.2	57.1	57.2	51.5	41.6	35.7	28.4	31.3	25.9
6/27/2004 18:30	DAY	900	40.3	47	43	39	35.9	35.2	51.6	47.1	45.3	37.9	34.3	35.8	29.5	32.4	28.4
6/27/2004 18:45	DAY	900	46.4	60.2	45.4	38.7	34.6	33.9	54.6	50.4	44.4	40.7	43.1	42.0	38.7	34.2	27.8
6/27/2004 19:00	DAY	900	55.8	69.6	54.9	38.3	35	34.2	60.8	67.5	68.6	60.6	49.6	42.7	37.1	32.6	26.2
6/27/2004 19:15	DAY	900	38.5	45.7	40.8	36.5	33.3	32.6	50.5	50.0	45.9	39.0	34.3	32.3	26.6	25.1	30.5
6/27/2004 19:30	DAY	900	49.9	63.2	50.5	42.6	39.3	38.6	54.6	58.6	62.1	52.5	44.0	38.3	28.6	21.5	43.7
6/27/2004 19:45	DAY	900	44.8	53.4	49.1	41	37.8	36.7	52.6	49.7	45.1	40.4	35.6	33.8	26.1	19.9	44.8
6/27/2004 20:00	DAY	900	43.1	54.7	41.1	37.4	33.8	33	50.3	42.4	50.2	46.6	37.4	36.5	34.6	28.0	33.8
6/27/2004 20:15	DAY	900	38.1	43.5	40.5	37.3	34.3	33.5	50.3	43.9	40.1	36.3	32.4	32.1	24.1	19.7	34.3
6/27/2004 20:30	DAY	900	39.4	44.7	41.8	38.7	35.4	33.9	50.7	42.3	43.9	36.5	33.5	33.5	25.7	22.9	35.6
6/27/2004 20:45	DAY	900	42.6	54.9	42.5	37.4	35.3	34.2	54.9	54.0	52.1	45.6	38.2	35.6	27.7	20.4	32.5
6/27/2004 21:00	DAY	900	47.2	56.4	43.1	38.6	35.3	34.6	51.3	64.8	50.4	44.6	41.3	39.8	37.0	33.2	35.1
6/27/2004 21:15	DAY	900	37.9	42.8	40.6	37.1	33.8	33.2	50.6	47.7	40.3	35.9	32.4	30.5	24.1	20.1	34.5
6/27/2004 21:30	DAY	900	38.4	43.9	40.8	37.9	34.1	33.2	52.6	48.7	45.1	38.1	32.3	30.1	22.4	18.2	34.9
6/27/2004 21:45	DAY	900	38	44.8	40	37.1	32.9	32.4	46.9	43.2	46.6	37.3	32.6	30.2	22.9	18.8	34.2
6/27/2004 22:00	NIGHT	900	38.7	45.4	41.1	37.6	34.5	33.8	45.9	47.9	46.4	37.8	33.9	33.8	26.2	21.0	31.2
6/27/2004 22:15	NIGHT	900	42.6	50.2	41.6	38.1	35.7	35.1	44.6	47.3	46.6	42.2	36.8	37.5	34.0	28.7	34.0
6/27/2004 22:30	NIGHT	900	38	45.6	39.9	36.4	33.5	33	43.4	46.0	41.7	38.3	35.7	32.8	26.3	19.4	28.7
6/27/2004 22:45	NIGHT	900	38.7	46.5	41	38	33.5	32.4	49.1	47.8	44.8	37.9	33.3	30.9	23.1	19.0	35.2
6/27/2004 23:00	NIGHT	900	38.2	44.3	40.6	37.4	35	33.8	45.2	46.2	45.0	35.8	30.0	28.6	20.7	20.8	35.9
6/27/2004 23:15	NIGHT	900	41.7	51.8	41.5	38.5	36.7	36.3	51.7	53.4	44.1	38.1	38.3	34.9	30.6	26.2	37.3
6/27/2004 23:30	NIGHT	900	38.7	45.7	42.5	37.3	34.3	33.4	42.6	43.4	40.4	33.1	28.7	27.9	21.7	21.1	37.5
6/27/2004 23:45	NIGHT	900	37.2	40.8	38.8	37.2	33.8	33	41.4	40.0	39.3	33.5	29.9	26.3	21.3	22.1	35.4
6/28/2004 0:00	NIGHT	900	37.5	41.2	39.6	36.9	34.7	34.3	41.3	39.4	38.6	34.8	31.1	28.0	21.9	22.3	35.3
6/28/2004 0:15	NIGHT	900	40.1	42.8	41.4	40.2	38.1	37.5	41.5	40.2	36.2	34.5	31.4	28.1	21.5	23.6	38.9
6/28/2004 0:30	NIGHT	900	40.6	50.2	41.2	39.7	36.4	35.9	42.6	44.3	43.1	42.0	36.5	29.8	23.1	24.7	36.9
6/28/2004 0:45	NIGHT	900	38.1	41.5	39.7	37.9	36.4	36.1	48.7	39.0	40.1	40.2	32.9	30.3	26.9	28.1	31.4
6/28/2004 1:00	NIGHT	900	38.2	41.8	39.8	37.9	36.2	35.9	48.2	39.3	39.1	39.9	32.3	29.8	27.9	29.4	31.5
6/28/2004 1:15	NIGHT	900	35.6	40.8	37.9	35	32	31.5	45.3	37.2	39.0	34.5	29.4	25.9	24.1	26.3	31.5
6/28/2004 1:30	NIGHT	900	35.7	38.9	37.4	35.7	33.1	32.5	40.9	36.9	34.6	33.4	29.8	26.2	23.6	25.0	33.1
6/28/2004 1:45	NIGHT	900	39	43.4	41.2	38.4	35.8	35.1	42.3	39.5	41.2	37.4	32.5	26.8	22.9	23.0	38.1
6/28/2004 2:00	NIGHT	900	44.8	58.6	43.4	38.2	34.4	32.9	51.3	55.9	56.8	48.3	39.1	28.7	20.5	21.0	38.1
6/28/2004 2:15	NIGHT	900	39.2	48.6	41.4	36.9	33.1	32.4	40.9	38.0	48.9	39.1	30.7	25.5	21.3	24.2	37.8

Appendix C: Tabular Sound Level Measurement Results

Table C5B: Sound Level Results at Measurement Location 5																	
Start Date and Time	Day / Night	Duration	Leq	L1.00	L10.00	L50.00	L90.00	L95.00	31.5	63	125	250	500	1000	2000	4000	8000
		(seconds)	(dB(A))	(dB(A))	(dB(A))	(dB(A))	(dB(A))	(dB(A))	dB	dB	dB	dB	dB	dB	dB	dB	dB
6/28/2004 2:30	NIGHT	900	38.3	42.4	39.4	38.1	36.9	36.4	42.6	34.3	35.3	35.4	31.5	26.6	25.4	29.1	35.4
6/28/2004 2:45	NIGHT	900	39.5	41.9	40.7	39.3	38.2	38.1	44.7	39.5	39.1	38.2	33.6	28.3	25.9	29.6	36.1
6/28/2004 3:00	NIGHT	900	40.1	43.6	41.1	39.8	39.1	38.8	59.7	50.1	44.8	38.7	35.0	30.8	26.8	29.0	36.2
6/28/2004 3:15	NIGHT	900	43.2	53.9	43.7	40.9	39.4	39.1	60.7	55.3	50.7	45.0	39.9	35.2	29.8	28.6	34.9
6/28/2004 3:30	NIGHT	900	39.7	42.8	40.9	39.5	38.4	38.1	60.6	52.3	47.0	36.0	31.4	30.5	31.3	30.5	33.8
6/28/2004 3:45	NIGHT	900	41.6	53.5	42.9	37.3	36	35.4	59.2	49.0	43.3	42.8	39.6	35.0	28.9	27.7	33.4
6/28/2004 4:00	NIGHT	900	41.8	52.9	44.5	36.2	32.9	32	59.1	54.0	53.3	43.9	38.8	33.9	28.1	20.0	22.4
6/28/2004 4:15	NIGHT	900	36.4	43.6	40.1	34.3	31.5	31.1	58.3	47.6	42.5	34.9	32.6	31.8	26.5	22.4	24.1
6/28/2004 4:30	NIGHT	900	36.6	42.6	39.6	35.4	32.6	32.2	58.4	48.4	43.5	34.9	32.5	32.7	26.0	20.7	23.8
6/28/2004 4:45	NIGHT	900	41.8	47.2	41	38.2	35.8	35.2	57.6	47.5	43.5	40.8	37.8	37.4	34.0	27.2	26.2
6/28/2004 5:00	NIGHT	900	50	63.3	47.4	43.7	40.2	39.5	59.5	56.8	55.3	53.9	48.2	43.0	37.5	27.7	25.9
6/28/2004 5:15	NIGHT	900	45.6	53	47.3	44.5	43.1	42.6	60.6	51.7	53.2	49.1	40.2	40.7	33.0	31.8	25.5
6/28/2004 5:30	NIGHT	900	48.3	52.5	50.1	48	45.8	45.3	61.1	54.1	53.1	49.0	42.7	40.8	38.3	42.0	34.3
6/28/2004 5:45	NIGHT	900	49.4	57.7	50.5	48	46.2	45.7	60.5	54.8	53.5	49.3	44.4	44.3	41.1	39.6	34.7
6/28/2004 6:00	NIGHT	900	48.8	58.7	49.7	46.7	44.7	44.1	57.8	54.4	51.6	48.1	44.8	43.9	40.9	37.1	30.9
6/28/2004 6:15	NIGHT	900	47.4	59.1	48.7	45.3	42.7	42.1	50.2	53.8	50.5	45.7	43.3	42.3	40.9	34.2	26.7
6/28/2004 6:30	NIGHT	900	51.1	60.9	50.8	46.8	43.6	42.7	52.7	56.3	52.9	51.1	48.7	46.0	41.9	39.6	33.4
6/28/2004 6:45	NIGHT	900	52.3	65.4	53.6	45.4	41.7	40.8	59.8	60.1	59.7	53.6	49.8	47.1	41.1	35.1	29.8
6/28/2004 7:00	DAY	900	47	57.7	47.1	43.3	40.7	40.1	56.9	54.5	52.5	46.3	42.5	43.0	37.5	34.0	29.1
6/28/2004 7:15	DAY	900	47.1	56.6	47.7	41.7	38.6	37.8	59.8	54.7	55.7	47.3	41.8	41.1	36.7	37.9	34.7
6/28/2004 7:30	DAY	900	50.7	63.4	53	42.7	35.9	34.8	51.8	56.0	52.8	47.8	43.2	44.1	44.1	40.0	44.2
6/28/2004 7:45	DAY	900	48.5	61.8	48.6	40.9	35.5	34.4	50.5	55.8	48.3	40.6	38.6	35.4	45.7	37.6	32.5
6/28/2004 8:00	DAY	900	40.5	48.5	43.1	38.8	35.2	34.3	53.3	52.0	44.9	36.7	34.3	34.9	29.1	32.3	34.1
6/28/2004 8:15	DAY	900	51.6	64.6	52.5	43.4	38.3	37.2	55.4	55.1	53.3	55.7	50.3	44.4	42.5	37.7	29.7
6/28/2004 8:30	DAY	900	43.3	50.5	46.6	41.5	37.8	36.6	54.2	54.1	45.6	39.9	38.2	38.0	33.2	35.6	31.7
6/28/2004 8:45	DAY	900	50.5	61.4	54.6	45	40	39.1	67.4	59.7	58.1	53.1	45.7	44.1	40.2	35.4	37.4
6/28/2004 9:00	DAY	900	51.3	62.4	55.9	43.3	39.1	38.3	56.7	52.9	48.0	41.2	39.1	39.4	48.2	42.9	34.6
6/28/2004 9:15	DAY	900	46.3	57.2	46.7	41	37.1	36.1	55.5	53.4	50.6	43.4	42.4	42.5	37.4	33.4	29.2
6/28/2004 9:30	DAY	900	50.7	63.1	53.1	43	38.6	37.6	56.2	57.1	57.3	50.7	47.6	46.2	41.9	34.7	27.7
6/28/2004 9:45	DAY	900	46.8	59.3	47.6	41.8	38.8	38.3	55.7	52.3	51.8	44.7	42.6	41.7	38.9	37.0	31.0
6/28/2004 10:00	DAY	900	49.6	62.1	51.8	44.4	41.4	40.6	57.8	57.2	53.8	48.9	46.1	45.0	40.5	37.7	32.1
6/28/2004 10:15	DAY	900	55	68.5	51.9	44	40.3	39.6	58.4	61.4	60.7	57.3	51.4	48.5	45.9	43.8	36.5
6/28/2004 10:30	DAY	900	51.7	61.9	55.4	45.6	41.6	40.5	56.9	57.1	51.9	48.6	49.5	45.2	43.2	42.8	36.4
6/28/2004 10:45	DAY	900	56.2	67.6	61	43.6	40.1	39.1	59.7	59.9	58.6	53.0	51.0	49.3	51.8	42.0	30.8
6/28/2004 11:00	DAY	900	45.6	56.6	46.3	40.8	37.7	37.2	60.3	56.8	49.8	42.2	41.3	40.1	36.8	37.0	31.2
6/28/2004 11:15	DAY	900	49.6	61.3	47	42.9	39.7	39.2	57.3	56.5	57.0	53.3	47.4	42.2	34.4	31.0	28.5
6/28/2004 11:30	DAY	900	49.7	61.6	50.7	42.8	39.4	38.6	60.8	63.9	59.3	52.6	45.2	42.4	37.9	38.0	32.6
6/28/2004 11:45	DAY	900	48.6	57.9	52.5	43.9	40.5	39.8	60.1	65.9	56.3	49.6	44.2	43.6	39.1	33.8	30.3
6/28/2004 12:00	DAY	900	52.1	64.8	53.4	44.1	39.5	38.7	57.8	55.3	57.3	57.1	49.3	44.7	39.5	33.9	29.7
6/28/2004 12:15	DAY	900	55	67.1	54.6	47.8	42.2	40.7	59.6	61.2	61.7	58.2	51.3	48.2	45.1	42.5	37.5
6/28/2004 12:30	DAY	900	55.4	71.2	53.6	46.1	41.4	40.7	58.6	59.2	55.8	54.9	53.0	50.9	46.0	41.4	35.5
6/28/2004 12:45	DAY	900	50.8	64.5	47.8	42.4	39.3	38.6	57.1	53.1	52.7	47.1	45.0	46.5	44.5	39.0	33.4
6/28/2004 13:00	DAY	900	54.1	63.8	58.9	48.3	39.5	38.3	64.5	67.9	58.6	52.3	51.5	46.3	45.5	42.0	37.8
6/28/2004 13:15	DAY	900	52.1	64.9	52.5	47.5	42.2	41.4	61.1	62.3	61.7	54.8	48.9	43.7	40.7	37.1	33.5
6/28/2004 13:30	DAY	900	52.2	66.7	53.4	41.1	37.5	36.9	57.1	58.1	60.1	56.2	49.4	44.9	39.3	33.1	28.7
6/28/2004 13:45	DAY	900	46.3	56.9	49.2	42.3	38.8	38.2	60.3	57.3	54.2	48.9	43.5	40.1	33.8	30.0	25.3
6/28/2004 14:00	DAY	900	50.3	61	52.3	44.5	40.2	39.4	56.6	57.0	56.0	49.0	47.6	46.0	40.5	34.5	29.8
6/28/2004 14:15	DAY	900	45.4	53.9	48.5	43.1	40.6	40	54.7	53.9	54.0	47.7	42.2	40.3	33.8	31.0	27.7
6/28/2004 14:30	DAY	900	47.6	59.3	49.8	42.8	40.8	40.2	54.1	53.4	47.7	42.3	40.2	39.2	39.0	42.6	38.4
6/28/2004 14:45	DAY	900	51.8	65.7	50.2	43.6	40.3	39.4	55.8	58.4	61.4	56.1	48.1	43.0	36.8	37.0	30.4
6/28/2004 15:00	DAY	900	48.9	60.3	52.5	43.9	41	40.3	55.8	56.2	56.4	50.3	45.4	43.9	39.2	34.2	27.4
6/28/2004 15:15	DAY	900	54.1	66.4	57.1	47.5	42.5	41.5	58.3	60.8	57.9	52.8	50.2	48.6	44.9	45.3	40.8
6/28/2004 15:30	DAY	900	52	64.7	52	43.5	40.8	40.3	61.2	58.6	58.0	54.5	49.4	46.1	41.0	36.4	30.1
6/28/2004 15:45	DAY	900	50.2	61.1	52.6	42.7	40.2	39.3	56.0	54.7	54.2	47.3	42.9	41.8	39.6	44.6	42.7
6/28/2004 16:00	DAY	900	56.3	68.8	59.3	44.9	40.4	39.8	57.5	65.5	64.2	57.9	52.2	46.7	39.7	48.9	45.8
6/28/2004 16:15	DAY	900	47.3	56.8	48.8	42	39	38.3	54.6	53.3	52.5	50.8	42.6	41.1	38.0	33.5	25.1
6/28/2004 16:30	DAY	900	54.6	66.5	57.5	46.6	38.9	38	57.6	61.2	64.2	57.1	48.1	43.7	45.9	45.0	41.7
6/28/2004 16:45	DAY	900	49	57.8	53.7	43.9	37.9	37.2	59.1	62.8	53.6	47.9	45.2	42.1	41.4	36.6	29.0
6/28/2004 17:00	DAY	900	44.3	54.1	46.1	41.1	37.5	36.6	52.3	53.5	48.4	42.1	39.0	39.7	35.2	34.9	30.1
6/28/2004 17:15	DAY	900	49.7	61.9	50	42	39.5	38.8	53.1	53.5	55.2	49.0	45.8	44.6	42.2	37.5	30.2
6/28/2004 17:30	DAY	900	48.3	62.5	46.6	43.3	41.1	40.3	52.6	51.6	50.5	47.2	45.3	44.6	39.0	34.5	28.2
6/28/2004 17:45	DAY	900	51.9	64.4	51.3	42	38.4	37.3	54.8	57.2	57.6	54.6	47.3	46.5	42.1	38.7	32.3
6/28/2004 18:00	DAY	900	47.2	58.8	45.9	42.3	39.4	38.4	52.2	51.1	53.0	47.5	41.9	42.3	38.3	37.4	31.5
6/28/2004 18:15	DAY	900	56.2	57.9	48.6	41.9	38.7	37.9	53.4	53.9	59.5	61.6	53.9	46.2	43.7	41.7	35.7
6/28/2004 18:30	DAY	900	44.2	56.1	43.4	38.7	35.8	35.2	51.7	50.2	46.9	42.6	40.1	40.2	34.3	33.9	29.2
6/28/2004 18:45	DAY	900	47.1	57.1	49.7	41.5	37.3	36.1	50.3	51.4	54.1	46.2	40.6	40.3	40.5	38.7	30.2
6/28/2004 19:00	DAY	900	50.1	56.4	54.4	48	39.4	36.2	49.9	48.0	47.3	50.8	44.5	40.4	44.8	42.4	34.3
6/28/2004 19:15	DAY	900	46.3	55.7	49.7	41.2	35.6	34.7	52.2	51.0	51.2	46.0	42.1	40.6	39.2	33.5	33.5
6/28/2004 19:30	DAY	900	54.3	65.9	55.7	47	42.8	42.1	58.1	62.4	64.6	58.8	51.0	43.9	38.4	34.6	41.6
6/28/2004 19:45	DAY	900	50.6	60.6	55.2	41.2	34.9	33.7	52.0	54.0	56.4	49.6	46.1	45.6	43.3	36.2	40.1
6/28/2004 20:00	DAY	900	42.8	52.1	44.5	39	36.6	36	50.6	50.0	50.3	41.7	38.6	38.4	33.2	25.0	33.1
6/28/2004 20:15	DAY	900	47.4	54.4	49.4	46.1	38.8	37.6	51.5	51.5	53.2	45.1	41.3	40.6	36.6	29.1	44.0

Table C5B: Sound Level Results at Measurement Location 5

Start Date and Time	Day / Night	Duration	Leq	L1.00	L10.00	L50.00	L90.00	L95.00	31.5	63	125	250	500	1000	2000	4000	8000
		(seconds)	(dB(A))	(dB(A))	(dB(A))	(dB(A))	(dB(A))	(dB(A))	dB	dB	dB	dB	dB	dB	dB	dB	dB
6/28/2004 20:30	DAY	900	45	54.2	47.8	40.4	36.8	36.2	50.3	51.7	53.0	45.1	40.8	40.3	35.5	29.4	31.5
6/28/2004 20:45	DAY	900	42.1	53.2	43.9	39.5	36.3	35.8	50.8	49.0	50.3	40.6	38.0	38.2	31.7	21.5	31.4
6/28/2004 21:00	DAY	900	43.1	52.9	45.1	40.6	37.6	36.7	48.9	49.6	53.1	41.7	38.4	38.4	31.6	21.9	33.5
6/28/2004 21:15	DAY	900	41.5	50.2	44.3	39.3	35.7	35	48.9	50.7	48.9	42.0	37.7	37.3	30.7	22.4	28.4
6/28/2004 21:30	DAY	900	44.9	54.9	48.7	40.5	36.4	34.9	53.8	55.2	54.7	47.0	40.6	39.5	33.8	26.3	27.8
6/28/2004 21:45	DAY	900	42.6	51.9	44.1	40	35.8	35.1	48.9	50.1	51.1	41.8	38.9	38.4	31.9	24.2	31.0
6/28/2004 22:00	NIGHT	900	40.7	51.9	42.9	37.8	34.4	33.7	49.6	52.4	48.5	40.7	37.2	36.8	29.5	21.2	26.3
6/28/2004 22:15	NIGHT	900	39.7	50.2	41.8	37.3	33.9	33.2	45.3	46.8	45.4	42.6	36.4	34.7	26.6	20.3	26.7
6/28/2004 22:30	NIGHT	900	40.4	49.4	43.7	37.8	34.6	34.1	47.8	47.1	42.8	43.9	38.9	34.1	26.2	18.8	29.3
6/28/2004 22:45	NIGHT	900	38.8	46	41.4	37.4	34.7	33.8	42.6	46.1	44.5	37.5	33.6	33.8	26.2	19.6	33.0
6/28/2004 23:00	NIGHT	900	45.2	51.7	41.7	37.8	35.5	35.1	43.7	49.5	52.0	44.0	40.9	40.1	36.9	32.4	34.4
6/28/2004 23:15	NIGHT	900	35.2	40.7	37.2	34.5	32.2	31.7	39.5	39.6	37.4	32.7	28.5	28.8	23.7	22.1	31.4
6/28/2004 23:30	NIGHT	900	39.3	45.3	38.2	34.9	32.6	31.7	41.5	54.4	41.9	35.7	33.5	34.5	30.5	25.6	31.8
6/28/2004 23:45	NIGHT	900	34.9	42	37.7	33.1	30.7	30.3	41.2	40.0	43.7	35.2	29.7	27.9	22.5	20.8	29.6
6/29/2004 0:00	NIGHT	900	32.6	37.9	34.7	31.8	30.1	29.6	39.4	37.1	36.5	32.4	28.1	26.9	21.3	19.0	26.8
6/29/2004 0:15	NIGHT	900	40.6	48.9	41.6	40	31.8	30.8	43.4	39.9	47.2	39.6	33.7	31.1	25.6	24.0	37.4
6/29/2004 0:30	NIGHT	900	35.4	42.7	37.2	34.2	32.2	31.6	45.6	37.3	35.5	32.1	29.3	29.3	26.4	27.0	28.9
6/29/2004 0:45	NIGHT	900	35.4	40.6	37.5	34.7	32.9	32.4	48.0	38.6	37.5	33.4	28.9	28.7	26.8	27.4	28.4
6/29/2004 1:00	NIGHT	900	34.4	40.6	35.9	33.8	32.4	32.1	41.6	36.7	36.4	33.1	28.7	26.8	24.7	25.3	29.4
6/29/2004 1:15	NIGHT	900	33.6	38.4	35.3	33	31.1	30.7	42.1	37.1	35.5	31.7	27.1	26.3	24.1	25.0	28.2
6/29/2004 1:30	NIGHT	900	32.5	36	33.8	32.3	31.1	30.6	39.8	35.3	35.3	31.5	26.4	23.6	22.4	22.7	28.8
6/29/2004 1:45	NIGHT	900	33.8	36.5	35	34.1	30.8	30.3	38.8	34.1	33.2	30.9	25.5	23.1	20.6	20.3	32.1
6/29/2004 2:00	NIGHT	900	31.1	37	32.8	30.5	28.8	28.4	39.4	35.5	33.5	29.6	25.3	24.3	21.1	19.8	26.5
6/29/2004 2:15	NIGHT	900	30.5	35.7	31.7	29.8	28.3	28	37.7	33.7	27.6	23.6	21.7	22.3	20.3	19.9	27.8
6/29/2004 2:30	NIGHT	900	32.2	37	34.1	31.6	29.2	28.7	39.3	34.8	29.2	24.5	22.3	24.0	22.3	20.1	30.2
6/29/2004 2:45	NIGHT	900	32.4	39.9	33.8	31.5	29.3	28.9	37.4	34.0	37.9	31.9	23.9	22.6	21.6	21.1	29.8
6/29/2004 3:00	NIGHT	900	50	64.7	36.6	32	30.6	30.3	55.1	59.3	61.9	54.5	45.8	37.9	28.9	23.2	25.6
6/29/2004 3:15	NIGHT	900	43	57.2	41.6	33.1	31.3	30.9	48.9	56.1	57.1	46.1	34.7	25.7	24.2	23.9	28.5
6/29/2004 3:30	NIGHT	900	35.8	37.5	36.6	35.7	35.1	35.1	40.6	36.5	32.9	29.1	25.4	26.2	30.8	28.5	27.5
6/29/2004 3:45	NIGHT	900	32.1	39.8	34	30.8	29.6	29.3	41.7	37.5	32.9	31.0	27.4	25.5	22.6	20.0	26.7
6/29/2004 4:00	NIGHT	900	30	35	32.3	28.9	27.5	27.3	42.0	37.4	33.0	27.2	24.0	22.3	18.9	17.6	26.5
6/29/2004 4:15	NIGHT	900	41	47.9	38.9	35.2	29.3	28.4	46.0	45.8	41.2	36.7	37.6	36.1	33.3	28.7	30.6
6/29/2004 4:30	NIGHT	900	36.6	44.1	38.7	35.4	32.5	32.1	42.4	40.6	36.8	35.7	32.9	31.6	25.0	21.0	30.3
6/29/2004 4:45	NIGHT	900	37.6	45	40.2	36.1	32.3	31.5	43.2	41.0	39.0	35.0	34.2	33.4	27.6	23.1	28.7
6/29/2004 5:00	NIGHT	900	40.5	51.4	42	38.3	35.5	35.1	45.7	48.0	51.7	37.7	34.9	34.5	28.1	24.3	32.2
6/29/2004 5:15	NIGHT	900	40.6	50.1	43.1	38.7	35.7	35.1	44.6	47.5	41.8	39.3	37.4	35.7	30.6	26.0	31.5
6/29/2004 5:30	NIGHT	900	44.4	49.6	46.2	43.9	41.7	41.1	46.6	50.7	46.5	38.4	36.4	35.1	34.6	40.0	35.5
6/29/2004 5:45	NIGHT	900	50.6	62.5	51.8	45.1	41.6	41.2	52.0	57.5	58.7	52.6	47.6	43.7	36.9	40.2	35.0
6/29/2004 6:00	NIGHT	900	50	63.3	51.2	43.3	40.5	40.1	48.5	55.4	47.8	42.5	40.6	41.7	44.7	43.6	37.9
6/29/2004 6:15	NIGHT	900	50.8	65.3	51	42.6	40.4	40.1	55.7	57.1	51.7	51.2	48.1	45.9	41.9	35.4	33.0
6/29/2004 6:30	NIGHT	900	48.9	59.5	45.9	41.3	38.5	37.8	50.9	54.6	53.1	51.4	46.2	44.0	40.0	33.8	27.0
6/29/2004 6:45	NIGHT	900	51.7	65.5	51.5	42.5	37.5	36.5	58.7	58.7	59.8	54.5	48.6	45.3	40.4	35.7	30.6
6/29/2004 7:00	DAY	900	46.5	56.7	49	41.6	37.8	36.7	58.8	57.1	54.4	49.8	42.5	40.3	34.2	33.0	27.9
6/29/2004 7:15	DAY	900	50.2	61.1	53.9	37.8	33.7	32.5	51.4	51.8	51.0	46.1	41.3	43.3	44.1	43.4	38.1
6/29/2004 7:30	DAY	900	46.3	59.2	44.3	39.2	36.5	35.8	52.0	52.4	46.7	42.3	40.7	42.7	39.5	33.5	28.4
6/29/2004 7:45	DAY	438.375	50.2	62.9	53.8	39.1	36.4	35.1	63.5	58.8	52.5	46.6	47.8	45.6	42.0	37.3	31.2

Table C6A: Sound Level Results at Measurement Location 6

Start Date and Time	Day / Night	Duration (seconds)	Leq (dB(A))	L1.00 (dB(A))	L10.00 (dB(A))	L50.00 (dB(A))	L90.00 (dB(A))	L95.00 (dB(A))	31.5 dB	63 dB	125 dB	250 dB	500 dB	1000 dB	2000 dB	4000 dB	8000 dB
6/25/2004 8:49	DAY	658.875	54.3	63.7	56.5	50.1	47.2	46.6	63.0	63.2	58.6	52.4	51.2	48.6	46.4	42.9	39.9
6/25/2004 9:00	DAY	900	52.2	62.7	53.7	48.2	45.4	45	63.4	63.2	57.9	54.1	49.4	45.2	40.5	42.2	38.8
6/25/2004 9:15	DAY	900	51.7	61.7	54.4	48.9	45.1	44.4	60.8	59.7	56.1	52.8	48.0	45.1	41.3	43.8	35.1
6/25/2004 9:30	DAY	900	52.7	62.5	54.8	49.9	47.2	46.4	63.2	61.2	53.6	52.3	50.1	47.6	42.6	42.8	33.1
6/25/2004 9:45	DAY	900	51.8	63.6	53.1	48.1	45	44.2	61.2	58.8	53.9	50.5	49.0	47.1	43.7	39.4	31.4
6/25/2004 10:00	DAY	900	49.7	57.6	52.2	48.3	45.3	44.5	60.6	55.5	52.8	46.4	45.3	45.1	42.4	39.4	32.7
6/25/2004 10:15	DAY	900	65.3	75.4	57.4	49.9	47	46.2	61.2	67.1	66.8	63.0	64.5	60.6	53.9	48.1	38.9
6/25/2004 10:30	DAY	900	51.1	58.4	54.1	49.5	45.8	44.7	61.6	63.0	54.2	49.0	49.0	46.5	41.7	38.1	32.7
6/25/2004 10:45	DAY	900	54.9	66.3	56	50.7	48.2	47.5	63.6	62.8	59.9	53.6	53.2	50.2	44.1	41.2	35.2
6/25/2004 11:00	DAY	900	53.2	61.6	55.2	51.3	48.4	47.7	63.8	60.9	55.9	50.1	49.9	48.7	45.3	41.1	38.1
6/25/2004 11:15	DAY	900	51.7	58.2	53.6	50.4	46.9	46	63.4	61.5	54.0	48.7	48.4	47.8	42.7	39.0	33.2
6/25/2004 11:30	DAY	900	53.9	66	55.2	50.7	48.3	47.8	62.2	63.3	59.4	55.5	51.9	48.5	42.7	36.5	30.2
6/25/2004 11:45	DAY	900	55.1	67.7	54.3	48.2	44.6	44.1	61.6	62.8	59.6	54.2	52.0	50.3	46.9	42.5	36.9
6/25/2004 12:00	DAY	900	48.1	57.7	50	46	42.9	42.4	61.7	57.2	49.6	45.9	45.2	44.1	39.0	35.7	26.3
6/25/2004 12:15	DAY	900	49.3	58.9	51.5	46.7	44.1	43.3	61.9	58.6	54.5	47.1	46.1	44.7	40.2	37.8	30.7
6/25/2004 12:30	DAY	900	55	66.4	58.9	48.5	45.3	44.4	64.3	64.4	61.6	57.8	52.5	48.1	43.9	40.4	43.4
6/25/2004 12:45	DAY	900	51.7	63.6	50.7	47	44.2	42.9	61.8	62.8	60.6	49.8	46.8	46.5	43.0	39.2	32.2
6/25/2004 13:00	DAY	900	50	57.7	52.1	48.9	45.6	44.7	61.6	63.6	53.5	48.3	45.0	43.9	39.5	43.2	37.0
6/25/2004 13:15	DAY	900	52.5	64.6	54.2	47.9	43.9	43.1	62.3	62.3	58.5	54.6	49.4	45.5	40.2	43.2	37.1
6/25/2004 13:30	DAY	900	53.3	65.5	53.7	47.8	43.9	42.8	61.9	64.1	61.9	57.7	50.2	45.2	39.8	38.1	30.5
6/25/2004 13:45	DAY	900	51	61.1	53.1	47.9	45.1	44.1	62.5	61.7	54.6	51.1	47.4	44.9	41.4	42.8	35.1
6/25/2004 14:00	DAY	900	56.3	66.9	55.2	50.1	46.7	45.9	62.1	68.2	60.3	54.2	51.9	50.7	48.5	46.6	39.8
6/25/2004 14:15	DAY	900	57	66.1	54.2	49.3	46	45.1	61.7	62.3	59.5	54.4	51.9	50.8	49.3	47.6	47.3
6/25/2004 14:30	DAY	900	47.5	52.7	50	46.7	43.7	43.2	61.3	60.3	48.7	44.8	43.6	43.9	39.0	33.5	27.3
6/25/2004 14:45	DAY	900	48.4	56.2	50.7	47	44.1	43.2	61.9	59.3	52.2	45.9	44.4	44.3	39.7	36.0	25.9
6/25/2004 15:00	DAY	900	52.8	64.3	55.8	47	43.4	42.7	63.4	61.4	61.2	55.1	49.3	45.7	42.3	42.1	34.2
6/25/2004 15:15	DAY	900	54.2	66.4	53.3	47.3	44.3	43.7	62.0	60.7	59.7	52.5	50.1	49.2	45.9	43.7	38.7
6/25/2004 15:30	DAY	900	56.8	68.9	57.4	47.1	43.4	42.6	61.7	60.5	59.1	58.2	55.5	50.9	46.6	43.5	39.0
6/25/2004 15:45	DAY	900	54.5	68.3	51.8	45.1	42.5	41.8	61.5	58.9	51.6	46.3	44.5	44.4	47.7	48.5	47.9
6/25/2004 16:00	DAY	900	53.8	65.4	51.6	44.8	41.2	40.3	61.5	63.0	61.1	56.0	45.4	47.0	45.6	43.0	38.6
6/25/2004 16:15	DAY	900	55.7	70.9	51.3	46.7	42.5	41.7	61.4	62.8	62.2	60.1	53.9	47.8	39.4	40.7	32.7
6/25/2004 16:30	DAY	900	52	66.4	51.6	44.2	40.5	39.8	61.4	62.4	59.3	55.9	50.0	44.7	39.2	35.7	30.7
6/25/2004 16:45	DAY	900	49.6	63.1	48.6	43.7	40.8	40.2	60.1	57.3	56.4	49.2	45.2	43.9	41.8	38.1	32.1
6/25/2004 17:00	DAY	900	42.9	50	45.2	41.8	39	38.4	60.3	52.3	48.6	39.3	37.6	37.8	33.0	35.4	28.9
6/25/2004 17:15	DAY	900	54.1	67	55.2	46.6	42.3	41.5	61.3	61.5	61.4	58.4	50.8	45.1	42.2	43.4	37.9
6/25/2004 17:30	DAY	900	46	56.7	49	42.1	38.2	37.4	60.4	54.4	49.0	42.3	40.5	39.2	38.5	39.6	28.9
6/25/2004 17:45	DAY	900	45.3	57.3	46.9	41.1	38.2	37.6	60.9	58.2	48.7	41.8	40.3	39.1	36.6	37.7	26.6
6/25/2004 18:00	DAY	900	52	64.5	52.4	43.7	39	38.4	60.9	54.3	52.5	51.3	48.6	45.5	43.4	44.3	35.2
6/25/2004 18:15	DAY	900	53.2	67.1	54.5	42.8	38.9	38.1	61.6	62.3	59.9	56.1	50.8	46.1	42.6	38.7	33.4
6/25/2004 18:30	DAY	900	42.8	51.5	43.8	40.8	38.4	37.7	60.5	53.2	45.0	38.2	37.2	38.3	34.9	33.9	27.8
6/25/2004 18:45	DAY	900	47	60.4	46.8	42	39.1	38.5	60.4	52.2	48.6	43.2	41.5	41.4	39.9	39.3	32.8
6/25/2004 19:00	DAY	900	51.2	61.6	47.3	41.4	37.5	36.8	60.8	55.2	60.9	53.1	47.9	43.8	40.8	35.8	30.0
6/25/2004 19:15	DAY	900	47.8	58.6	44.9	37.6	36.1	35.8	60.5	56.0	58.2	48.5	43.8	41.2	38.0	36.5	30.6
6/25/2004 19:30	DAY	900	44.4	55.6	45.1	40.7	38.6	38	60.5	54.4	47.8	43.0	39.8	39.0	35.2	29.4	38.3
6/25/2004 19:45	DAY	900	51.5	61.5	54.7	46.9	43.6	43.1	60.5	52.6	49.3	50.7	48.4	44.1	37.5	29.4	48.1
6/25/2004 20:00	DAY	900	54.1	66.9	52.9	49.1	47	46.4	62.0	62.8	61.8	57.3	50.5	44.7	37.3	30.6	49.0
6/25/2004 20:15	DAY	900	53.7	66.1	54.3	48.4	47.2	46.9	61.5	61.9	59.3	55.7	51.0	46.3	38.7	33.0	47.6
6/25/2004 20:30	DAY	900	48	53.6	49	47.4	46.2	46	60.4	51.5	47.8	42.6	41.6	39.5	34.6	28.4	46.3
6/25/2004 20:45	DAY	900	50.4	62.2	50.3	47.3	44.7	43.9	61.3	57.7	54.7	50.6	47.4	42.3	36.0	24.1	46.3
6/25/2004 21:00	DAY	900	49.5	62	48.9	46.7	45.5	45.2	60.3	54.3	51.2	47.7	45.1	42.4	38.6	32.8	45.6
6/25/2004 21:15	DAY	900	52.5	64	52.9	48.2	46.3	46	61.9	60.0	57.1	53.6	50.1	45.7	39.9	30.0	46.1
6/25/2004 21:30	DAY	900	51	60.2	50.3	47.1	46.1	45.5	60.6	56.8	54.5	48.4	45.5	43.8	42.6	37.9	46.0
6/25/2004 21:45	DAY	900	49.8	61.9	47.6	45.5	44	43.4	61.4	59.5	55.0	49.4	48.7	41.3	33.7	22.3	44.3
6/25/2004 22:00	NIGHT	900	47.2	52.3	45.9	45.2	44.2	44	57.5	50.1	46.6	41.3	40.6	40.3	36.3	29.9	44.5
6/25/2004 22:15	NIGHT	900	49.1	61.9	47.2	45.4	43.5	42.8	58.6	57.7	53.2	49.2	46.0	42.2	35.8	28.7	44.2
6/25/2004 22:30	NIGHT	900	49.3	61.6	46.7	45.2	44	43.2	52.9	52.2	50.7	47.5	44.1	43.2	39.5	34.6	44.7
6/25/2004 22:45	NIGHT	900	46	48.4	46.8	45.8	45.1	44.7	51.6	46.9	44.2	38.5	36.8	35.6	30.2	23.6	45.2
6/25/2004 23:00	NIGHT	900	45.4	48.6	46.3	45.3	44.2	44	51.5	46.4	43.2	38.6	36.5	35.8	30.2	23.2	44.4
6/25/2004 23:15	NIGHT	900	46.9	56.2	47.6	45.3	42.3	41.1	53.8	50.5	44.8	43.0	42.8	40.5	35.1	29.1	43.4
6/25/2004 23:30	NIGHT	900	44.2	47.5	45.6	44.1	42.1	41	51.7	48.1	42.4	38.4	36.2	35.7	30.4	23.2	42.6
6/25/2004 23:45	NIGHT	900	44.6	55.1	45.7	41.5	39.3	39	52.0	47.7	46.6	41.5	39.5	38.3	34.5	29.6	40.3
6/26/2004 0:00	NIGHT	900	43.3	55.9	43	40.3	37.9	37.3	51.7	51.0	47.0	42.4	38.6	37.3	32.5	30.8	37.7
6/26/2004 0:15	NIGHT	900	50.9	62.3	54.8	44.7	41.3	40.8	52.3	55.8	51.3	47.9	45.8	45.9	43.5	40.7	40.0
6/26/2004 0:30	NIGHT	900	46.3	57.9	47.9	41.4	38.2	37.6	50.7	46.4	46.1	44.3	40.4	41.7	39.0	36.5	35.4
6/26/2004 0:45	NIGHT	900	54.6	61.7	59.2	51	41.8	40.4	54.4	46.3	44.5	44.1	46.1	49.3	48.9	46.7	44.1
6/26/2004 1:00	NIGHT	900	54.6	59.5	57.8	54.2	47.2	46.2	49.7	49.7	45.5	44.4	44.7	48.7	49.2	46.9	45.1
6/26/2004 1:15	NIGHT	900	52.8	56.9	55.8	52.2	42	40.9	51.2	42.3	39.2	36.7	41.4	46.5	47.5	45.5	44.0
6/26/2004 1:30	NIGHT	900	45.3	52.9	49	41.5	38.7	38.3	51.7	43.5	39.0	36.6	35.4	38.6	39.6	38.4	36.1
6/26/2004 1:45	NIGHT	900	39.2	46.5	41.8	37.8	35.8	35.4	51.4	43.2	38.6	34.7	32.3	31.5	32.9	30.8	32.2
6/26/2004 2:00	NIGHT	900	40.9	48.5	43.4	39.2	36.4	35.4	50.9	42.8	39.5	35.0	32.6	34.1	35.5	33.0	31.4
6/26/2004 2:15	NIGHT	900	42	44.8	43.8	42	37.5	36.6	51.0	42.3	41.2	34.0	30.1	28.3	29.5	28.9	40.9

Table C6A: Sound Level Results at Measurement Location 6

Start Date and Time	Day / Night	Duration (seconds)	Leq (dB(A))	L1.00 (dB(A))	L10.00 (dB(A))	L50.00 (dB(A))	L90.00 (dB(A))	L95.00 (dB(A))	31.5 dB	63 dB	125 dB	250 dB	500 dB	1000 dB	2000 dB	4000 dB	8000 dB
6/26/2004 2:30	NIGHT	900	52.3	58.5	56.3	50.4	41.3	40.8	52.3	44.0	40.8	36.2	40.6	45.7	47.1	45.1	43.1
6/26/2004 2:45	NIGHT	900	50.9	59.5	56.3	44.7	38.3	38.1	52.5	46.3	40.7	37.8	40.4	44.4	45.4	43.7	42.0
6/26/2004 3:00	NIGHT	900	44.5	51.5	47.4	41.9	37.5	36.6	50.5	42.8	38.6	33.6	32.5	36.4	37.2	37.1	39.7
6/26/2004 3:15	NIGHT	900	45.7	53.7	48.5	45.2	37.2	36.3	57.0	56.9	52.4	45.8	37.8	31.0	29.4	30.5	43.4
6/26/2004 3:30	NIGHT	900	44	49.4	46.4	43.3	40.6	39.1	58.4	47.1	40.0	34.8	32.0	30.6	30.2	32.3	44.1
6/26/2004 3:45	NIGHT	900	43.5	49.8	45	42.9	41.2	40.7	54.9	47.2	40.8	37.7	35.8	32.4	29.6	32.1	42.6
6/26/2004 4:00	NIGHT	900	46.7	59.9	46.7	42.5	40.2	39.8	55.8	57.7	52.8	47.5	45.1	36.7	30.3	29.6	42.3
6/26/2004 4:15	NIGHT	900	42.3	45.2	43.9	42.2	39.7	38.6	53.2	45.5	39.9	32.8	32.0	31.7	28.3	33.6	41.1
6/26/2004 4:30	NIGHT	900	46.1	51.6	47.6	42.9	40.7	40.3	53.0	45.8	44.8	40.0	37.6	39.2	35.6	38.1	41.6
6/26/2004 4:45	NIGHT	900	47.2	49	48.7	47.6	43.7	40.7	50.9	50.0	39.3	34.6	33.3	33.7	27.6	41.7	44.7
6/26/2004 5:00	NIGHT	900	45.9	49.8	48.6	45.8	39.2	38.6	51.8	47.3	43.2	36.6	35.9	38.0	31.1	39.6	42.3
6/26/2004 5:15	NIGHT	900	49.7	59.3	53.4	45.5	39.4	38.7	51.9	50.4	42.2	37.9	37.0	40.1	42.0	46.3	36.2
6/26/2004 5:30	NIGHT	900	48.7	56.9	52.3	46.4	42.8	41.9	52.0	52.8	44.0	37.5	37.1	39.5	41.6	44.8	36.6
6/26/2004 5:45	NIGHT	900	43.5	50	45.9	42.5	39.8	39.2	51.5	48.8	42.0	37.9	36.4	39.0	34.4	37.2	31.3
6/26/2004 6:00	NIGHT	900	44.9	58.3	45.6	41.2	38	37	54.5	54.1	45.7	43.3	43.4	39.5	34.4	33.6	29.7
6/26/2004 6:15	NIGHT	900	44.8	53.1	47.6	42.9	40.1	39.3	52.5	51.9	45.1	38.9	38.4	40.2	37.9	37.1	25.5
6/26/2004 6:30	NIGHT	900	44.2	52.2	46.6	42.3	39	38.1	52.6	53.2	46.3	39.7	39.2	39.8	35.1	36.8	29.0
6/26/2004 6:45	NIGHT	900	51.9	65.6	51	42.6	39.8	39.1	58.2	61.4	59.8	55.4	50.3	45.0	37.2	33.4	27.3
6/26/2004 7:00	DAY	900	47.4	57.9	51	42.9	39.8	39.2	54.1	54.3	55.1	49.5	43.0	38.9	37.9	39.5	28.3
6/26/2004 7:15	DAY	900	43	52.8	44.2	41.2	38.8	38.2	55.4	52.3	46.2	40.2	38.0	38.0	34.8	34.9	21.0
6/26/2004 7:30	DAY	900	49	58.7	54.4	42.7	39.8	39.3	57.8	54.7	46.4	39.2	38.0	39.0	34.6	46.1	41.5
6/26/2004 7:45	DAY	900	50.1	64	51	40.2	37.6	37.1	58.1	52.4	54.0	54.1	48.1	40.5	40.4	42.0	29.6
6/26/2004 8:00	DAY	900	45.5	59.1	45	39.2	36.3	35.5	59.0	53.7	49.5	44.4	41.2	40.7	34.9	36.6	33.3
6/26/2004 8:15	DAY	900	46.9	58.8	49.7	40.7	37	36.3	59.6	56.1	47.9	42.0	38.8	38.0	37.5	43.0	32.8
6/26/2004 8:30	DAY	900	52.8	67.7	48.8	41	37.7	37.2	61.2	61.6	60.5	57.8	50.6	43.7	36.6	35.0	26.2
6/26/2004 8:45	DAY	300.625	50.4	65.7	46.1	39.5	36.7	36.1	60.2	51.1	47.6	45.5	44.8	43.0	36.2	34.7	29.6

Table C6B: Sound Level Results at Measurement Location 6																
Start Date and Time	Day / Night	Duration	Leq	L1.00	L10.00	L50.00	L90.00	L95.00	31.5	63	125	250	500	1000	2000	4000	8000
		(seconds)	(dB(A))	(dB(A))	(dB(A))	(dB(A))	(dB(A))	(dB(A))	dB	dB	dB	dB	dB	dB	dB	dB	dB
6/27/2004 8:47	DAY	759.875	55	69.3	55.2	42.2	37.1	36.1	60.2	54.1	60.8	55.2	52.9	48.1	46.2	41.6	34.7
6/27/2004 9:00	DAY	900	53.4	67.8	49.5	40.2	37.9	37.4	61.1	61.6	60.9	58.9	51.2	44.1	36.6	34.4	30.3
6/27/2004 9:15	DAY	900	47.7	62.8	46.8	40.1	37.2	36.4	59.8	55.4	51.2	45.9	44.2	42.9	40.1	36.0	28.9
6/27/2004 9:30	DAY	900	49.3	61.9	51.2	41.8	37.6	37.1	59.6	54.1	51.3	49.8	44.5	41.3	39.8	43.1	34.8
6/27/2004 9:45	DAY	900	45	56.8	47.9	40.1	36.7	36.2	59.8	53.8	47.4	41.7	37.8	35.0	37.2	39.0	36.6
6/27/2004 10:00	DAY	900	46.3	58.1	47.7	40.9	37.7	37.2	59.8	54.5	50.8	44.7	38.8	36.7	39.5	39.9	29.7
6/27/2004 10:15	DAY	900	51.7	65.6	53.4	44.2	39.2	38.2	60.9	58.3	57.7	54.9	48.5	42.9	37.0	43.3	40.1
6/27/2004 10:30	DAY	900	43.7	51.6	46	42.3	38.8	38.1	60.0	51.1	47.1	41.4	38.5	38.7	35.4	35.3	28.5
6/27/2004 10:45	DAY	900	52.1	67	47.7	43.1	40.4	39.8	63.0	59.6	57.4	52.4	49.1	45.1	44.0	42.4	33.7
6/27/2004 11:00	DAY	900	45	55	46.5	42.7	39.2	38.5	59.7	52.6	48.9	43.7	40.9	40.6	36.7	33.0	26.4
6/27/2004 11:15	DAY	900	48.1	60.3	50.6	43.4	40.5	39.9	59.8	58.9	52.8	46.5	43.4	41.9	39.1	40.1	31.6
6/27/2004 11:30	DAY	900	49.1	60.8	50.8	43.8	41	40.3	59.9	53.6	51.2	45.4	44.5	44.4	41.6	39.8	32.4
6/27/2004 11:45	DAY	900	53.3	67.2	49.1	44.1	41.6	41	60.8	59.6	59.0	56.9	52.2	46.6	38.7	33.6	28.1
6/27/2004 12:00	DAY	900	49	59.7	51.8	45.5	41.2	40.2	60.4	55.6	54.5	48.8	41.3	40.5	42.2	41.7	35.8
6/27/2004 12:15	DAY	900	49.8	61.6	51	45.1	42.3	41.6	60.8	56.5	52.3	48.2	46.4	43.1	41.0	41.9	35.3
6/27/2004 12:30	DAY	900	51.9	65.5	52.3	46.6	44.1	43.5	60.9	60.0	58.5	53.8	48.7	44.2	42.0	43.0	36.0
6/27/2004 12:45	DAY	900	52.9	65.1	55.2	46.5	42.5	41.4	61.7	60.5	57.3	52.9	49.7	45.9	43.6	45.0	36.4
6/27/2004 13:00	DAY	900	48.3	56.8	51.6	45.9	42.4	41.2	60.5	54.3	52.1	46.8	43.9	43.1	39.2	40.2	31.5
6/27/2004 13:15	DAY	900	53.9	67.6	53.5	46.9	43.3	42.3	61.1	59.5	58.6	55.3	51.9	46.8	43.6	43.9	35.3
6/27/2004 13:30	DAY	900	48.8	57.1	49.1	45.5	42.9	42.2	61.5	61.0	55.4	49.9	44.7	43.1	37.6	37.0	29.5
6/27/2004 13:45	DAY	900	46.2	53.9	48.6	45	42.1	41	60.6	55.8	49.6	43.9	42.3	41.7	37.3	35.9	28.5
6/27/2004 14:00	DAY	900	49.8	61.2	52.7	45.9	43.1	42.3	62.0	60.4	55.1	51.5	46.2	44.2	39.1	38.8	30.6
6/27/2004 14:15	DAY	900	51.9	65.2	53.1	45.5	41.7	40.9	62.8	59.2	58.1	49.7	46.0	46.0	45.4	42.7	34.3
6/27/2004 14:30	DAY	900	47.4	57.2	49.3	44.7	41.7	41	60.4	54.7	48.4	42.0	39.9	41.2	38.0	42.5	34.9
6/27/2004 14:45	DAY	900	58	69.6	51.3	44.7	42	41.3	61.1	64.4	66.5	61.6	55.5	50.5	43.8	40.9	41.2
6/27/2004 15:00	DAY	900	49.3	59.6	52.9	44.2	41	40.3	60.2	51.9	46.8	42.5	42.3	41.0	43.5	43.6	32.1
6/27/2004 15:15	DAY	900	46.7	55.9	48.6	44.2	41.2	40.4	60.2	52.8	53.2	46.9	41.3	41.4	38.3	37.6	27.8
6/27/2004 15:30	DAY	900	44.3	51.8	46.2	42.5	39.3	38.5	60.2	53.3	48.9	44.4	38.7	38.9	33.8	36.8	25.6
6/27/2004 15:45	DAY	900	50.3	63.6	51.5	41.4	37.2	36.6	61.5	61.4	58.2	54.5	46.9	40.8	36.9	39.7	27.1
6/27/2004 16:00	DAY	900	45.4	56	50	37.6	35.6	35.2	60.1	48.9	42.8	35.3	34.4	31.4	33.5	41.9	39.2
6/27/2004 16:15	DAY	900	54.1	69.3	50.2	41.7	38.2	37.1	61.8	61.3	60.7	57.6	52.3	45.6	43.5	38.8	29.5
6/27/2004 16:30	DAY	900	53.7	68.1	54.6	44.3	41.2	40.5	61.3	60.9	60.5	57.2	50.9	46.3	38.9	43.4	37.1
6/27/2004 16:45	DAY	900	46.3	58.2	47.8	41.4	38.2	37.5	59.9	50.8	51.1	44.9	38.5	38.8	36.7	40.9	34.0
6/27/2004 17:00	DAY	900	45.6	54.5	48.6	41.6	39.1	38.5	60.1	51.4	48.2	40.9	37.2	35.4	37.8	41.1	32.8
6/27/2004 17:15	DAY	900	46.7	57.9	48.9	43	39.6	39	59.7	48.6	46.7	37.6	36.0	35.4	40.5	42.3	35.4
6/27/2004 17:30	DAY	900	48.5	59.3	42.7	39.6	38.2	38	61.2	68.2	52.6	45.2	41.5	39.3	37.0	36.2	31.8
6/27/2004 17:45	DAY	900	47.5	58.5	51.5	40.5	37.7	37.1	60.5	55.7	45.4	44.1	43.6	38.3	36.9	42.9	33.5
6/27/2004 18:00	DAY	900	49.3	61.5	51.6	41	38	37.3	59.9	48.1	45.5	40.4	40.9	35.8	40.1	46.3	38.0
6/27/2004 18:15	DAY	900	49.5	61.7	52.6	39.7	37.1	36.6	61.1	61.0	58.4	53.2	45.7	39.9	36.3	39.8	33.3
6/27/2004 18:30	DAY	900	41.5	47.3	43.7	40.5	38.1	37.4	60.1	48.6	43.9	35.1	35.0	34.6	33.0	35.9	30.1
6/27/2004 18:45	DAY	900	49.7	64.6	46.2	39.5	36.6	36.2	61.5	55.0	46.7	43.8	45.4	44.1	43.8	39.1	30.8
6/27/2004 19:00	DAY	900	58.3	74	53.7	40.1	36.9	36.2	63.9	66.9	68.5	63.9	54.5	47.5	42.5	36.8	25.4
6/27/2004 19:15	DAY	900	49.4	63.4	42.9	37.7	35.5	35.2	60.0	55.3	48.0	41.9	39.2	37.7	33.5	30.0	49.0
6/27/2004 19:30	DAY	900	52.2	61.5	57.6	44.2	39.4	38.4	61.1	59.5	55.2	51.4	44.8	36.9	29.0	24.7	50.9
6/27/2004 19:45	DAY	900	61.6	71.4	68.1	55.3	42.4	41.3	60.8	52.1	45.5	38.8	35.7	33.2	28.9	21.5	62.1
6/27/2004 20:00	DAY	900	46.6	49.5	48.4	46.6	44	42	59.9	48.5	43.7	35.0	34.7	34.2	28.6	20.7	46.9
6/27/2004 20:15	DAY	900	42.5	47.8	45.8	39.9	38.3	38.1	59.9	47.2	42.2	35.0	34.0	32.0	28.5	21.2	41.8
6/27/2004 20:30	DAY	900	44.9	46.9	46	45.1	42.1	41.5	60.2	48.1	43.1	35.1	34.2	32.2	28.3	20.1	44.5
6/27/2004 20:45	DAY	900	47.7	55.5	48.1	47.3	46	44.8	60.2	55.5	49.8	45.1	38.0	34.0	29.4	20.3	46.8
6/27/2004 21:00	DAY	900	45.9	51.6	47.8	45	43.1	42.1	59.4	48.1	43.9	38.1	36.3	35.8	33.6	20.0	45.0
6/27/2004 21:15	DAY	900	48.2	61.6	46.2	42.5	40.1	39.6	60.1	55.3	56.9	48.0	42.2	41.5	39.1	35.0	42.4
6/27/2004 21:30	DAY	900	42.8	50.2	44.3	40.8	39.6	39.3	58.9	51.9	45.9	40.2	37.3	35.1	31.8	24.6	39.5
6/27/2004 21:45	DAY	900	40.7	42.8	41.7	40.6	39.8	39.4	54.8	45.9	42.5	36.2	33.9	30.8	28.6	22.0	38.9
6/27/2004 22:00	NIGHT	900	41.9	44.2	42.8	41.8	41.1	41	52.3	49.8	44.0	36.1	34.1	32.3	28.5	20.4	40.5
6/27/2004 22:15	NIGHT	900	46.6	53.7	48.6	46.5	41.2	40.9	50.9	49.4	43.3	39.6	38.7	35.5	28.6	18.2	46.5
6/27/2004 22:30	NIGHT	900	47	49.9	48.6	47.1	44.3	43.1	50.8	46.2	42.9	36.4	35.3	33.1	27.4	18.2	47.6
6/27/2004 22:45	NIGHT	900	42.8	52.7	43.2	41.3	40.2	40	52.6	53.6	49.7	41.5	37.0	31.4	25.3	17.9	40.9
6/27/2004 23:00	NIGHT	900	42.3	48.2	44.6	41.6	40.1	39.6	53.0	53.8	48.1	40.0	34.0	29.3	25.0	19.2	41.1
6/27/2004 23:15	NIGHT	900	42.4	45.5	43.5	42.3	41.1	40.8	55.0	52.5	43.6	38.2	33.3	29.0	24.0	19.1	41.6
6/27/2004 23:30	NIGHT	900	42.6	45.4	44.3	42.1	40.8	40.4	50.3	43.1	41.2	34.2	30.4	27.6	23.4	19.8	42.6
6/27/2004 23:45	NIGHT	900	53.4	57	56.6	54.2	40.9	40.4	51.3	43.3	41.5	38.2	33.9	31.5	26.6	21.9	53.7
6/28/2004 0:00	NIGHT	900	43.1	46.8	44	42.9	42	41.5	51.0	43.9	42.4	39.5	35.6	34.4	28.7	24.4	41.5
6/28/2004 0:15	NIGHT	900	43.1	44.9	43.9	43.1	41.8	41.4	51.1	44.6	41.0	39.6	35.3	32.3	27.5	24.3	41.6
6/28/2004 0:30	NIGHT	900	44.6	46.9	45.8	44.6	43.1	42.6	51.3	44.3	41.6	41.5	36.7	33.9	28.2	25.7	43.2
6/28/2004 0:45	NIGHT	900	43.9	46.8	45.1	43.9	42.1	41.1	53.6	44.5	41.7	43.6	38.1	35.4	31.0	30.5	40.6
6/28/2004 1:00	NIGHT	900	44.1	46.8	45.4	44.1	42.2	41.4	53.9	46.0	44.3	43.8	38.3	35.3	32.1	32.1	40.3
6/28/2004 1:15	NIGHT	900	48.2	55.8	54	44.2	40.6	40.2	52.4	43.6	42.4	39.9	35.1	31.8	29.0	29.5	48.9
6/28/2004 1:30	NIGHT	900	53.6	60.3	56.7	53.4	42.2	41.6	51.3	44.9	40.8	39.4	35.1	31.6	26.9	26.0	54.7
6/28/2004 1:45	NIGHT	900	49.2	55.7	54.1	47.7	40.8	39.9	52.4	43.5	41.2	41.2	36.9	32.6	27.9	27.0	49.8
6/28/2004 2:00	NIGHT	900	47.2	57.2	48	45.4	43.1	42.1	56.0	57.6	53.9	48.4	41.2	33.2	25.9	24.9	44.9
6/28/2004 2:15	NIGHT	900	47	51.8	49	46.5	45.2	44	50.7	46.1	43.4	38.7	34.4	30.3	24.7	25.1	47.0
6/28/2004 2:30	NIGHT	900	49.5	52	51.6	49.4	45.5	45	50.7	42.3	40.9	40.4	35.8	31.8	26.7	27.4	50.3

Table C6B: Sound Level Results at Measurement Location 6

Start Date and Time	Day / Night	Duration (seconds)	Leq (dB(A))	L1.00 (dB(A))	L10.00 (dB(A))	L50.00 (dB(A))	L90.00 (dB(A))	L95.00 (dB(A))	31.5 dB	63 dB	125 dB	250 dB	500 dB	1000 dB	2000 dB	4000 dB	8000 dB
6/28/2004 2:45	NIGHT	900	44.6	48.6	46.8	44.6	39.8	39.2	55.3	47.2	44.1	42.2	38.2	34.8	30.3	28.7	42.4
6/28/2004 3:00	NIGHT	900	47.3	49.9	48.2	47.2	46.2	46	70.6	57.5	51.6	46.6	43.1	40.2	34.2	30.6	42.5
6/28/2004 3:15	NIGHT	900	49.1	60.8	48.8	46.9	45.5	45.3	71.5	59.7	54.1	49.9	46.3	41.5	37.6	29.8	43.0
6/28/2004 3:30	NIGHT	900	45	46.6	45.9	45.1	44.1	44	71.2	58.0	51.5	41.8	39.0	34.3	28.5	26.9	43.5
6/28/2004 3:45	NIGHT	900	49.6	59.8	49.6	48.1	45.1	44.6	70.1	57.9	51.4	47.5	47.0	40.4	33.8	28.6	48.2
6/28/2004 4:00	NIGHT	900	48.4	59.5	49.4	45.1	42.3	41.3	69.9	60.3	55.3	49.8	46.9	39.0	31.4	28.1	42.9
6/28/2004 4:15	NIGHT	900	41.5	44.7	42.4	41.3	40.3	40.1	70.0	57.2	50.6	41.1	38.7	34.5	27.6	24.5	30.5
6/28/2004 4:30	NIGHT	900	42.3	45.9	43.4	42.2	41.2	41.1	70.0	56.8	49.9	40.9	38.9	35.8	29.1	25.7	35.2
6/28/2004 4:45	NIGHT	900	44	47.9	45.6	42.7	41.4	41.2	69.9	56.7	50.1	43.8	40.9	38.3	33.0	28.8	33.4
6/28/2004 5:00	NIGHT	900	53.3	67.2	52.1	48.2	45.7	45.4	70.4	61.5	55.6	55.1	51.5	48.0	43.1	33.7	37.2
6/28/2004 5:15	NIGHT	900	49.3	54.9	51.3	48.5	47.1	46.6	71.3	58.6	52.8	49.6	45.8	44.7	38.6	38.2	32.5
6/28/2004 5:30	NIGHT	900	50	54	52.1	49.5	47.2	46.6	71.9	58.3	52.6	45.3	44.2	44.3	41.3	43.6	38.0
6/28/2004 5:45	NIGHT	900	51.7	59.3	54.8	49.8	46.6	46.2	71.6	59.4	53.5	46.3	45.0	46.7	43.1	44.5	41.7
6/28/2004 6:00	NIGHT	900	49.6	57.7	51.7	48.4	46.2	45.4	68.6	57.7	52.8	47.3	46.3	45.6	41.0	36.4	30.8
6/28/2004 6:15	NIGHT	900	48	54.2	50.9	46.8	44	43.2	55.8	57.8	50.7	45.2	44.7	44.2	39.3	34.1	24.7
6/28/2004 6:30	NIGHT	900	51.9	64.5	53	47.4	43.8	43.2	56.8	57.9	52.1	51.4	50.2	47.7	41.7	35.5	25.3
6/28/2004 6:45	NIGHT	900	54.9	68.1	57.6	46.1	41.7	40.9	58.6	60.5	58.8	56.2	53.1	49.0	43.4	44.0	38.2
6/28/2004 7:00	DAY	900	50.3	62.6	50.1	42.9	40.6	40.2	57.2	59.5	53.3	48.1	44.8	44.9	43.2	41.6	34.7
6/28/2004 7:15	DAY	900	47.7	61	46.7	42.3	40	39.4	57.9	57.7	48.6	46.6	46.4	42.0	37.3	36.8	27.4
6/28/2004 7:30	DAY	900	54.1	63.8	49.3	41.7	38.2	37.6	57.7	60.6	55.7	55.7	50.2	48.4	46.3	42.9	37.4
6/28/2004 7:45	DAY	900	45.3	57	46.9	40.6	37.9	37.4	58.0	58.3	49.6	44.7	39.8	37.2	36.5	38.5	29.5
6/28/2004 8:00	DAY	900	49.4	60.3	44.9	41.1	38.7	38.2	59.7	61.7	50.9	46.3	44.0	44.3	42.6	39.6	32.8
6/28/2004 8:15	DAY	900	51.3	64.6	51.1	45.3	42.4	41.3	60.9	59.4	61.3	53.5	50.5	43.6	38.4	37.3	30.1
6/28/2004 8:30	DAY	900	45	51.6	46.7	43.8	41.3	40.8	59.9	59.1	48.3	41.6	43.0	38.9	34.3	35.7	29.0
6/28/2004 8:45	DAY	900	49.9	62.8	51.2	44.2	41.4	40.9	62.2	62.2	57.6	53.6	47.7	42.0	36.2	36.0	30.1
6/28/2004 9:00	DAY	900	50.3	64.1	48.5	43.9	41.6	41.2	60.3	55.4	46.2	40.6	41.8	38.9	39.7	46.8	42.2
6/28/2004 9:15	DAY	900	47.1	57.3	46.9	43.7	41.5	41.1	59.7	56.1	52.7	46.6	43.9	42.3	38.0	34.9	27.8
6/28/2004 9:30	DAY	900	57	69	60.6	46	41.7	41.2	60.6	59.8	58.7	52.5	51.2	48.8	47.9	52.0	47.1
6/28/2004 9:45	DAY	900	48.5	59.7	48.6	43.5	41	40.2	59.8	56.5	52.4	47.4	45.4	43.1	39.6	38.0	33.8
6/28/2004 10:00	DAY	900	53.8	66.5	53.8	44.2	41.4	40.7	60.4	62.2	55.8	52.4	49.5	49.0	46.5	41.3	35.6
6/28/2004 10:15	DAY	900	52.7	66.6	53	45	41.7	41	61.2	62.9	59.5	57.1	50.7	44.9	38.5	34.5	27.1
6/28/2004 10:30	DAY	900	50.3	62.6	50.6	44.4	42.1	41.5	59.9	58.4	53.6	48.5	44.2	42.9	43.1	43.3	32.4
6/28/2004 10:45	DAY	900	50.8	64.9	52	44.4	41.2	40.6	62.5	60.9	58.0	53.8	47.5	43.2	40.4	39.5	29.7
6/28/2004 11:00	DAY	900	48.3	59.6	49.8	44.9	42.4	41.9	60.6	60.5	50.1	43.2	43.0	40.9	40.8	41.0	37.1
6/28/2004 11:15	DAY	900	51.3	64.7	49.7	45.2	42.8	42.3	60.2	59.4	52.0	50.8	47.3	43.0	43.0	44.7	35.8
6/28/2004 11:30	DAY	900	50.3	64.4	48.3	43.1	40.9	40.3	60.0	58.4	58.2	53.4	45.9	42.9	40.5	39.0	31.8
6/28/2004 11:45	DAY	900	48.4	60.2	50.5	44.1	41.5	41.1	59.5	57.2	54.6	49.2	45.6	44.0	39.0	32.8	27.6
6/28/2004 12:00	DAY	900	55.5	70	55.4	45.9	40.8	40.2	61.1	63.3	63.1	57.3	52.4	48.8	46.4	44.1	38.6
6/28/2004 12:15	DAY	900	52.7	65.2	55	45.3	41.4	40.6	61.9	61.3	59.3	56.4	50.8	46.1	39.5	32.6	25.4
6/28/2004 12:30	DAY	900	55.6	71	52.7	45.2	42.2	41.6	62.4	61.9	57.8	57.7	53.9	49.2	45.3	40.9	35.1
6/28/2004 12:45	DAY	900	46.8	56.6	49.1	43.9	41.6	41.2	60.8	57.0	51.2	45.7	43.1	41.0	39.3	35.6	28.1
6/28/2004 13:00	DAY	900	50.6	61.9	54.4	44.9	42.3	41.7	61.3	57.8	52.3	48.1	43.5	42.6	44.4	44.1	32.5
6/28/2004 13:15	DAY	900	54	66.9	52.6	45.5	42.6	41.8	63.1	61.9	59.7	55.9	50.8	47.5	44.8	42.1	37.2
6/28/2004 13:30	DAY	900	52.8	66.5	51.6	42.6	40.1	39.6	61.8	60.4	58.1	56.6	50.9	46.2	40.1	36.3	32.6
6/28/2004 13:45	DAY	900	56.3	68.7	59.6	47.4	42.4	41.5	63.4	63.2	55.3	52.7	47.1	44.5	42.2	52.4	50.3
6/28/2004 14:00	DAY	900	52.4	61.5	56.1	46.8	43.6	43	62.3	60.5	59.9	50.2	50.0	47.2	43.1	40.9	31.4
6/28/2004 14:15	DAY	900	49.2	58.3	51.2	47.2	44	43.1	63.2	57.5	53.7	49.0	45.9	44.7	40.7	36.2	29.7
6/28/2004 14:30	DAY	900	46.6	54.8	48.6	45.3	42.7	42.1	63.2	57.1	47.1	42.4	42.2	42.3	38.3	37.2	28.9
6/28/2004 14:45	DAY	900	52.8	63	56	48	44.1	43	61.1	60.8	56.2	52.5	47.6	45.7	41.3	46.9	41.0
6/28/2004 15:00	DAY	900	52	60.8	56.2	48.9	44.6	43.7	61.7	60.7	55.5	50.8	47.9	45.8	43.7	44.4	33.9
6/28/2004 15:15	DAY	900	56.8	68.2	61.2	49	45.6	45	64.3	64.1	60.0	56.0	53.1	52.3	48.8	43.2	35.7
6/28/2004 15:30	DAY	900	53.6	66.7	53.4	48	45	44.2	61.8	63.7	59.7	55.8	50.8	47.8	43.7	39.5	32.5
6/28/2004 15:45	DAY	900	69.6	83.4	52	46.7	43.9	43.1	61.4	65.5	73.9	71.7	64.1	64.0	61.2	58.5	51.6
6/28/2004 16:00	DAY	900	59.4	72.6	59.2	48.3	43.2	42.3	62.9	69.1	68.6	60.7	55.8	52.8	50.0	47.8	40.9
6/28/2004 16:15	DAY	900	47.6	56.1	50.4	45.8	42.6	42.1	60.9	56.0	51.7	50.0	42.4	41.2	38.5	38.9	30.8
6/28/2004 16:30	DAY	900	51.9	63.5	53.2	44.6	41.2	40.4	61.2	62.5	60.7	57.2	48.7	43.2	37.1	30.4	30.2
6/28/2004 16:45	DAY	900	44.4	51.6	46.2	43.5	41.1	40.4	59.4	55.2	47.6	40.9	41.3	39.7	35.8	32.7	24.6
6/28/2004 17:00	DAY	900	46.4	56.3	48.6	43.5	40.6	39.9	59.1	53.6	50.7	43.6	40.9	38.9	39.0	39.4	31.4
6/28/2004 17:15	DAY	900	51	59.9	51.5	47.4	44.1	43	60.3	62.0	60.4	53.0	47.2	44.5	40.8	37.7	30.4
6/28/2004 17:30	DAY	900	52.5	60.1	55.9	49.8	42.7	41.9	61.3	66.3	62.3	55.3	46.6	46.4	42.9	37.2	30.7
6/28/2004 17:45	DAY	900	55.2	64.2	58.9	52.3	40.1	39.3	61.9	67.3	64.7	59.7	50.1	46.6	43.7	41.9	37.9
6/28/2004 18:00	DAY	900	50.3	60	48.1	42	38.3	37.6	59.2	51.9	53.5	48.7	46.2	42.7	44.2	41.6	35.1
6/28/2004 18:15	DAY	900	54.7	59.8	46.1	40.9	38.3	37.7	60.7	54.5	65.4	57.2	47.3	44.6	41.6	38.5	29.6
6/28/2004 18:30	DAY	900	43.9	55.9	42.5	38.6	36.7	36.3	59.6	53.6	49.5	42.1	39.4	38.2	35.3	34.4	31.1
6/28/2004 18:45	DAY	900	41.9	52.8	44.3	38.9	36.6	36.2	58.4	49.4	47.7	38.4	37.4	37.7	31.8	32.4	28.2
6/28/2004 19:00	DAY	900	39.1	45.2	40.9	38.2	36.6	36.3	58.7	49.1	42.9	35.9	35.2	33.6	31.6	28.8	23.3
6/28/2004 19:15	DAY	900	43.2	53.9	44.4	39.5	37	36.4	59.6	52.9	48.0	43.6	39.9	37.9	34.9	29.2	25.9
6/28/2004 19:30	DAY	900	57.2	70.3	57.8	48.5	39.7	39.2	62.4	62.9	61.7	58.8	52.0	46.5	36.6	26.0	54.8
6/28/2004 19:45	DAY	900	61.9	70.3	65.9	58.4	49	46.9	60.5	53.7	52.7	44.6	45.9	42.4	36.7	27.1	62.5
6/28/2004 20:00	DAY	900	54.7	62.5	60.3	48.3	40.9	40.1	59.5	52.6	51.3	42.0	43.2	40.5	35.0	25.4	55.3
6/28/2004 20:15	DAY	900	55.5	60.2	56.5	55.2	54.1	53.8	59.1	53.9	52.9	43.9	45.7	42.0	36.6	27.0	56.3
6/28/2004 20:30	DAY	900	54.9	59.2	56.6	54.9	50.1	49.5	58.8	53.9	53.6	46.7	45.1	41.8	35.5	26.1	55.5

Table C6B: Sound Level Results at Measurement Location 6

Start Date and Time	Day / Night	Duration	Leq	L1.00	L10.00	L50.00	L90.00	L95.00	31.5	63	125	250	500	1000	2000	4000	8000
		(seconds)	(dB(A))	(dB(A))	(dB(A))	(dB(A))	(dB(A))	(dB(A))	dB	dB	dB	dB	dB	dB	dB	dB	dB
6/28/2004 20:45	DAY	900	50.2	59.7	54.9	42.4	39.7	38.9	58.8	52.6	51.5	43.0	42.2	40.0	34.9	25.1	50.3
6/28/2004 21:00	DAY	900	44.2	55.5	45.1	41.9	40.1	39.5	58.5	51.5	50.1	41.2	41.5	39.0	33.1	24.0	37.5
6/28/2004 21:15	DAY	900	50	56	53.7	44.7	40.7	40.3	58.6	51.4	48.6	39.2	39.7	37.9	32.4	25.3	50.8
6/28/2004 21:30	DAY	900	50.3	57.9	54.6	42	39.8	39.2	59.6	56.2	53.2	45.9	43.1	39.7	34.3	26.9	50.2
6/28/2004 21:45	DAY	900	45.7	57.9	46.2	41.3	39.1	38.6	57.9	52.1	51.5	42.7	43.7	40.8	36.0	28.3	36.5
6/28/2004 22:00	NIGHT	900	44.4	54.3	45.6	43.6	38.4	38	56.5	51.9	47.6	39.1	39.1	37.0	31.1	24.1	42.5
6/28/2004 22:15	NIGHT	900	42.3	45.8	44.6	41.5	39.2	38.6	52.7	47.4	44.5	36.8	35.9	33.8	27.1	19.9	41.3
6/28/2004 22:30	NIGHT	900	43.8	47.7	45.8	43.9	40.7	40.3	51.4	47.7	44.0	37.6	38.4	33.4	26.7	17.8	43.3
6/28/2004 22:45	NIGHT	900	40.4	44.9	42	40.2	38	37.5	49.4	44.6	43.9	33.9	34.4	32.8	26.7	22.1	38.3
6/28/2004 23:00	NIGHT	900	40	43.7	41.7	39.7	38.1	37.6	48.6	46.0	42.9	33.7	34.3	33.2	27.8	25.7	37.1
6/28/2004 23:15	NIGHT	900	39.2	44.5	41.7	38.5	36.3	35.5	48.4	42.2	41.1	32.1	30.2	28.9	24.8	23.5	38.4
6/28/2004 23:30	NIGHT	900	43.5	48.5	46.9	41.9	38.5	38.1	49.8	43.5	41.5	33.1	31.8	29.2	25.2	24.6	43.9
6/28/2004 23:45	NIGHT	900	44.2	49.2	46.7	44.2	39.2	38.6	49.8	44.5	43.7	35.4	32.1	28.9	25.3	25.2	44.6
6/29/2004 0:00	NIGHT	900	41.4	44.8	43.6	41	38.3	36.4	48.9	42.7	40.7	32.8	29.7	27.1	23.2	23.9	41.0
6/29/2004 0:15	NIGHT	900	57.2	66.7	64.6	46.5	43.2	42.4	50.7	43.9	43.0	33.9	33.2	29.7	25.9	28.8	58.5
6/29/2004 0:30	NIGHT	900	65.2	69	68.3	65.5	46.5	45.7	50.5	42.9	41.3	32.1	31.0	29.8	28.6	31.0	66.3
6/29/2004 0:45	NIGHT	900	48.1	50.8	50	48.1	45.1	43.8	53.1	43.4	41.3	32.5	31.4	30.6	29.9	31.9	47.8
6/29/2004 1:00	NIGHT	900	47.9	50	49.3	47.9	45.6	44.8	51.1	42.5	41.1	33.1	31.1	29.0	27.5	30.5	47.9
6/29/2004 1:15	NIGHT	900	51.2	62	52.1	49	47.8	47.4	50.2	42.6	41.0	31.7	29.9	28.5	26.8	30.7	50.1
6/29/2004 1:30	NIGHT	900	57.3	65.9	62.8	51.2	43.1	42.5	49.0	41.8	42.4	31.6	29.7	27.1	25.5	27.8	57.1
6/29/2004 1:45	NIGHT	900	50.4	53.1	51.8	50.4	48.7	48.1	49.3	41.2	40.3	31.6	28.5	26.2	23.6	28.6	50.8
6/29/2004 2:00	NIGHT	900	61.4	70	68.8	49	38.9	37.9	48.3	40.7	40.9	31.0	27.7	25.8	22.7	27.8	62.4
6/29/2004 2:15	NIGHT	900	67.1	70	69.6	67.5	46.5	45.9	48.4	40.1	40.3	28.9	26.5	23.9	21.8	29.2	68.4
6/29/2004 2:30	NIGHT	900	48.9	51.9	50.8	49.1	45.1	42.3	50.2	47.7	40.4	29.8	27.9	25.2	21.8	26.8	49.0
6/29/2004 2:45	NIGHT	900	40.7	44.7	43	40.2	39.1	38.6	48.4	40.0	40.7	29.5	27.6	25.2	23.6	25.7	40.5
6/29/2004 3:00	NIGHT	900	51.2	65	41.7	39.3	38.2	38	56.2	60.4	59.2	55.6	49.2	42.3	34.5	27.2	37.8
6/29/2004 3:15	NIGHT	900	59.2	64.5	64.1	45.4	42.3	41.4	54.0	56.2	55.0	47.7	37.3	30.5	26.1	29.8	60.0
6/29/2004 3:30	NIGHT	900	39.3	44.9	43.5	37.9	36.2	36.1	50.2	44.8	41.6	34.6	30.8	26.6	23.7	27.4	37.8
6/29/2004 3:45	NIGHT	900	38.4	41.1	39	38.3	37.3	37.2	50.3	46.6	41.7	34.9	31.7	27.9	23.4	21.8	36.5
6/29/2004 4:00	NIGHT	900	38.2	40	39	38.2	37.2	37	51.0	44.6	41.3	35.2	31.6	28.2	24.2	22.8	36.1
6/29/2004 4:15	NIGHT	900	43.1	51.9	43.9	38.3	36.3	36	51.7	49.7	44.9	40.1	38.7	38.1	34.8	28.3	35.6
6/29/2004 4:30	NIGHT	900	40.4	43.9	42.6	41.1	33.8	33.3	50.2	49.0	42.1	35.8	32.8	29.7	22.5	17.5	40.1
6/29/2004 4:45	NIGHT	900	40.1	45.6	42.7	37.9	34.8	34.3	50.8	48.6	44.3	36.0	35.0	32.3	23.8	17.0	38.7
6/29/2004 5:00	NIGHT	900	41.1	45.3	43	41.2	36.8	36.1	50.1	48.9	44.6	34.9	34.4	34.1	26.7	21.7	38.5
6/29/2004 5:15	NIGHT	900	45.6	57.4	46.7	43.4	41.6	41.2	50.6	50.3	44.1	42.0	42.8	38.8	35.7	31.2	40.3
6/29/2004 5:30	NIGHT	900	50.6	57	54.4	48.7	43.9	43.1	51.7	50.5	45.5	38.8	37.4	36.3	44.7	46.6	39.9
6/29/2004 5:45	NIGHT	900	52.9	66.9	52.4	46.9	43.6	43.2	56.2	58.7	55.9	54.6	52.8	45.3	40.9	40.3	37.3
6/29/2004 6:00	NIGHT	900	46.9	53.6	48.8	44.7	42.8	42.3	53.0	54.7	48.8	43.3	42.2	41.7	39.4	37.4	34.7
6/29/2004 6:15	NIGHT	900	53.4	66.3	50.9	45.4	42.8	42.3	59.3	58.8	55.9	53.7	51.2	48.6	43.4	38.1	26.4
6/29/2004 6:30	NIGHT	900	49.2	63	48	43.1	41.1	40.5	54.8	55.6	51.1	50.4	47.6	43.8	39.9	36.2	27.0
6/29/2004 6:45	NIGHT	900	52.3	65.8	53.4	40.9	37.8	37.3	57.8	61.9	58.4	55.5	50.8	45.8	38.6	32.2	24.2
6/29/2004 7:00	DAY	900	49.6	60.8	49.1	41.9	38.6	38.1	59.4	59.9	54.6	51.6	47.7	42.8	40.9	34.7	29.4
6/29/2004 7:15	DAY	900	49	57.2	53.1	46	41.6	40.7	60.3	59.6	47.4	42.7	41.6	42.1	41.3	42.1	41.3
6/29/2004 7:30	DAY	900	49.4	57.7	52.5	47.4	42.6	41.6	60.7	58.5	48.3	42.8	43.1	41.4	42.6	42.4	41.4
6/29/2004 7:45	DAY	797.875	48.3	55.8	50.4	45.6	40.6	39.5	60.3	58.3	51.1	45.2	45.4	43.7	40.1	36.3	32.9

Table C7A: Sound Level Results at Measurement Location 7

Start Date and Time	Day / Night	Duration (seconds)	Leq (dB(A))	L1.00 (dB(A))	L10.00 (dB(A))	L50.00 (dB(A))	L90.00 (dB(A))	L95.00 (dB(A))	31.5 dB	63 dB	125 dB	250 dB	500 dB	1000 dB	2000 dB	4000 dB	8000 dB
6/25/2004 9:15	DAY	899.625	55.2	64.8	57.3	50	47.1	46.3	58.4	59.5	57.7	55.8	51.0	49.2	44.8	41.5	49.3
6/25/2004 9:30	DAY	900	54.7	63.8	58.2	51.4	47.4	46.4	61.4	59.2	54.0	52.1	51.1	49.3	45.0	47.9	35.2
6/25/2004 9:45	DAY	900	57.1	67.1	61.6	51.4	47.8	46.8	58.4	56.6	57.8	52.3	51.3	50.2	47.0	52.9	39.7
6/25/2004 10:00	DAY	900	55.8	65.4	59.7	51.6	47.9	46.7	58.6	54.5	54.4	50.2	50.3	49.4	45.6	51.5	37.8
6/25/2004 10:15	DAY	900	64.7	75.1	62	51.8	47.4	46.3	60.2	62.8	66.2	64.6	62.9	60.4	54.0	50.2	40.5
6/25/2004 10:30	DAY	900	56.1	64.8	56.3	51.8	47.6	46.6	58.4	58.7	59.8	56.6	55.9	50.0	45.4	38.7	32.9
6/25/2004 10:45	DAY	900	62.1	76	61.2	52	48.6	48	61.6	64.8	63.0	62.1	61.3	56.5	52.8	46.6	41.3
6/25/2004 11:00	DAY	900	61.7	71.4	56	51.9	48.2	47.1	62.0	59.6	58.4	62.6	60.8	56.3	52.9	47.4	42.9
6/25/2004 11:15	DAY	900	56.3	67.4	55.1	51.7	48.1	46.9	61.9	59.3	55.7	53.7	53.5	52.5	47.8	41.9	37.0
6/25/2004 11:30	DAY	900	59.2	72.7	59.3	52.6	48.8	48.1	62.3	67.8	60.5	60.5	57.0	53.1	50.3	46.1	39.5
6/25/2004 11:45	DAY	900	55.6	66.8	57	50.8	47	46.2	58.7	58.4	56.4	52.7	52.8	52.1	46.9	39.7	33.5
6/25/2004 12:00	DAY	900	56.7	66.9	60.3	52	47.8	46.7	58.5	57.0	56.0	52.5	54.6	51.5	47.9	45.3	46.0
6/25/2004 12:15	DAY	900	65.1	74.4	71.9	52.1	48.4	47.5	58.6	55.2	60.4	56.3	62.5	58.7	59.9	50.8	43.4
6/25/2004 12:30	DAY	900	61.5	72.8	61.2	52	47.4	46.3	63.0	61.3	62.9	61.2	59.1	55.9	53.6	46.6	40.7
6/25/2004 12:45	DAY	900	53	62.8	55	50.1	46.6	46	58.0	59.1	59.7	48.3	49.8	48.8	44.4	37.1	28.2
6/25/2004 13:00	DAY	900	54.3	64.2	54.5	49.5	45.8	44.7	61.5	54.7	51.7	50.8	51.2	51.3	45.7	35.9	28.6
6/25/2004 13:15	DAY	900	55.5	69.4	55	49.5	46.3	45.5	59.4	55.8	56.9	58.0	55.0	49.5	43.0	34.1	26.7
6/25/2004 13:30	DAY	900	57.3	70.6	55.8	50.1	46.6	45.5	58.9	59.6	61.4	62.4	55.5	49.2	43.2	34.6	27.1
6/25/2004 13:45	DAY	900	56	64.7	55.6	50.3	47.1	46.4	61.3	58.8	54.7	57.0	53.0	51.6	47.4	41.5	36.9
6/25/2004 14:00	DAY	900	57.4	69.9	58.1	51.9	48.4	47.2	60.0	66.0	60.0	56.6	54.6	52.5	48.9	43.8	37.8
6/25/2004 14:15	DAY	900	57.3	67.8	57.3	50.9	46.8	45.8	58.4	59.8	62.6	54.5	53.2	52.5	49.4	45.7	45.3
6/25/2004 14:30	DAY	900	51.5	60.5	53.1	49.8	46.6	45.8	58.2	54.7	46.8	46.0	47.2	47.5	43.7	42.2	28.8
6/25/2004 14:45	DAY	900	57.2	69.8	54.8	51.1	47.6	46.7	60.7	58.0	55.0	54.6	53.2	52.6	50.3	45.6	38.0
6/25/2004 15:00	DAY	900	55.4	68.3	56.3	49.8	47.1	46.3	62.1	57.3	58.1	57.7	54.5	49.5	43.4	34.2	25.1
6/25/2004 15:15	DAY	900	60.2	73.4	63	52.2	47.9	47	61.8	69.4	62.6	56.8	56.2	55.3	51.8	51.2	42.3
6/25/2004 15:30	DAY	900	58.1	70.7	61.7	51.3	47.7	47	59.5	58.0	56.1	56.2	55.6	52.1	47.6	51.6	38.2
6/25/2004 15:45	DAY	900	55.7	66.7	59	50.4	47.2	46.2	58.6	58.8	54.9	50.2	49.6	48.8	45.8	51.5	40.1
6/25/2004 16:00	DAY	900	62.4	74.5	57	49	45.2	44.4	59.6	67.1	71.6	66.8	60.2	53.5	50.9	47.6	42.5
6/25/2004 16:15	DAY	900	59.2	74.4	56	49.4	45.9	45.1	58.3	58.3	58.5	63.0	58.7	51.9	45.5	40.3	31.4
6/25/2004 16:30	DAY	900	55.6	67.7	56.7	48.6	44.7	43.4	59.0	58.0	58.8	56.2	52.9	49.7	45.3	46.8	37.3
6/25/2004 16:45	DAY	900	54.6	64.9	59.1	49.1	46	45.3	56.4	55.4	51.6	48.2	48.1	48.0	45.3	50.5	35.1
6/25/2004 17:00	DAY	900	56.1	65.1	59.3	48.2	44	42.9	56.8	51.8	60.8	59.5	51.0	45.9	43.2	50.8	34.3
6/25/2004 17:15	DAY	900	58.7	71.9	61.8	48.9	44.5	43.9	58.2	57.3	59.0	61.1	57.2	49.7	45.2	51.4	35.3
6/25/2004 17:30	DAY	900	54.3	66.8	56.2	46.4	42.8	42	56.3	56.1	56.7	45.9	46.0	46.4	44.0	51.1	38.1
6/25/2004 17:45	DAY	900	51.9	65.1	52.4	46.7	43.3	42.5	58.5	55.7	46.0	43.8	45.9	46.3	44.2	45.7	38.3
6/25/2004 18:00	DAY	900	55.8	67.2	59.4	46.9	43.5	42.5	57.7	56.7	58.0	55.9	51.6	49.5	45.3	48.6	45.9
6/25/2004 18:15	DAY	900	56.3	69.4	56.1	46.8	43.2	42.3	59.4	60.6	56.8	57.0	54.8	50.9	47.1	38.5	31.9
6/25/2004 18:30	DAY	900	49.1	61.1	48.1	46	42.2	40.8	57.0	52.3	45.1	41.4	43.8	44.8	41.7	40.4	32.9
6/25/2004 18:45	DAY	900	50.4	62.3	51.6	47.3	44.3	43.6	56.2	51.7	48.3	44.3	46.2	47.1	43.0	36.8	33.8
6/25/2004 19:00	DAY	900	51.5	61.3	50.7	46.6	42.9	42.1	56.8	59.6	59.4	50.0	48.7	45.6	41.5	33.3	28.2
6/25/2004 19:15	DAY	900	59.8	68.7	64.6	47.9	41	39.9	56.2	59.8	60.9	48.6	47.7	45.8	41.8	38.5	60.3
6/25/2004 19:30	DAY	900	61.4	68.8	65.8	58.3	46.8	44.8	56.4	54.1	45.7	44.4	44.6	44.4	40.0	31.5	62.2
6/25/2004 19:45	DAY	900	63.4	68.8	67	62.4	49.9	48.8	56.6	53.6	51.5	56.5	55.1	48.2	42.8	33.1	64.0
6/25/2004 20:00	DAY	900	55.7	68.5	57.9	48.4	44.2	43.4	58.4	57.9	58.8	58.3	53.0	47.9	43.7	35.7	51.0
6/25/2004 20:15	DAY	900	54.9	68.3	53.6	47.6	43.5	42.4	57.6	56.0	57.7	58.3	53.7	48.5	42.2	31.4	27.6
6/25/2004 20:30	DAY	900	49.8	59.5	52.1	47.1	44	43	56.4	52.0	47.4	45.4	47.7	46.4	41.3	31.2	28.7
6/25/2004 20:45	DAY	900	61	75.1	52.2	46.8	43.5	42.7	58.5	56.2	67.3	64.4	61.1	51.1	47.1	40.8	36.6
6/25/2004 21:00	DAY	900	50.9	64.1	50.8	46.6	42.5	41.3	56.4	54.9	49.7	48.8	48.2	47.4	41.8	33.1	34.1
6/25/2004 21:15	DAY	900	53.2	65.4	54.3	47.5	43.6	42.8	59.6	57.8	54.0	53.8	51.9	48.5	43.7	32.1	24.5
6/25/2004 21:30	DAY	900	52.2	65.2	50	44.2	41.5	40.8	56.8	55.3	52.1	49.2	48.7	47.2	45.8	39.4	35.0
6/25/2004 21:45	DAY	900	47.2	57.8	48.5	44.6	40.7	39.2	58.9	57.2	51.9	47.4	44.7	43.0	37.5	23.0	23.3
6/25/2004 22:00	NIGHT	900	49.5	57.9	53	43.5	39.4	38.7	53.8	48.8	48.3	43.2	43.4	44.3	40.6	32.6	45.9
6/25/2004 22:15	NIGHT	900	53.9	62.2	59.5	43.7	39.7	38.4	58.3	56.2	50.3	47.7	46.0	44.6	38.9	28.0	54.2
6/25/2004 22:30	NIGHT	900	44.9	53.3	46.8	43.4	40.3	39.4	50.9	49.6	42.1	42.2	41.9	41.4	36.5	24.8	29.1
6/25/2004 22:45	NIGHT	900	48.3	58.7	48.6	44.5	40.9	40.1	50.4	50.8	46.9	44.2	44.2	45.1	40.2	32.9	29.5
6/25/2004 23:00	NIGHT	900	45.8	53.3	49	44.1	39.9	39.4	50.1	47.8	41.0	43.2	41.7	42.7	37.9	25.6	29.4
6/25/2004 23:15	NIGHT	900	49.7	55.9	52.6	46.3	41.3	40.2	53.9	53.7	43.9	46.0	45.7	46.6	41.9	32.2	28.0
6/25/2004 23:30	NIGHT	900	49.2	58	50.3	45.1	40.8	40.2	50.5	50.8	51.2	49.7	45.5	44.5	41.0	32.4	28.5
6/25/2004 23:45	NIGHT	900	54.5	64.1	49.4	44.3	40.9	39.9	50.3	50.3	63.6	54.9	54.1	45.9	41.9	34.9	31.4
6/26/2004 0:00	NIGHT	900	47.3	60	47.4	42.6	39.3	38.4	49.7	50.0	45.6	46.4	43.4	43.9	38.8	29.8	25.2
6/26/2004 0:15	NIGHT	900	53.6	66.2	55.4	46.3	41.6	40.3	50.5	55.1	51.1	49.5	49.6	49.8	46.0	41.7	38.1
6/26/2004 0:30	NIGHT	900	53.6	60	53.8	49.8	45.8	43.2	52.0	47.3	47.3	44.6	46.5	48.9	47.6	45.0	40.7
6/26/2004 0:45	NIGHT	900	56.1	60.5	56.7	52.4	46.9	46.3	50.3	46.5	43.5	44.6	50.7	51.6	49.9	46.6	44.3
6/26/2004 1:00	NIGHT	900	53.6	57.9	56.4	52.7	49.2	48.4	46.1	49.8	41.2	41.6	44.0	48.7	48.4	44.2	43.3
6/26/2004 1:15	NIGHT	900	51.4	56.5	54.6	50.4	46.4	45.1	47.3	43.1	36.8	39.8	41.0	46.5	46.2	42.1	41.3
6/26/2004 1:30	NIGHT	900	45.3	52.5	48.3	43.3	40.4	39.8	47.8	45.4	46.2	44.7	38.1	39.8	38.8	34.5	33.2
6/26/2004 1:45	NIGHT	900	42.2	47.6	44.2	41.5	39.4	38.8	47.0	44.6	39.1	42.7	37.1	37.1	34.7	29.7	28.1
6/26/2004 2:00	NIGHT	900	40	47.5	42.4	38.4	36.3	36	47.4	43.5	37.4	40.2	34.9	35.3	32.5	27.0	23.8
6/26/2004 2:15	NIGHT	900	36.6	43.1	39.1	35.5	31.6	31.2	47.1	43.0	39.8	38.2	32.5	31.8	27.5	20.2	20.5
6/26/2004 2:30	NIGHT	900	45	50.3	48.2	44.4	39.4	38.9	47.0	44.8	39.8	37.7	36.9	40.5	39.5	34.9	32.9
6/26/2004 2:45	NIGHT	900	43.4	49.9	47.1	41.5	38.2	37.5	48.2	45.1	39.9	42.5	38.9	39.1	35.9	30.2	28.2

Table C7A: Sound Level Results at Measurement Location 7

Start Date and Time	Day / Night	Duration (seconds)	Leq (dB(A))	L1.00 (dB(A))	L10.00 (dB(A))	L50.00 (dB(A))	L90.00 (dB(A))	L95.00 (dB(A))	31.5 dB	63 dB	125 dB	250 dB	500 dB	1000 dB	2000 dB	4000 dB	8000 dB
6/26/2004 3:00	NIGHT	900	40.5	46	44.3	38.2	33.6	31.5	46.2	43.3	35.4	38.7	34.5	35.9	33.8	29.0	27.6
6/26/2004 3:15	NIGHT	900	42	52.7	45.5	37	31.5	30.6	53.8	54.9	52.5	45.4	38.1	33.8	30.2	24.0	22.9
6/26/2004 3:30	NIGHT	900	37.4	44	40.2	36	34.3	34	48.0	43.6	37.0	36.2	33.9	33.5	29.0	23.4	22.1
6/26/2004 3:45	NIGHT	900	41.1	51.5	42.9	38.1	35	34.4	47.0	45.3	37.9	39.9	39.5	37.2	31.7	24.0	19.9
6/26/2004 4:00	NIGHT	900	43.5	55.3	45.8	38	31.6	30.7	53.3	54.8	50.5	46.7	41.7	36.8	31.7	21.9	20.9
6/26/2004 4:15	NIGHT	900	41.9	49	45.7	39.7	34.5	33.6	48.3	46.4	42.6	36.6	37.8	39.2	33.7	22.8	21.1
6/26/2004 4:30	NIGHT	900	47.1	59.3	48.4	41.6	34.4	33.3	50.8	51.2	44.6	42.2	42.7	43.9	39.6	31.9	26.9
6/26/2004 4:45	NIGHT	900	49.2	58.7	47.8	42.4	37.4	36.1	51.6	55.6	56.5	46.4	43.7	44.8	41.3	36.2	36.9
6/26/2004 5:00	NIGHT	900	47.5	55.1	50.7	45.6	39.3	37.6	49.1	46.7	42.1	41.1	43.0	44.7	40.3	26.2	17.8
6/26/2004 5:15	NIGHT	900	51.9	60.7	54.1	49.7	42	39.5	50.4	51.0	50.0	45.4	44.7	46.9	44.5	45.1	39.7
6/26/2004 5:30	NIGHT	900	53.2	62	54.8	51.3	46.6	45.3	50.7	51.5	46.5	43.3	46.2	47.3	42.9	48.7	43.2
6/26/2004 5:45	NIGHT	900	49.8	58.9	52.2	47.4	43.7	42.1	49.7	49.4	41.5	41.5	43.4	45.0	43.3	41.9	36.9
6/26/2004 6:00	NIGHT	900	49.8	60.6	50.1	46.4	42.3	41.3	53.7	56.2	45.1	43.2	43.3	44.2	45.8	36.6	29.7
6/26/2004 6:15	NIGHT	900	50.3	59.9	52.6	48.7	45.4	44.7	51.2	50.7	43.8	42.9	45.1	46.6	43.4	40.2	28.8
6/26/2004 6:30	NIGHT	900	52.8	64.4	53.9	49.8	45.9	44.9	52.4	53.4	54.1	46.0	47.9	48.9	44.7	43.4	39.7
6/26/2004 6:45	NIGHT	900	56.9	68.9	57.8	50.4	46	44.8	55.7	57.2	58.7	58.4	54.0	51.5	48.4	43.2	37.1
6/26/2004 7:00	DAY	900	51.7	59.1	54.5	50	46.2	45.3	52.1	52.8	51.9	49.8	48.6	46.8	43.8	41.5	27.7
6/26/2004 7:15	DAY	900	49.2	57.7	51.5	47.9	44.2	43	51.4	53.1	47.6	44.5	46.2	45.3	41.3	38.0	27.0
6/26/2004 7:30	DAY	900	48.8	55.5	51.6	47.4	44.3	43.6	53.4	51.7	46.0	42.4	45.5	45.5	41.2	33.8	24.5
6/26/2004 7:45	DAY	900	50.2	61.4	51.5	46.8	43.9	42.8	52.9	51.1	54.8	51.8	47.8	44.6	40.3	39.2	33.4
6/26/2004 8:00	DAY	900	50.3	63.4	49	45.3	41.9	40.9	54.1	53.0	49.4	46.2	46.2	47.5	42.2	34.7	27.6
6/26/2004 8:15	DAY	900	45.9	54.6	48.1	43.9	40.3	39.6	55.7	53.1	46.9	44.5	42.3	42.3	36.9	31.8	25.0
6/26/2004 8:30	DAY	291.875	60.6	73.1	59.9	45.4	42.7	42.1	60.4	59.5	61.1	63.6	60.9	52.9	44.5	36.0	31.8

Table C7B: Sound Level Results at Measurement Location 7

Start Date and Time	Day / Night	Duration (seconds)	Leq (dB(A))	L1.00 (dB(A))	L10.00 (dB(A))	L50.00 (dB(A))	L90.00 (dB(A))	L95.00 (dB(A))	31.5 dB	63 dB	125 dB	250 dB	500 dB	1000 dB	2000 dB	4000 dB	8000 dB
6/27/2004 8:14	DAY	15.125	46.6	51.5	49.5	45	42.9	42.4	52.4	47.5	39.5	39.3	39.3	41.9	38.9	38.9	38.0
6/27/2004 8:15	DAY	900	48.6	61	48.4	43.8	39.7	38.7	54.2	51.4	45.1	40.7	42.4	44.6	41.6	39.9	32.7
6/27/2004 8:30	DAY	900	48.1	60.1	48.9	44.3	39.8	37.8	53.9	51.4	46.1	43.8	45.0	44.4	39.5	37.2	26.8
6/27/2004 8:45	DAY	900	54.4	67.4	54.7	44.3	39.6	38.6	54.0	50.6	58.1	54.7	52.6	49.7	43.6	35.6	29.0
6/27/2004 9:00	DAY	900	57.5	71.9	53.6	43.4	39.6	39	57.6	56.0	59.3	60.9	57.1	50.6	42.8	37.2	30.3
6/27/2004 9:15	DAY	900	49.5	62.7	49	44.6	41.2	40.2	54.5	56.7	50.0	45.9	44.6	45.8	42.5	35.7	27.2
6/27/2004 9:30	DAY	900	60	66.8	50.3	43.7	40.1	39.3	54.7	56.0	63.5	62.7	59.3	52.7	48.0	41.8	34.6
6/27/2004 9:45	DAY	900	55.6	65.5	59	45	40.5	39.7	54.4	55.2	56.7	55.0	52.7	43.7	42.3	51.7	37.2
6/27/2004 10:00	DAY	900	57.6	65	57.7	46.4	41.4	40.5	54.7	55.4	63.3	58.8	56.0	47.7	44.6	50.0	36.4
6/27/2004 10:15	DAY	900	56.2	70	51.7	45.5	41.5	40.6	56.3	54.7	59.2	58.7	55.9	48.1	43.6	41.5	34.5
6/27/2004 10:30	DAY	900	56	62.7	48.6	45.4	42.3	41.7	54.4	51.0	62.2	58.1	55.8	47.0	42.1	40.2	32.6
6/27/2004 10:45	DAY	900	56.6	70.4	50.9	46.9	43.7	42.7	59.1	57.2	59.1	57.3	55.4	50.3	48.3	42.1	35.6
6/27/2004 11:00	DAY	900	48.5	58.6	49.8	46.2	42.5	41.5	56.2	52.0	48.7	46.2	44.1	45.0	40.8	34.5	25.5
6/27/2004 11:15	DAY	900	48.2	56.6	50.7	46.6	43.3	42.3	57.5	55.9	48.3	45.6	44.7	44.5	39.8	34.0	26.5
6/27/2004 11:30	DAY	900	55.2	61	52.5	47.4	44.5	43.8	58.2	53.9	64.0	58.9	53.8	47.7	44.3	38.3	33.0
6/27/2004 11:45	DAY	900	57.3	71.1	52	47.6	44.5	43.6	58.9	56.2	57.9	60.4	57.1	50.1	43.6	35.6	28.2
6/27/2004 12:00	DAY	900	51.5	58.7	50.6	47.1	43.7	42.9	57.9	57.7	59.2	51.8	47.1	46.3	43.1	38.6	31.8
6/27/2004 12:15	DAY	900	54.5	65.9	57.4	48.1	45.3	44.6	58.4	53.7	50.0	52.7	50.3	46.2	43.5	50.0	37.3
6/27/2004 12:30	DAY	900	55.5	67.3	58.8	49.5	45.9	45	58.7	54.4	55.0	55.4	51.5	47.4	43.9	50.7	37.5
6/27/2004 12:45	DAY	900	56	66.3	60.6	49.4	45.4	44.3	60.1	56.6	54.0	55.3	52.0	48.4	44.5	74.8	76.6
6/27/2004 13:00	DAY	900	55.4	65	60	49.8	44.9	43.8	58.3	52.7	49.3	48.8	47.4	47.0	44.4	52.4	40.1
6/27/2004 13:15	DAY	900	58	70.6	61	50	45.7	44.7	58.4	55.4	57.2	59.3	55.4	49.0	44.9	52.4	40.8
6/27/2004 13:30	DAY	900	54.5	64.4	58.2	48.5	44.7	44.1	58.3	60.3	55.1	49.0	47.1	46.8	43.3	51.0	39.9
6/27/2004 13:45	DAY	900	54.5	65.4	58.4	48.6	44.6	43.7	57.4	51.7	46.0	44.8	44.7	45.7	44.3	51.7	39.0
6/27/2004 14:00	DAY	900	55.1	66	58.1	48.6	45.1	44.4	60.0	58.7	52.6	53.4	51.0	48.7	46.6	48.7	36.7
6/27/2004 14:15	DAY	900	51	61.2	51	47.3	44.1	43.1	56.3	51.7	58.6	47.1	47.1	47.2	42.3	35.1	29.7
6/27/2004 14:30	DAY	900	51	62.3	50.9	47.4	44.1	43.3	57.3	56.6	50.2	45.4	46.8	47.4	43.1	38.8	32.3
6/27/2004 14:45	DAY	900	70.2	73.8	51.9	48.2	45.1	44.3	57.1	67.1	70.6	67.4	68.9	65.6	61.0	54.5	53.3
6/27/2004 15:00	DAY	900	48.1	54.7	50.6	47.1	43.7	42.9	55.8	50.6	45.3	43.3	44.3	45.1	40.2	31.5	24.1
6/27/2004 15:15	DAY	900	50.2	60.7	51	47.3	44.3	43.6	55.7	52.7	52.5	47.5	46.6	46.5	42.5	35.0	29.1
6/27/2004 15:30	DAY	900	47.9	55.2	50	45.5	42.1	41.3	54.8	50.6	47.3	44.7	42.1	43.6	40.5	38.8	29.6
6/27/2004 15:45	DAY	900	54.1	68.9	50.3	43.8	40.4	39.8	57.5	55.2	55.6	56.7	53.9	47.6	40.0	32.8	23.5
6/27/2004 16:00	DAY	900	43.1	49	45.1	41.3	38.8	38.1	54.9	50.8	44.5	39.0	39.0	39.6	34.8	30.3	23.8
6/27/2004 16:15	DAY	900	58.6	73.6	51.1	46.5	43.6	43	57.6	55.6	58.9	61.1	58.2	52.1	46.4	38.1	29.8
6/27/2004 16:30	DAY	900	55.9	70.3	53.3	47.8	44.3	43.7	57.7	56.0	57.7	59.1	55.8	48.6	41.7	36.6	27.9
6/27/2004 16:45	DAY	900	47.4	55.4	49	45.1	42.3	41.6	53.8	49.8	49.8	44.2	43.9	44.2	38.8	32.3	25.7
6/27/2004 17:00	DAY	900	52.7	61	48.8	45.9	42.8	41.6	54.4	50.1	58.5	53.7	53.2	45.0	41.5	37.8	30.9
6/27/2004 17:15	DAY	900	46.2	51.9	48	45.2	42.4	41.5	53.0	50.0	47.7	40.3	41.8	43.0	37.1	35.4	25.5
6/27/2004 17:30	DAY	900	48.3	57.7	49.4	44.8	41.4	40.6	55.6	60.3	50.4	44.9	43.5	43.4	39.2	38.9	30.5
6/27/2004 17:45	DAY	900	47.1	57.7	48	43.7	40.8	40	55.0	53.3	46.4	44.8	44.3	43.3	38.0	34.0	25.4
6/27/2004 18:00	DAY	900	57.8	65.8	49.2	45.6	42.8	41.3	54.3	53.5	58.0	58.6	58.1	49.5	44.9	45.0	37.4
6/27/2004 18:15	DAY	900	52.3	65.2	51.6	45.3	42	40.6	56.0	54.6	55.4	55.5	51.5	45.7	38.9	35.5	29.7
6/27/2004 18:30	DAY	900	47.9	55.3	48.9	45.9	43.9	43.3	54.1	50.7	46.5	41.3	42.9	44.2	40.4	37.1	34.2
6/27/2004 18:45	DAY	900	51.8	66.6	49.4	45.8	42.9	41.6	59.6	55.1	46.7	46.7	46.8	47.5	45.8	40.4	33.5
6/27/2004 19:00	DAY	900	57	71.7	52.6	46.1	42.1	41	60.2	63.8	61.9	61.9	56.0	48.2	39.8	29.6	42.0
6/27/2004 19:15	DAY	900	60.3	67.7	64.9	56.6	42.3	40.9	54.1	53.8	46.6	43.4	43.0	42.0	36.5	28.0	61.3
6/27/2004 19:30	DAY	900	62.7	68.3	66.7	60.6	52.9	49.9	56.2	54.3	55.6	55.4	50.8	43.8	36.0	24.1	63.7
6/27/2004 19:45	DAY	900	58.9	65.8	64	55.2	45.8	44.6	55.5	51.2	43.7	42.3	41.8	41.6	35.3	24.3	60.0
6/27/2004 20:00	DAY	900	52.3	60.8	58.7	46.3	40.4	39.4	53.8	47.3	43.6	40.4	40.7	41.4	36.3	25.8	52.8
6/27/2004 20:15	DAY	900	48.2	55	54.1	43	39.9	39.3	54.2	47.3	40.0	39.0	40.5	40.9	34.7	23.4	47.6
6/27/2004 20:30	DAY	900	42.8	48	45.3	42	38.7	37.8	54.3	47.8	43.3	39.1	39.6	39.9	34.0	22.2	22.2
6/27/2004 20:45	DAY	900	47.8	59.9	48.8	42.6	38.2	36.9	56.3	52.2	46.9	47.7	44.7	43.8	39.1	29.1	32.7
6/27/2004 21:00	DAY	900	48.9	58	53.6	44.7	40.8	39.5	53.8	48.9	46.0	42.4	44.9	42.5	37.3	27.8	46.9
6/27/2004 21:15	DAY	900	48.5	61.9	46.8	41.4	37.9	37	55.3	53.9	49.8	45.6	44.7	44.5	40.8	34.6	29.9
6/27/2004 21:30	DAY	900	47.8	59	52.6	40.9	38.1	37.5	55.7	52.0	46.7	44.9	43.3	41.7	35.7	27.4	45.0
6/27/2004 21:45	DAY	900	42	47.3	44.3	41.2	38.6	37.9	50.4	47.6	44.8	39.9	38.7	38.5	32.8	20.6	29.3
6/27/2004 22:00	NIGHT	900	46.2	53.3	46.9	43.5	40.5	39.4	50.3	54.8	51.7	46.1	42.3	42.1	37.7	30.7	25.8
6/27/2004 22:15	NIGHT	900	46.6	55	46.9	43.2	39.2	38.1	48.7	55.3	45.6	43.3	42.2	43.3	38.6	32.1	29.1
6/27/2004 22:30	NIGHT	900	44.6	51.6	47.5	43.1	39.2	38.3	48.0	48.2	42.2	40.4	41.8	41.5	35.9	23.4	28.1
6/27/2004 22:45	NIGHT	900	42.3	49.7	45.7	40.2	36.2	35.4	51.1	50.0	44.4	42.0	39.7	38.5	32.2	21.8	22.0
6/27/2004 23:00	NIGHT	900	40.4	46.9	43.1	39.3	36.1	35.4	50.3	49.4	44.6	41.1	36.7	36.6	29.9	19.1	22.6
6/27/2004 23:15	NIGHT	900	44.5	50.7	44.5	40.4	36.5	36.1	55.4	53.8	44.2	43.0	41.2	40.1	36.4	27.5	33.3
6/27/2004 23:30	NIGHT	900	40.7	46.8	45.2	38.3	34.3	33.4	47.4	45.5	37.8	35.7	34.5	35.1	29.6	20.3	38.4
6/27/2004 23:45	NIGHT	900	49.9	55.9	54.8	41.2	36	35.4	48.8	45.1	39.0	41.3	34.8	34.8	29.4	18.9	50.9
6/28/2004 0:00	NIGHT	900	47.3	52.4	49.6	47.3	39.7	38.5	49.3	45.7	41.5	43.9	35.9	35.1	29.2	18.3	48.0
6/28/2004 0:15	NIGHT	900	50.4	53.3	51.4	50.2	48	40.8	49.5	46.8	42.6	44.8	36.9	41.3	30.2	18.9	51.1
6/28/2004 0:30	NIGHT	900	51.7	57.3	54.1	51.1	40.5	39.5	50.2	47.3	45.3	47.1	42.0	36.5	30.9	21.9	52.6
6/28/2004 0:45	NIGHT	900	42.8	53.3	43.8	39.1	36.3	35.7	50.9	44.1	41.8	41.2	37.7	34.6	30.0	21.4	41.2
6/28/2004 1:00	NIGHT	900	56.7	60.5	51.3	40.6	36.1	35.3	52.1	46.7	53.7	58.4	58.1	46.8	44.0	38.8	46.8
6/28/2004 1:15	NIGHT	900	37.5	42.2	39.5	37	34.7	34.1	49.2	44.4	41.6	40.8	34.5	30.2	24.7	20.3	27.0
6/28/2004 1:30	NIGHT	900	38.7	42.7	40.7	38.4	36.3	35.8	48.9	45.6	40.5	42.6	34.9	31.4	25.5	19.2	30.1
6/28/2004 1:45	NIGHT	900	39.4	44.2	41	38.8	36.6	36.1	50.0	45.8	43.0	42.0	36.6	32.0	25.0	17.5	33.5

Table C7B: Sound Level Results at Measurement Location 7

Start Date and Time	Day / Night	Duration (seconds)	Leq (dB(A))	L1.00 (dB(A))	L10.00 (dB(A))	L50.00 (dB(A))	L90.00 (dB(A))	L95.00 (dB(A))	31.5 dB	63 dB	125 dB	250 dB	500 dB	1000 dB	2000 dB	4000 dB	8000 dB
6/28/2004 2:00	NIGHT	900	47	60.1	47.2	40.1	37.2	36.6	55.0	58.2	57.6	51.3	43.9	33.6	24.8	16.7	38.9
6/28/2004 2:15	NIGHT	900	40.5	49.4	41.8	39.2	37.1	36.4	48.9	48.5	47.7	44.9	36.8	33.5	27.0	18.5	25.8
6/28/2004 2:30	NIGHT	900	37.7	43.6	39.7	36.9	35.2	34.7	48.9	44.3	40.1	41.4	33.9	31.1	26.6	17.0	24.0
6/28/2004 2:45	NIGHT	900	47.8	59.4	42.2	38.8	36.3	35.7	51.0	47.0	47.4	46.0	42.9	41.3	41.8	38.5	33.7
6/28/2004 3:00	NIGHT	900	42.1	47.6	43.7	41.6	39.6	39	63.9	54.1	46.4	45.1	39.9	35.2	29.2	20.2	23.4
6/28/2004 3:15	NIGHT	900	47	60	48.4	42	39.7	39.3	64.8	56.4	50.7	49.1	44.6	40.9	38.0	23.4	25.1
6/28/2004 3:30	NIGHT	900	41.3	47.1	44.9	39.6	37.3	37.1	64.3	53.9	47.6	41.5	37.4	36.8	31.8	19.7	24.5
6/28/2004 3:45	NIGHT	900	46.4	58.8	48.9	40.1	37.1	36.6	63.3	52.8	48.0	46.8	43.6	41.7	37.7	28.4	25.8
6/28/2004 4:00	NIGHT	900	51.2	64.9	51.2	42.5	38.2	37.6	63.6	59.3	56.9	54.2	50.5	44.4	37.2	24.6	29.2
6/28/2004 4:15	NIGHT	900	43.2	52.7	45.9	40.6	36.8	35.9	63.2	52.2	47.7	41.6	39.6	39.5	34.5	25.3	21.3
6/28/2004 4:30	NIGHT	900	43.7	51.9	47	41.5	36.7	36.1	62.9	50.8	45.7	39.9	40.4	40.5	35.0	22.5	17.3
6/28/2004 4:45	NIGHT	900	47.1	57.6	49.3	44	39.8	38.8	63.1	51.5	46.3	43.2	42.9	44.2	39.0	29.9	24.1
6/28/2004 5:00	NIGHT	900	53.2	67.5	51.9	45.7	42	41.2	64.2	58.0	53.0	54.0	52.3	47.8	43.1	30.8	20.8
6/28/2004 5:15	NIGHT	900	49.5	54.1	52.4	48.3	45.3	44.7	65.2	57.2	50.9	47.0	43.7	41.7	37.0	45.0	39.2
6/28/2004 5:30	NIGHT	900	53.5	62	56.2	50.7	47.9	47.3	65.5	55.0	48.9	45.5	44.9	45.0	40.8	50.1	46.0
6/28/2004 5:45	NIGHT	900	53.7	65.9	53.5	49.9	47.1	46.2	64.7	55.7	49.8	46.2	46.0	47.2	50.0	42.7	37.0
6/28/2004 6:00	NIGHT	900	62.3	70.6	55.8	51.9	48.5	47.5	62.0	54.2	51.1	49.6	49.9	50.2	60.1	51.0	44.5
6/28/2004 6:15	NIGHT	900	58.5	69.4	58.3	52.8	49.6	48.8	56.4	62.2	59.0	55.5	55.3	54.7	50.5	45.9	38.8
6/28/2004 6:30	NIGHT	900	58.2	68.9	61.3	53.6	50.1	49.3	57.7	60.6	61.1	55.8	55.7	53.9	50.3	43.1	36.5
6/28/2004 6:45	NIGHT	900	61.2	72.5	63.5	52.5	48.3	47.2	58.3	60.8	60.5	59.8	58.2	54.7	56.1	44.6	38.9
6/28/2004 7:00	DAY	900	52.6	64.2	52.5	49.2	46.3	45.8	56.4	61.4	57.8	51.0	49.9	48.3	43.6	39.0	32.1
6/28/2004 7:15	DAY	900	53.3	65.8	54	47.2	43.8	43	57.8	60.6	51.3	49.3	50.1	49.6	45.5	39.4	36.6
6/28/2004 7:30	DAY	900	53.8	65.8	50.1	43.9	40.6	40.1	57.0	59.0	53.9	53.6	50.3	47.7	46.5	42.7	36.5
6/28/2004 7:45	DAY	900	47.1	58.7	48.2	42.8	39.5	38.9	55.0	55.8	49.9	45.2	43.9	43.1	38.0	34.5	25.6
6/28/2004 8:00	DAY	900	49.7	62.4	50.4	46.4	43.2	42.2	57.5	58.6	51.0	45.0	46.1	46.0	41.1	37.9	35.8
6/28/2004 8:15	DAY	900	61	69	63.9	58.9	53.5	52	57.1	60.2	61.4	55.2	57.0	55.6	56.2	44.7	37.7
6/28/2004 8:30	DAY	900	60.8	71.1	62.7	56.3	47.1	46	65.7	66.7	62.9	57.2	56.7	56.0	54.8	45.9	39.8
6/28/2004 8:45	DAY	900	57.5	68.1	60.4	54.6	48.6	47.1	59.7	56.8	55.6	56.5	54.9	51.9	51.3	39.2	29.8
6/28/2004 9:00	DAY	900	56.5	62.4	59.4	55.2	51.9	50.9	56.4	53.7	49.1	45.0	51.9	51.4	51.7	41.8	32.1
6/28/2004 9:15	DAY	900	57.2	66.6	58.9	54.2	49.9	48.5	56.2	55.1	58.0	54.5	55.2	51.7	50.8	39.7	33.3
6/28/2004 9:30	DAY	900	61	71.6	63.2	55.4	48.9	47.3	58.3	60.1	64.3	59.5	56.5	55.4	53.5	52.6	40.4
6/28/2004 9:45	DAY	900	56.2	65.2	60	53.4	46.2	45.1	56.7	54.6	51.2	49.9	50.7	49.3	49.0	50.8	36.1
6/28/2004 10:00	DAY	900	57.1	68.9	60.5	50.8	46	45.1	58.9	62.9	54.4	54.9	52.1	51.5	49.0	50.5	38.2
6/28/2004 10:15	DAY	900	60.4	72.9	60.2	50	46.3	45.4	60.6	60.1	62.2	62.5	59.5	53.2	48.7	47.0	39.4
6/28/2004 10:30	DAY	900	57.1	63.5	55.2	51.7	49.2	48.4	60.9	59.1	58.6	54.1	53.0	52.5	50.0	44.1	37.7
6/28/2004 10:45	DAY	900	55.3	68.5	54.6	51.3	48.2	47.2	60.6	58.9	57.1	55.4	53.7	50.0	47.1	38.2	31.1
6/28/2004 11:00	DAY	900	53.6	64.9	54.6	50.4	48.1	47.4	58.0	57.8	53.9	50.1	50.0	49.7	46.5	39.0	30.9
6/28/2004 11:15	DAY	900	55.7	69	55	49.9	47	46.1	59.9	57.7	53.9	56.5	54.3	50.3	47.0	39.5	32.1
6/28/2004 11:30	DAY	900	52.3	65.2	53.1	47.9	44.8	44.2	59.2	54.4	52.1	50.4	48.6	48.4	44.0	40.3	32.6
6/28/2004 11:45	DAY	900	53.9	63.8	56.8	50.2	46.4	45.5	58.2	57.4	56.8	53.5	51.0	49.4	45.6	40.4	29.8
6/28/2004 12:00	DAY	900	56.1	70.1	55.9	49.5	45.2	44.5	59.3	61.6	62.6	58.1	52.4	50.8	48.2	41.3	32.9
6/28/2004 12:15	DAY	900	57	69.7	59.1	50	46.3	45	59.7	59.1	57.3	59.4	55.8	51.2	46.4	39.7	29.1
6/28/2004 12:30	DAY	900	55.3	70.5	53.8	49.2	45.8	45	61.9	59.5	56.7	56.4	52.6	50.3	46.4	40.4	32.6
6/28/2004 12:45	DAY	900	53.9	64.9	53.7	48.7	45.2	44.4	57.9	56.0	52.2	50.1	50.3	49.9	46.6	40.2	33.0
6/28/2004 13:00	DAY	900	52.8	63.7	53.1	48.9	44.9	43.6	58.4	55.3	51.4	49.1	49.3	48.5	45.6	39.5	31.8
6/28/2004 13:15	DAY	900	57.2	71.1	54.2	48.6	45.6	44.7	59.1	59.6	57.4	58.5	55.8	51.9	47.4	42.2	36.7
6/28/2004 13:30	DAY	900	59.5	73	60.2	47.5	43.9	43.3	67.0	70.1	62.8	60.6	57.8	53.5	50.0	44.1	39.4
6/28/2004 13:45	DAY	900	60.6	74.9	58.3	49.6	45.2	44	60.6	66.0	59.0	60.0	58.2	55.8	52.3	45.9	39.5
6/28/2004 14:00	DAY	900	55.7	64.1	58.8	50.5	46.8	46	59.8	58.5	55.6	55.0	52.8	51.4	47.5	40.2	33.0
6/28/2004 14:15	DAY	900	54.5	62.5	54	49.8	46.3	45.6	58.6	55.7	52.4	53.3	52.0	50.3	45.9	41.0	32.4
6/28/2004 14:30	DAY	900	57.3	67.6	53.4	48.8	46	45.4	58.0	60.5	56.5	53.4	53.9	53.7	49.6	44.2	35.2
6/28/2004 14:45	DAY	900	55	68.1	54.7	49.1	45.1	43.7	57.8	57.1	57.1	56.9	53.3	50.0	44.2	38.2	34.3
6/28/2004 15:00	DAY	900	57.5	69.5	59.8	50.5	45.8	44.5	59.8	66.4	58.5	55.2	53.6	53.0	50.2	45.3	38.6
6/28/2004 15:15	DAY	900	58.8	69.6	62.4	50.5	46.3	45.1	61.8	62.8	61.2	57.6	55.6	54.8	50.7	43.4	37.9
6/28/2004 15:30	DAY	900	58.6	72.5	59.2	48.9	45.6	45	59.7	70.5	62.9	59.2	56.8	52.3	50.0	44.4	37.9
6/28/2004 15:45	DAY	900	59.5	71.2	51.7	48.2	45	43.1	57.5	60.3	62.1	54.9	57.3	54.9	50.0	47.3	41.1
6/28/2004 16:00	DAY	900	59.6	72.9	57.1	47.7	44.2	43.5	59.8	60.0	63.8	62.2	59.9	52.3	47.8	41.7	39.2
6/28/2004 16:15	DAY	900	53.4	64	50.6	45.9	42.9	42.4	57.4	55.2	58.3	55.5	53.4	45.8	42.2	35.3	29.6
6/28/2004 16:30	DAY	900	56.5	69.1	60.5	47.5	44	42.7	57.4	56.1	57.9	59.0	54.2	47.7	41.1	50.2	35.4
6/28/2004 16:45	DAY	900	56.1	66.1	61.4	47.9	44.2	43.3	55.1	53.0	44.6	43.1	44.5	45.3	42.8	54.3	38.9
6/28/2004 17:00	DAY	900	57.2	66.9	62.5	49.4	44.4	43.1	54.8	52.9	55.1	46.3	45.6	46.8	44.4	55.1	40.6
6/28/2004 17:15	DAY	900	56.4	66.3	61.7	49.1	45.1	44.2	55.7	55.0	56.4	50.4	49.8	48.7	45.9	52.8	41.2
6/28/2004 17:30	DAY	900	52.1	65.6	51.8	46.4	42.6	41.6	56.0	56.3	50.3	47.2	48.4	48.5	44.4	39.7	32.6
6/28/2004 17:45	DAY	900	59.2	72.1	56.9	46.5	42.9	41.9	56.4	55.8	65.4	64.0	58.1	50.2	44.8	41.6	34.0
6/28/2004 18:00	DAY	900	50.8	62.2	50.8	45.7	41.5	40.6	55.0	52.0	49.8	47.7	46.1	45.0	44.5	42.2	33.8
6/28/2004 18:15	DAY	900	51.5	64.2	50.5	45.6	41.4	40.5	58.0	54.1	54.1	46.0	47.2	47.4	44.0	40.5	35.8
6/28/2004 18:30	DAY	900	47.9	59.7	48.3	44	41	39.9	54.9	53.5	47.9	43.6	43.8	44.1	40.9	33.8	27.7
6/28/2004 18:45	DAY	900	48.9	59.9	51	46.1	42.4	41.6	53.1	50.9	47.5	43.8	44.3	44.8	40.9	40.0	32.7
6/28/2004 19:00	DAY	900	49	55.9	52.7	46.8	42.7	41.9	53.5	50.5	42.6	39.1	41.2	42.2	43.8	42.3	33.6
6/28/2004 19:15	DAY	900	62.1	71.6	67.9	46.2	42.2	41.1	55.0	51.4	45.9	45.9	45.1	43.3	37.1	27.2	63.2
6/28/2004 19:30	DAY	900	65.3	73.6	68.9	62.6	48.9	46.3	58.6	56.9	59.6	62.0	58.5	50.0	40.0	25.4	65.5
6/28/2004 19:45	DAY	900	67.5	72.9	71.8	66	47.8	44.3	55.7	55.5	51.7	50.5	47.3	45.9	41.0	32.2	68.4

Table C7B: Sound Level Results at Measurement Location 7

Start Date and Time	Day / Night	Duration	Leq	L1.00	L10.00	L50.00	L90.00	L95.00	31.5	63	125	250	500	1000	2000	4000	8000
		(seconds)	(dB(A))	(dB(A))	(dB(A))	(dB(A))	(dB(A))	(dB(A))	dB	dB	dB	dB	dB	dB	dB	dB	dB
6/28/2004 20:00	DAY	900	58.4	66.7	63.6	50.4	45.6	44.6	54.7	53.5	49.4	47.8	46.0	45.7	40.9	31.5	59.0
6/28/2004 20:15	DAY	900	51.3	60.2	55.8	47.3	42.9	41.9	54.8	55.3	51.1	50.2	47.4	46.2	40.9	31.3	46.0
6/28/2004 20:30	DAY	900	50.6	59.4	54.7	47.1	43	41.6	53.2	53.8	50.4	48.9	46.4	46.0	40.8	30.9	44.8
6/28/2004 20:45	DAY	900	47.9	58.4	49.6	46.2	41.6	40.1	53.9	52.6	48.2	45.5	44.5	44.7	39.6	28.3	25.8
6/28/2004 21:00	DAY	900	48.4	57.8	50.7	46.4	42.2	41.1	52.1	52.0	50.7	46.7	45.1	45.0	39.8	28.2	22.8
6/28/2004 21:15	DAY	900	58.5	67.8	66.2	46.4	41.6	40.6	52.0	51.9	47.8	45.8	43.9	44.1	39.0	27.9	59.5
6/28/2004 21:30	DAY	900	49.1	59.3	51	46	42	41.1	55.0	55.6	52.4	50.6	46.4	44.6	39.4	29.0	24.5
6/28/2004 21:45	DAY	900	49.1	59.6	51.3	46.4	42.6	41.6	52.4	53.6	49.7	48.0	46.3	45.2	40.2	30.7	37.0
6/28/2004 22:00	NIGHT	900	55.8	65.2	61.3	45.1	40.7	39.7	52.4	54.1	47.5	45.4	43.5	43.4	37.6	27.5	56.6
6/28/2004 22:15	NIGHT	900	53.2	62.4	59.6	44.7	40.6	39.2	48.1	48.8	45.1	42.1	41.9	41.9	35.7	24.9	53.8
6/28/2004 22:30	NIGHT	900	45	51	47.6	44.3	39.8	38.9	51.0	49.6	42.4	43.4	42.8	41.3	36.2	25.4	26.9
6/28/2004 22:45	NIGHT	900	45.4	54.9	46.8	42.7	39.6	38.7	47.1	45.6	43.1	40.3	41.7	42.4	36.9	28.0	30.8
6/28/2004 23:00	NIGHT	900	53.5	63.6	55.9	44.6	38.3	36.8	46.0	45.9	41.7	38.6	40.7	40.8	35.1	24.5	53.5
6/28/2004 23:15	NIGHT	900	39.4	45.9	42.8	37.9	33	32.3	44.4	44.0	37.6	35.8	35.1	36.3	31.7	21.5	21.4
6/28/2004 23:30	NIGHT	900	39.7	46.3	42.2	38.8	35.2	34.4	46.0	46.6	41.7	37.9	36.6	36.1	30.6	20.3	26.0
6/28/2004 23:45	NIGHT	900	39.7	50.5	41.7	37.9	33.9	32.7	46.5	45.6	42.6	38.0	36.7	36.0	30.5	22.0	23.2
6/29/2004 0:00	NIGHT	900	49.5	59.5	56.1	36.9	32.9	31.8	45.3	45.1	38.4	34.9	33.9	33.3	27.3	19.0	50.4
6/29/2004 0:15	NIGHT	900	57.8	64	63.1	52.5	35.5	34.3	45.3	44.7	45.7	40.8	39.6	36.4	30.6	20.9	58.6
6/29/2004 0:30	NIGHT	900	47.7	53.9	52.6	41.8	32.5	31.8	44.4	39.6	33.9	34.7	35.3	34.9	29.9	22.5	48.0
6/29/2004 0:45	NIGHT	900	42.9	52.9	44.1	35.8	32.5	32.1	44.1	42.2	37.9	35.3	33.3	33.0	28.8	23.7	42.3
6/29/2004 1:00	NIGHT	900	37.4	45.8	40.8	35	33	32.5	45.6	40.7	35.1	35.5	34.1	32.2	27.1	22.5	32.1
6/29/2004 1:15	NIGHT	900	50.5	61.3	49.8	36.4	31.5	31.1	46.5	41.9	36.9	34.3	32.6	33.2	27.0	22.1	50.9
6/29/2004 1:30	NIGHT	900	48.6	60.6	55.2	35.6	32.3	31.9	44.2	42.0	38.5	34.3	34.3	29.6	23.5	20.2	49.5
6/29/2004 1:45	NIGHT	900	45.9	57.5	41.8	34.1	32.2	31.9	45.7	42.7	37.9	34.1	31.5	28.9	23.8	18.2	47.3
6/29/2004 2:00	NIGHT	900	48.9	59.8	47.5	35.8	31.1	30.5	43.7	42.4	38.1	32.8	30.7	31.0	25.6	17.7	49.7
6/29/2004 2:15	NIGHT	900	42.1	59.4	36.3	30.8	28.3	28	44.2	44.8	40.4	29.7	26.6	26.7	22.2	15.9	42.9
6/29/2004 2:30	NIGHT	900	47	50.9	50	47.8	31.2	30.4	45.7	45.3	37.2	28.6	28.0	30.2	25.2	16.6	47.7
6/29/2004 2:45	NIGHT	900	34.8	47.5	34.8	30.1	27.7	27.3	43.8	43.0	38.0	32.7	31.6	30.2	25.0	18.4	27.9
6/29/2004 3:00	NIGHT	900	51.5	65	49.5	33.7	30.5	30.1	53.4	54.6	56.7	55.9	50.4	42.7	34.5	21.5	40.8
6/29/2004 3:15	NIGHT	900	56.8	66.9	64.3	39	33.8	33.2	49.5	50.9	51.6	49.3	42.5	39.3	38.2	35.4	57.7
6/29/2004 3:30	NIGHT	900	39.4	50.9	37.6	34.8	33.2	33	48.2	45.3	37.2	37.6	32.9	29.2	23.8	18.5	38.3
6/29/2004 3:45	NIGHT	900	36.3	42.5	38.4	35.5	34	33.5	48.7	46.9	38.0	38.9	33.6	31.3	24.4	16.7	20.4
6/29/2004 4:00	NIGHT	900	48.5	55.8	54.4	38.5	35.3	34.8	48.7	45.8	39.4	40.6	33.8	31.5	24.5	16.5	48.9
6/29/2004 4:15	NIGHT	900	45.1	55.8	48.4	39.5	35.9	35.2	50.8	49.4	40.8	42.1	41.4	41.1	38.5	27.7	29.0
6/29/2004 4:30	NIGHT	900	40.2	45.9	43	38.9	36	35.4	49.1	48.1	38.1	39.1	37.6	36.9	29.4	18.2	25.1
6/29/2004 4:45	NIGHT	900	43.9	51.1	46.8	42.2	37.3	35.9	48.9	47.2	40.9	39.5	41.8	40.7	35.0	24.9	20.1
6/29/2004 5:00	NIGHT	900	46.1	54.2	48.8	43.6	38.2	36.1	48.6	49.5	45.5	39.3	42.3	43.3	38.2	27.7	19.8
6/29/2004 5:15	NIGHT	900	50.1	57	53.6	48.8	38.3	36.8	48.7	49.1	41.5	44.3	45.2	45.9	41.8	42.0	37.3
6/29/2004 5:30	NIGHT	900	51.5	59.2	53.3	49.7	47.1	46.3	50.4	56.2	48.3	46.2	45.7	46.7	43.4	44.4	38.1
6/29/2004 5:45	NIGHT	900	54.4	68.3	52.8	47.5	45	44.4	55.6	58.1	58.7	58.4	52.2	47.4	42.0	39.0	31.7
6/29/2004 6:00	NIGHT	900	50.6	63.3	50.7	46	44.1	43.6	53.2	53.7	49.3	46.5	46.8	46.2	43.6	39.7	34.0
6/29/2004 6:15	NIGHT	900	56.5	70.1	58.4	48.3	45.6	45.1	58.2	57.7	57.9	56.2	53.2	50.8	50.2	41.7	34.7
6/29/2004 6:30	NIGHT	900	54.9	66.5	57.8	47.5	44.8	44.2	58.3	61.8	60.3	53.4	51.6	50.1	47.1	42.2	33.6
6/29/2004 6:45	NIGHT	900	58	69.4	61.5	47.6	43.9	42.6	57.8	59.3	62.9	58.1	55.6	52.6	50.2	41.8	34.7
6/29/2004 7:00	DAY	900	54	66.6	54.2	46.5	42.4	41.6	59.3	66.3	53.3	53.4	51.5	48.9	45.2	39.3	32.9
6/29/2004 7:15	DAY	900	48.8	60.8	46.6	42.9	39.9	39.3	57.0	59.5	48.1	44.5	44.1	44.6	41.3	38.0	31.4
6/29/2004 7:30	DAY	900	53.1	67	49.8	43.8	40.5	39.7	56.8	62.8	54.3	49.2	49.8	48.8	45.4	40.1	31.9
6/29/2004 7:45	DAY	900	54.7	67.5	54.3	47.5	43.4	42.5	56.8	57.8	57.9	50.7	51.9	49.9	46.6	44.1	39.2
6/29/2004 8:00	DAY	241.375	52.1	65.5	51.7	48.3	45.7	44.6	58.5	57.5	48.8	46.1	49.1	49.0	42.6	39.3	34.9

Table C8: Sound Level Results at Measurement Location 8

Start Date and Time	Day / Night	Duration (seconds)	Leq (dB(A))	L1.00 (dB(A))	L10.00 (dB(A))	L50.00 (dB(A))	L90.00 (dB(A))	L95.00 (dB(A))	31.5 dB	63 dB	125 dB	250 dB	500 dB	1000 dB	2000 dB	4000 dB	8000 dB
6/25/2004 15:07	DAY	468.5	54.4	64.7	58.1	49.4	45.7	45	64.8	62.8	63.7	56.3	52.7	46.8	40.9	34.1	28.7
6/25/2004 15:15	DAY	900	47.8	53.2	50	47	44.5	44.1	62.7	55.3	48.6	45.6	45.3	44.4	37.7	27.7	19.9
6/25/2004 15:30	DAY	900	56.6	70.5	52.9	47.7	45.5	45	63.5	57.1	55.2	55.3	55.1	52.4	47.4	39.4	30.1
6/25/2004 15:45	DAY	900	47.9	54.5	49.8	47	45.1	44.7	62.8	55.2	47.7	43.7	45.3	44.6	38.2	28.3	20.8
6/25/2004 16:00	DAY	900	47.9	53.4	50	47.1	44.8	44.2	63.6	57.7	47.2	43.6	45.8	43.9	38.4	29.0	24.1
6/25/2004 16:15	DAY	900	52.6	66	51.5	47.1	43.6	43.1	63.5	58.8	59.8	53.3	52.4	45.8	38.7	28.6	23.0
6/25/2004 16:30	DAY	900	51.5	63.8	52	46	43	42.3	63.3	59.2	59.4	52.7	50.1	45.3	38.3	28.1	22.1
6/25/2004 16:45	DAY	900	48	58.3	49.7	46.6	43.9	43.2	63.5	55.4	47.5	45.2	45.7	44.3	38.7	28.7	23.1
6/25/2004 17:00	DAY	900	45.5	50.6	47.9	44.5	42.1	41.5	64.0	55.9	46.8	39.3	40.2	42.1	38.4	28.5	22.9
6/25/2004 17:15	DAY	900	52.4	65.8	51.7	46.4	43.6	42.4	63.4	59.3	60.5	53.6	51.3	45.9	38.4	28.0	22.5
6/25/2004 17:30	DAY	900	47	51.5	49.2	46.4	44.3	43.7	62.9	55.3	47.5	42.4	44.3	43.5	38.0	28.4	21.9
6/25/2004 17:45	DAY	900	45.9	51.7	48.4	45.3	41.7	40.6	61.9	56.4	44.6	38.5	40.8	42.9	38.3	27.8	15.9
6/25/2004 18:00	DAY	900	54.8	68.7	49.3	46.1	44	43.4	62.7	57.4	57.2	56.3	54.4	48.5	42.8	37.6	32.8
6/25/2004 18:15	DAY	900	50.9	63.3	51.9	46.5	44.1	43.3	62.7	60.0	60.2	50.9	48.9	44.9	38.0	28.3	15.7
6/25/2004 18:30	DAY	900	45.9	49.8	47.8	45.5	43.5	43.1	62.3	54.3	43.7	39.0	43.1	42.8	36.3	26.8	14.9
6/25/2004 18:45	DAY	900	46	49.8	47.9	45.6	43.3	42.7	62.0	53.8	43.4	38.0	41.4	43.0	38.6	27.1	14.5
6/25/2004 19:00	DAY	900	46.7	51.1	48.9	46.1	43.9	43.3	62.2	54.7	47.0	41.5	42.7	43.8	38.1	27.2	13.9
6/25/2004 19:15	DAY	900	45.2	50.2	47.3	44.8	41.8	41.1	62.2	54.3	44.2	36.0	38.8	41.9	39.0	28.4	18.8
6/25/2004 19:30	DAY	900	46.7	53.9	50.8	44.3	41	40.3	63.0	56.5	48.6	42.2	43.8	42.8	38.5	27.9	24.8
6/25/2004 19:45	DAY	900	54.5	66.5	54.2	50.3	46.8	46.1	63.3	57.9	54.6	53.3	53.1	50.0	45.0	34.2	27.0
6/25/2004 20:00	DAY	900	54.6	65.8	55.8	52.4	48.1	47.2	63.9	62.7	63.2	52.5	51.4	49.7	45.1	34.7	30.7
6/25/2004 20:15	DAY	900	56.1	64.8	57	54.7	50.5	49.7	64.0	60.7	60.4	54.4	54.5	51.7	46.1	35.7	18.4
6/25/2004 20:30	DAY	900	54.8	56.9	55.9	54.7	53.4	53.1	63.6	57.6	50.5	49.0	51.7	51.6	46.7	36.1	19.4
6/25/2004 20:45	DAY	900	54.5	59	55.9	54.2	52.3	51.8	63.5	58.1	52.5	50.4	51.9	50.8	46.4	35.8	20.8
6/25/2004 21:00	DAY	900	53	57.3	55.1	52.6	49.2	48.3	63.2	57.6	51.5	48.3	49.7	49.7	44.8	34.5	20.8
6/25/2004 21:15	DAY	900	52.8	63.4	54.3	50.7	44.8	43.4	63.7	59.5	56.0	53.1	51.7	47.6	42.3	31.2	19.7
6/25/2004 21:30	DAY	900	49.1	54.8	51.9	48.4	43.3	42.6	63.0	58.0	52.9	48.5	46.9	44.5	39.8	29.5	17.6
6/25/2004 21:45	DAY	900	57.8	71.7	52	49.2	47.4	47.1	63.4	60.4	59.3	59.5	58.1	51.3	43.1	30.2	18.4
6/25/2004 22:00	NIGHT	900	47.4	51.5	49.4	46.9	44.8	44.3	60.8	56.6	49.1	46.3	44.9	42.9	38.3	28.6	18.6
6/25/2004 22:15	NIGHT	900	54	61.3	55.8	53.5	48.3	47.6	58.2	57.6	53.6	52.2	51.9	50.0	44.9	34.2	17.8
6/25/2004 22:30	NIGHT	900	52.4	57.5	55.9	49.7	45.5	44	48.7	48.1	45.9	49.9	50.1	48.6	43.9	32.8	18.9
6/25/2004 22:45	NIGHT	900	49.1	56	50.4	48.4	47.1	46.7	47.5	45.9	44.8	50.0	45.9	45.3	38.5	26.7	16.7
6/25/2004 23:00	NIGHT	900	49.7	54.5	51.6	49.2	47.4	47.1	47.9	45.7	44.6	50.9	46.5	45.6	39.4	28.2	17.2
6/25/2004 23:15	NIGHT	900	49.1	53.7	51	48.6	46.6	46.2	48.3	46.8	45.5	50.1	46.2	45.0	38.4	27.1	22.2
6/25/2004 23:30	NIGHT	900	49.1	52.4	50.8	48.7	47.4	47.2	48.1	46.1	45.2	50.7	45.4	45.0	38.9	28.2	18.4
6/25/2004 23:45	NIGHT	900	49.4	53.6	50.9	48.9	47.4	47.2	48.6	46.5	46.5	51.4	46.1	44.9	38.3	27.5	15.9
6/26/2004 0:00	NIGHT	900	49.9	57.2	50.8	48.9	47.6	47.3	48.3	46.6	46.1	51.7	46.8	45.3	39.1	28.7	16.7
6/26/2004 0:15	NIGHT	900	49.3	54	51	48.8	46.6	44.7	48.2	49.2	49.7	51.7	46.4	44.1	38.0	27.1	16.8
6/26/2004 0:30	NIGHT	900	43.3	49.3	46.5	42.1	38.3	37.7	46.7	44.6	41.5	42.4	41.2	39.2	32.8	22.9	16.6
6/26/2004 0:45	NIGHT	900	45.8	54.4	50.1	42.9	37	36.2	52.6	45.0	46.0	46.0	42.2	36.8	33.7	36.6	40.1
6/26/2004 1:00	NIGHT	900	57.9	64.9	63.2	54.4	45.6	44.5	53.2	46.6	42.7	44.3	47.5	47.3	48.3	50.9	54.7
6/26/2004 1:15	NIGHT	900	48.6	56.3	51.9	47	42.9	42.3	46.1	45.4	39.9	39.5	40.2	40.1	40.6	41.1	43.7
6/26/2004 1:30	NIGHT	900	40.9	46.5	43.8	39.8	37.2	36.6	49.0	46.6	41.3	37.0	33.4	32.1	32.4	33.0	35.1
6/26/2004 1:45	NIGHT	900	42	51.4	45.9	37.7	34.1	33.5	50.4	46.6	40.9	37.7	34.2	33.5	33.4	34.0	36.7
6/26/2004 2:00	NIGHT	900	46	53.7	49.9	42.3	37.1	36.1	50.2	47.6	46.7	45.7	40.8	37.7	36.2	36.7	39.6
6/26/2004 2:15	NIGHT	900	37.4	47.4	40.5	33.6	31.8	31.4	46.9	45.5	49.2	38.8	31.2	28.3	26.3	26.2	28.9
6/26/2004 2:30	NIGHT	900	46.4	52.9	50.7	44.8	32.7	32.2	53.1	46.8	40.5	36.5	36.7	37.0	38.2	39.3	41.9
6/26/2004 2:45	NIGHT	900	48.5	57.2	51.5	44.7	40.3	38.8	52.7	49.8	47.6	47.1	44.5	41.2	39.5	39.1	40.9
6/26/2004 3:00	NIGHT	900	44.8	50.9	47.5	43.8	38.6	37.4	49.4	48.4	43.9	45.8	41.6	38.8	33.8	32.0	33.0
6/26/2004 3:15	NIGHT	900	50.4	63.5	44.3	37.8	36	35.4	58.5	63.9	61.8	55.9	45.4	37.5	28.8	20.7	16.7
6/26/2004 3:30	NIGHT	900	34.2	37.9	36.1	33.8	32.2	31.9	57.1	48.1	39.7	34.1	31.6	28.9	23.2	18.2	16.0
6/26/2004 3:45	NIGHT	900	43.6	59.5	41.1	36.8	34.5	34.1	52.2	48.3	45.9	45.8	43.1	38.0	30.5	19.4	15.2
6/26/2004 4:00	NIGHT	900	53	66	51.2	39.2	36.3	35.7	57.4	63.3	62.4	56.0	51.8	45.5	36.7	20.8	14.9
6/26/2004 4:15	NIGHT	900	36.8	42.9	39.4	35.7	33.6	33.2	50.9	46.4	40.4	34.6	33.7	33.0	27.1	17.8	15.2
6/26/2004 4:30	NIGHT	900	43	49	46.6	41.3	37	35.9	49.0	48.3	43.4	43.1	40.6	38.8	32.0	21.0	14.2
6/26/2004 4:45	NIGHT	900	45.8	50.4	49	44.5	40.6	39.5	48.7	49.4	46.0	46.6	43.9	41.0	34.5	23.0	14.0
6/26/2004 5:00	NIGHT	900	49.2	54	50.9	48.8	46.6	46	49.5	50.0	48.2	49.8	47.6	44.3	37.7	26.5	14.4
6/26/2004 5:15	NIGHT	900	48.6	51.2	49.8	48.5	47.1	46.7	49.8	49.8	47.6	48.9	46.4	44.2	38.2	26.9	14.2
6/26/2004 5:30	NIGHT	900	50.2	54.8	51.8	49.7	47.8	47.1	49.7	50.2	48.0	50.4	48.3	45.6	39.5	30.2	15.1
6/26/2004 5:45	NIGHT	900	49.5	51.8	50.6	49.4	48.2	48	49.4	50.1	48.3	50.6	48.1	43.8	37.7	29.3	15.2
6/26/2004 6:00	NIGHT	900	50.8	62.6	51.3	49.3	47.5	46.8	51.1	52.2	51.1	51.3	50.1	45.2	39.2	29.2	14.7
6/26/2004 6:15	NIGHT	900	48.5	53.4	51.3	47.6	44.1	43.3	49.8	51.7	48.9	46.8	45.8	44.9	38.3	28.5	14.0
6/26/2004 6:30	NIGHT	900	51.2	55.3	53.1	50.7	48.5	47.9	50.0	51.1	49.7	50.4	49.6	46.9	39.8	29.5	14.6
6/26/2004 6:45	NIGHT	900	53.4	63.6	55.3	50.5	45.4	44.3	55.6	59.3	60.3	53.1	52.6	48.0	40.4	29.2	15.0
6/26/2004 7:00	DAY	900	49.2	59.8	51.2	46	42.2	41.5	51.5	53.9	55.3	49.5	48.8	43.9	35.9	26.2	13.7
6/26/2004 7:15	DAY	900	44.7	49.5	46.4	44.2	42.6	42.2	53.1	52.0	47.1	42.0	42.3	41.2	34.5	25.8	14.2
6/26/2004 7:30	DAY	900	44.5	48.5	46.3	44	42.4	42.1	53.9	51.7	44.5	42.0	43.1	40.5	33.0	24.8	15.3
6/26/2004 7:45	DAY	900	49	63	45.6	42.5	40.9	40.4	55.4	52.4	55.8	53.4	47.5	42.0	35.2	27.2	15.9
6/26/2004 8:00	DAY	264.5	43.7	55.8	43.8	41.6	40	39.5	56.0	50.6	44.0	42.8	41.5	39.6	33.3	27.2	20.2

Table C9: Sound Level Results at Measurement Location 9

Start Date and Time	Day / Night	Duration	Leq	L1.00	L10.00	L50.00	L90.00	L95.00	31.5	63	125	250	500	1000	2000	4000	8000
		(seconds)	(dB(A))	(dB(A))	(dB(A))	(dB(A))	(dB(A))	(dB(A))	dB	dB	dB	dB	dB	dB	dB	dB	dB
6/27/2004 9:10	DAY	290.125	47.9	63.1	42.7	35.1	32.3	31.8	53.6	47.8	44.7	46.9	46.2	40.3	39.8	37.7	35.1
6/27/2004 9:15	DAY	900	40.9	54.2	38.6	35.3	31.9	31.2	55.0	51.8	44.6	37.6	38.7	36.9	31.1	23.2	21.5
6/27/2004 9:30	DAY	900	42.3	54.5	45.5	36.7	32.6	31.8	54.4	52.8	48.6	44.1	41.8	35.0	28.1	22.9	21.6
6/27/2004 9:45	DAY	900	38.5	48	40.3	35.5	32.8	32.2	55.0	51.1	44.7	38.4	36.9	32.4	26.4	23.2	21.8
6/27/2004 10:00	DAY	900	39.2	47.2	42.4	36.9	34.4	33.8	54.1	49.9	43.8	38.4	37.3	33.7	27.6	27.5	20.9
6/27/2004 10:15	DAY	900	50.9	65	50.1	40.2	36	35.3	55.7	56.2	57.5	50.9	51.7	39.3	32.2	40.5	31.5
6/27/2004 10:30	DAY	900	43.6	54.2	47.7	38.2	35.7	35.2	54.3	44.3	36.2	33.3	36.2	34.1	32.1	40.6	30.9
6/27/2004 10:45	DAY	900	48.3	60.9	50.4	39.8	37.1	36.2	59.9	57.6	53.4	49.4	46.2	37.2	33.2	42.4	33.9
6/27/2004 11:00	DAY	900	40.8	48.8	43.1	39.4	37	36.3	58.2	49.4	41.6	38.1	38.7	35.7	30.6	30.1	27.5
6/27/2004 11:15	DAY	900	43.1	52.5	46.1	39.9	37.4	37	58.4	57.0	47.5	42.2	41.3	36.5	30.9	30.0	26.8
6/27/2004 11:30	DAY	900	42.6	51.5	46	40.1	37.7	37.2	57.6	49.8	46.6	41.2	41.5	37.7	31.8	27.2	25.8
6/27/2004 11:45	DAY	900	51.7	66.5	48.4	40.9	38.8	38.3	59.1	59.2	59.8	53.2	52.4	41.5	32.3	27.3	25.9
6/27/2004 12:00	DAY	900	43.9	52.9	46.8	41.2	39	38.4	59.0	53.2	52.6	47.6	40.9	36.0	29.9	26.8	26.3
6/27/2004 12:15	DAY	900	45.3	57	45.9	41.8	39.3	38.9	60.0	55.9	49.1	46.6	45.3	38.3	31.3	26.8	25.4
6/27/2004 12:30	DAY	900	48.8	61.6	47.3	42.8	40.3	39.9	60.7	58.8	56.2	50.6	49.5	39.1	31.2	28.5	26.6
6/27/2004 12:45	DAY	900	48.5	61.2	48.7	41.9	38.8	38.1	62.3	59.0	53.5	51.1	48.7	40.1	31.9	27.7	27.0
6/27/2004 13:00	DAY	900	43.2	51.5	46	41	39.1	38.5	59.1	52.8	47.2	44.1	42.7	36.9	30.3	26.1	25.6
6/27/2004 13:15	DAY	900	50.5	63.5	49	41.5	38.6	38.1	59.2	58.4	56.4	52.6	51.6	41.2	31.8	25.5	24.5
6/27/2004 13:30	DAY	900	42.8	52.3	43.8	41.1	39	38.4	60.3	52.9	49.5	46.4	40.2	36.3	30.3	26.7	26.3
6/27/2004 13:45	DAY	900	42.1	50.2	44	40.8	39	38.2	60.5	52.3	44.4	42.4	40.9	36.0	30.5	27.5	27.4
6/27/2004 14:00	DAY	900	45.8	55.5	48.8	42.3	39.3	38.7	60.8	57.8	51.2	47.4	45.4	38.2	31.7	27.4	26.9
6/27/2004 14:15	DAY	900	42.2	50	44.8	40.5	38.4	38	58.4	49.8	43.8	40.6	41.5	37.0	31.4	26.6	25.0
6/27/2004 14:30	DAY	900	46.1	51.1	48.5	45.3	43	42.3	58.6	48.2	42.3	40.2	45.3	40.8	37.2	31.5	26.1
6/27/2004 14:45	DAY	900	51.1	64.5	51.6	45.4	42.5	41.5	58.5	59.6	57.7	51.7	51.7	43.0	36.5	29.8	23.6
6/27/2004 15:00	DAY	900	44	53.5	45.9	41	38.6	38.2	59.1	51.3	44.2	43.6	44.1	37.8	31.6	27.1	25.8
6/27/2004 15:15	DAY	900	42.7	51	44.7	40.8	38.5	38.1	58.6	53.3	50.5	43.6	41.9	36.8	30.0	25.7	24.4
6/27/2004 15:30	DAY	900	41	49.2	44.4	38.8	33.7	33.1	54.9	50.9	47.7	44.0	38.1	35.4	28.4	22.9	19.2
6/27/2004 15:45	DAY	900	50.6	65.6	46	37.7	34.3	33.5	60.0	63.4	62.3	52.1	49.5	38.9	28.7	23.1	21.1
6/27/2004 16:00	DAY	900	36.4	48	37.5	34.7	32.9	31.9	53.3	46.3	37.5	35.4	34.8	32.1	25.0	20.4	19.0
6/27/2004 16:15	DAY	900	54.5	69.8	47.7	39.5	35.8	35.2	57.2	60.3	61.9	55.3	55.7	45.0	33.7	24.4	20.9
6/27/2004 16:30	DAY	900	54.1	68.6	49.7	42.2	38.5	37.8	57.5	59.8	60.7	55.8	55.4	43.7	33.8	26.8	22.2
6/27/2004 16:45	DAY	900	40.2	47.3	43	37.8	35.2	34.5	56.2	48.1	46.4	42.0	35.2	33.8	29.0	32.2	25.9
6/27/2004 17:00	DAY	900	39.6	46.1	42.1	38.4	35.7	35.2	56.4	50.0	42.8	38.3	37.2	34.3	29.3	27.6	26.1
6/27/2004 17:15	DAY	900	39.9	47.9	42.9	38.2	34.7	33.9	57.4	49.8	46.7	36.8	37.7	33.9	29.8	29.6	26.8
6/27/2004 17:30	DAY	900	40.2	52.1	41.3	37.5	33.8	32.8	58.9	51.3	44.6	38.6	38.7	33.9	29.7	28.6	26.8
6/27/2004 17:45	DAY	900	41.6	53.9	42.5	34.8	30.9	30.2	55.8	55.2	44.9	42.0	41.1	34.6	28.9	22.9	21.4
6/27/2004 18:00	DAY	900	36.1	41	38.6	35.6	32.3	31.5	54.3	47.4	35.7	29.4	33.6	32.1	26.8	23.4	21.3
6/27/2004 18:15	DAY	900	47.2	60.7	47.5	35.9	31	30.1	57.5	61.1	57.9	48.9	46.5	36.2	26.8	21.5	18.9
6/27/2004 18:30	DAY	900	35.9	41.7	38.5	35	31.3	30.5	52.7	45.8	38.0	30.6	34.1	31.7	25.9	22.1	19.1
6/27/2004 18:45	DAY	900	41.3	54	41.8	34.8	31	29.8	54.4	48.7	38.2	35.5	39.5	36.9	33.2	23.9	18.7
6/27/2004 19:00	DAY	900	55.2	68.6	47.6	35.7	30.7	29.9	61.1	64.2	62.9	58.6	55.6	44.0	31.3	19.7	16.6
6/27/2004 19:15	DAY	900	47.6	55	52.8	36.9	30.7	29.5	53.0	48.1	45.1	34.7	33.4	31.5	25.2	19.9	47.8
6/27/2004 19:30	DAY	900	58.8	66.8	62.9	55.2	50.1	48.9	55.9	58.7	56.9	51.0	49.4	38.7	29.5	17.9	58.9
6/27/2004 19:45	DAY	900	53.6	60.9	56.5	52	47.5	46.4	53.9	49.6	41.6	35.9	36.7	33.4	26.2	16.0	54.2
6/27/2004 20:00	DAY	900	46.4	56	51.3	40.4	36.6	35.8	52.8	43.7	38.5	30.8	37.4	34.5	26.7	17.3	46.1
6/27/2004 20:15	DAY	900	37.3	43.7	39.7	36.5	33.2	32.6	51.9	43.8	35.3	31.4	35.0	32.6	25.3	15.5	31.7
6/27/2004 20:30	DAY	900	37.4	43.9	40.4	36	32.8	32.1	52.6	42.8	37.6	31.9	35.3	33.1	25.8	15.1	30.7
6/27/2004 20:45	DAY	900	44.4	57.8	43.9	38.4	34.7	34.1	56.2	55.0	50.1	45.0	43.0	37.7	32.3	21.2	34.4
6/27/2004 21:00	DAY	900	49.7	61.8	45.5	41.4	39	38.4	53.6	48.6	41.1	35.7	39.6	35.8	29.3	19.1	49.3
6/27/2004 21:15	DAY	900	39.1	45.1	42.1	37.8	35.3	34.9	52.8	47.5	36.3	30.2	33.4	32.1	25.1	15.4	37.6
6/27/2004 21:30	DAY	900	42.5	55.6	42.5	36.6	34.5	34.1	56.0	53.1	48.0	43.3	42.3	35.1	26.1	14.4	32.0
6/27/2004 21:45	DAY	900	38.9	42.8	40.8	38.5	36.6	36.2	50.0	43.3	41.7	34.4	36.2	33.2	26.5	15.9	34.3
6/27/2004 22:00	NIGHT	900	40.5	45.5	42.4	39.8	38	37.4	46.9	47.7	42.5	36.0	38.3	36.1	29.8	18.4	32.5
6/27/2004 22:15	NIGHT	900	42.5	55.4	42.8	39.4	37.3	36.8	44.6	45.6	41.6	43.3	41.6	37.2	29.4	18.3	31.7
6/27/2004 22:30	NIGHT	900	41.4	50.7	43.7	39.4	35.4	34.6	44.1	47.1	40.2	35.8	40.3	34.7	28.2	17.9	36.9
6/27/2004 22:45	NIGHT	900	42.6	55.6	44.7	37.2	34.1	33.6	46.2	47.1	44.9	41.7	41.9	34.7	27.0	16.9	37.2
6/27/2004 23:00	NIGHT	900	39.1	47.1	42.2	37.2	35.2	34.8	47.0	48.1	46.7	37.7	34.5	31.6	23.9	14.8	36.1
6/27/2004 23:15	NIGHT	900	43	56.7	43.9	37	34.2	33.8	54.2	50.9	45.1	42.4	44.6	33.7	26.1	14.9	34.4
6/27/2004 23:30	NIGHT	900	40	42.6	41.8	40.5	35.3	34.5	44.5	43.0	33.6	28.0	29.9	27.5	20.8	15.4	39.7
6/27/2004 23:45	NIGHT	900	39.8	44	42	40.3	32.4	31.7	44.6	37.5	31.8	26.5	26.6	22.5	16.9	16.8	40.0
6/28/2004 0:00	NIGHT	900	39.4	43	41.6	40.1	32.3	31	53.3	42.2	33.1	28.5	28.4	25.7	22.4	23.3	38.9
6/28/2004 0:15	NIGHT	900	41.5	45.9	43.8	40.8	38.8	35.8	48.3	44.4	37.1	25.3	26.6	25.0	19.5	19.8	41.6
6/28/2004 0:30	NIGHT	900	41.3	45.1	42.7	40.8	40	39.5	44.6	43.5	34.7	31.4	31.4	26.4	19.3	17.9	41.2
6/28/2004 0:45	NIGHT	900	41.5	46.2	44	41.3	35.8	33.7	54.5	42.4	34.6	33.7	33.1	27.2	22.5	23.7	41.2
6/28/2004 1:00	NIGHT	900	36.3	41.7	40.4	34.5	32.4	32	54.9	42.8	33.3	32.6	31.6	26.2	22.5	23.8	33.8
6/28/2004 1:15	NIGHT	900	53.3	64.8	45.7	37.4	30.8	30.1	51.1	39.4	39.6	29.5	26.6	22.2	19.7	21.0	54.8
6/28/2004 1:30	NIGHT	900	49.8	56.2	52.8	48	44.3	43.5	52.6	40.8	31.3	26.9	26.8	23.5	21.3	22.2	50.5
6/28/2004 1:45	NIGHT	900	52.9	61	57.1	48.8	44	43.3	46.1	37.9	36.6	30.3	29.2	22.8	17.3	18.6	53.1
6/28/2004 2:00	NIGHT	900	53.2	61	58.4	46.6	44.2	43.8	53.5	58.8	57.9	50.1	44.2	29.8	18.8	17.1	52.3
6/28/2004 2:15	NIGHT	900	36.6	46.3	39.5	33	30.5	29.8	40.8	41.8	41.1	29.2	31.1	27.6	23.0	17.3	35.3
6/28/2004 2:30	NIGHT	900	40.2	47.9	45.9	31.2	29.4	29.1	43.8	33.6	28.5	25.5	26.3	24.0	17.4	14.8	40.1
6/28/2004 2:45	NIGHT	900	36.8	41.8	40	35	31.8	31.3	44.9	37.5	31.9	29.4	28.1	24.6	18.0	17.0	37.2

Table C9: Sound Level Results at Measurement Location 9

Start Date and Time	Day / Night	Duration (seconds)	Leq (dB(A))	L1.00 (dB(A))	L10.00 (dB(A))	L50.00 (dB(A))	L90.00 (dB(A))	L95.00 (dB(A))	31.5 dB	63 dB	125 dB	250 dB	500 dB	1000 dB	2000 dB	4000 dB	8000 dB
6/28/2004 3:00	NIGHT	900	40.2	48.7	42.4	38.2	33.6	32.6	60.1	48.1	39.8	38.9	38.8	32.0	23.2	15.9	37.2
6/28/2004 3:15	NIGHT	900	49.1	63.2	50.4	42.9	40.1	39.6	61.2	55.6	50.1	51.0	48.5	43.0	36.7	18.4	34.6
6/28/2004 3:30	NIGHT	900	41.8	46.5	43.4	41.3	39.6	39.2	61.3	51.2	45.9	42.2	39.9	34.8	26.9	17.5	36.1
6/28/2004 3:45	NIGHT	900	48.1	62.3	47.1	40.9	39.2	38.5	61.3	52.3	47.6	50.4	48.3	41.2	31.6	19.6	27.6
6/28/2004 4:00	NIGHT	900	51	64.5	48.9	40.2	36	34.8	61.4	61.1	58.7	55.2	50.2	40.1	29.6	17.6	26.4
6/28/2004 4:15	NIGHT	900	38.5	44.4	40.8	37.8	35	34.4	60.1	48.6	41.6	38.2	37.6	33.6	25.3	17.4	23.9
6/28/2004 4:30	NIGHT	900	39.3	44.3	41.7	38.5	35.9	35.3	59.9	48.1	42.0	38.2	38.0	34.8	27.0	18.8	25.8
6/28/2004 4:45	NIGHT	900	39.8	46.2	43	38.1	34.6	33.8	57.6	43.8	36.6	35.1	37.4	36.8	29.2	20.5	26.4
6/28/2004 5:00	NIGHT	900	51.5	66.4	48.3	42.5	39.1	38	59.2	57.8	53.7	53.3	52.0	44.4	36.2	23.1	27.6
6/28/2004 5:15	NIGHT	900	42.4	46.4	44	41.9	40.3	40.1	59.6	50.9	47.4	44.2	41.1	36.8	27.9	22.5	25.1
6/28/2004 5:30	NIGHT	900	44.4	48.9	46.5	43.7	42	41.5	59.1	50.5	45.7	43.3	42.6	40.1	34.0	29.4	24.7
6/28/2004 5:45	NIGHT	900	46.7	50.7	48.8	46.3	43.8	43.4	58.7	50.3	46.3	45.0	44.5	43.5	35.2	29.4	20.4
6/28/2004 6:00	NIGHT	900	47	55.7	48.5	45.9	44.2	43.8	57.1	50.1	46.8	45.6	45.5	43.0	36.1	31.8	19.0
6/28/2004 6:15	NIGHT	900	51.6	62.3	55.4	47.6	45.1	44.3	48.6	49.3	47.1	46.2	46.7	42.9	40.6	47.5	40.7
6/28/2004 6:30	NIGHT	900	51.6	58.9	55.4	49.5	46.1	45.1	51.4	52.5	47.6	48.8	48.9	45.0	40.6	45.5	38.1
6/28/2004 6:45	NIGHT	900	53.5	64.2	57.6	47.9	43.7	43.1	57.2	61.2	58.7	54.5	52.9	45.1	39.9	44.2	36.4
6/28/2004 7:00	DAY	900	49.8	60.6	54.5	43.9	40	38.8	52.2	54.2	54.0	48.6	46.6	40.9	38.4	44.6	36.4
6/28/2004 7:15	DAY	900	47	56.5	52.3	40.9	37.8	37.2	55.8	50.3	42.5	41.0	40.9	37.8	37.0	43.3	34.0
6/28/2004 7:30	DAY	900	47.2	57.4	52.4	39.5	34.4	34	51.0	53.1	49.9	42.3	39.8	32.5	37.0	44.2	34.7
6/28/2004 7:45	DAY	900	46.8	57.6	51.5	37.9	34.2	33.6	51.5	53.9	43.5	37.7	35.6	33.5	37.8	43.9	34.7
6/28/2004 8:00	DAY	900	43.5	56.6	42.7	36.5	34.1	33.4	53.9	48.9	39.4	32.0	33.8	33.6	34.3	40.4	31.4
6/28/2004 8:15	DAY	900	48.5	61.5	46	39.7	36.9	35.9	55.0	50.6	51.7	53.2	47.1	42.1	35.6	28.5	20.9
6/28/2004 8:30	DAY	900	39.4	44.9	42.1	38.3	35.3	34.7	54.3	55.2	38.8	35.7	37.4	34.6	28.5	24.2	20.8
6/28/2004 8:45	DAY	900	48.5	61.4	49.4	40.4	37.2	36.4	60.4	60.0	58.2	49.6	48.4	39.7	31.3	25.2	23.2
6/28/2004 9:00	DAY	900	41	45.2	43	40.5	38.1	37.3	55.3	50.2	39.9	35.3	39.5	37.0	30.9	25.7	22.6
6/28/2004 9:15	DAY	900	40.9	48.8	43.4	39.4	36.3	35.6	56.7	51.4	45.7	38.6	39.3	36.2	29.7	26.0	24.4
6/28/2004 9:30	DAY	900	45.1	54	49	40.6	37.1	36.5	55.2	53.2	53.0	45.1	44.2	39.6	33.7	27.0	22.1
6/28/2004 9:45	DAY	900	42.3	51.1	44.7	40.2	37.4	36.8	55.3	51.0	48.7	40.7	41.4	36.9	30.5	29.1	23.4
6/28/2004 10:00	DAY	900	47.6	60.3	47.9	42.2	38.3	37.3	59.3	55.0	50.7	46.3	44.8	43.0	39.1	32.3	27.7
6/28/2004 10:15	DAY	900	50.3	62.5	50.2	43	39.8	39	59.7	59.8	57.2	51.3	51.0	40.8	33.2	30.8	27.1
6/28/2004 10:30	DAY	900	43.2	51.2	45.5	41.5	39.1	38.5	56.6	55.8	46.6	43.4	41.0	38.3	31.9	26.9	24.1
6/28/2004 10:45	DAY	900	48	61.6	47.3	41.3	38.8	38.2	59.4	57.6	56.2	49.8	47.4	40.0	33.9	26.9	23.1
6/28/2004 11:00	DAY	900	40.4	48	42.6	39.2	36.5	36.1	56.5	54.5	42.2	37.0	38.9	35.8	29.2	25.1	24.4
6/28/2004 11:15	DAY	900	47.2	56	45.5	40.4	37.7	37.1	56.7	53.2	49.5	47.1	48.6	39.1	31.1	26.1	24.1
6/28/2004 11:30	DAY	900	47.8	62.8	44.8	40.3	38	37.4	59.8	56.8	57.0	49.3	47.6	38.3	30.9	28.3	27.9
6/28/2004 11:45	DAY	900	44.1	52.4	47.3	41.8	39.3	38.9	60.2	55.2	50.9	43.9	43.0	38.7	32.3	28.0	27.9
6/28/2004 12:00	DAY	900	48.5	60.9	51.3	42.4	39	38.4	58.4	53.7	55.2	54.8	46.1	38.8	32.4	26.9	25.4
6/28/2004 12:15	DAY	900	51.5	65.8	51.7	43.9	39.9	39.3	58.9	60.1	58.7	53.9	52.3	41.2	32.8	26.5	25.1
6/28/2004 12:30	DAY	900	49.5	63.2	49.4	41.6	39	38.4	58.8	55.3	50.9	51.8	47.7	44.0	37.7	29.1	24.7
6/28/2004 12:45	DAY	900	42.9	51.8	44.8	41	38.8	38.2	56.5	50.9	47.0	42.5	42.3	37.6	30.8	24.8	23.3
6/28/2004 13:00	DAY	900	42.8	53	44.9	39.9	37.4	36.9	57.3	52.8	46.5	42.1	42.2	37.3	30.7	25.7	24.2
6/28/2004 13:15	DAY	900	51	65.1	47.6	41.1	38.7	38.3	58.6	59.8	58.8	51.9	52.0	41.2	31.7	22.8	20.7
6/28/2004 13:30	DAY	900	52.6	67.9	50	40	37.2	36.8	58.2	60.7	59.5	53.3	53.6	43.3	33.7	23.0	19.4
6/28/2004 13:45	DAY	900	46.3	57.8	47.4	41.9	39.4	39	58.7	55.0	52.2	47.9	46.0	38.9	32.6	31.3	22.3
6/28/2004 14:00	DAY	900	45.8	53	48.7	44.4	40.7	40.1	57.0	54.0	50.1	45.2	45.4	40.7	34.3	25.5	20.3
6/28/2004 14:15	DAY	900	45.3	51.9	47.8	44.2	41.4	41	56.4	52.0	50.2	44.9	45.0	39.7	33.7	25.8	21.3
6/28/2004 14:30	DAY	900	44.4	49.3	46.5	43.8	41.9	41.3	56.0	50.3	41.9	41.5	44.2	39.3	33.9	26.2	21.5
6/28/2004 14:45	DAY	900	48.5	62.1	46.9	43.5	41.1	40.6	56.5	57.2	54.8	49.3	49.3	39.8	32.9	24.9	20.2
6/28/2004 15:00	DAY	900	45.7	53.1	49.2	43.3	40.5	40.1	57.0	52.5	51.7	47.9	45.0	39.5	32.9	24.7	22.0
6/28/2004 15:15	DAY	900	47.1	57	50.3	43.4	40.7	40	58.7	56.4	51.1	48.2	46.0	41.7	35.2	26.6	23.9
6/28/2004 15:30	DAY	900	49.1	63.3	48.3	42.4	40.4	40	57.6	56.7	56.5	49.7	50.0	40.2	31.8	23.0	19.0
6/28/2004 15:45	DAY	900	44.1	54	44.1	41.8	40.3	40	56.0	50.0	44.7	45.0	43.5	38.4	31.1	27.2	21.4
6/28/2004 16:00	DAY	900	54.1	67.5	52	43.4	41	40.4	58.9	61.4	60.5	56.6	55.2	42.8	33.0	34.2	26.6
6/28/2004 16:15	DAY	900	46	55.2	49.7	42.6	39.6	38.9	56.6	52.8	51.8	51.6	43.0	36.4	30.4	33.4	26.1
6/28/2004 16:30	DAY	900	51.7	65.1	52.5	41.5	39.2	38.5	58.5	61.9	60.1	54.5	52.1	39.7	30.8	21.2	16.8
6/28/2004 16:45	DAY	900	42.1	48.5	44.2	41.1	38.9	38.1	54.1	52.3	43.9	41.4	41.5	36.7	30.2	23.2	16.8
6/28/2004 17:00	DAY	900	42	52.8	43	39.7	37.6	37	53.3	50.6	44.6	42.0	41.7	36.2	29.1	23.7	17.6
6/28/2004 17:15	DAY	900	43.4	52.9	47	40.4	38.4	38	53.8	47.9	48.3	44.5	43.1	37.1	30.4	22.2	14.9
6/28/2004 17:30	DAY	900	40.3	48.1	42.2	38.9	36.5	36.1	53.6	48.6	41.4	38.0	39.6	35.5	28.7	25.5	15.9
6/28/2004 17:45	DAY	900	50	63.2	50.2	37.4	34.9	34.3	55.6	58.0	57.1	51.9	50.8	39.9	30.8	23.2	14.1
6/28/2004 18:00	DAY	900	40.7	50.9	42.7	37	34.4	33.8	53.3	45.9	47.5	43.4	38.7	33.4	27.2	30.7	21.7
6/28/2004 18:15	DAY	900	41.4	49.3	45.4	38.6	34.4	33.6	54.2	52.1	42.9	35.6	38.3	36.5	30.7	33.6	25.7
6/28/2004 18:30	DAY	900	37.2	46.7	40.8	34	30.4	29.5	53.9	48.5	34.9	25.5	29.6	30.0	26.7	33.2	24.6
6/28/2004 18:45	DAY	900	37.8	46.9	40	35.7	32.4	31.3	51.9	48.0	42.9	33.5	36.6	33.6	27.3	18.4	13.4
6/28/2004 19:00	DAY	900	36.3	41.8	39	35.3	32.8	32.3	51.8	45.9	36.3	31.7	34.7	32.2	26.6	20.5	13.5
6/28/2004 19:15	DAY	900	48.7	55.8	53.3	40.3	33	31.7	53.6	50.0	44.6	40.1	41.4	35.1	27.3	18.2	48.8
6/28/2004 19:30	DAY	900	58.5	69.8	61.3	53.9	50.1	49	58.5	61.8	61.3	56.7	57.4	44.9	32.7	17.0	56.1
6/28/2004 19:45	DAY	900	56.7	64.5	60.9	52.6	44.3	41.9	53.6	49.0	48.1	39.4	41.1	37.0	29.1	19.0	57.4
6/28/2004 20:00	DAY	900	44.3	54.2	48.3	40.5	36.3	35.7	52.3	48.7	46.7	38.6	40.2	37.0	29.7	19.0	41.5
6/28/2004 20:15	DAY	900	48	56.9	55	42.4	38.8	37.9	53.5	51.9	49.1	41.4	42.1	38.6	30.6	19.0	46.9
6/28/2004 20:30	DAY	900	44.3	50.9	47.7	42.7	38.7	37.8	52.5	53.3	52.4	44.3	43.2	38.5	30.6	19.5	33.2
6/28/2004 20:45	DAY	900	42.8	50.2	45.4	41.5	38	37.4	54.3	52.8	50.3	42.2	40.5	36.7	29.2	18.8	36.3

Table C9: Sound Level Results at Measurement Location 9

Start Date and Time	Day / Night	Duration (seconds)	Leq (dB(A))	L1.00 (dB(A))	L10.00 (dB(A))	L50.00 (dB(A))	L90.00 (dB(A))	L95.00 (dB(A))	31.5 dB	63 dB	125 dB	250 dB	500 dB	1000 dB	2000 dB	4000 dB	8000 dB
6/28/2004 21:00	DAY	900	42.7	47.9	45.5	41.7	38.5	38.1	50.9	50.6	48.8	41.1	41.0	36.9	29.3	18.9	35.8
6/28/2004 21:15	DAY	900	41.2	49.1	43.5	39.8	36.8	36.2	51.2	50.2	46.4	38.8	39.4	36.2	29.2	20.0	32.5
6/28/2004 21:30	DAY	900	43.6	53.8	46	40.7	37.2	36.4	55.7	54.8	50.7	44.2	42.2	37.5	30.6	23.4	31.1
6/28/2004 21:45	DAY	900	43.8	53.1	47.6	40.8	37.4	36.7	51.7	49.4	46.8	39.1	40.0	37.3	30.7	23.0	41.3
6/28/2004 22:00	NIGHT	900	46.4	54.8	50.8	41.4	38.2	37.5	51.1	51.4	42.9	36.2	38.0	35.5	28.1	19.8	46.4
6/28/2004 22:15	NIGHT	900	43.2	50.4	47.6	39.3	36.8	36.3	46.5	46.6	39.9	36.2	38.7	34.7	27.0	19.5	42.0
6/28/2004 22:30	NIGHT	900	41.2	51.1	42.9	38.9	36.7	36.2	47.7	46.7	38.0	37.8	42.1	33.7	27.5	19.1	34.5
6/28/2004 22:45	NIGHT	900	38.2	44.3	40.5	37.4	33.6	32.7	46.3	42.7	37.6	32.9	35.7	32.9	25.8	18.0	34.0
6/28/2004 23:00	NIGHT	900	38	45.3	40.3	37	33.9	33.3	47.9	42.5	36.6	33.4	36.0	32.8	25.3	19.0	32.9
6/28/2004 23:15	NIGHT	900	35.8	40.8	38.2	35.1	32.3	31.1	45.3	38.6	33.4	30.0	30.8	27.8	21.9	17.6	33.9
6/28/2004 23:30	NIGHT	900	54	59.7	57.9	52.7	36.7	35.8	45.4	42.2	35.0	31.6	32.8	28.3	21.6	16.5	54.6
6/28/2004 23:45	NIGHT	900	40.6	46.1	43.4	39.5	36.1	35.3	47.8	43.0	42.5	35.8	33.3	27.4	21.3	18.0	40.4
6/29/2004 0:00	NIGHT	900	36.6	41.4	39.2	35.7	34.4	34.1	43.4	38.3	32.0	29.0	30.0	26.2	20.2	16.4	35.7
6/29/2004 0:15	NIGHT	900	44.6	53.8	50	38.3	35.1	34	50.1	41.4	36.3	34.1	32.9	28.4	23.3	21.3	45.4
6/29/2004 0:30	NIGHT	900	36.5	45.1	39.3	34.3	31.6	31.2	57.9	46.2	36.0	31.4	31.5	28.8	28.2	28.7	29.5
6/29/2004 0:45	NIGHT	900	38.1	47	41.6	35	32.5	31.9	59.3	47.1	36.6	32.4	31.6	29.0	30.5	31.0	31.4
6/29/2004 1:00	NIGHT	900	38.2	45.2	42.6	35.5	32.2	31.6	57.5	45.6	36.9	32.6	31.8	27.0	25.4	26.8	36.4
6/29/2004 1:15	NIGHT	900	35.8	41.7	39	34.5	31.4	31.1	54.9	43.6	34.4	30.8	29.8	25.1	21.6	23.2	34.3
6/29/2004 1:30	NIGHT	900	48.2	53.8	51.9	46.8	41.2	40.1	50.9	40.3	34.5	30.3	29.9	21.3	18.2	20.2	48.9
6/29/2004 1:45	NIGHT	900	55.4	63.8	60.7	51.2	43.1	41.5	45.3	37.7	31.5	28.6	28.4	22.1	16.7	17.6	56.5
6/29/2004 2:00	NIGHT	900	46	52.3	49.4	44.7	37.7	34.8	44.8	37.0	30.2	27.0	27.0	22.6	17.4	16.4	46.7
6/29/2004 2:15	NIGHT	900	31.7	38	35.4	29.3	26.3	26	43.5	34.6	25.3	21.5	21.6	21.5	19.2	18.3	31.1
6/29/2004 2:30	NIGHT	900	50	58.1	56.7	38.7	31.5	30.5	42.2	34.6	26.8	21.3	21.4	21.2	16.3	16.0	51.1
6/29/2004 2:45	NIGHT	900	42	49.7	46.9	38.3	32.7	31.5	49.3	40.4	30.2	29.0	26.4	20.4	19.2	20.3	43.0
6/29/2004 3:00	NIGHT	900	55.5	69.8	43.6	32.8	30.7	30.3	58.6	61.6	61.0	58.0	56.3	46.8	35.8	22.3	32.6
6/29/2004 3:15	NIGHT	900	45.5	56.6	46	39.7	33.8	33.2	54.0	57.5	54.9	49.3	41.4	30.5	20.8	20.9	40.7
6/29/2004 3:30	NIGHT	900	36.1	43.1	39.6	34.9	29.8	29.3	49.3	40.9	35.2	31.3	31.9	23.3	17.7	19.5	35.4
6/29/2004 3:45	NIGHT	900	43.4	53	46.3	40.2	30.6	29.8	43.3	40.4	34.9	31.9	38.2	27.9	19.2	18.1	43.7
6/29/2004 4:00	NIGHT	900	46	54.7	53.3	37.8	33.9	33.2	44.1	41.3	37.5	33.6	30.9	26.9	19.5	19.0	46.7
6/29/2004 4:15	NIGHT	900	43.9	53	48.6	39.7	34.4	32.8	47.4	48.7	42.0	43.0	42.0	38.6	34.1	19.1	36.2
6/29/2004 4:30	NIGHT	900	37.7	44.7	39	36.8	34.2	33.6	43.5	42.4	35.4	33.0	35.2	31.6	23.7	19.6	34.1
6/29/2004 4:45	NIGHT	900	38.2	44.9	40.3	36.9	34.2	33.7	43.5	43.2	41.7	37.0	36.6	33.7	25.5	19.8	27.8
6/29/2004 5:00	NIGHT	900	39.8	48	42	38	35.1	34.4	44.1	44.7	40.7	34.7	38.8	35.6	27.9	23.4	26.8
6/29/2004 5:15	NIGHT	900	42.8	55.7	43.8	39.9	35.5	34.8	44.1	43.7	41.4	44.0	42.1	37.9	29.2	20.7	23.8
6/29/2004 5:30	NIGHT	900	44.1	49.3	46.3	43.6	40.9	40.4	45.0	46.5	43.5	41.8	42.0	40.7	33.6	28.5	21.4
6/29/2004 5:45	NIGHT	900	50.8	63	51.8	46.9	43.9	43.3	52.1	58.2	55.3	53.4	49.6	44.6	35.9	30.8	18.6
6/29/2004 6:00	NIGHT	900	46	52	47.9	45	43.3	43	47.3	48.3	46.2	43.8	44.0	42.4	34.6	32.6	20.3
6/29/2004 6:15	NIGHT	900	50	60.1	51.6	48.3	46.4	46.1	52.6	54.9	50.3	51.2	48.7	44.9	37.1	34.8	23.4
6/29/2004 6:30	NIGHT	900	47.8	56.3	49.9	46.5	43.7	43.2	50.4	53.0	50.0	47.7	46.5	43.1	35.5	35.1	24.7
6/29/2004 6:45	NIGHT	900	51.3	63.8	51	44	40.5	40	55.0	58.6	57.2	52.5	52.0	43.3	34.8	33.8	22.8
6/29/2004 7:00	DAY	900	49	60.4	50.4	44.7	39.9	38.6	56.8	56.6	53.5	50.0	49.5	40.9	34.0	35.1	25.2
6/29/2004 7:15	DAY	900	40.4	48.8	43.3	38.3	35.1	34.3	50.5	48.4	41.1	29.7	32.9	34.4	30.8	35.9	26.4
6/29/2004 7:30	DAY	467.125	45.6	60	42.7	36.3	34.3	34	50.3	46.8	43.1	44.4	42.4	37.7	36.3	37.1	34.3

Appendix D: Modeled Source Sound Power Levels

Table D1: Computer Model Data for Existing Plant Noise Sources

				Center Point Coordinates			Size (m or m^2)	Total PWL	PWL per unit	SPL inside	Komega Correction	A-weighted Total PWL per Source								
Super Group	Group	Source	SrcType	X	Y	Z	l or S	Lw	Lw'	Li	Ko	31	63	125	250	500	1000	2000	4000	8000
Add1	Addendum 1 Sources	Control Bldg AC	Area	150.9	189.4	102.2	9.28	95.5	85.9	0	0	57.7	70.8	75.5	83.5	89.4	89	89.7	88	78.9
Add1	Addendum 1 Sources	Raw Water Pump North	Line	161.3	198.1	101.0	2.65	76.5	72.3	0	0	28.6	43.8	55.9	64.4	68.8	71	71.2	68	62.9
Add1	Addendum 1 Sources	Demin Water Transfer Pump 1	Point	99.8	30.9	101.0		76.5	76.5	0	0	28.6	43.8	55.9	64.4	68.8	71	71.2	68	62.9
Add1	Addendum 1 Sources	Demin Water Transfer Pump 2	Point	102.0	30.9	101.0		76.5	76.5	0	0	28.6	43.8	55.9	64.4	68.8	71	71.2	68	62.9
Add1	Addendum 1 Sources	Demin Water Transfer Pump 3	Point	104.8	31.0	101.0		76.5	76.5	0	0	28.6	43.8	55.9	64.4	68.8	71	71.2	68	62.9
Add1	Addendum 1 Sources	Demin Water Transfer Pump 4	Point	107.0	30.9	101.0		76.5	76.5	0	0	28.6	43.8	55.9	64.4	68.8	71	71.2	68	62.9
Add1	Addendum 1 Sources	Fuel Transfer Pump East	Point	63.8	62.6	101.0		76.5	76.5	0	0	28.6	43.8	55.9	64.4	68.8	71	71.2	68	62.9
Add1	Addendum 1 Sources	Fuel Transfer Pump West	Point	62.3	62.5	101.0		76.5	76.5	0	0	28.6	43.8	55.9	64.4	68.8	71	71.2	68	62.9
Add1	Addendum 1 Sources	Fuel Unloading Pump East	Point	69.4	62.4	101.0		72.5	72.5	0	0	24.6	39.8	51.9	60.4	64.8	67	67.2	64	58.9
Add1	Addendum 1 Sources	Fuel Unloading Pump West	Point	67.6	62.4	101.0		72.5	72.5	0	0	24.6	39.8	51.9	60.4	64.8	67	67.2	64	58.9
Add1	Addendum 1 Sources	Raw Water Pump South	Line	161.3	196.7	101.0	2.66	76.5	72.3	0	0	28.6	43.8	55.9	64.4	68.8	71	71.2	68	62.9
Add1	Addendum 1 Sources	Solids Settl. Basin Sump Pump East	Point	129.9	14.5	101.0		67.5	67.5	0	0	18.6	34.8	46.9	55.4	59.8	62	62.2	59	53.9
Add1	Addendum 1 Sources	Solids Settl. Basin Sump Pump West	Point	128.3	14.5	101.0		67.5	67.5	0	0	18.6	34.8	46.9	55.4	59.8	62	62.2	59	53.9
Add1	Addendum 1 Sources	Transformer, Existing, Middle	Line	172.4	112.7	101.5	5.26	80.7	73.5	0	0	36.9	47.5	64.8	66.7	78.3	75.1	69	58.8	49.9
Add1	Addendum 1 Sources	Transformer, Existing, North	Line	172.4	124.7	101.5	5.26	80.7	73.5	0	0	36.9	47.5	64.8	66.7	78.3	75.1	69	58.8	49.9
Add1	Addendum 1 Sources	Transformer, Existing, South	Line	172.4	100.2	101.5	5.26	80.7	73.5	0	0	36.9	47.5	64.8	66.7	78.3	75.1	69	58.8	49.9
Add1	Addendum 1 Sources	Waste Water Reinjection Pump East	Line	117.0	8.0	101.0	1.5	82.5	80.8	0	0	37.6	49.8	61.9	70.4	74.8	77	77.2	74	68.9
Add1	Addendum 1 Sources	Waste Water Reinjection Pump West	Line	114.7	8.0	101.0	1.5	82.5	80.8	0	0	37.6	49.8	61.9	70.4	74.8	77	77.2	74	68.9
CT-2	Auxiliary Transformers	Transformer, Aux, North	Line	151.4	183.8	101.5	4.39	80.7	74.2	0	0	36.9	47.5	64.8	66.7	78.3	75.1	69	58.8	49.9
CT-2	Auxiliary Transformers	Transformer, Aux, South	Line	151.4	179.2	101.3	4.06	80.7	74.6	0	0	36.9	47.5	64.8	66.7	78.3	75.1	69	58.8	49.9
CT-2	CT-2 Auxiliary Skids	CT-2 Fuel Pump Skid	Point	119.8	91.7	101.0		80.5	80.5	0	0	49.4	56.6	62	75	74.1	72.9	73	70.7	63.5
CT-2	CT-2 Auxiliary Skids	CT-2 Lube Oil Cooler	Area	130.7	77.0	107.5	6.95	99.6	91.2	0	0	71.3	81.1	88.2	91.3	93.7	93.1	91.3	89.2	86.3
CT-2	CT-2 Auxiliary Skids	CT-2 Water Injection Skid	Point	114.4	77.8	101.0		88.6	88.6	0	0	51.3	56.2	61.6	71.3	77.5	85.5	84.1	75.1	63.6
CT-2	CT-2 Enclosure	CT-2 Enclosure East	Area	145.0	77.0	103.0	23.74	86.9	73.2	105	3	70.4	79.6	80.7	83.2	76.6	71.8	66	62.8	57.7
CT-2	CT-2 Enclosure	CT-2 Enclosure North	Area	134.0	79.0	103.0	131.38	94.3	73.2	105	3	77.8	87	88.1	90.6	84	79.2	73.4	70.2	65.1
CT-2	CT-2 Enclosure	CT-2 Enclosure South	Area	134.0	75.0	103.0	131.38	94.3	73.2	105	3	77.8	87	88.1	90.6	84	79.2	73.4	70.2	65.1
CT-2	CT-2 Enclosure	CT-2 Enclosure West	Area	123.0	77.0	103.0	23.74	86.9	73.2	105	3	70.4	79.6	80.7	83.2	76.6	71.8	66	62.8	57.7
CT-2	CT-2 Enclosure	Roof	Area	134.0	77.0	106.0	87.48	92.6	73.2	105	0	76	85.2	86.3	88.8	82.2	77.4	71.6	68.4	63.3
CT-2	CT-2 Enclosure	CT-2 Generator Vent Disch	Point	140.5	78.9	106.5		106.9	106.9	0	0	84.3	87.5	90.7	104.8	96.8	96.7	96.2	94	87.8
CT-2	CT-2 Enclosure	CT-2 Huff n Puff Blower	Point	126.6	74.6	106.5		97.3	97.3	0	0	63.2	73.8	83.4	92.6	89.4	87.6	89.3	88.8	83.5
CT-2	CT-2 Enclosure	CT-2 Turbine Vent Disch 1	Point	138.3	78.1	107.0		105.9	105.9	0	0	68.5	74.8	82.2	103.5	98.5	98.2	94.6	80.9	71.1
CT-2	CT-2 Enclosure	CT-2 Turbine Vent Disch 1	Point	138.3	78.1	7.0		105.9	105.9	0	0	68.5	74.8	82.2	103.5	98.5	98.2	94.6	80.9	71.1
CT-2	CT-2 Enclosure	CT-2 Turbine Vent Disch 2	Point	138.9	77.1	107.0		105.9	105.9	0	0	68.5	74.8	82.2	103.5	98.5	98.2	94.6	80.9	71.1
CT-2	CT-2 Enclosure	CT-2 Turbine Vent Disch 2	Point	138.9	77.1	7.0		105.9	105.9	0	0	68.5	74.8	82.2	103.5	98.5	98.2	94.6	80.9	71.1
CT-2	CT-2 Exhaust	CT-2 Exhaust	Point	135.4	70.7	115.0		101.6	101.6	0	0	84.3	88	94	93	95.4	95.7	91.2	86.4	69.6
CT-2	CT-2 Intake	CT-2 Turbine Intake	Line	118.0	77.0	107.0	5.39	91.4	84.1	0	0	58.1	68.4	74.3	82.5	85.7	86.5	84.6	77.3	68.2
CT4-5	Air Inlet GT-4	CT4, Intake Noise due to Vents, Existing	Area	107.5	153.7	104.0	28.98	104.1	89.5	0	0	-39.4	-26.2	-16.1	-8.6	102.4	98.8	87.3	82.3	66
CT4-5	Air Inlet GT-5	CT5, Intake, Existing	Area	106.8	215.5	104.0	30.02	106.6	91.8	0	0	62.5	83.6	91.7	102.6	99.1	98.3	96.2	97.7	85.6
CT4-5	CT4 Enclosure	CT4 Enclosure - East	Area	109.4	166.2	102.2	84.73	92.7	73.4	0	3	62.2	71.2	78.7	83.1	81.6	84.1	84.8	87.8	84.4
CT4-5	CT4 Enclosure	CT4 Enclosure - North	Area	107.3	176.1	102.2	16.99	85.7	73.4	0	3	55.2	64.2	71.7	76.1	74.6	77.1	77.8	80.8	77.4
CT4-5	CT4 Enclosure	CT4 Enclosure - Roof	Area	107.4	166.2	104.3	80.48	92.5	73.4	0	3	62	71	78.5	82.9	81.4	83.9	84.6	87.6	84.2
CT4-5	CT4 Enclosure	CT4 Enclosure - West	Area	105.4	166.2	102.2	84.5	92.7	73.4	0	3	62.2	71.2	78.7	83.1	81.6	84.1	84.8	87.8	84.4
CT4-5	CT4 Enclosure	CT4 Gen Comp Vent Blower Body 1	Point	106.3	161.1	105.5		94.4	94.4	0	0	63.7	76.3	83.2	88.5	88	89.7	81.8	76.9	69.4
CT4-5	CT4 Enclosure	CT4 Gen Comp Vent Blower Body 2	Point	108.9	161.2	105.5		94.4	94.4	0	0	63.7	76.3	83.2	88.5	88	89.7	81.8	76.9	69.4
CT4-5	CT4 Enclosure	CT4 Turb Comp Vent Exh 1	Point	106.4	165.7	108.5		93.9	93.9	0	0	63.6	78.4	84.9	82	86.8	90.3	84.5	79.2	72.5
CT4-5	CT4 Enclosure	CT4 Turb Comp Vent Exh 2	Point	108.5	165.7	108.5		93.9	93.9	0	0	63.6	78.4	84.9	82	86.8	90.3	84.5	79.2	72.5
CT4-5	CT5 Enclosure	CT5 Enclosure - East	Area	109.0	202.7	102.2	86.83	92.8	73.4	0	3	62.3	71.3	78.8	83.2	81.7	84.2	84.9	87.9	84.5
CT4-5	CT5 Enclosure	CT5 Enclosure - Roof	Area	106.8	202.7	104.3	91.41	93	73.4	0	3	62.5	71.5	79	83.4	81.9	84.4	85.1	88.1	84.7

Table D1: Computer Model Data for Existing Plant Noise Sources

				Center Point Coordinates			Size (m or m^2)	Total PWL	PWL per unit	SPL inside	Komega Correction	A-weighted Total PWL per Source								
Super Group	Group	Source	SrcType	X	Y	Z	l or S	Lw	Lw'	Li	Ko	31	63	125	250	500	1000	2000	4000	8000
CT4-5	CT5 Enclosure	CT5 Enclosure - South	Area	106.8	192.6	102.2	19.36	86.3	73.4	0	3	55.8	64.8	72.3	76.7	75.2	77.7	78.4	81.4	78
CT4-5	CT5 Enclosure	CT5 Enclosure - West	Area	104.6	202.7	102.2	86.64	92.8	73.4	0	3	62.3	71.3	78.8	83.2	81.7	84.2	84.9	87.9	84.5
CT4-5	CT5 Enclosure	CT5 Gen Comp Vent Blower Body 1	Point	108.4	209.3	105.5		94.4	94.4	0	0	63.7	76.3	83.2	88.5	88	89.7	81.8	76.9	69.4
CT4-5	CT5 Enclosure	CT5 Gen Comp Vent Blower Body 2	Point	105.4	209.4	105.5		94.4	94.4	0	0	63.7	76.3	83.2	88.5	88	89.7	81.8	76.9	69.4
CT4-5	CT5 Enclosure	CT5 Turb Comp Vent Exh 1	Point	105.9	202.6	108.0		93.9	93.9	0	0	63.6	78.4	84.9	82	86.8	90.3	84.5	79.2	72.5
CT4-5	CT5 Enclosure	CT5 Turb Comp Vent Exh 2	Point	108.2	202.6	108.0		93.9	93.9	0	0	63.6	78.4	84.9	82	86.8	90.3	84.5	79.2	72.5
CT4-5	Turbine Exhaust Duct	CT-4 Turbine Exh Duct Breach	Line	159.4	179.3	106.4	3.14	55.8	50.9	0	0	52.6	51.8	43.9	36.4	41.8	33	30.2	31	23.9
CT4-5	Turbine Exhaust Duct	CT-4 Turbine Exh Duct Diverter	Line	127.8	169.1	106.4	2.19	76.3	72.9	0	0	62.6	75.8	59.9	42.4	44.8	48	56.2	56	57.9
CT4-5	Turbine Exhaust Duct	CT-4 Turbine Exh Duct Sil 1	Line	132.8	174.8	106.4	6.82	67.9	59.6	0	0	61.6	64.8	52.9	40.4	45.8	48	56.2	56	57.9
CT4-5	Turbine Exhaust Duct	CT-4 Turbine Exh Duct Sil 2	Line	139.7	174.8	106.4	5.97	66.1	58.4	0	0	59.6	61.8	50.9	39.4	45.8	48	56.2	56	57.9
CT4-5	Turbine Exhaust Duct	CT-4 Turbine Exh Duct T1	Line	111.8	168.7	102.5	2.4	89.2	85.4	0	0	70.6	77.8	85.9	80.4	83.8	70	68.2	58	49.9
CT4-5	Turbine Exhaust Duct	CT-4 Turbine Exh Duct T2	Line	116.0	168.7	103.5	5.98	88.2	80.4	0	0	69.6	76.8	84.9	79.4	82.8	69	67.2	57	48.9
CT4-5	Turbine Exhaust Duct	CT-4 Turbine Exh Duct T3	Line	123.0	168.7	105.2	7.83	81.2	72.2	0	0	67.6	80.8	64.9	46.4	49.8	48	56.2	56	57.9
CT4-5	Turbine Exhaust Duct	CT-4 Turbine Exh Duct T4	Line	128.2	173.1	106.4	5.58	78.9	71.4	0	0	71.6	77.8	61.9	44.4	46.8	48	56.2	56	57.9
CT4-5	Turbine Exhaust Duct	CT-4 Turbine Exh Duct T5	Line	149.1	174.8	106.4	11.75	63.8	53.1	0	0	60.6	59.8	51.9	44.4	49.8	41	38.2	39	32.9
CT4-5	Turbine Exhaust Duct	CT-4 Turbine Exh Duct T6	Line	157.5	176.0	106.4	5.3	59	51.7	0	0	55.6	54.8	47.9	40.4	45.8	37	34.2	35	27.9
CT4-5	Turbine Exhaust Duct	CT-5 Turbine Exh Duct Breach	Line	159.4	189.8	106.4	2	55.8	52.8	0	0	52.6	51.8	43.9	36.4	41.8	33	30.2	31	23.9
CT4-5	Turbine Exhaust Duct	CT-5 Turbine Exh Duct Diverter	Line	127.8	200.1	106.4	1.84	76.3	73.6	0	0	62.6	75.8	59.9	42.4	44.8	48	56.2	56	57.9
CT4-5	Turbine Exhaust Duct	CT-5 Turbine Exh Duct Sil 1	Line	132.8	194.3	106.4	6.82	67.9	59.6	0	0	61.6	64.8	52.9	40.4	45.8	48	56.2	56	57.9
CT4-5	Turbine Exhaust Duct	CT-5 Turbine Exh Duct Sil 2	Line	139.7	194.4	106.4	5.97	66.1	58.4	0	0	59.6	61.8	50.9	39.4	45.8	48	56.2	56	57.9
CT4-5	Turbine Exhaust Duct	CT-5 Turbine Exh Duct T1	Line	111.8	200.3	102.5	2.4	89.2	85.4	0	0	70.6	77.8	85.9	80.4	83.8	70	68.2	58	49.9
CT4-5	Turbine Exhaust Duct	CT-5 Turbine Exh Duct T2	Line	116.0	200.3	103.5	5.99	88.2	80.4	0	0	69.6	76.8	84.9	79.4	82.8	69	67.2	57	48.9
CT4-5	Turbine Exhaust Duct	CT-5 Turbine Exh Duct T3	Line	123.0	200.3	105.2	7.83	81.2	72.2	0	0	67.6	80.8	64.9	46.4	49.8	48	56.2	56	57.9
CT4-5	Turbine Exhaust Duct	CT-5 Turbine Exh Duct T4	Line	128.1	196.2	106.4	6.09	78.9	71.1	0	0	71.6	77.8	61.9	44.4	46.8	48	56.2	56	57.9
CT4-5	Turbine Exhaust Duct	CT-5 Turbine Exh Duct T5	Line	149.1	194.4	106.4	11.75	63.8	53.1	0	0	60.6	59.8	51.9	44.4	49.8	41	38.2	39	32.9
CT4-5	Turbine Exhaust Duct	CT-5 Turbine Exh Duct T6	Line	157.5	192.9	106.4	5.26	59	51.8	0	0	55.6	54.8	47.9	40.4	45.8	37	34.2	35	27.9
CT4-5	Turbine Exhaust Exit	GT-4 Turbine Exhaust Discharge	Point	159.2	183.2	131.7		78.8	78.8	0	0	66.6	65.8	66.9	70.4	72.8	72	70.2	67	56.9
CT4-5	Turbine Exhaust Exit	GT-5 Turbine Exhaust Discharge	Point	159.2	186.7	131.7		78.8	78.8	0	0	66.6	65.8	66.9	70.4	72.8	72	70.2	67	56.9
CT4-5 Aux	ACCWS	ACCWS, Existing	Line	75.1	163.6	101.0	1.47	99.1	97.4	0	0	58.5	72.7	87.7	90	94.7	94.2	88.5	80.9	73.9
CT4-5 Aux	Fuel Oil Skids	Fuel Oil Skid, CT4, Existing	Line	113.4	152.9	101.0	3.82	93	87.2	0	0	49.7	73	88.2	83.3	81.6	84.4	84.1	83.7	82.9
CT4-5 Aux	Fuel Oil Skids	Fuel Oil Skid, CT5, Existing	Line	130.8	208.3	101.0	2.76	93	88.6	0	0	49.7	73	88.2	83.3	81.6	84.4	84.1	83.7	82.9
CT4-5 Aux	Lube Oil Coolers	Lube Oil Cooler 4	Area	113.6	176.1	103.2	10.51	104.8	94.6	0	0	67.5	89.6	93.6	97.6	96	99.1	96.7	95.8	89.5
CT4-5 Aux	Lube Oil Coolers	Lube Oil Cooler 5	Area	113.5	189.8	103.2	10.4	104.8	94.7	0	0	67.5	89.6	93.6	97.6	96	99.1	96.7	95.8	89.5
CT4-5 Aux	Main Transformer Walls	Transformer, Main , South	Area	171.0	158.4	102.1	19.26	85.6	72.8	0	0	62.7	74.4	78.3	77.1	78.4	76.9	78.3	74.3	66.6
CT4-5 Aux	Main Transformer Walls	Transformer, Main, North	Area	170.4	165.6	102.1	19.4	85.6	72.8	0	0	62.7	74.4	78.3	77.1	78.4	76.9	78.3	74.3	66.6
CT4-5 Aux	Water Injection	Water Inj Skid, CT5, Existing	Line	123.1	207.9	101.0	4.38	101.6	95.2	0	0	57.9	77.1	88.4	84.7	90.7	95.5	98.3	92	83.9
CT4-5 Aux	Water Injection	Water Inj Skid, CT4, Existing	Line	123.5	158.8	101.0	4.87	101.6	94.7	0	0	57.9	77.1	88.4	84.7	90.7	95.5	98.3	92	83.9
D-23	D23 Enclosure	D23 Enclosure East	Area	146.0	107.6	101.9	12.56	83.7	72.7	107	3	53.6	66.8	77.9	80.4	75.8	71	65.2	62	57.9
D-23	D23 Enclosure	D23 Enclosure East	Area	146.0	99.9	101.9	12.56	83.7	72.7	107	3	53.6	66.8	77.9	80.4	75.8	71	65.2	62	57.9
D-23	D23 Enclosure	D23 Enclosure East	Area	146.0	92.2	101.9	12.56	83.7	72.7	107	3	53.6	66.8	77.9	80.4	75.8	71	65.2	62	57.9
D-23	D23 Enclosure	D23 Enclosure North	Area	139.5	109.2	101.9	47.68	89.4	72.7	107	3	59.4	72.6	83.7	86.2	81.6	76.8	71	67.8	63.7
D-23	D23 Enclosure	D23 Enclosure North	Area	139.5	101.5	101.9	47.68	89.4	72.7	107	3	59.4	72.6	83.7	86.2	81.6	76.8	71	67.8	63.7
D-23	D23 Enclosure	D23 Enclosure North	Area	139.5	93.8	101.9	47.68	89.4	72.7	107	3	59.4	72.6	83.7	86.2	81.6	76.8	71	67.8	63.7
D-23	D23 Enclosure	D23 Enclosure Roof	Area	139.5	107.5	103.7	44.41	89.1	72.7	107	3	59.1	72.3	83.4	85.9	81.3	76.5	70.7	67.5	63.4
D-23	D23 Enclosure	D23 Enclosure Roof	Area	139.5	99.8	103.7	44.41	89.1	72.7	107	3	59.1	72.3	83.4	85.9	81.3	76.5	70.7	67.5	63.4
D-23	D23 Enclosure	D23 Enclosure Roof	Area	139.5	92.1	103.7	44.41	89.1	72.7	107	3	59.1	72.3	83.4	85.9	81.3	76.5	70.7	67.5	63.4
D-23	D23 Enclosure	D23 Enclosure South	Area	139.5	105.8	101.9	47.79	89.5	72.7	107	3	59.4	72.6	83.7	86.2	81.6	76.8	71	67.8	63.7
D-23	D23 Enclosure	D23 Enclosure South	Area	139.5	98.1	101.9	47.79	89.5	72.7	107	3	59.4	72.6	83.7	86.2	81.6	76.8	71	67.8	63.7

Appendix D: Modeled Source Sound Power Levels

Table D1: Computer Model Data for Existing Plant Noise Sources

				Center Point Coordinates			Size (m or m^2)	Total PWL	PWL per unit	SPL inside	Komega Correction	A-weighted Total PWL per Source								
Super Group	**Group**	**Source**	**SrcType**	**X**	**Y**	**Z**	**l or S**	**Lw**	**Lw'**	**Li**	**Ko**	**31**	**63**	**125**	**250**	**500**	**1000**	**2000**	**4000**	**8000**
D-23	D23 Enclosure	D23 Enclosure South	Area	139.5	90.4	101.9	47.79	89.5	72.7	107	3	59.4	72.6	83.7	86.2	81.6	76.8	71	67.8	63.7
D-23	D23 Enclosure	D23 Enclosure West	Area	133.0	107.4	101.9	12.55	83.7	72.7	107	3	53.6	66.8	77.9	80.4	75.8	71	65.2	62	57.9
D-23	D23 Enclosure	D23 Enclosure West	Area	133.0	99.7	101.9	12.55	83.7	72.7	107	3	53.6	66.8	77.9	80.4	75.8	71	65.2	62	57.9
D-23	D23 Enclosure	D23 Enclosure West	Area	133.0	92.0	101.9	12.55	83.7	72.7	107	3	53.6	66.8	77.9	80.4	75.8	71	65.2	62	57.9
D-23	D23 Enclosure	D-23 Generator Ventilation Inlet	Line	146.2	107.5	101.0	2.91	94.1	89.5	0	0	64.3	76.1	85.8	87.4	86.4	87.6	86.8	80.3	69.3
D-23	D23 Enclosure	D-23 Generator Ventilation Inlet	Line	146.2	99.8	101.0	2.91	94.1	89.5	0	0	64.3	76.1	85.8	87.4	86.4	87.6	86.8	80.3	69.3
D-23	D23 Enclosure	D-23 Generator Ventilation Inlet	Line	146.2	92.1	101.0	2.91	94.1	89.5	0	0	64.3	76.1	85.8	87.4	86.4	87.6	86.8	80.3	69.3
D-23	D23 Exhaust	D23 Exhaust	Point	128.3	107.3	108.6		105.1	105.1	0	0	71	83.8	83.6	82.5	99.2	102.8	95.8	87.1	54
D-23	D23 Exhaust	D23 Exhaust	Point	128.3	99.6	108.6		105.1	105.1	0	0	71	83.8	83.6	82.5	99.2	102.8	95.8	87.1	54
D-23	D23 Exhaust	D23 Exhaust	Point	128.3	91.9	108.6		105.1	105.1	0	0	71	83.8	83.6	82.5	99.2	102.8	95.8	87.1	54
D-23	D23 Exhaust	D-23 Exhaust Pipe	Line	135.2	107.4	104.3	13.46	85.6	74.3	0	0	62.8	70.1	83.2	79.7	76.1	66.3	66.5	60.3	55.2
D-23	D23 Exhaust	D-23 Exhaust Pipe	Line	135.2	99.7	104.3	13.46	85.6	74.3	0	0	62.8	70.1	83.2	79.7	76.1	66.3	66.5	60.3	55.2
D-23	D23 Exhaust	D-23 Exhaust Pipe	Line	135.2	92.0	104.3	13.46	85.6	74.3	0	0	62.8	70.1	83.2	79.7	76.1	66.3	66.5	60.3	55.2
D-23	D23 Radiator	D-23 Radiator Exhaust	Line	136.0	107.5	104.3	3.31	95	89.8	0	0	67	81.1	85.2	83.6	88.6	90.3	87.9	78.4	69.1
D-23	D23 Radiator	D-23 Radiator Exhaust	Line	136.0	99.8	104.3	3.31	95	89.8	0	0	67	81.1	85.2	83.6	88.6	90.3	87.9	78.4	69.1
D-23	D23 Radiator	D-23 Radiator Exhaust	Line	136.0	92.1	104.3	3.31	95	89.8	0	0	67	81.1	85.2	83.6	88.6	90.3	87.9	78.4	69.1
D-23	D23 Radiator	D-23 Radiator Intake North Side	Line	134.1	109.3	103.6	1.99	98.8	95.8	0	0	69	84.7	88.9	90.2	91.4	92.4	91.8	88.9	71
D-23	D23 Radiator	D-23 Radiator Intake North Side	Line	134.1	101.6	103.6	1.99	98.8	95.8	0	0	69	84.7	88.9	90.2	91.4	92.4	91.8	88.9	71
D-23	D23 Radiator	D-23 Radiator Intake North Side	Line	134.1	93.9	103.6	1.99	98.8	95.8	0	0	69	84.7	88.9	90.2	91.4	92.4	91.8	88.9	71
D-23	D23 Radiator	D-23 Radiator Intake South Side	Line	134.2	105.6	103.6	1.86	98.8	96.1	0	0	69	84.7	88.9	90.2	91.4	92.4	91.8	88.9	71
D-23	D23 Radiator	D-23 Radiator Intake South Side	Line	134.2	97.9	103.6	1.86	98.8	96.1	0	0	69	84.7	88.9	90.2	91.4	92.4	91.8	88.9	71
D-23	D23 Radiator	D-23 Radiator Intake South Side	Line	134.2	90.2	103.6	1.86	98.8	96.1	0	0	69	84.7	88.9	90.2	91.4	92.4	91.8	88.9	71
D-23	D23 Radiator	D-23 Radiator Intake West Side	Line	132.9	107.4	103.0	3.18	104	99	0	0	74.7	90	94	94.1	99	97.9	94.7	92.7	75.5
D-23	D23 Radiator	D-23 Radiator Intake West Side	Line	132.9	99.7	103.0	3.18	104	99	0	0	74.7	90	94	94.1	99	97.9	94.7	92.7	75.5
D-23	D23 Radiator	D-23 Radiator Intake West Side	Line	132.9	92.0	103.0	3.18	104	99	0	0	74.7	90	94	94.1	99	97.9	94.7	92.7	75.5

Appendix C: Tabular Sound Level Measurement Results

Table C7A: Sound Level Results at Measurement Location 7

Start Date and Time	Day / Night	Duration (seconds)	Leq (dB(A))	L1.00 (dB(A))	L10.00 (dB(A))	L50.00 (dB(A))	L90.00 (dB(A))	L95.00 (dB(A))	31.5 dB	63 dB	125 dB	250 dB	500 dB	1000 dB	2000 dB	4000 dB	8000 dB
6/25/2004 9:15	DAY	899.625	55.2	64.8	57.3	50	47.1	46.3	58.4	59.5	57.7	55.8	51.0	49.2	44.8	41.5	49.3
6/25/2004 9:30	DAY	900	54.7	63.8	58.2	51.4	47.4	46.4	61.4	59.2	54.0	52.1	51.1	49.3	45.0	47.9	35.2
6/25/2004 9:45	DAY	900	57.1	67.1	61.6	51.4	47.8	46.8	58.4	56.6	57.8	52.3	51.3	50.2	47.0	52.9	39.7
6/25/2004 10:00	DAY	900	55.8	65.4	59.7	51.6	47.9	46.7	58.6	54.5	54.4	50.2	50.3	49.4	45.6	51.5	37.8
6/25/2004 10:15	DAY	900	64.7	75.1	62	51.8	47.4	46.3	60.2	62.8	66.2	64.6	62.9	60.4	54.0	50.2	40.5
6/25/2004 10:30	DAY	900	56.1	64.8	56.3	51.8	47.6	46.6	58.4	58.7	59.8	56.6	55.9	50.0	45.4	38.7	32.9
6/25/2004 10:45	DAY	900	62.1	76	61.2	52	48.6	48	61.6	64.8	63.0	62.1	61.3	56.5	52.8	46.6	41.3
6/25/2004 11:00	DAY	900	61.7	71.4	56	51.9	48.2	47.1	62.0	59.6	58.4	62.6	60.8	56.3	52.9	47.4	42.9
6/25/2004 11:15	DAY	900	56.3	67.4	55.1	51.7	48.1	46.9	61.9	59.3	55.7	53.7	53.5	52.5	47.8	41.9	37.0
6/25/2004 11:30	DAY	900	59.2	72.7	59.3	52.6	48.8	48.1	62.3	67.8	60.5	60.5	57.0	53.1	50.3	46.1	39.5
6/25/2004 11:45	DAY	900	55.6	66.8	57	50.8	47	46.2	58.7	58.4	56.4	52.7	52.8	52.1	46.9	39.7	33.5
6/25/2004 12:00	DAY	900	56.7	66.9	60.3	52	47.8	46.7	58.5	57.0	56.0	52.5	54.6	51.5	47.9	45.3	46.0
6/25/2004 12:15	DAY	900	65.1	74.4	71.9	52.1	48.4	47.5	58.6	55.2	60.4	56.3	62.5	58.7	59.9	50.8	43.4
6/25/2004 12:30	DAY	900	61.5	72.8	61.2	52	47.4	46.3	63.0	61.3	62.9	61.2	59.1	55.9	53.6	46.6	40.7
6/25/2004 12:45	DAY	900	53	62.8	55	50.1	46.6	46	58.0	59.1	59.7	48.3	49.8	48.8	44.4	37.1	28.2
6/25/2004 13:00	DAY	900	54.3	64.2	54.5	49.5	45.8	44.7	61.5	54.7	51.7	50.8	51.2	51.3	45.7	35.9	28.6
6/25/2004 13:15	DAY	900	55.5	69.4	55	49.5	46.3	45.5	59.4	55.8	56.9	58.0	55.0	49.5	43.0	34.1	26.7
6/25/2004 13:30	DAY	900	57.3	70.6	55.8	50.1	46.6	45.5	58.9	59.6	61.4	62.4	55.5	49.2	43.2	34.6	27.1
6/25/2004 13:45	DAY	900	56	64.7	55.6	50.3	47.1	46.4	61.3	58.8	54.7	57.0	53.0	51.6	47.4	41.5	36.9
6/25/2004 14:00	DAY	900	57.4	69.9	58.1	51.9	48.4	47.2	60.0	66.0	60.0	56.6	54.6	52.5	48.9	43.8	37.8
6/25/2004 14:15	DAY	900	57.3	67.8	57.3	50.9	46.8	45.8	58.4	59.8	62.6	54.5	53.2	52.5	49.4	45.7	45.3
6/25/2004 14:30	DAY	900	51.5	60.5	53.1	49.8	46.6	45.8	58.2	54.7	46.8	46.0	47.2	47.5	43.7	42.2	28.8
6/25/2004 14:45	DAY	900	57.2	69.8	54.8	51.1	47.6	46.7	60.7	58.0	55.0	54.6	53.2	52.6	50.3	45.6	38.0
6/25/2004 15:00	DAY	900	55.4	68.3	56.3	49.8	47.1	46.3	62.1	57.3	58.1	57.7	54.5	49.5	43.4	34.2	25.1
6/25/2004 15:15	DAY	900	60.2	73.4	63	52.2	47.9	47	61.8	69.4	62.6	56.8	56.2	55.3	51.8	51.2	42.3
6/25/2004 15:30	DAY	900	58.1	70.7	61.7	51.3	47.7	47	59.5	58.0	56.1	56.2	55.6	52.1	47.6	51.6	38.2
6/25/2004 15:45	DAY	900	55.7	66.7	59	50.4	47.2	46.2	58.6	58.8	54.9	50.2	49.6	48.8	45.8	51.5	40.1
6/25/2004 16:00	DAY	900	62.4	74.5	57	49	45.2	44.4	59.6	67.1	71.6	66.8	60.2	53.5	50.9	47.6	42.5
6/25/2004 16:15	DAY	900	59.2	74.4	56	49.4	45.9	45.1	58.3	58.3	58.5	63.0	58.7	51.9	45.5	40.3	31.4
6/25/2004 16:30	DAY	900	55.6	67.7	56.7	48.6	44.7	43.4	59.0	58.0	58.8	56.2	52.9	49.7	45.3	46.8	37.3
6/25/2004 16:45	DAY	900	54.6	64.9	59.1	49.1	46	45.3	56.4	55.4	51.6	48.2	48.1	48.0	45.3	50.5	35.1
6/25/2004 17:00	DAY	900	56.1	65.1	59.3	48.2	44	42.9	56.8	51.8	60.8	59.5	51.0	45.9	43.2	50.8	34.3
6/25/2004 17:15	DAY	900	58.7	71.9	61.8	48.9	44.5	43.9	58.2	57.3	59.0	61.1	57.2	49.7	45.2	51.4	35.3
6/25/2004 17:30	DAY	900	54.3	66.8	56.2	46.4	42.8	42	56.3	56.1	56.7	45.9	46.0	46.4	44.0	51.1	38.1
6/25/2004 17:45	DAY	900	51.9	65.1	52.4	46.7	43.3	42.5	58.5	55.7	46.0	43.8	45.9	46.3	44.2	45.7	38.3
6/25/2004 18:00	DAY	900	55.8	67.2	59.4	46.9	43.5	42.5	57.7	56.7	58.0	55.9	51.6	49.5	45.3	48.6	45.9
6/25/2004 18:15	DAY	900	56.3	69.4	56.1	46.8	43.2	42.3	59.4	60.6	56.8	57.0	54.8	50.9	47.1	38.5	31.9
6/25/2004 18:30	DAY	900	49.1	61.1	48.1	46	42.2	40.8	57.0	52.3	45.1	41.4	43.8	44.8	41.7	40.4	32.9
6/25/2004 18:45	DAY	900	50.4	62.3	51.6	47.3	44.3	43.6	56.2	51.7	48.3	44.3	46.2	47.1	43.0	36.8	33.8
6/25/2004 19:00	DAY	900	51.5	61.3	50.7	46.6	42.9	42.1	56.8	59.6	59.4	50.0	48.7	45.6	41.5	33.3	28.2
6/25/2004 19:15	DAY	900	59.8	68.7	64.6	47.9	41	39.9	56.2	59.8	60.9	48.6	47.7	45.8	41.8	38.5	60.3
6/25/2004 19:30	DAY	900	61.4	68.8	65.8	58.3	46.8	44.8	56.4	54.1	45.7	44.4	44.6	44.4	40.0	31.5	62.2
6/25/2004 19:45	DAY	900	63.4	68.8	67	62.4	49.9	48.8	56.6	53.6	51.5	56.5	55.1	48.2	42.8	33.1	64.0
6/25/2004 20:00	DAY	900	55.7	68.5	57.9	48.4	44.2	43.4	58.4	57.9	58.8	58.3	53.0	47.9	43.7	35.7	51.0
6/25/2004 20:15	DAY	900	54.9	68.3	53.6	47.6	43.5	42.4	57.6	56.0	57.7	58.3	53.7	48.5	42.2	31.4	27.6
6/25/2004 20:30	DAY	900	49.8	59.5	52.1	47.1	44	43	56.4	52.0	47.4	45.4	47.7	46.4	41.3	31.2	28.7
6/25/2004 20:45	DAY	900	61	75.1	52.2	46.8	43.5	42.7	58.5	56.2	67.3	64.4	61.1	51.1	47.1	40.8	36.6
6/25/2004 21:00	DAY	900	50.9	64.1	50.8	46.6	42.5	41.3	56.4	54.9	49.7	48.8	48.2	47.4	41.8	33.1	34.1
6/25/2004 21:15	DAY	900	53.2	65.4	54.3	47.5	43.6	42.8	59.6	57.8	54.0	53.8	51.9	48.5	43.7	32.1	24.5
6/25/2004 21:30	DAY	900	52.2	65.2	50	44.2	41.5	40.8	56.8	55.3	52.1	49.2	48.7	47.2	45.8	39.4	35.0
6/25/2004 21:45	DAY	900	47.2	57.8	48.5	44.6	40.7	39.2	58.9	57.2	51.9	47.4	44.7	43.0	37.5	23.0	23.3
6/25/2004 22:00	NIGHT	900	49.5	57.9	53	43.5	39.4	38.7	53.8	48.8	48.3	43.2	43.4	44.3	40.6	32.6	45.9
6/25/2004 22:15	NIGHT	900	53.9	62.2	59.5	43.7	39.7	38.4	58.3	56.2	50.3	47.7	46.0	44.6	38.9	28.0	54.2
6/25/2004 22:30	NIGHT	900	44.9	53.3	46.8	43.4	40.3	39.4	50.9	49.6	42.1	42.2	41.9	41.4	36.5	24.8	29.1
6/25/2004 22:45	NIGHT	900	48.3	58.7	48.6	44.5	40.9	40.1	50.4	50.8	46.9	44.2	44.2	45.1	40.2	32.9	29.5
6/25/2004 23:00	NIGHT	900	45.8	53.3	49	44.1	39.9	39.4	50.1	47.8	41.0	43.2	41.7	42.7	37.9	25.6	29.4
6/25/2004 23:15	NIGHT	900	49.7	55.9	52.6	46.3	41.3	40.2	53.9	53.7	43.9	46.0	45.7	46.6	41.9	32.2	28.0
6/25/2004 23:30	NIGHT	900	49.2	58	50.3	45.1	40.8	40.2	50.5	50.8	51.2	49.7	45.5	44.5	41.0	32.4	28.5
6/25/2004 23:45	NIGHT	900	54.5	64.1	49.4	44.3	40.9	39.9	50.3	50.3	63.6	54.9	54.1	45.9	41.9	34.9	31.4
6/26/2004 0:00	NIGHT	900	47.3	60	47.4	42.6	39.3	38.4	49.7	50.0	45.6	46.4	43.4	43.9	38.8	29.8	25.2
6/26/2004 0:15	NIGHT	900	53.6	66.2	55.4	46.3	41.6	40.3	50.5	55.1	51.1	49.5	49.6	49.8	46.0	41.7	38.1
6/26/2004 0:30	NIGHT	900	53.6	60	53.8	49.8	45.8	43.2	52.0	47.3	47.3	44.6	46.5	48.9	47.6	45.0	40.7
6/26/2004 0:45	NIGHT	900	56.1	60.5	56.7	52.4	46.9	46.3	50.3	46.5	43.5	44.6	50.7	51.6	49.9	46.6	44.3
6/26/2004 1:00	NIGHT	900	53.6	57.9	56.4	52.7	49.2	48.4	46.1	49.8	41.2	41.6	44.0	48.7	48.4	44.2	43.3
6/26/2004 1:15	NIGHT	900	51.4	56.5	54.6	50.4	46.4	45.1	47.3	43.1	36.8	39.8	41.0	46.5	46.2	42.1	41.3
6/26/2004 1:30	NIGHT	900	45.3	52.5	48.3	43.3	40.4	39.8	47.8	45.4	46.2	44.7	38.1	39.8	38.8	34.5	33.2
6/26/2004 1:45	NIGHT	900	42.2	47.6	44.2	41.5	39.4	38.8	47.0	44.6	39.1	42.7	37.1	37.1	34.7	29.7	28.1
6/26/2004 2:00	NIGHT	900	40	47.5	42.4	38.4	36.3	36	47.4	43.5	37.4	40.2	34.9	35.3	32.5	27.0	23.8
6/26/2004 2:15	NIGHT	900	36.6	43.1	39.1	35.5	31.6	31.2	47.1	43.0	39.8	38.2	32.5	31.8	27.5	20.2	20.5
6/26/2004 2:30	NIGHT	900	45	50.3	48.2	44.4	39.4	38.9	47.0	44.8	39.8	37.7	36.9	40.5	39.5	34.9	32.9
6/26/2004 2:45	NIGHT	900	43.4	49.9	47.1	41.5	38.2	37.5	48.2	45.1	39.9	42.5	38.9	39.1	35.9	30.2	28.2

Appendix D: Modeled Source Sound Power Levels

Table D2: Computer Model Data for Future Plant Noise Sources

				Center Point Coordinates			Size (m or m^2)	Total PWL	PWL per unit	SPL inside	Komega Correction	A-weighted Total PWL per Source								
Super Group	Group	Source	SrcType	X	Y	Z	l or S	Lw	Lw'	Li	Ko	31	63	125	250	500	1000	2000	4000	8000
CT4-5	Ext Encl Turbine Walls GT-4	GT-4 Turbine E Wall	Area	110.0	166.8	103.5	49.21	63.4	46.5	86	3	54.1	61.2	57.2	47.9	40.1	36.5	20.8	23	17.1
CT4-5	Ext Encl Turbine Walls GT-4	GT-4 Turbine Highbay - East	Area	110.0	161.3	104.7	34.61	61.9	46.5	86	3	52.6	59.7	55.7	46.4	38.6	35	19.3	21.5	15.6
CT4-5	Ext Encl Turbine Walls GT-4	GT-4 Turbine Highbay - North	Area	106.9	163.2	108.2	14.64	58.1	46.5	86	3	48.9	56	52	42.7	34.9	31.3	15.6	17.8	11.9
CT4-5	Ext Encl Turbine Walls GT-4	GT-4 Turbine Highbay - Roof	Area	106.9	161.4	109.9	24.91	66.9	52.9	86.3	0	51.2	65.6	60.4	48	36.5	30.2	14.4	15.9	10.4
CT4-5	Ext Encl Turbine Walls GT-4	GT-4 Turbine Highbay - West	Area	103.8	161.4	104.7	34.61	60.9	45.5	85.9	3	44.8	58.9	55.6	46.4	38.6	35	19.3	21.5	15.6
CT4-5	Ext Encl Turbine Walls GT-4	GT-4 Turbine Roof	Area	106.9	166.8	107.0	44.98	69.5	52.9	86.3	0	53.7	68.1	62.9	50.5	39	32.7	16.9	18.4	12.9
CT4-5	Ext Encl Turbine Walls GT-4	GT-4 Turbine W Wall	Area	103.8	166.9	103.5	49.21	62.4	45.5	85.9	3	46.3	60.4	57.1	47.9	40.1	36.5	20.8	23	17.1
CT4-5	Ext Encl Turbine Walls GT-5	GT-5 Turbine E Wall	Area	110.0	202.5	103.5	49.49	58.1	41.2	85.8	3	42.3	55.4	53.1	47.9	40.1	36.5	20.8	23	17.1
CT4-5	Ext Encl Turbine Walls GT-5	GT-5 Turbine Highbay - East	Area	110.0	208.0	104.7	34.23	61.8	46.5	86	3	52.5	59.6	55.6	46.3	38.5	34.9	19.2	21.4	15.5
CT4-5	Ext Encl Turbine Walls GT-5	GT-5 Turbine Highbay - North	Area	104.5	209.8	104.8	10.23	56.6	46.5	86	3	47.3	54.4	50.4	41.1	33.3	29.7	14	16.2	10.3
CT4-5	Ext Encl Turbine Walls GT-5	GT-5 Turbine Highbay - Roof	Area	106.9	208.0	109.5	22.53	66.3	52.8	86.2	0	43.2	65	59.9	47.5	36	29.7	13.9	15.4	9.9
CT4-5	Ext Encl Turbine Walls GT-5	GT-5 Turbine Highbay - South	Area	107.0	206.1	108.3	12.64	63.9	52.9	86.3	3	48.2	62.6	57.4	45	33.5	27.2	11.4	12.9	7.4
CT4-5	Ext Encl Turbine Walls GT-5	GT-5 Turbine Highbay - West	Area	103.8	208.0	104.7	34.23	60.8	45.5	85.9	3	44.7	58.8	55.5	46.3	38.5	34.9	19.2	21.4	15.5
CT4-5	Ext Encl Turbine Walls GT-5	GT-5 Turbine Roof	Area	106.9	202.5	107.0	45.23	57.7	41.2	85.8	0	42	55.1	52.8	47.6	39.8	36.2	20.5	22.7	16.8
CT4-5	Ext Encl Turbine Walls GT-5	GT-5 Turbine W Wall	Area	103.8	202.5	103.5	49.49	58.1	41.2	85.8	3	42.3	55.4	53.1	47.9	40.1	36.5	20.8	23	17.1
CT4-5	Filter House Side Walls GT-4	GT-4 Air Intake E wall	Area	109.0	157.9	105.0	27.44	53.4	39	0	3	44.6	41.8	38.9	24.4	30.8	46	44.2	50	30.1
CT4-5	Filter House Side Walls GT-4	GT-4 Air Intake Roof	Area	106.9	157.9	109.3	13.32	53.4	42.2	0	0	44.6	41.8	38.9	24.4	30.8	46	44.2	50	30.1
CT4-5	Filter House Side Walls GT-4	GT-4 Air Intake W wall	Area	104.8	157.9	105.0	27.44	53.4	39	0	3	44.6	41.8	38.9	24.4	30.8	46	44.2	50	30.1
CT4-5	Filter House Side Walls GT-5	GT-5 Air Intake N wall	Area	113.4	215.3	104.7	29.42	40.3	25.6	0	3	38.6	34.8	25.9	7.4	4.8	1	1.2	1	-1.1
CT4-5	Filter House Side Walls GT-5	GT-5 Air Intake S wall	Area	114.6	211.2	104.7	29.42	40.3	25.6	0	3	38.6	34.8	25.9	7.4	4.8	1	1.2	1	-1.1
CT4-5	Filter House Side Walls GT-5	GT-5 Air Intake Roof	Area	114.0	213.2	109.3	13.32	36.2	25	0	0	34.6	30.8	20.9	2.4	0.8	0	1.2	1	-1.1
CT4-5	Filter Housing Base Skids GT-4	GT-4 Air Intake Base E	Area	109.0	157.9	100.4	1.98	58.2	55.3	0	3	49.4	46.6	43.7	29.2	35.6	50.8	49	54.8	34.9
CT4-5	Filter Housing Base Skids GT-4	GT-4 Air Intake Base S	Area	106.9	156.3	100.4	2.64	59.5	55.3	0	3	50.6	47.8	44.9	30.4	36.8	52	50.2	56	40.9
CT4-5	Filter Housing Base Skids GT-4	GT-4 Air Intake Base W	Area	104.8	157.9	100.4	1.98	58.2	55.3	0	3	49.4	46.6	43.7	29.2	35.6	50.8	49	54.8	34.9
CT4-5	GT-4 Enclosure Exhausts	GT-4 Enclosure Exhaust NE	Area	107.3	171.9	108.0	1	66	66	84.2	0	51.9	63	61.1	55.7	53	19.2	11.5	25.8	29.8
CT4-5	GT-4 Enclosure Exhausts	GT-4 Enclosure Exhaust NW	Area	105.8	171.9	108.0	1	66	66	84.2	0	51.9	63	61.1	55.7	53	19.2	11.5	25.8	29.8
CT4-5	GT-4 Enclosure Exhausts	GT-4 Enclosure Exhaust SE	Area	107.3	161.5	110.5	1	67.9	67.9	86.3	0	53.2	65.6	61.4	58	55.5	21.2	12.4	28.9	33.4
CT4-5	GT-4 Enclosure Exhausts	GT-4 Enclosure Exhaust SW	Area	105.8	161.5	110.5	1	67.9	67.9	86.3	0	53.2	65.6	61.4	58	55.5	21.2	12.4	28.9	33.4
CT4-5	GT-4 Enclosure Intakes	GT-4 Enclosure Intake NE	Area	110.0	176.8	101.2	0.85	64.3	65	83.6	3	48.2	54.9	63.3	50.1	49.7	19.6	14.2	25.8	29
CT4-5	GT-4 Enclosure Intakes	GT-4 Enclosure Intake NW	Area	103.8	176.8	101.2	0.85	61.3	62	80.6	3	45.2	51.9	60.3	47.1	46.7	16.6	11.2	22.8	26
CT4-5	GT-4 Enclosure Intakes	GT-4 Enclosure Intake SE	Area	110.0	164.4	101.2	0.84	62.2	62.9	86	3	52.4	57.5	54.5	54.2	55.4	23.8	15.1	32.3	36.4
CT4-5	GT-4 Enclosure Intakes	GT-4 Enclosure Intake SW	Area	103.8	164.0	101.2	0.84	61.5	62.2	85.9	3	44.6	56.7	54.4	54.2	55.4	23.8	15.1	32.3	36.4
CT4-5	GT-5 Enclosure Exhausts	GT-5 Enclosure Exhaust NE	Area	107.4	206.1	107.9	1	65.5	65.5	86.3	3	53.2	61.6	59.4	58	55.5	21.2	12.4	28.9	33.4
CT4-5	GT-5 Enclosure Exhausts	GT-5 Enclosure Exhaust NW	Area	105.9	206.1	107.9	1	65.5	65.5	86.3	3	53.2	61.6	59.4	58	55.5	21.2	12.4	28.9	33.4
CT4-5	GT-5 Enclosure Exhausts	GT-5 Enclosure Exhaust SE	Area	107.3	196.8	108.0	1	63.7	63.7	84.2	0	51.9	59	59.1	55.7	53	19.2	11.5	25.8	29.8
CT4-5	GT-5 Enclosure Exhausts	GT-5 Enclosure Exhaust SW	Area	105.8	196.8	108.0	1	63.7	63.7	84.2	0	51.9	59	59.1	55.7	53	19.2	11.5	25.8	29.8
CT4-5	GT-5 Enclosure Intakes	GT-5 Enclosure Intake NE	Area	110.0	205.3	101.2	0.84	60.8	61.6	86	3	52.4	53.5	52.5	54.2	55.4	23.8	15.1	32.3	36.4
CT4-5	GT-5 Enclosure Intakes	GT-5 Enclosure Intake NW	Area	103.8	204.8	101.2	0.84	60.1	60.8	85.9	3	44.6	52.7	52.4	54.2	55.4	23.8	15.1	32.3	36.4
CT4-5	GT-5 Enclosure Intakes	GT-5 Enclosure Intake SE	Area	110.0	192.1	101.2	0.84	62.3	63.1	83.6	3	48.1	50.8	61.2	50	49.6	19.5	14.1	25.7	28.9
CT4-5	GT-5 Enclosure Intakes	GT-5 Enclosure Intake SW	Area	103.8	192.5	101.2	0.84	59.3	60.1	80.6	3	45.1	47.8	58.2	47	46.6	16.5	11.1	22.7	25.9
CT4-5	GT-5 Inlet Transition Walls	GT-5 Elbow Roof	Area	107.4	211.5	109.3	14.77	56.5	44.8	0	0	43.6	47.8	52.9	51.4	43.8	29	26.2	26	19.9
CT4-5	GT-5 Inlet Transition Walls	GT-5 Elbow Wall 1	Area	105.2	211.4	104.7	29.88	61.7	46.9	0	3	48.6	53.8	57.9	56.4	49.8	34	31.2	31	24.9
CT4-5	GT-5 Inlet Transition Walls	GT-5 Elbow Wall 2	Area	107.3	213.4	104.7	29.42	59.7	45	0	3	46.6	51.8	55.9	54.4	47.8	32	29.2	29	22.9
CT4-5	GT-5 Inlet Transition Walls	GT-5 Inlet Elbow Inside	Line	110.1	209.7	105.0	9	61.4	51.9	0	0	48.6	52.8	57.9	56.4	48.8	32	23.2	26	22.9
CT4-5	Silencer Housing Walls GT-5	GT-5 Intake Silencer N Wall	Area	110.3	214.3	104.7	29.42	57.5	42.8	0	3	45.4	48.9	53.9	52.4	44.8	30	27.2	27	20.9
CT4-5	Silencer Housing Walls GT-5	GT-5 Intake Silencer S Wall	Area	111.6	210.3	104.7	29.42	57.5	42.8	0	3	45.4	48.9	53.9	52.4	44.8	30	27.2	27	20.9
CT4-5	Silencer Housing Walls GT-5	GT-5 Silencer Roof	Area	110.9	212.3	109.3	13.32	54.6	43.3	0	0	42.4	46.4	50.9	49.4	41.8	27	24.2	24	18
CT4-5	Turbine Exhaust Duct	CT-4 Turbine Exh Duct Breach w HRSG	Line	159.4	179.6	106.4	2.68	51.9	47.6	0	0	48.6	48.8	37.9	23.4	6.8	-6	-13.8	-6	-4.1

Appendix D: Modeled Source Sound Power Levels

Table D2: Computer Model Data for Future Plant Noise Sources																						
				Center Point Coordinates			Size (m or m^2)	Total PWL	PWL per unit	SPL inside	Komega Correction	A-weighted Total PWL per Source								
Super Group	Group	Source	SrcType	X	Y	Z	l or S	Lw	Lw'	Li	Ko	31	63	125	250	500	1000	2000	4000	8000
CT4-5	Turbine Exhaust Duct	CT-4 Turbine Exh Duct Diverter	Line	127.9	168.7	106.3	1.59	51.6	49.6	0	0	50.6	44.8	23.9	7.4	-3.2	1	2.2	2	-0.1
CT4-5	Turbine Exhaust Duct	CT-4 Turbine Exh Duct T1	Line	111.8	168.7	102.5	2.4	62.1	58.3	0	0	58.6	58.8	49.9	45.4	35.8	23	14.2	4	-8.1
CT4-5	Turbine Exhaust Duct	CT-4 Turbine Exh Duct T2	Line	116.0	168.7	103.5	5.98	61.1	53.3	0	0	57.6	57.8	48.9	44.4	34.8	22	13.2	3	-9.1
CT4-5	Turbine Exhaust Duct	CT-4 Turbine Exh Duct T3	Line	123.0	168.7	105.2	7.83	56.6	47.7	0	0	55.6	49.8	28.9	11.4	1.8	1	2.2	2	-0.1
CT4-5	Turbine Exhaust Duct	CT-4 Turbine Exh Duct T4	Line	130.9	168.8	106.4	3.35	54.4	49.2	0	0	53.6	46.8	25.9	9.4	-1.2	1	2.2	2	-0.1
CT4-5	Turbine Exhaust Duct	CT-4 Turbine Exh Duct T5 w HRSG	Line	152.1	171.3	106.4	7.86	50.9	41.9	0	0	47.6	47.8	36.9	22.4	5.8	-7	-15.8	-8	-6.1
CT4-5	Turbine Exhaust Duct	CT-4 Turbine Exh Duct T6 w HRSG	Line	157.5	176.1	106.4	5.34	60.4	53.1	0	0	56.6	57.8	45.9	31.4	14.8	2	-5.8	2	3.9
CT4-5	Turbine Exhaust Duct	CT-4 Turbine HRSG Body 1	Line	135.5	168.8	110.0	5.06	58.9	51.9	0	0	55.6	55.8	44.9	30.4	14.8	2	2.2	8	13.9
CT4-5	Turbine Exhaust Duct	CT-4 Turbine HRSG Body 2	Line	143.6	168.8	110.0	10.12	54.9	44.8	0	0	51.6	51.8	40.9	26.4	9.8	-3	-9.8	-1	2.9
CT4-5	Turbine Exhaust Duct	CT-5 Turbine Exh Duct Breach w HRSG	Line	159.4	189.8	106.4	2	51.9	48.9	0	0	48.6	48.8	37.9	23.4	6.8	-6	-13.8	-6	-4.1
CT4-5	Turbine Exhaust Duct	CT-5 Turbine Exh Duct Diverter	Line	127.6	200.3	106.3	0.91	51.6	52	0	0	50.6	44.8	23.9	7.4	-3.2	1	2.2	2	-0.1
CT4-5	Turbine Exhaust Duct	CT-5 Turbine Exh Duct T1	Line	111.8	200.3	102.5	2.4	62.1	58.3	0	0	58.6	58.8	49.9	45.4	35.8	23	14.2	4	-8.1
CT4-5	Turbine Exhaust Duct	CT-5 Turbine Exh Duct T2	Line	116.0	200.3	103.5	5.99	61.1	53.3	0	0	57.6	57.8	48.9	44.4	34.8	22	13.2	3	-9.1
CT4-5	Turbine Exhaust Duct	CT-5 Turbine Exh Duct T3	Line	123.0	200.3	105.2	7.83	56.6	47.7	0	0	55.6	49.8	28.9	11.4	1.8	1	2.2	2	-0.1
CT4-5	Turbine Exhaust Duct	CT-5 Turbine Exh Duct T4	Line	130.3	200.3	106.4	3.84	54.4	48.6	0	0	53.6	46.8	25.9	9.4	-1.2	1	2.2	2	-0.1
CT4-5	Turbine Exhaust Duct	CT-5 Turbine Exh Duct T5 w HRSG	Line	152.6	197.6	106.4	7.25	50.9	42.3	0	0	47.6	47.8	36.9	22.4	5.8	-7	-15.8	-8	-6.1
CT4-5	Turbine Exhaust Duct	CT-5 Turbine Exh Duct T6 w HRSG	Line	157.6	192.8	106.4	5.05	60.4	53.4	0	0	56.6	57.8	45.9	31.4	14.8	2	-5.8	2	3.9
CT4-5	Turbine Exhaust Duct	CT-5 Turbine HRSG Body 1	Line	136.6	200.3	110.0	8.06	58.9	49.8	0	0	55.6	55.8	44.9	30.4	14.8	2	2.2	8	13.9
CT4-5	Turbine Exhaust Duct	CT-5 Turbine HRSG Body 2	Line	145.3	200.4	110.0	8.44	54.9	45.6	0	0	51.6	51.8	40.9	26.4	9.8	-3	-9.8	-1	2.9
CT4-5	Turbine Exhaust Exit	GT-4 Turbine Exhaust Disch w HRSG	Point	159.2	183.2	131.7		66.6	66.6	0	0	58.6	64.8	57.9	50.4	47.8	46	34.2	29	14.9
CT4-5	Turbine Exhaust Exit	GT-5 Turbine Exhaust Disch w HRSG	Point	159.2	186.7	131.7		66.6	66.6	0	0	58.6	64.8	57.9	50.4	47.8	46	34.2	29	14.9
CT4-5 Aux	Centrifuge Enclosure	Centrifuge Encl - East	Area	100.1	44.6	102.2	16.14	65.2	53.1	78.7	3	36.7	42.9	47	51.5	51.9	64.1	55.3	44.1	29
CT4-5 Aux	Centrifuge Enclosure	Centrifuge Encl - North	Area	95.1	46.5	102.2	43.1	69.4	53.1	78.7	3	40.9	47.1	51.2	55.7	56.1	68.3	59.5	48.3	33.2
CT4-5 Aux	Centrifuge Enclosure	Centrifuge Encl - Roof	Area	95.2	44.7	104.7	43.44	69.5	53.1	78.7	0	41	47.2	51.3	55.8	56.2	68.4	59.6	48.4	33.3
CT4-5 Aux	Centrifuge Enclosure	Centrifuge Encl - South	Area	95.1	42.7	102.2	42.14	69.3	53.1	78.7	3	40.8	47	51.1	55.6	56	68.2	59.4	48.2	33.1
CT4-5 Aux	Centrifuge Enclosure	Centrifuge Encl - West	Area	90.0	44.6	102.2	16.14	65.2	53.1	78.7	3	36.7	42.9	47	51.5	51.9	64.1	55.3	44.1	29
CT4-5 Aux	Centrifuge Vent Exhausts	Centrifuge Encl - Vent Exhaust	Area	98.6	45.1	105.4	1.2	58.7	57.9	78.7	0	27.4	33.6	36.7	51.2	48.6	55.8	49	47.8	37.7
CT4-5 Aux	Centrifuge Vent Intakes	Centrifuge Encl - South - Intake	Area	91.2	42.7	101.0	0.96	57.7	57.9	78.7	3	26.4	32.6	35.7	50.2	47.6	54.8	48	46.8	36.7
CT4-5 Aux	Fuel Oil Skid Walls GT-4	Fuel Oil 4 E Wall	Area	114.9	152.4	101.5	11.32	73.9	63.4	97.6	3	40.1	54.3	66.4	70.9	66.3	64.5	55.7	48.5	38.4
CT4-5 Aux	Fuel Oil Skid Walls GT-4	Fuel Oil 4 N Wall	Area	113.4	154.4	101.5	8.88	72.9	63.4	97.6	3	39.1	53.3	65.4	69.9	65.3	63.5	54.7	47.5	37.4
CT4-5 Aux	Fuel Oil Skid Walls GT-4	Fuel Oil 4 Roof	Area	113.3	152.4	103.5	15.62	75.3	63.4	97.6	0	41.5	55.7	67.8	72.3	67.7	65.9	57.1	49.9	39.8
CT4-5 Aux	Fuel Oil Skid Walls GT-4	Fuel Oil 4 S Wall	Area	113.4	150.4	101.5	8.88	72.9	63.4	97.6	3	39.1	53.3	65.4	69.9	65.3	63.5	54.7	47.5	37.4
CT4-5 Aux	Fuel Oil Skid Walls GT-4	Fuel Oil 4 W Wall	Area	111.89	152.39	101.5	11.74	74.1	63.4	97.6	3	40.3	54.5	66.6	71.1	66.5	64.7	55.9	48.7	38.6
CT4-5 Aux	Fuel Oil Skid Walls GT-5	Fuel Oil 5 E Wall	Area	130.9	207.38	101.5	11.74	61	50.3	97.6	3	37.3	51.5	57.6	55.1	46.5	50.7	44.9	40.7	31.6
CT4-5 Aux	Fuel Oil Skid Walls GT-5	Fuel Oil 5 N Wall	Area	129.4	209.37	101.5	8.88	59.8	50.3	97.6	3	36.1	50.3	56.4	53.9	45.3	49.5	43.7	39.5	30.4
CT4-5 Aux	Fuel Oil Skid Walls GT-5	Fuel Oil 5 Roof	Area	129.45	207.35	103.46	15.12	62.1	50.3	97.6	0	38.4	52.6	58.7	56.2	47.6	51.8	46	41.8	32.7
CT4-5 Aux	Fuel Oil Skid Walls GT-5	Fuel Oil 5 S Wall	Area	129.39	205.4	101.5	8.88	59.8	50.3	97.6	3	36.1	50.3	56.4	53.9	45.3	49.5	43.7	39.5	30.4
CT4-5 Aux	Fuel Oil Skid Walls GT-5	Fuel Oil 5 W Wall	Area	127.89	207.4	101.52	11.38	60.8	50.3	97.6	3	37.2	51.4	57.5	55	46.4	50.6	44.8	40.6	31.5
CT4-5 Aux	Fuel Oil Vent Exhausts	Fuel Oil 4 Vent Exhaust	Area	112.58	152.14	104.1	1.2	66	65.2	97.6	0	40.4	50.6	55.7	61.2	51.6	51.8	55	55.8	60.7
CT4-5 Aux	Fuel Oil Vent Exhausts	Fuel Oil 5 Vent Exhaust	Area	129.78	207.14	104.1	1.2	66	65.2	97.6	0	40.4	50.6	55.7	61.2	51.6	51.8	55	55.8	60.7
CT4-5 Aux	Fuel Oil Vent Intakes	Fuel Oil 4 E Wall - Intake	Area	114.9	153.26	100.91	0.42	61.4	65.2	97.6	3	35.8	46	51.1	56.6	47	47.2	50.4	51.2	56.1
CT4-5 Aux	Fuel Oil Vent Intakes	Fuel Oil 5 W Wall - Intake	Area	127.89	207.06	100.91	0.36	60.8	65.2	97.6	3	35.2	45.4	50.5	56	46.4	46.6	49.8	50.6	55.5
CT4-5 Aux	Gen Compartment Exhaust GT-	GT-4 Gen Encl Exh Vent	Point	106.91	175.1	108		72.3	72.3	0	0	44.6	59.8	71.9	40.4	41.8	43	43.2	43	53.9
CT4-5 Aux	Gen Compartment Exhaust GT-	GT-5 Gen Encl Vent Exhaust	Point	106.91	194.2	108		72.3	72.3	0	0	44.6	59.8	71.9	40.4	41.8	43	43.2	43	53.9
CT4-5 Aux	Hydraulic Startup Skids	Hydr Startup Skid 4 E Wall	Area	115.9	158.71	101.5	8.94	61.2	51.7	102.5	3	30.1	44.2	51.5	58.4	52.3	51	46.3	50.3	25.9
CT4-5 Aux	Hydraulic Startup Skids	Hydr Startup Skid 4 N Wall	Area	113.93	160.23	101.5	11.68	62.3	51.7	102.5	3	31.3	45.4	52.7	59.6	53.5	52.2	47.5	51.5	27.1
CT4-5 Aux	Hydraulic Startup Skids	Hydr Startup Skid 4 Roof	Area	113.98	158.79	103.46	15.29	63.5	51.7	102.5	0	32.4	46.5	53.8	60.7	54.6	53.3	48.6	52.6	28.2
CT4-5 Aux	Hydraulic Startup Skids	Hydr Startup Skid 4 Roof - Exhaust	Area	114.34	159.19	104.1	1.28	70.4	69.4	102.5	0	34.7	44.8	51.1	66	58.9	53.6	57.9	66.9	56.5

Table D2: Computer Model Data for Future Plant Noise Sources

				Center Point Coordinates			Size (m or m^2)	Total PWL	PWL per unit	SPL inside	Komega Correction	A-weighted Total PWL per Source								
Super Group	Group	Source	SrcType	X	Y	Z	l or S	Lw	Lw'	Li	Ko	31	63	125	250	500	1000	2000	4000	8000
CT4-5 Aux	Hydraulic Startup Skids	Hydr Startup Skid 4 S Wall	Area	113.92	157.2	101.5	11.68	62.3	51.7	102.5	3	31.3	45.4	52.7	59.6	53.5	52.2	47.5	51.5	27.1
CT4-5 Aux	Hydraulic Startup Skids	Hydr Startup Skid 4 W - Vent Intake	Area	111.95	158.43	100.91	0.38	65.2	69.4	102.5	3	29.4	39.5	45.8	60.7	53.6	48.3	52.6	61.6	51.2
CT4-5 Aux	Hydraulic Startup Skids	Hydr Startup Skid 4 W Wall	Area	111.95	158.73	101.53	8.56	61	51.7	102.5	3	29.9	44	51.3	58.2	52.1	50.8	46.1	50.1	25.7
CT4-5 Aux	Hydraulic Startup Skids	Hydr Startup Skid 5 E Wall	Area	115.9	205.71	101.5	8.94	61.2	51.7	102.5	3	30.1	44.2	51.5	58.4	52.3	51	46.3	50.3	25.9
CT4-5 Aux	Hydraulic Startup Skids	Hydr Startup Skid 5 N Wall	Area	113.93	207.23	101.5	11.68	62.3	51.7	102.5	3	31.3	45.4	52.7	59.6	53.5	52.2	47.5	51.5	27.1
CT4-5 Aux	Hydraulic Startup Skids	Hydr Startup Skid 5 Roof	Area	113.98	205.82	103.46	15.16	63.5	51.7	102.5	3	32.4	46.5	53.8	60.7	54.6	53.3	48.6	52.6	28.2
CT4-5 Aux	Hydraulic Startup Skids	Hydr Startup Skid 5 Roof - Exhaust	Area	114.36	206.3	104.11	1.2	70.1	69.4	102.5	0	34.4	44.5	50.8	65.7	58.6	53.3	57.6	66.6	56.2
CT4-5 Aux	Hydraulic Startup Skids	Hydr Startup Skid 5 S Wall	Area	113.92	204.2	101.5	11.68	62.3	51.7	102.5	3	31.3	45.4	52.7	59.6	53.5	52.2	47.5	51.5	27.1
CT4-5 Aux	Hydraulic Startup Skids	Hydr Startup Skid 5 W Wall	Area	111.95	205.7	102.18	23.69	65.4	51.7	102.5	3	34.3	48.4	55.7	62.6	56.5	55.2	50.5	54.5	30.1
CT4-5 Aux	Hydraulic Startup Skids	Hydr Startup Skid 5 W Wall - Intake	Area	111.93	205.51	106.93	0.38	65.2	69.4	102.5	3	29.4	39.5	45.8	60.7	53.6	48.3	52.6	61.6	51.2
CT4-5 Aux	Lube Oil Coolers	Lube Oil Cooler 4	Area	113.62	176.13	103.24	10.51	80.3	70.1	0	0	45.2	58.4	66.4	71.4	75.2	75.5	71.9	65	54
CT4-5 Aux	Lube Oil Coolers	Lube Oil Cooler 5	Area	113.54	189.79	103.24	10.4	80.3	70.1	0	0	45.2	58.4	66.4	71.4	75.2	75.5	71.9	65	54
CT4-5 Aux	Main Transformer Walls	Transformer, Main , South	Area	171.04	158.38	102.06	19.26	85.6	72.8	0	0	62.7	74.4	78.3	77.1	78.4	76.9	78.3	74.3	66.6
CT4-5 Aux	Main Transformer Walls	Transformer, Main, North	Area	170.43	165.62	102.05	19.4	85.6	72.8	0	0	62.7	74.4	78.3	77.1	78.4	76.9	78.3	74.3	66.6
CT4-5 Aux	Water Inj Skid Walls GT-4	Water Inj Skid 5 E Wall	Area	125.4	158.41	101.51	15.85	61.3	49.3	93.8	3	42.6	56.8	57.9	50.4	42.8	49	42.2	37	23.9
CT4-5 Aux	Water Inj Skid Walls GT-4	Water Inj Skid 5 N Wall	Area	123.74	161.17	101.5	9.83	59.2	49.3	93.8	3	40.5	54.7	55.8	48.3	40.7	46.9	40.1	34.9	21.8
CT4-5 Aux	Water Inj Skid Walls GT-4	Water Inj Skid 5 Roof	Area	123.7	158.41	103.44	21.33	62.6	49.3	93.8	0	43.9	58.1	59.2	51.7	44.1	50.3	43.5	38.3	25.2
CT4-5 Aux	Water Inj Skid Walls GT-4	Water Inj Skid 5 S Wall	Area	123.73	155.7	101.5	9.83	59.2	49.3	93.8	3	40.5	54.7	55.8	48.3	40.7	46.9	40.1	34.9	21.8
CT4-5 Aux	Water Inj Skid Walls GT-4	Water Inj Skid 5 W Wall	Area	122.07	158.44	101.5	16.21	61.4	49.3	93.8	3	42.7	56.9	58	50.5	42.9	49.1	42.3	37.1	24
CT4-5 Aux	Water Inj Skid Walls GT-5	Water Inj Skid 5 E Wall	Area	125.4	207.43	101.5	16.21	61.4	49.3	93.8	3	42.7	56.9	58	50.5	42.9	49.1	42.3	37.1	24
CT4-5 Aux	Water Inj Skid Walls GT-5	Water Inj Skid 5 N Wall	Area	123.74	210.17	101.5	9.83	59.2	49.3	93.8	3	40.5	54.7	55.8	48.3	40.7	46.9	40.1	34.9	21.8
CT4-5 Aux	Water Inj Skid Walls GT-5	Water Inj Skid 5 Roof	Area	123.73	207.41	103.44	21.26	62.6	49.3	93.8	0	43.9	58.1	59.2	51.7	44.1	50.3	43.5	38.3	25.2
CT4-5 Aux	Water Inj Skid Walls GT-5	Water Inj Skid 5 S Wall	Area	123.73	204.7	101.5	9.83	59.2	49.3	93.8	3	40.5	54.7	55.8	48.3	40.7	46.9	40.1	34.9	21.8
CT4-5 Aux	Water Inj Skid Walls GT-5	Water Inj Skid 5 W Wall	Area	122.07	207.46	101.51	15.85	61.3	49.3	93.8	3	42.6	56.8	57.9	50.4	42.8	49	42.2	37	23.9
CT4-5 Aux	Water Injection Vent Exhausts	Water Inj Skid 4 Vent Exhaust	Area	123.46	158.04	104.1	1.2	61.6	60.8	93.8	0	44.4	54.6	54.7	55.2	46.6	48.8	51	50.8	51.7
CT4-5 Aux	Water Injection Vent Exhausts	Water Inj Skid 5 Vent Exhaust	Area	123.66	207.04	104.1	1.2	61.6	60.8	93.8	0	44.4	54.6	54.7	55.2	46.6	48.8	51	50.8	51.7
CT4-5 Aux	Water Injection Vent Intakes	Water Inj Skid 5 E Wall - Intake	Area	125.4	159.51	100.91	0.36	61.3	65.8	93.8	3	41.2	49.4	53.5	56	50.4	50.6	49.8	54.6	45.5
CT4-5 Aux	Water Injection Vent Intakes	Water Inj Skid 5 W Wall - Intake	Area	122.07	206.46	100.91	0.36	61.3	65.8	93.8	3	41.2	49.4	53.5	56	50.4	50.6	49.8	54.6	45.5
ST-7	ST7 Building	ST7 Bldg - East Wall	Area	73.55	174.14	107.5	42	69.3	53.1	85	3	21.8	50	66.1	63.6	62	56.2	45.4	45.2	38.1
ST-7	ST7 Building	ST7 Bldg - Roof	Area	64.07	174.15	109	287.85	77.7	53.1	85	0	30.2	58.4	74.5	72	70.4	64.6	53.8	53.6	46.5
ST-7	ST7 Building	ST7 Bldg - South Wall	Area	64.07	166.54	104.5	169.93	75.4	53.1	85	3	27.9	56.1	72.2	69.7	68.1	62.3	51.5	51.3	44.2
ST-7	ST7 Building	ST7 Bldg - South Wall	Area	64.08	181.76	104.5	169.93	75.4	53.1	85	3	27.9	56.1	72.2	69.7	68.1	62.3	51.5	51.3	44.2
ST-7	ST7 Building	ST7 Bldg - South Wall	Area	54.59	174.15	104.5	136.44	74.5	53.1	85	3	26.9	55.1	71.2	68.7	67.1	61.3	50.5	50.3	43.2
ST-7	ST7 Condenser	ST7 Air Cooled Condenser	Area	67.3	131.96	108.3	1371.72	87.8	56.5	0	0	64.6	69.6	79.6	79.6	79.6	79.6	79.6	80.6	73.6
ST-7	Turbine Compartment Exhausts	Turbine Comp Vent A GT-4	Point	106.26	167.9	108.4		76.6	76.6	0	0	58.6	63.8	58.9	56.4	59.8	64	65.2	74	69.9
ST-7	Turbine Compartment Exhausts	Turbine Comp Vent A GT-5	Point	107.46	201.4	108.4		76.6	76.6	0	0	58.6	63.8	58.9	56.4	59.8	64	65.2	74	69.9
ST-7	Turbine Compartment Exhausts	Turbine Comp Vent B GT-4	Point	107.46	167.9	108.4		76.6	76.6	0	0	58.6	63.8	58.9	56.4	59.8	64	65.2	74	69.9
ST-7	Turbine Compartment Exhausts	Turbine Comp Vent B GT-5	Point	106.26	201.4	108.4		76.6	76.6	0	0	58.6	63.8	58.9	56.4	59.8	64	65.2	74	69.9

CLIMATE AND AIR QUALITY ASSESSMENT

HAWAII ELECTRIC LIGHT COMPANY, INC. - KEAHOLE GENERATING STATION

AND AIRPORT SUBSTATION, NORTH KONA, HAWAII

JULY 2004

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ENVIRONMENTAL SETTING, IMPACTS, AND MITIGATION MEASURES

PHYSICAL RESOURCES

I. CLIMATE AND AIR QUALITY

The State of Hawaii Department of Health (DOH) issued an *Ambient Air Quality Impact Report* for Alternative 1 and Alternative 2 without SCR on December 27, 2000. That impact analysis used dispersion modeling to predict emissions of regulated air pollutants expected to be emitted from the Keahole Generating Station. While the subject property consists of the generating station and the airport substation, the latter is not discussed in this section because it has no regulated emission sources. The *Ambient Air Quality Impact Report* addresses the implementation of the improvements to add Alternative 1 and Alternative 2 without SCR to the existing Keahole Generating Station facilities. The addition of Alternative 2 (including SCR) requires updates to the *Ambient Air Quality Impact Study* to address the impact of adding SCR. The addition of SCR reduces NO_X emissions and adds a small amount of ammonia emissions.

II. EXISTING CONDITIONS

A. TOPOGRAPHY

The Keahole Generating Station is located in terrain that slopes gently downward from the mountains east of the station to the Pacific Ocean. Contours of constant elevation parallel the coastline. There are no significant terrain features (such as cliffs, bluffs, and hills) in the immediate area that would affect air circulation. The site's elevation ranges between 190 and 230 feet above mean sea level.

B. METEOROLOGY/CLIMATE

The Big Island is located in a belt of relatively uniform winds blowing from the northeast. The windward slopes of Mauna Loa and Mauna Kea are connected by the high Humu'ala saddle, which effectively blocks most trade wind air. Due to the massive mountains, the diurnal land and sea breezes are the dominant conditions for the project area. Blockage of the northeasterly trade winds by the mountains results in a large-scale clockwise air circulation pattern of winds from the southeast through the southwest. These trade winds are modified along the North Kona coast.

Meteorological data for the Keahole Generating Station were collected from March 1993 through February 1994 at Site 062, an air quality monitoring station located approximately 0.8 mile southeast of the project site. This station was operated in compliance with U.S. Environmental Protection Agency (EPA) guidelines. Figure 1 shows a strong daily recurring (diurnal) flow for much of the year.

Average monthly temperatures at the proposed site range from the low 70s (°F) in the coldest month of February to the upper 70s in August and September. Annual rainfall is approximately 10 to 20 inches per year. Rainfall is uniformly distributed from March to October, with 60 percent or more of the annual rainfall occurring in the remaining four winter months.

C. Air Quality

HELCO has operated air quality monitoring stations at the Huehue Substation (Site 063, approximately 3.4 miles east-northeast of the Keahole Generating Station) and at the Kakahiaka Monitoring Station (Site 064, approximately 1.2 miles southeast of the Keahole Generating Station). Air quality data were collected at the Kakahiaka monitor at the request of DoH and EPA Region 9 to confirm that Huehue air quality data were representative of the Keahole Generating Station maximum impact areas. Table 3 shows maximum background concentrations of sulfur dioxide (SO_2), particulate matter less than 10 microns in diameter (PM_{10}), and carbon monoxide (CO).

The Keahole Generating Station is located about 1 mile east of the Keahole Airport and about 2 miles northwest of the Kalaoa residential area. No other major industrial stationary sources are in the vicinity.

The Kilauea volcano emissions may contribute to the background SO_2 and PM_{10} concentrations in the Kona area. Northeast trade winds transport the volcanic emissions around the southern point of the island and up the Kona Coast. HELCO studies of the volcanic emissions found that much of the SO_2 emitted by the erupting volcano is converted to sulfate aerosol by the time it arrives at the Keahole area. The studies also found that rapid fluctuations (spikes) in the SO_2 concentrations, were due to local sources, not the volcano.

D. Applicable Federal Regulations

Emissions of air pollutants are regulated at the federal level pursuant to the Clean Air Act (CAA). The following are major provisions of the CAA:

- National Ambient Air Quality Standards (NAAQS)
- New Source Review (NSR)
- Prevention of Significant Deterioration (PSD) Program
- Nonattainment Regulations
- New Source Performance Standards (NSPS)
- National Emissions Standards for Hazardous Air Pollutants (NESHAP)
- Maximum Achievable Control Technology (MACT) Standards
- Good Engineering Practice (GEP) Stack Height Provisions

NATIONAL AMBIENT AIR QUALITY STANDARDS.

The NAAQS represent the maximum pollution levels considered to be acceptable, with an adequate margin of safety, to protect public health and welfare. These standards must be attained in all ambient areas that are accessible to the general public. The following are the six criteria pollutants for which NAAQS have been established: sulfur dioxide (SO_2), nitrogen dioxide (NO_2), carbon monoxide (CO), ozone (O_3), particulate matter (PM_{10} and $PM_{2.5}$), and lead (Pb).

Hawaii's State Ambient Air Quality Standards (SAAQS) are very similar to the NAAQS, although the State has more stringent standards for carbon monoxide and nitrogen dioxide and has not adopted a standard for $PM_{2.5}$. Hawaii also has a standard for hydrogen sulfide (H_2S). Table 1 shows the federal and state ambient air quality standards.

NEW SOURCE REVIEW

The PSD regulations (40 Code of Federal Regulations [CFR] 52.21) define a major source as any source that belongs to a list of 28 source categories that emit or have the potential to emit 100 tons per year or more of any pollutant regulated under the CAA, or any other source type that emits or has the potential to emit pollutants in amounts equal to or greater than 250 tons per year. Keahole Generating Station is currently classified as a major stationary source.

A PSD review is required in attainment areas for all pollutants from a major source showing significant net increases in emissions due to a modification. Because the Keahole Generating Station area has been designated either attainment or unclassifiable for all the NAAQS, a PSD review was required for all the pollutants that showed a significant net emissions increase associated with the addition of CT-4 and CT-5 (Alternative 1 or Alternative 2 without SCR). Table 2 compares the project emissions with the PSD significant levels.

Because the project was a major source in an area that is in attainment for all NAAQS, the PSD permitting process rather than the nonattainment permitting process was followed. Hawaii's attainment status for all criteria pollutants means that the nonattainment regulations do not apply.

De minimis refers to those levels below which the DOH may exempt a stationary source or modification from the air quality analysis pre-construction monitoring requirements. The pre-construction monitoring *de minimis* levels are listed in Table 1. The net emissions increases for the addition of CT-4 and CT-5 are shown in Table 2. These emission increases are based on worst-case operations of 8,760 hours per year. On this basis, the addition of CT-4 and CT-5 was a significant source of sulfur dioxide, carbon monoxide, volatile organic compounds, particulate matter, sulfuric acid mist, arsenic, and benzene. Per the July 30, 1997 Supplement B.1 to the ambient air quality impact report, the modification netted out of PSD review for NO_x by proposing contemporaneous NO_x emissions decreases for units D18, D19, D20, and D21. The addition of CT-4 and CT-5 was not a significant source for beryllium (Be), mercury (Hg), lead (Pb), or fluorides (Fl). Therefore, the project was subject to PSD review only for sulfur dioxide, carbon monoxide, volatile organic compounds, PM/PM_{10}, sulfuric acid mist, arsenic, and benzene as follows:

- Application of Best Available Control Technology (BACT)
- Analysis of ambient air quality impacts from the project (PSD Class II increments for sulfur dioxide and PM/PM_{10}; NAAQS/SAAQS for sulfur dioxide, PM/PM_{10}, and carbon monoxide)
- Analysis of air quality and/or visibility impacts on Class I areas
- Analysis of air quality-related values such as soils, vegetation, and visibility that are affected directly as a result of the project and general commercial, residential, and other growth associated with the project

The PSD regulations provide for the designation of all geographic areas into one of three classes:

- Class I applies to areas where practically any deterioration in air quality would be significant.
- Class II applies to areas where moderate, well-controlled, and sited industrial growth would be permitted.
- Class III applies where industrial areas would be allowed to experience the greatest degree of air quality deterioration.

DoH has designated the Keahole area as Class II. The closest Class I area is the Volcanoes National Park, which is approximately 50 miles southeast of the project site. The Class I and Class II PSD increments and the NAAQS/SAAQS for sulfur dioxide, nitrogen dioxide, PM/PM_{10}, and carbon monoxide are presented in Table 1. The modeling significant impact levels and *de minimis* monitoring levels for sulfur dioxide, nitrogen dioxide, carbon monoxide, and PM/PM_{10} are also presented.

NEW SOURCE PERFORMANCE STANDARDS

The New Source Performance Standards (NSPS) are a set of national emission standards that apply to new, modified, or reconstructed stationary source categories that include the emission limitations that apply to a new, oil-fired combustion turbine:

- Sulfur dioxide--0.015 percent sulfur dioxide in the exhaust gas at 15 percent oxygen, or 0.8 percent sulfur fuel by weight
- Nitrogen oxide--75 parts per million (ppm) in the exhaust gas at 15 percent oxygen

NATIONAL EMISSIONS STANDARDS FOR HAZARDOUS AIR POLLUTANTS (NESHAPS).

The Keahole Generating Station with Alternative 1 or Alternative 2 added is not a major source of hazardous air pollutants (HAP) (i.e., has a potential to emit (PTE) of less than 10 tons per year (tpy) for any HAP and less than 25 tpy for all HAPs collectively). Thus, NESHAP standards do not apply.

MAXIMUM ACHIEVABLE CONTROL TECHNOLOGY (MACT) STANDARDS

The Keahole Generating Station with Alternative 1 or Alternative 2 added is not a major source of hazardous air pollutants (HAP) (i.e., has a potential to emit (PTE) of less than 10 tons per year (tpy) for any HAP and less than 25 tpy for all HAPs collectively). Thus, MACT standards do not apply.

GOOD ENGINEERING PRACTICE ("GEP") STACK HEIGHT PROVISIONS

The federal guidelines for GEP stack height apply to all alternatives. These guidelines identify design criteria acceptable to regulatory agencies to establish a method for determining the stack height that will minimize the influence of nearby structures on normal plume dispersion. The GEP stack height analysis performed for the Keahole Generating Station results in a 104-foot-high exhaust stack.

APPLICABLE HAWAII REGULATIONS

In addition to the federal regulations, the State regulates air pollution under Hawaii Administrative Rules (HAR), Title 11, Chapters 59 and 60 Hawaii State Ambient Air Quality Standards (SAAQS) and Hawaii Air Pollution Control Rules. The Environmental Management Division of DOH, Clean Air Branch (CAB), is responsible for implementing and enforcing both the state and federal air quality regulations.

As noted above, the SAAQS have been set for the same criteria pollutants as the federal standards, with the exceptions of H_2S and $PM_{2.5}$.

Per HAR 11-60.1 requirements, HELCO has obtained a PSD permit for Alternative 1 and Alternative 2 without SCR from the State DOH and Federal EPA.

III. PROJECT IMPACTS

EPA guideline dispersion models ISCST2 and COMPLEXI were used to calculate maximum concentrations of combustion pollutants that would potentially result from the Alternative 1 and Alternative 2 without SCR additions at the Keahole Generating Station. The two models were used to estimate the impacts in the various terrain types surrounding the generating station. The following information was used to predict the maximum ground-level concentrations of air pollutants from Keahole Generating Station:

- A full year of meteorological data collected at the Keahole monitoring station, Site 062
- CT-4 and CT-5 emission rates as defined in Table 2
- The emission rates as defined in PSD permit application 88-01, which includes CT-2 and all existing sources at the generating station
- The existing generating station configuration GEP analysis

A. Construction Air Emissions

Completing construction will produce two types of emissions: (1) exhaust from vehicles and construction equipment and (2) dust generated during site excavation and equipment movement. Equipment exhaust emissions will be small, localized, and transient. Dust emissions will also be insignificant because the average level of on-site vehicle activity on unpaved roads is only 0.7 vehicle-miles per weekday during the 12-month construction period for ST-7 with SCR. The worst-case week for vehicle activity during the 12-month construction period for ST-7 with SCR is 1.9 vehicle-miles per weekday (scheduled for month 2, week 3). Pursuant to HAR 11-60.1-33, reasonable precautions will be implemented to minimize fugitive dust. Watering trucks will wet unpaved roads at least three times per day (and more frequently if dust is observed). Also, many unpaved roads have been surfaced with gravel to minimize dust from vehicle movement. Therefore, construction emissions are expected to be insignificant.

B. Operational Air Emissions

The modeling analysis predicted the maximum ground-level concentrations for SO_2, CO, and PM_{10} for the CT-4 and CT-5 and the existing diesel and combustion turbine units at Keahole. The maximum predicted concentrations were added to the maximum background concentration data and compared with the most stringent state or federal AAQS. Table 3 contains the results.

According to these modeling results, no federal or state AAQS are exceeded. The pollutant with the largest impact is carbon monoxide. The maximum annual concentration for carbon monoxide added to the background concentration will consume 57 percent of the SAAQS. As stated earlier, this maximum ground-level concentration is from all existing units at the generating station plus CT-4 and CT-5.

The addition of selective catalytic reduction (SCR) for NO_X emission control, will result in some ammonia emissions. Based on a manufacturer's guaranteed ammonia slip of 10 parts per million on dry volume (ppmvd), with a 100 percent load gas flow rate of 559,440 pound/hour, at 59 °F, with water injected for NO_x control, this equals 4.3 pound NH_3/hour per combustion turbine. Modeled 1-hour unit impacts for CO and annual unit impacts for SO_2 can be proportionally scaled to estimate the 1-hour and annual impacts of 4.3 lb NH_3/hour per combustion turbine. The calculations are as follows:

$$2{,}291\ \mu g\ CO/m^3 / 954\ lb\ CO/hr \times 4.3\ lb\ NH_3/hr\ per\ CT \times 2\ CTs = 20.7\ \mu g\ NH_3/m^3\ (1\text{-hr average})$$

$$5\ \mu g\ SO_2/m^3 / 221\ lb\ SO_2/hr \times 4.3\ lb\ NH_3/hr\ per\ CT \times 2\ CTs = 0.2\ \mu g\ NH_3/m^3\ (\text{annual average})$$

The 2,291 μg CO/m^3 and 5 µg SO_2/m^3 impact values are from the 09/28/95 Hawaii DOH Ambient Air Quality Impact report, Table 4, page 34. The 954 lb CO/hr and 221 lb SO_2/hr emission rates are from the 09/28/95 Hawaii DOH Ambient Air Quality Impact report, Table 1, page 31.

The Hawaii Dept. of Health does not have any ammonia ambient standards. Therefore, Texas Commission on Environmental Quality (TCEQ) Effects Screening Levels (ESLs) has been used to evaluate the 20.7 μg NH_3/m^3 (1-hr average) and 0.2 µg NH_3/m^3 (annual average) ammonia emissions impacts. ESLs are used to evaluate the potential for effects to occur as a result of exposure to concentrations of constituents in air. ESLs are based on data concerning health effects, odor nuisance potential, effects with respect to vegetation, and corrosion effects. They are not ambient air standards. If predicted or measured airborne levels of a constituent do not exceed the screening level, adverse health or welfare effects would not be expected to result. The TCEQ short-term (1-hr) and long-term (annual) ESLs for ammonia are 170 µg/m^3 and 17 µg/m^3, respectively. The 20.7 µg NH_3/m^3 (1-hr) ammonia slip emissions impact for CT-4 and CT-5 with SCR would only be 12% of the ESL, and the 0.2 µg NH_3/m^3 (annual) ammonia slip emissions impact would only be 1% of the ESL. Therefore, ammonia emissions are expected to be insignificant.

The DOH's December 4, 1998 report *Assessment of Health Effects Associated with Volcanic Emissions: Year One Preparations for a Future Health Study*, described how SO_2 emitted by the Kilauea volcano oxidizes in the atmosphere and produces a visible haze referred to as "vog." The purpose of the study was to begin assessing the possible health impacts to people from volcanic emissions. HELCO undertook a study to determine if SO_2 emissions from CT-4 and CT-5 would contribute to vog in the Keahole Generating Station area. HELCO's January 27, 1995 report *Estimated Increases in Vog Levels from the Proposed CT4 and CT5 Emissions at the Keahole Generating Station* concluded that the maximum predicted increase in SO_4 due to units CT-4 and CT-5 is 1.7 percent of measured SO_4 concentrations. This maximum impact will occur over the ocean approximately 10 miles northwest of the Keahole Generating Station. The maximum land-based impact, representing less than 1.5 percent of measured vog levels, as SO_4, will occur in the lava fields approximately 1.75 miles northeast of the power plant. This location is over 1.5 miles from the nearest inhabited area.

On August 30, 2000, HELCO submitted a report (*Impact of Climate, Weather, and Volcanic Emissions on the Variability of Sulfur Dioxide Observed Along the Kona Coast*) authored by Dr. Steven Businger of the University of Hawaii's Department of Meteorology, who was contracted by HELCO's consultant. Dr. Businger found that the impact of the Kilauea volcano on SO_2 concentrations at the Huehue and Kakahiaka monitoring stations during the February through April 2000 study period was small. The report concluded that much of the SO_2 emitted by the erupting volcano is converted to sulfate aerosol by the time it arrives at the Keahole Generating Station. Dr. Businger observed SO_2 concentrations that rapidly increased from zero to the maximum 1-hr concentration of 49 ppb, then rapidly decreased to zero. He concluded that the source of these "spikes" is local sources. Dr. Businger also found that the distribution of vog is relatively uniform in the vicinity of Keahole. Thus, the location of air quality monitors is not critical for observing the volcanic impact.

The PSD permit for CT-4 and CT-5 includes the following:

- Impacts of the proposed combustion turbine units
- An update of the NAAQS/SAAQS data as necessary
- Comparisons with applicable Class II increments
- Other potential impacts (such as soils, vegetation, and visibility)

C. IMPACTS TO VEGETATION

Federal Primary Air Quality Standards are based on the protection of human health. Federal Secondary Air Quality Standards (which in most cases are no less stringent than the primary standards) are based on human "welfare," which includes such considerations as impacts to vegetation, animals, visibility, and comfort. Based on the air quality modeling, which indicates that secondary air quality standards will not be exceeded, HELCO has concluded that no significant impacts to vegetation will occur.

Because of concerns expressed about the proximity of the project to the Keahole Agricultural Park (which is located to the south of the Keahole Generating Station), HELCO commissioned a study by Dr. Robert Paull of the potential effects of ethylene, SO_2, and NO_x emissions from the expanded Keahole Plant on plants and crops in the Keahole area. Dr. Paull concluded as follows: "In summary, I anticipate no effect of the current or planned expansion at the generation plant on the agricultural park or surrounding area. Dr. Paull's report is included in Volume 2 of the EIS as Appendix L.

It is important to note that the PSD modeling process makes a number of conservative assumptions that overstate emissions from the generating station. Therefore, projected concentrations that result from the modeling can be considered "worst case," and typical ground-level concentrations should be lower than those described in the PSD application. Post-construction monitoring is designed to confirm that this is the case.

Because the Alternative 1 and Alternative 2 without SCR modifications received a permit for construction and operation dated July 25, 2001, State and Federal regulatory authorities were satisfied that the modification fully complies with the applicable rules, regulations, and air quality standards. The provisions of the permit incorporate mitigation measures that will minimize air quality impact. Mitigation measures include limitations on the fuel sulfur content, water injection for NO_x control, GEP stack height for CT exhaust, emission limitations (3-hr averages) for five pollutants, and NO_x netting resulting in the retirement of units D18-D20 and a fuel limitation on unit D21. Post-construction air quality monitoring will be performed continuously for one year after initial startup.

In addition to the mitigation measures described above, HELCO will reduce noise impacts by (1) installing enclosures around certain equipment and (2) installing silencers in the CT horizontal exhaust ducts at ground level. HELCO's December 19, 2003 letter to DoH provided analysis results confirming that the installations of enclosures and silencers do not change the results of the ambient air quality impact modeling analysis for the modification.

FIGURE 1: MONITORING SITE 062 WIND ROSE

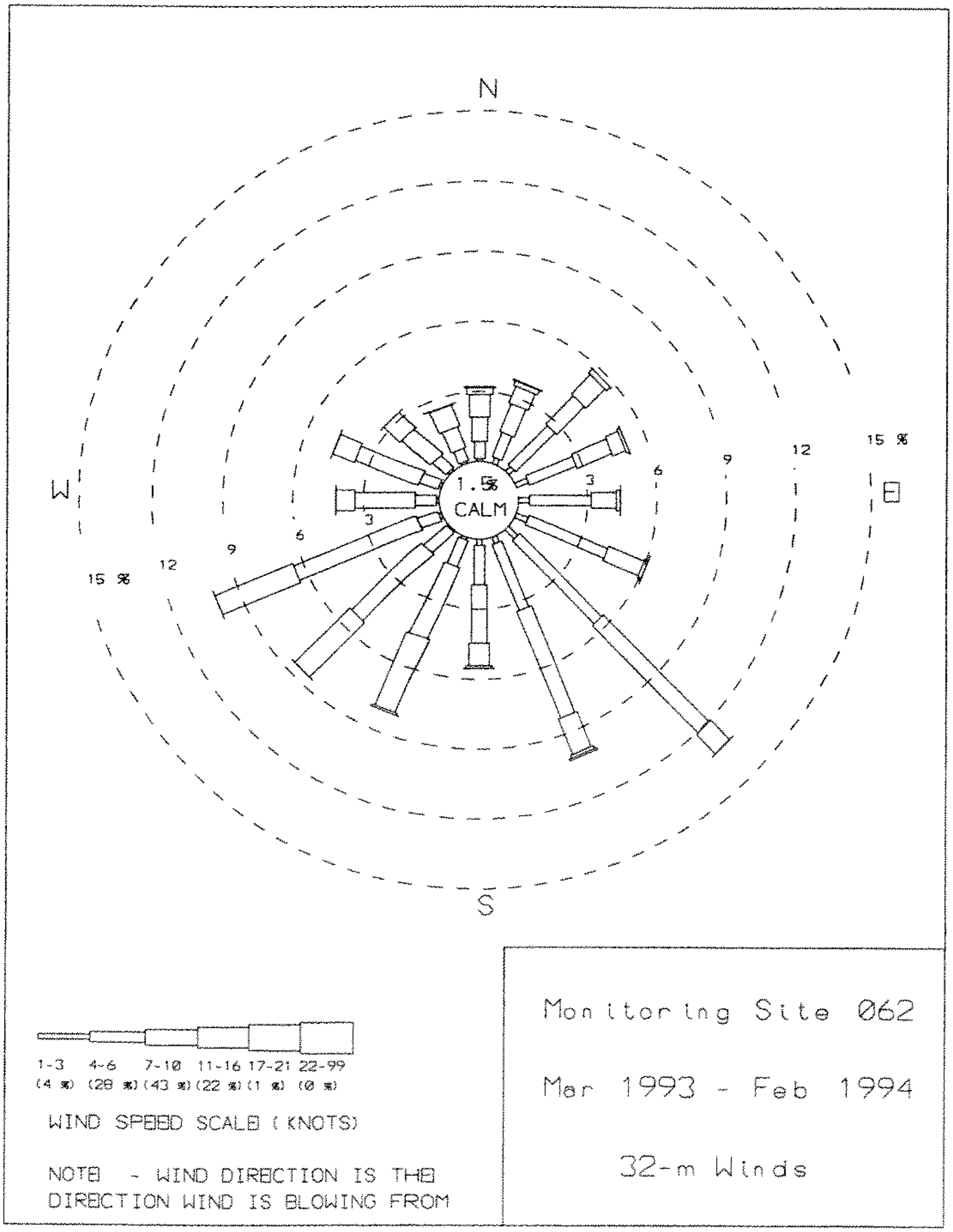

Table 1: Summary of Modeling Significant Impact Levels, Monitoring De Minimis Levels, PSD Increments, and State and Federal Standards for Selected Pollutants

Pollutant	Averaging Period	Modeling Significant Impact Levels (μg/m³)	Monitoring De Minimis Levels (μg/m³)	PSD Increment Class I (μg/m³)	PSD Increment Class II (μg/m³)	NAAQS (μg/m³)	SAAQS (μg/m³)
SO_2	3-hour	25	-	25[a]	512[a]	1300[a,b]	1300[a]
	24-hour	5	13	5[a]	91[a]	365[a]	365[a]
	Annual	1	-	2[c]	20[c]	80[c]	80[c]
NO_2	Annual	1	14	2.5[c]	25[c]	100[c]	70[c]
$PM_{2.5}$	24-hour					65[i]	-
	Annual					15[j]	-
PM_{10}	24-hour	5	10	8[f]	30[f]	150[d]	150[d]
	Annual	1	-	4[f]	17[f]	50[e]	50[e]
PM	24-hour	5	10	10[a]	37[a]	-	-
	Annual	1	-	5[a]	19[c]	-	-
CO	1-hour	2000	-	-	-	40,000[a]	10,000[a]
	8-hour	500	575	-	-	10,000[a]	5,000[a]
O_3	1-hour	-	-	-	-	235[d]	-
	8-hour	-	-	-	-	-	157 [d]
	Annual	-[g]	-[h]	-	-	-	-
H_2S	1-hour	-	0.2	-	-	-	35
Pb	3-month	-	0.1	-	-	1.5[c]	1.5[c]

Notes:

a. Not to be exceeded more than once per year.

b. Secondary Standard.

c. Never to be exceeded.

d. Standard is attained when the expected number of exceedances is less than or equal to 1.

e. Standard is attained when the expected annual arithmetic mean is less than or equal to 50 μg/m³.

f. Effective June 3, 1994.

g. No significant ambient impact concentration has been established. Instead, any net emissions increase of 100 tons per year of VOC subject to PSD would be required to perform an ambient impact analysis.

h. Any new source or modified existing source located in an unclassified or attainment area for ozone that is equal to or greater than 100 tons per year emissions will be required to monitor ozone.

i. Standard is attained when the 3-year average of the 98th percentile of 24-hour concentrations at each population-oriented monitor within an area must not exceed 65 μg/m³.

j. Standard is attained when the 3-year average of the annual arithmetic mean $PM_{2.5}$ concentrations from single or multiple community-oriented monitors must not exceed 15 μg/m³.

Table 2: Comparison of Net Project Emission Rates to PSD Significant Net Emission Rates

Air Pollutant	Net Project Emissions[a] (tons/yr)	PSD Significant Level (tons/yr)
Nitrogen Oxides	39.8	40
Sulfur Dioxide	964	40
Carbon Monoxide	4,166	100
Volatile Organic Compounds	2,607	40
Particulate Matter (TSP)	173	25
Particulate Matter (PM_{10})	173	15
Lead	0.1	0.6
Sulfuric Acid Mist	18	7
Beryllium	0.00035	0.0004
Mercury	0.001	0.01
Fluorides	0.018	3
Arsenic	0.0098	[b]
Benzene	0.22	[b]

Source:
09/28/95 Hawaii Dept. of Health Ambient Air Quality Impact report, Table 3, page 33, except for NO_x net project emissions, which were revised to 39.8 tpy in DoH's July 30, 1997 Supplement B.1, page 4.

[a] – Estimated emissions are based on CT-4 and CT-5 units operating 8760 hours per year, and on the emergency diesel fire pump operating 80 hours per year.

[b] – Any emission rate.

Table 3: Ambient Air Quality Impact Analysis (Data Sets: Huehue – February 1, 1999 to May 17, 2000 and Kakahiaka – February 5, 2000 to May 17, 2000)

Air Pollutant	Period	Maximum Concentration[a] ($\mu g/m^3$)	Background ($\mu g/m^3$)	Total Concentration ($\mu g/m^3$)	Air Standard ($\mu g/m^3$)	Percent of Standard (%)
Sulfur Dioxide	3-Hour	381	87	468	1,300	36
	24-Hour	71	34	105	365	29
	Annual	14	4[b]	18	80	23
Particulate (PM_{10})	24-Hour	34	27	61	150	41
	Annual	7	12[b]	19	50	38
Carbon Monoxide	1-Hour	4,718	969	5,687	10,000	57
	8-Hour	1,178	736	1,914	5,000	38

Source: 12/27/00 Hawaii Dept. of Health Ambient Air Quality Impact report, Supplement D, Table 2, page 13.

a. Maximum concentrations are the greater of Scenario 1 and Scenario 2. Scenario 1 includes CTs-2, 4 & 5, units D18 - D23, the emergency fire pump, and the black start unit. Scenario 2 includes CTs-2, 4 & 5, units D20 - D23, the emergency fire pump, and the black start unit. See Supplement A of the Ambient Air Quality Impact Report dated September 28, 1995.

b. "Annual" concentrations are the highest, rolling 12-month averages.

Climate and Air Quality Assessment
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AN ASSESSMENT OF POTENTIAL IMPACTS TO THE MARINE ENVIRONMENT

HAWAII ELECTRIC LIGHT COMPANY INC.
KEAHOLE GENERATING STATION
AND
AIRPORT SUBSTATION

KEAHOLE, NORTH KONA, HAWAII

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I. INTRODUCTION AND PURPOSE

I.A INTRODUCTION

Hawaii Electric Light Company, Inc. (HELCO) is in the planning process for the reclassification of the Keahole Generating Station and Airport Substation lands from the Conservation District to the Urban District. The 15.643-acre site is located in Keahole, North Kona, Hawaii on the mauka side of Queen Kaahumanu Highway, directly across from the Kona International Airport access road intersection. The facilities of the Hawaii Ocean Science and Technology (HOST) Park and the Natural Energy Laboratory of Hawaii (NELH) lie adjacent to one another at Keahole Point, North Kona, Hawaii, which is nearly directly downslope from the HELCO site (Figure 1). These facilities are owned and operated by the State of Hawaii, and administered by the Natural Energy Laboratory of Hawaii Authority (NELHA). These two facilities are intended to accommodate "*...tenants doing business in ocean-related science and technology industries limited to or providing research, the development and commercial application of technology-intensive activities that utilize ocean water as a resource or depend on proximity to the ocean, including aquaculture, mariculture, and ocean-related activities.*"

Improvements and expansion of the generating station, necessitated a simultaneous need for the lands to be reclassified for urban and industrial use (HELCO's project). HELCO's project has the potential to impact brackish groundwater in the vicinity of the plant through several means including: 1) alteration of supply of onsite brackish groundwater, 2) subsurface disposal of the plant wastewater, and 3) disposal of domestic wastewater generated by operation of the power plant. In addition, HELCO's project will result in potential changes to the supply from the Hawaii County Department of Water Supply (DWS) system. The potential effect from each of these factors is considered in a companion report prepared by Tom Nance Water Resources Engineering (TNWRE Report).

As all groundwater that is not pumped from the aquifer ultimately reaches the ocean, alteration of groundwater flow and/or composition also constitutes a factor that can potentially alter the nearshore marine environment. It is also important to note that alteration of groundwater flowing under the HELCO's project site will represent a subsidy to existing conditions that may already be affected by other anthropogenic activities. In the case of the HELCO generating station, the location of the project site dictates that groundwater flow to the ocean will interact to some degree with the functional aspects of NELH and HOST Park, in terms of both water usage and discharge of "used" water back to the marine environment. These interactions are important because of the reliance on "high quality" ocean water for NELHA mariculture uses. In addition, because of existing data, it is possible to put into context the magnitude of changes that could be caused by HELCO's project with respect to the historical alteration to groundwater discharge to the ocean that is a result of NELH/HOST Park activities. Such a contextual evaluation will provide a valid basis for assessing the potential for impacts directly attributable to HELCO's project. Within this framework, it is the purpose of this report to provide an assessment of the potential impacts of HELCO's project to the nearshore marine waters, which in turn can provide an estimate of impact to marine biotic communities.

I.B DATA SOURCES

This report was prepared without the acquisition of new field data. Data describing groundwater dynamics and potential changes to such dynamics from HELCO's project are taken from the TNWRE Report.

As stated above, NELH and HOST Park are located nearly directly downslope from the HELCO site. As a result, much of the consideration of potential impacts from HELCO's project is directed at potential alteration of marine waters resulting from NELH and HOST Park. Both NELHA facilities use and dispose of large quantities of warm and cold seawater brought ashore and distributed through a network of pipes owned and operated by NELHA. Once used by the tenants, the seawater is discharged into a multitude of excavations into the porous lava substratum that comprises Keahole Point. Following discharge into the disposal excavations, return water flows seaward within the basal aquifer and eventually reaches the nearshore ocean.

Discharged return waters presently in use can be classified into two types:

- "Non-contact" water which is utilized only for thermal properties. Except for having a slightly higher temperature, this water has the same quality when it enters the ground as it did when it entered the ocean intake or supply well. Non-contact water should remain essentially unchanged (except for temperature and perhaps oxygen concentration) between intake and return.
- "Contact water", which is used to grow or maintain the variety of organisms used in the various mariculture activities. Return contact water contains materials generated by the mariculture activities and may differ substantially in composition from the intake water.

Since the inception of NELHA, a requirement of the overall operation has been the implementation of a monitoring program to evaluate the effects of returning used water back to the natural environment off Keahole Point.

The original monitoring program, termed the Comprehensive Environmental Monitoring Program (CEMP) has been modified several times since the original plan was laid out in the Environmental Impact Statements for the NELH and HOST Park facilities in 1987. In all of the versions, however, the program has two broad objectives: 1) to protect the unique environmental resources of the Keahole Point area and their diverse uses, and 2) to provide the information necessary to comply with the permit requirements of various county, State and federal agencies.

From the inception of the monitoring program in 1989 until the present, the water quality components of the CEMP have produced a massive amount of data that likely comprises the largest set of continuous water quality data in the state for a single location. Until 2001 the data generated by the monitoring program existed only as tabular listings of numerical results in sequential order of sample collection. Virtually no other analysis or interpretation of the data had been conducted or reported.

In 2001, Planning Solutions, Inc. was funded by the State of Hawaii to provide a comprehensive review of the Seawater Return system at NELH. The review included a thorough examination of the CEMP performed by Marine Research Consultants, which consisted in part of analysis of the tabulated data. The data analysis was designed to elucidate the effects that the discharge of return water has had on the nearshore marine receiving environment. With the large existing data set, a clear "story" of the effects of the discharge became evident. Because the return seawater is mixed with low salinity groundwater prior to discharge to the ocean, utilization of a conservative hydrographic mixing model proved to be an effective tool for evaluating the results of the CEMP. Because the effects to NELH/HOST Park are a concern in planning of HELCO's project, we take advantage of the long-term data set that comprises the NELHA CEMP. Thus, the NELH CEMP provides the database for the present evaluation of the potential effects of HELCO's project.

II. INTERPRETATION OF CEMP WATER CHEMISTRY DATA

I.A SAMPLING LOCATIONS

There are a variety of water sources that are sampled as part of the CEMP including disposal trenches, wells, anchialine ponds, and shoreline and offshore ocean samples. Each water source is considered separately in the sections below, which is followed by a summary of potential impacts from HELCO's project.

II.A.1 Disposal Trenches

Sampling for the CEMP presently includes two disposal trenches, the NPPE trench on the northern side of Keahole Point and one of the aquaculture disposal trenches on the southern side of Keahole Point. Figures 2 and 3 show plots of silica (Si), nitrate nitrogen (NO_3^-), phosphate phosphorus (PO_4^{3-}), and ammonium nitrogen (NH_4^+) as functions of salinity for samples collected from the disposal trenches from 1992 to mid-2000. These four nutrient constituents provide a good representation of the processes that are affecting groundwater composition as a result of the discharge of return water. Each plot also contains two straight lines, which are the conservative mixing lines constructed by connecting the "endpoint" concentrations within the system. The solid mixing line was created by connecting the average concentrations from NELHA Well 1 (W1), which is considered to be above the influence of any discharged return water from NELH-HOST Park, and open ocean surface seawater (SSW). The dashed mixing line was created by connecting the average concentration of Well 1 and the average concentration of deep seawater (DSW).

If the constituent in question displays purely conservative behavior (no input or removal from any process other than physical mixing), data points should fall on, or near, the conservative mixing line. If, however, external material is added to the system, data points from samples will fall above the mixing line. If material is being removed from the system by processes such as biological uptake, data points from samples will fall below the mixing line.

Examination of Figure 2 indicates that most of the data points representing the concentrations of Si in the disposal trenches fall in a linear array along the mixing lines ($R^2 = 0.80$ for the entire data set). Removal of the two most conspicuous outliers in the surface (NPPE samples at salinities of 32‰ and 35‰) increased the R^2 to 0.87. The good linearity of the Si data set along the mixing lines indicates that the hydrographic mixing model is a valid method of representing the processes occurring within the groundwater-marine system at NELH-HOST Park.

Examination of the plots of NO_3^-, PO_4^{3-}, and NH_4^+as functions of salinity (Figures 2 and 3) are similar in that there are large divergences from the mixing lines in the Aquaculture trench at salinities of 33-35‰. Such excursions from the mixing line indicate discharge into the trench of water with substantial nutrient subsidies. On the other hand, with a few exceptions, water from the NPPE trench does not contain such subsidies and consists mainly of a mixture of groundwater and ocean water. In fact, the occurrence of many of the data points below the mixing lines suggests uptake of nutrients from the water that is discharged into the disposal trenches.

II.A.2 Anchialine Ponds

Two anchialine ponds (defined as brackish ponds with no open connection to the ocean) have been monitored as part of the CEMP since 1993. Pond 1 is located at the northern end of the property while Pond 2 is located at the southern end of the property.

Figures 4 and 5 show mixing plots of water chemistry constituents collected in the ponds from 1989 to 2000. In all of the plots, it is apparent that the salinity in Pond 1 is consistently lower than in Pond 2. This result is somewhat unexpected, as Pond 1 is closer to the ocean shoreline than Pond 2. Because of the consistency in the pattern of salinity between the two ponds, it is apparent that there is substantially more groundwater flow through the region of Pond 2 than there is through the region in which Pond 1 is located. Examination of the mixing plots of NO_3^-, PO_4^{3-}, and NH_4^+ reveal few or no linear relationships between salinity and nutrient concentrations in either pond. Rather, nutrient concentrations in the ponds have a relatively wide range at a given salinity. As the majority of the data points in the mixing diagrams occur below the mixing lines, it is likely that there is substantial uptake of nutrients within the ponds. In addition, the occurrence of data points above the mixing lines suggests that there are also nutrient subsidies to the ponds during some of the periods of sampling.

II.A.3 Well Water

Groundwater monitoring wells (3.8 inch diameter) are located at eight locations on the grounds of the NELH-HOST Park (Figure 1). Well 1, located just *makai* of the entry road off Queen Kaahumanu Highway is a single well 135 feet deep. The other seven sites each contain a cluster of three wells; one well in each cluster draws from shallow, middle, and deep depths. Sampling depths vary from 14 feet to 69 feet. Figures 6 and 7 show time course plots (mid-1989 to mid-2003) of salinity, silica, and nitrate in the shallow wells. Inputs to groundwater from activities on land should be most evident in the upper layer of the aquifer. Examination of the time-course plot of salinity reveals that each well has a slightly different overall salinity, and that salinity does vary over time. In addition, the data show that there have been no major changes in salinities of the wells over the course of the monitoring program.

The same pattern is not evident in the time course plots of NO_3^- (Figure 6) and Si (Figure 7). Several large excursions of NO_3^- are evident in several of the shallow wells (particularly Wells 5 and 8) that increase the concentrations by approximately four to seven-fold over the background conditions. Such anomalies indicate that there are periodic subsidies to groundwater from activities on land.

Figures 7-10 show plots of silica (Si), nitrate nitrogen (NO_3^-), phosphate phosphorus (PO_4^{3-}), and ammonium nitrogen (NH_4^+) as functions of salinity for samples collected from the eight monitoring wells divided into shallow, mid-depth, and deep wells. As described above, these four constituents provide a good representation of the processes that are affecting groundwater composition as a result of discharge of return water. Each plot also contains two straight lines, which are the conservative mixing lines constructed by connecting the "endpoint" concentrations within the system. For NO_3^-, PO_4^{3-} and NH_4^+ two plots are shown for each constituent. The top plot of each figure shows the entire range of concentrations that were measured in each well, while the bottom plot shows concentrations that extend only through the main body of data points, thus eliminating the high concentration outliers. Several important points are conspicuous in the mixing plots for the combined data sets:

- First, in all cases plots of Si from the shallow and deep wells fall in linear arrays along the mixing lines, with data from each sampling depth extending corresponding to a distinct envelope of salinity. In all cases, the shallow wells had the lowest salinities and the deep wells had the highest salinity. Such a result is expected if the mixing model is an accurate method to portray the mixing dynamics between freshwater and seawater. Plots of mid-depth wells show a data grouping that is does not fall along the mixing gradient. All of these data points are from a single well (Well 4). Such a departure from the mixing model indicates mixing of other water sources in addition to groundwater and ocean water.
- Secondly, it is evident that there are substantial nutrient subsidies to several of the wells, and no subsidies to other wells. As with Si, the most evident departures of NO_3^-, PO_4^3, NH_4^+ data points from the mixing lines occurred with the mid-depth wells. However at the lower concentration scale shown in the bottom plots of Figures 8, 9 and 10, it can be seen that there are also clear subsidies to several shallow and deep wells. These subsidies can all be traced to Wells 4-8, located within the region of return water discharge. Data from these wells show substantial subsidies of NO_3^-, PO_4^{3-}, and NH_4^+ during a large proportion of the samplings. The most conspicuous subsidies occur in Well 4, where many of the nutrient concentrations were substantially higher than in treated sewage effluent. Such consistent elevation of scaled nutrient concentrations above the conservative mixing lines clearly indicates that discharge of return water results in elevation of nutrient concentrations in groundwater flowing under the NELH-HOST Park facility.
- A third major finding from the mixing analysis is the absence of substantial differences between the different sampling depths at each well site. For the constituents that occur at concentrations essentially on the mixing line, sampling at any point will provide a concentration that reflects the salinity at that point. For the constituents in wells that occur at concentrations above the conservative mixing lines, there is little variation in the concentration at all three depths. Unfortunately, Well 4, which showed the most dramatic evidence of subsidies from return water, had no shallow sampling depth. However, for all other wells, the sample results acquired from the shallow depth provide the same information as sampling at all three depths. Thus, data from the shallow well alone are sufficient to evaluate the nutrient subsidy to groundwater from discharged return water.

II.A.4 Shoreline Samples

Eleven shoreline stations located off of Keahole Point have been sampled as part of the CEMP. These stations are sampled from the shoreline at points where freshwater input from land enters the ocean. Hence, the data from these stations represents the region of maximal mixing of groundwater with ocean water. Figures 11 and 12 show time-course data from each of the shoreline sampling points from the initiation of the monitoring program in 1989 to mid-2000. Several of the stations (C-1 and C-27) display large variations in concentrations of NO_3^- and PO_4^{3-} over the course of monitoring. These elevations in nutrient concentrations are mirrored by corresponding decreases in salinity, indicating that the nutrient subsidies are a result of input of groundwater. Ammonium (NH_4^+) shows a very different pattern, with all stations displaying similar oscillations. Such a pattern indicates that the variation in concentration of NH_4^+ is a result of biotic process within the nearshore ocean.

Figures 13 and 14 show mixing plots of Si, NO_3^-, PO_4^{3-} and NH_4^+ as functions of salinity for all of the shoreline samples. For all four of the nutrients it is apparent that the sampling location with the most variability is Station C-24, located near the turn in the entry road near the southern boundary of the NELH-HOST Park property. This station is near a beach bathhouse that reportedly utilized a septic system for treatment and disposal of domestic waste. The occurrence of a small cove in the lava beach rock also makes this area an attractive place for swimmers, especially children. It is possible that the large variation in nutrient input at this site is the result of seepage of the septic system or swimmers rather than NELH-HOST Park seawater return. Another possibility is that there is another source of groundwater distinctly different in composition than the groundwater from Well 1, which was used to construct the mixing lines. The scatter of NO_3^- and PO_4^{3-} data points at the low end of the salinity range (<15‰) suggest the mixing of more than two water masses.

It can also be seen in Figures 13 and 14 that the conservative mixing lines for NO_3^- and PO_4^{3-} differ substantially between shallow and deep seawater. The high nutrient content, along with reduced temperature, are the driving forces for the NELH-HOST Park operation. It can be seen, however, that virtually none of the data points from the shoreline samples (excluding Station C-24) falls near the deep water mixing line. Many of the data points from Station C-1, located in the lee of Keahole Point within Ho'ona Bay, fall below the shallow seawater conservative mixing line, suggesting uptake of NO_3^- and PO_4^{3-} in the nearshore zone.

The situation for NH_4^+ is slightly different as this form of nitrogen occurs in low concentrations in both groundwater and open ocean water. As a rêsult, it is not possible to compare the concentrations along the mixing gradients. It can be seen however, that there is not a substantial subsidy of NH_4^+ at Station C-24. The lack of peak values of NH_4^+ at this site may argue against the input of sewage materials from the beach bathhouse at this location. Rather, the somewhat elevated concentrations at some of the stations (e.g., Station C-1) may reflect the input of high organic loads in the return water. It is also of interest that there is no noticeable elevation of NH_4^+ at shoreline stations C-16 and C-17, which are closest to the aquaculture trench that showed substantially elevated levels of NH_4^+.

II.A.5 Offshore Sampling Sites

Six offshore sampling sites were also established as part of the CEMP. Each offshore water-sampling site consists of five locations separated by a linear distance of 50 feet, and beginning 25 feet from the shoreline. Hence, sampling points are at distances of 25, 75, 125, 175, and 225 feet from the shoreline. Because it was presumed during the development of the CEMP sampling regime that return water could reach the ocean floor as a result of its lower-than-ambient temperature, the offshore sampling scheme includes collection of water from within both one meter of the surface and one meter of the sea floor.

Offshore monitoring data revealed very little linear (or any other) pattern for any of the water chemistry constituents. Rather, the data points are apparently randomly scattered within the small envelope of salinity (33.6-35.2‰). There is also little indication of any substantial elevation of any of the constituents in bottom water. If any pattern is evident, it is that bottom samples consistently have lower concentrations than surface samples. Hence, the belief held at the time the CEMP was first formulated that cold return water could sink and slide along the bottom does not appear to be borne out by the monitoring data. This indicates that cold return water entering the ground either warms to ambient temperature as it flows through the permeable rock to the shoreline, or is rapidly mixed to background levels at the shoreline as evidenced by the shoreline and offshore monitoring results.

III. EVALUATION OF ALTERATION OF GROUNDWATER FROM HELCO PROJECT

The TNWRE Report describedthe four potential impacts to water resources from the HELCO's project. In summary these findings show:

1) Increased pumpage from DWS high elevation wells would result in a negligible decrease in groundwater flowrate that would be far too small to have an effect on any water features near the coastline.
2) Changes to salinity of groundwater in the coastal area would be inconsequential, primarily because of the large amount of saltwater disposal that is ongoing throughout the NELH facility.
3) Subsurface disposal of wastewater generated by the Power Plant would be mixed into saline groundwater. However, the injectate plume could not rise any

higher than into the lower half of the transition zone. The resultant horizontal and vertical separation of the HELCO and downslope wells, together with the ongoing disposal activities at NELH, mitigate against any adverse impact.

4) As a result of HELCO's project, the amount of domestic wastewater that will be treated and disposed of in the existing power plant and leachfield system will be increased by approximately 2000 gallons per day (GPD). All of this water will ultimately reach the underlying basal lens. The primary issue with this method of disposal is the addition of nutrients to the underlying basal lens. TNWRE provides the calculations to estimate the nutrient contributions to groundwater from the additional domestic sewage disposal. The disposal of 2000 GPD of domestic wastewater would add 0.066 pounds per day of nitrogen and 0.010 pounds per day of phosphorus to the flow of groundwater beneath the site. These subsidies are equivalent to 0.3% and 0.2% of nitrogen and phosphorus, respectively, that flow to the shoreline in "natural" fluxes of groundwater. When combined with the present nutrient subsidies from the existing HELCO facility, nutrient loading to groundwater would amount to less than 0.5% of nitrogen and phosphorus that are continually discharged into the marine environment through natural groundwater flux.

IV. DISCUSSION AND CONCLUSIONS

A detailed analysis of various fresh and marine water sources near the shoreline of Keahole Point directly downslope of the HELCO generating station was possible owing the NELHA CEMP database. One consistent thread through the evaluation of disposal trenches, anchialine ponds, wells, and the nearshore ocean is that the disposal of seawater from NELH/HOST Park activities is responsible for periodic large nutrient subsidies that reach the ocean. The structure of the CEMP was such that it was not possible to trace the exact source of the subsidies, although it is virtually certain that it is at least one of the mariculture ventures. While these subsidies are not continuous, they have been ongoing for decades. In addition, the discharge contains a percentage of "deep seawater" which contains substantially more nutrients than surface seawater. While not described in detail in this report, time-course biological monitoring that was also part of the NELHA CEMP showed no impacts to the benthos or fish communities that could be attributable to the nutrient subsidies. Biotic monitoring did indicate, however, that there were changes to the biota from other factors (e.g., storm for the benthos, and fishing pressure).

It is possible to quantitatively compare the magnitude of nutrient subsidies from existing operations at NELH/HOST Park to the estimates of potential change of nutrient loading from HELCO's project. The only potential source of change to nutrient loading to groundwater from HELCO's project is disposal of domestic sewage generated at the plant. As described above, TNWRE estimates that the maximum change in loading of nitrogen and phosphorus from the total (existing plus future) discharge of domestic sewage effluent would amount to a maximum of 0.5% of the nutrient load that exists in natural groundwater that is unaltered by human activities. On the other hand, mixing plots scaling nearshore nutrient concentrations to salinity can be used to calculate the percentage increase of nutrient subsidies from land relative to natural concentrations. In the case of nitrogen and phosphorus, there is an increase of up to about 20-30% over natural conditions in nearshore waters, which is likely a result of mariculture discharge. The potential changes attributable to HELCO's project of less than 1% are likely below the limits of detection compared the existing fluctuations.

It is also important to note that there is little potential for impact to marine communities in the nearshore area downslope form the project site. While anthropogenic activities can increase the concentration of nitrate in groundwater entering the nearshore ocean, the concentration of natural groundwater (~80 μM) is approximately three orders of magnitude (i.e., one thousand times) higher than coastal ocean water. Hence, if nutrient subsidies were responsible for negative impacts to nearshore marine communities, such impacts would likely occur under natural conditions, with no subsidies from the activities of man. Rather, it is apparent that Hawaiian nearshore marine communities are adapted to substantial input of groundwater nutrients.

Other land-use projects that have been in place in West Hawaii for decades also illustrate that it is very unlikely that there would be any effects to the nearshore marine environment as a result of increases in nutrient concentrations in groundwater from HELCO's project . Dollar and Atkinson (1992) modeled the input of nutrients to the ocean downslope from two golf courses at Keauhou in West Hawaii over a four-year period. Discharge to the ocean of groundwater that flows under the golf courses is focused into Keauhou Bay, which is a small semi-enclosed basin with restricted circulation relative to the open ocean.

Results of the studies showed that groundwater entering Keauhou Bay was enriched in nitrate nitrogen by about 100% over natural groundwater, while phosphate phosphorus enrichment was about 20% over natural conditions (compared to less than 1% projected for HELCO's project). Because the nutrients were retained within a well-stratified surface layer, however, there was no exposure to the benthos. Other areas of similar input along open coastlines do not exhibit such strong stratification owing to rapid mixing of the water column. The major impact to coral reef communities from nutrient subsidies does not occur from a toxic effect to the corals, but rather from a changing competitive advantage between corals and macroalgae. In high nutrient conditions, algae may increase growth rates to either smother existing corals, or to monopolize settling sites to prevent attachment of coral planulae. With no increase in nutrient concentrations in the bottom waters, owing to the stratified water column or thorough mixing, such shifts in competitive advantage do not occur. Circulation within the embayment was also rapid enough to prevent phytoplankton blooms. These results indicated that even with long-term input of extremely high nutrient subsidies, there were no negative effects to the receiving environment. The situation at Keauhou can be considered extreme relative to that at Keahole Point; hence it is also unlikely that there will be any negative effects from the operation of HELCO's project.

Based on these results, it is reasonable to conclude that the improvements and expansion of the Keahole generating station will not have a significant or even measurable effect on marine waters in the region.

IV. Literature Cited

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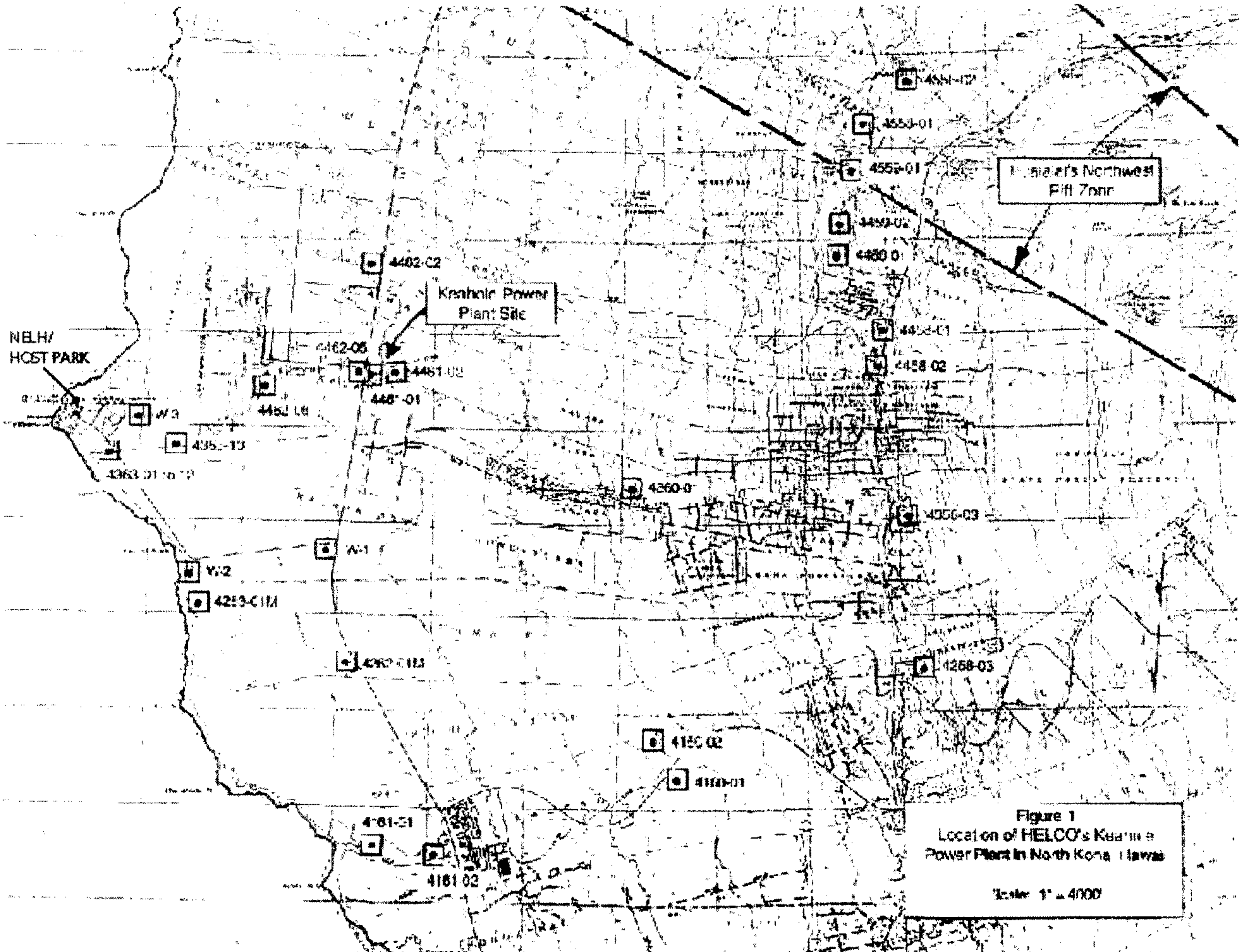


Figure 1
Location of HELCO's Keahole
Power Plant in North Kona, Hawaii

Scale: 1" = 4000'

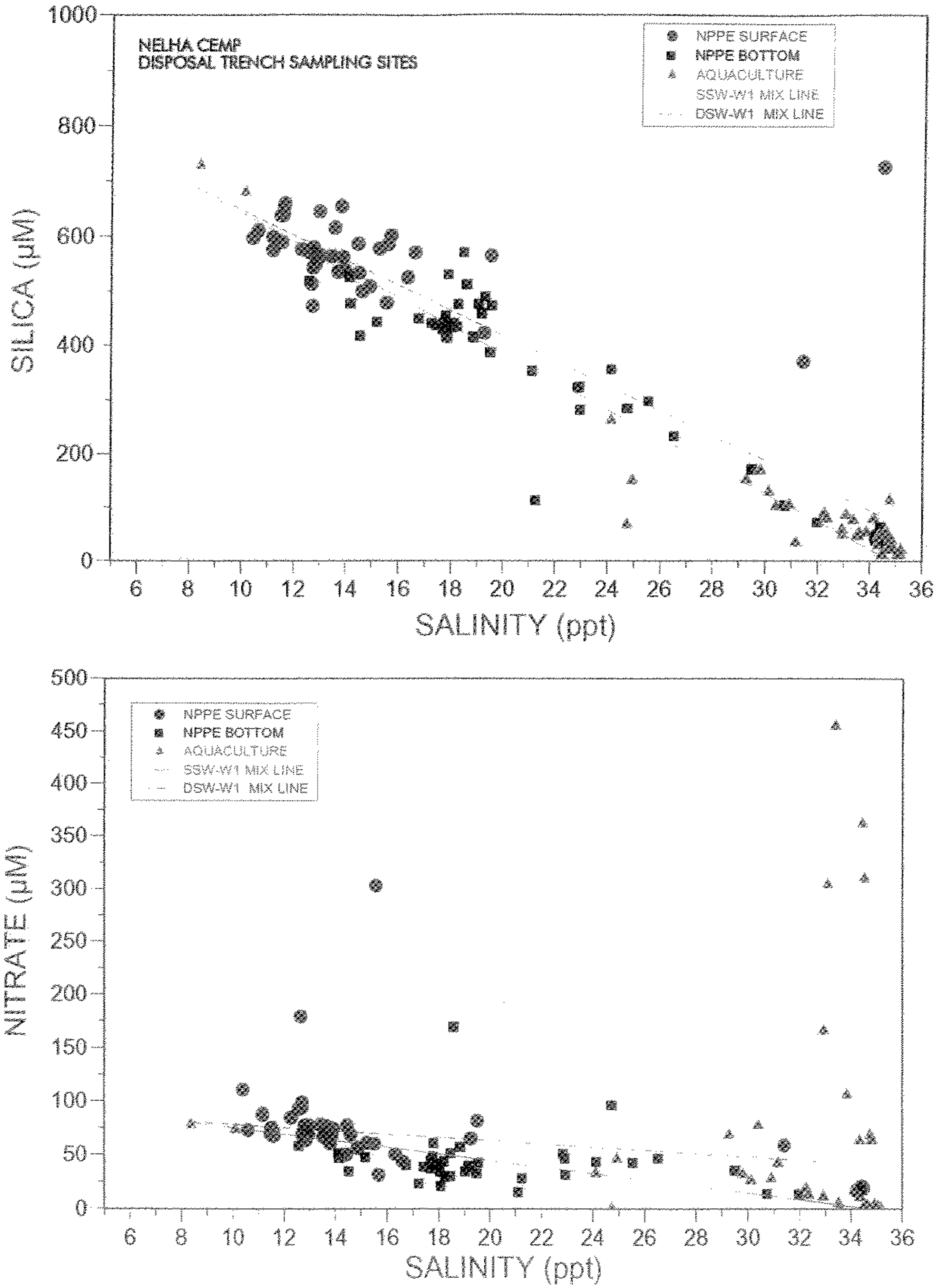
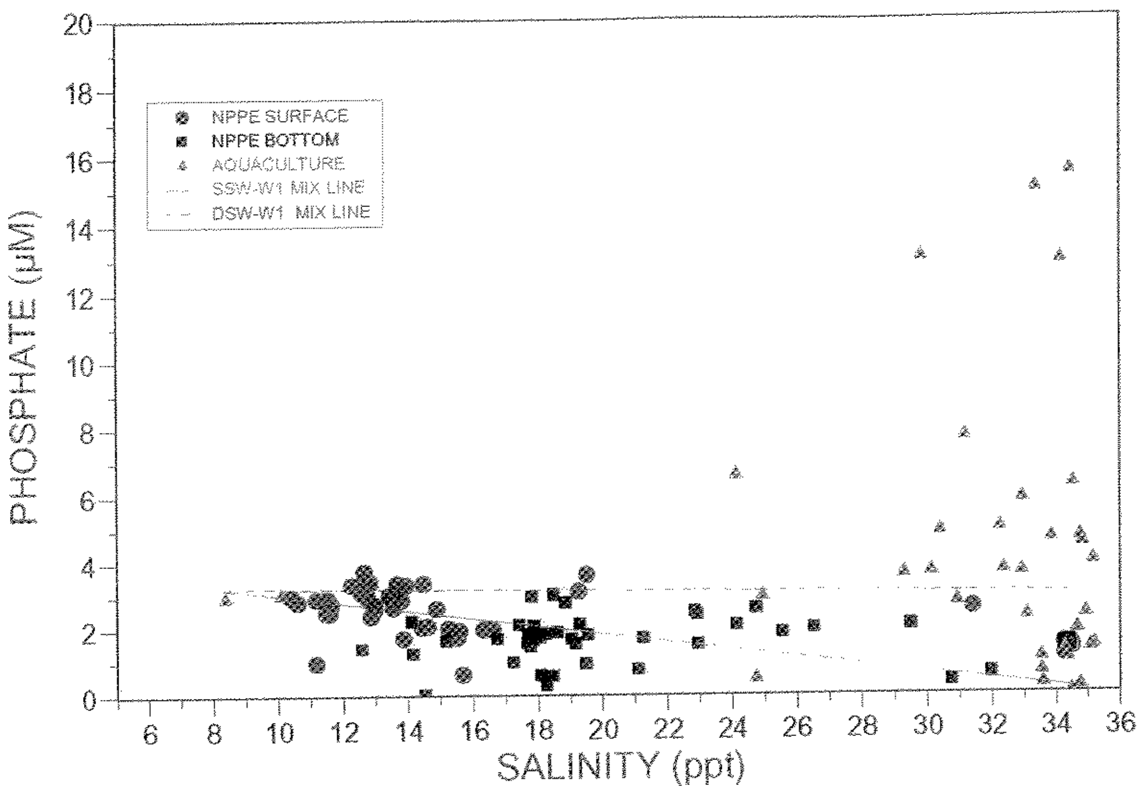


FIGURE 2. Mixing plots of Silica (top) and Nitrate nitrogen (bottom) as functions of salinity from water collected in trenches (NPPE and Aquaculture) on the grounds of the Natural Energy Laboratory of Hawaii (NELH). Data from the NELHA Comprehensive Environmental Monitoring Program (CEMP) conducted from 1989 to 2003.



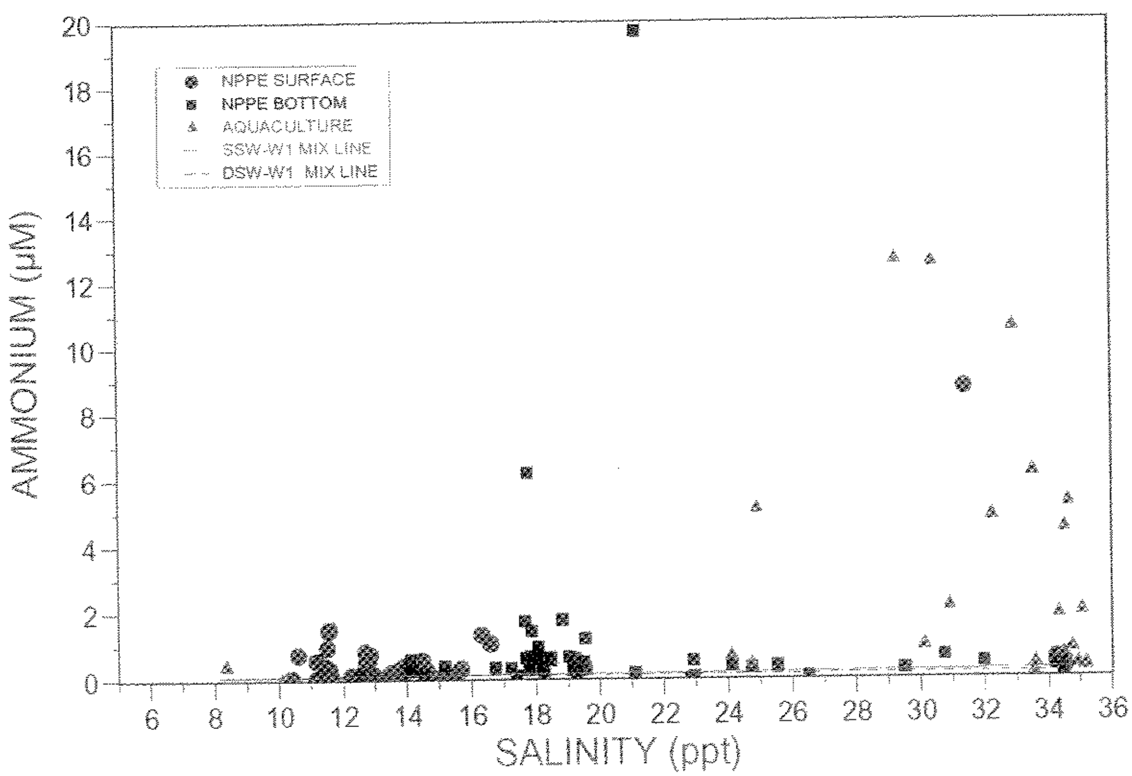
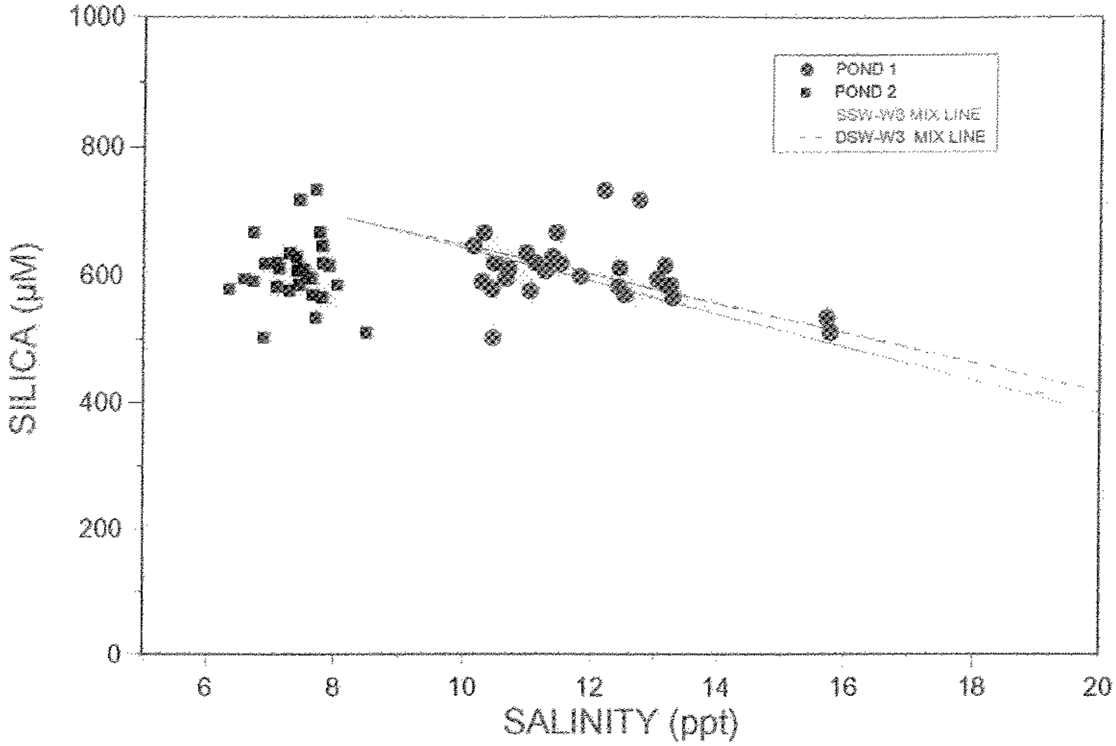


FIGURE 3. Mixing plots of phosphate phosphorus (top) and ammonium nitrogen (bottom) as functions of salinity from water collected in trenches (NPPE and Aquaculture) on the grounds of the Natural Energy Laboratory of Hawaii (NELH). Data from the NELHA Comprehensive Environmental Monitoring Program (CEMP) conducted from 1989 to 2003.



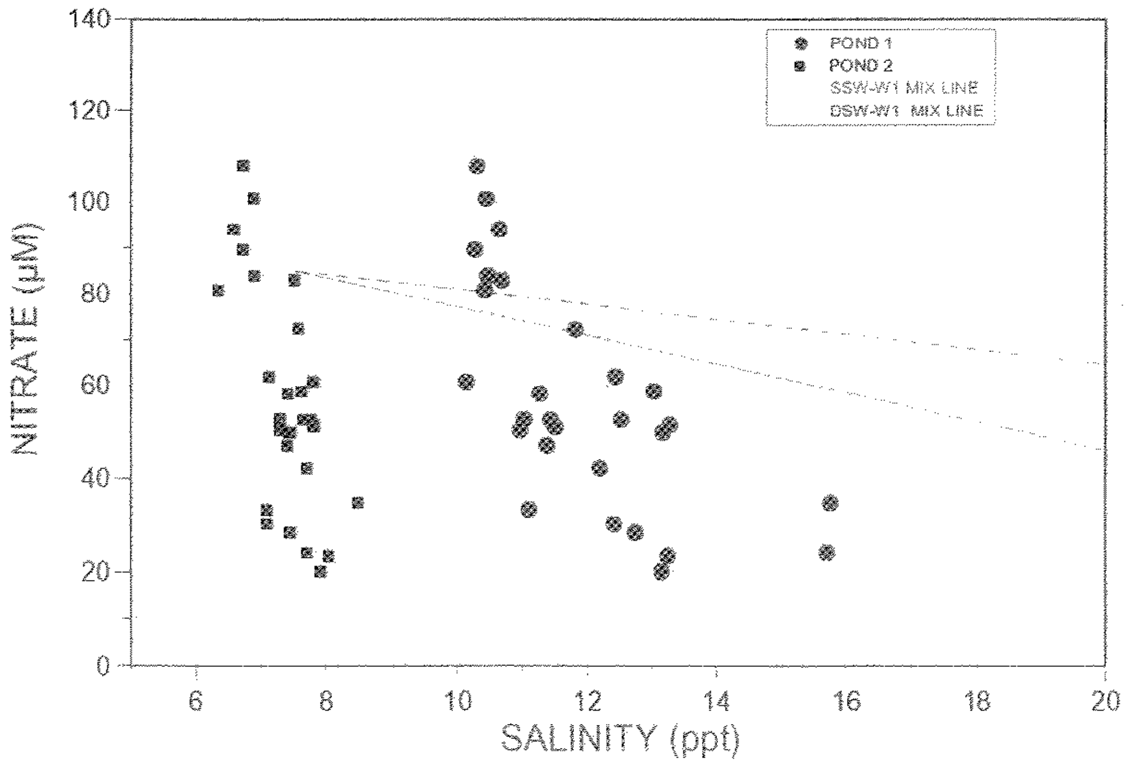


FIGURE 4. Mixing plots of Silica (top) and Nitrate nitrogen (bottom) as functions of salinity from water collected in two anchialine ponds on the grounds of the Natural Energy Laboratory of Hawaii (NELH). Data from the NELHA Comprehensive Environmental Monitoring Program (CEMP) conducted from 1989 to 2000.

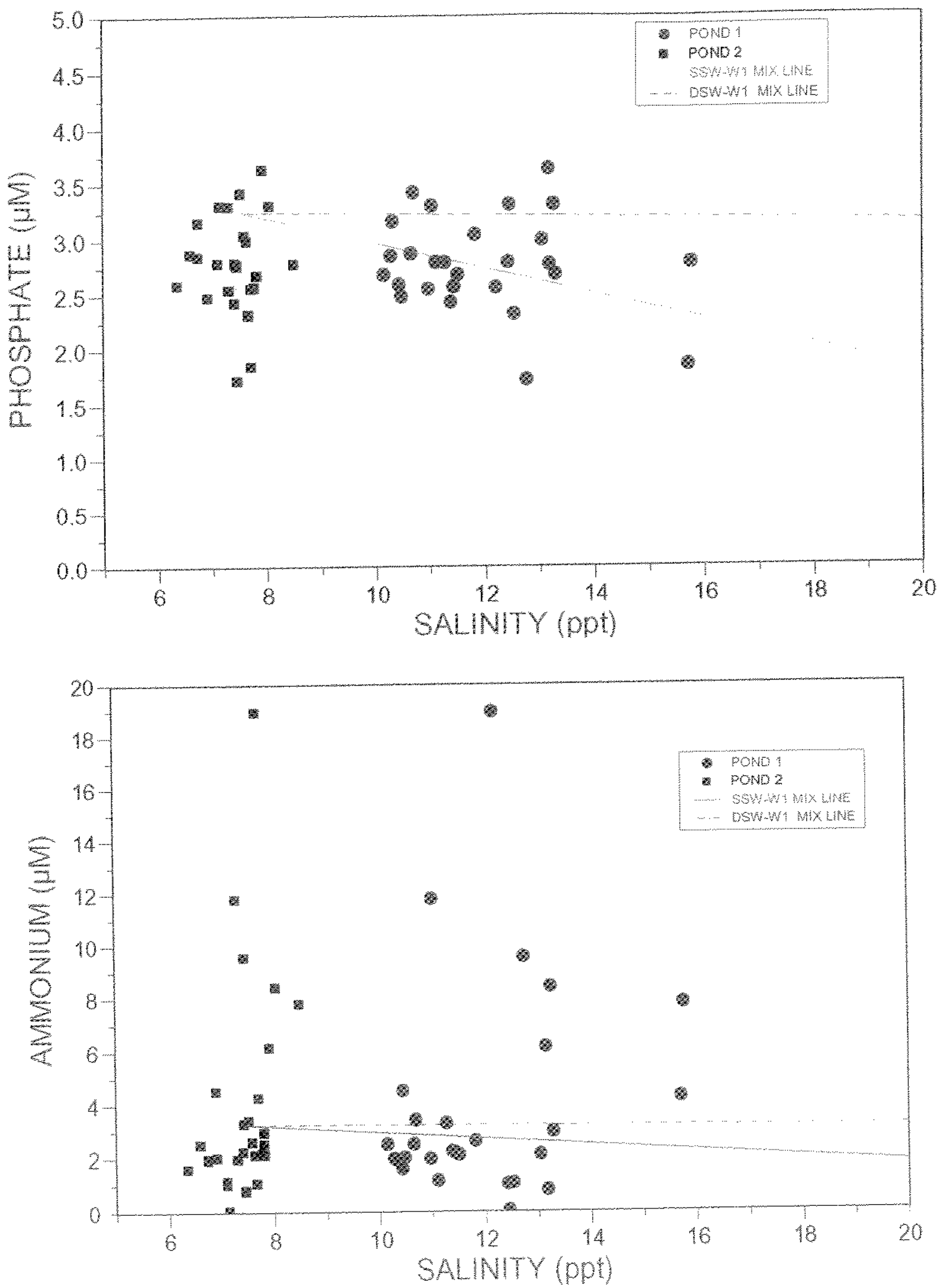


FIGURE 5. Mixing plots of phosphate phosphorus (top) and ammonium nitrogen (bottom) as functions of salinity from water collected in two anchialine ponds on the grounds of the Natural Energy Laboratory of Hawaii (NELH). Data from the NELHA Comprehensive Environmental Monitoring Program (CEMP) conducted from 1989 to 2000.

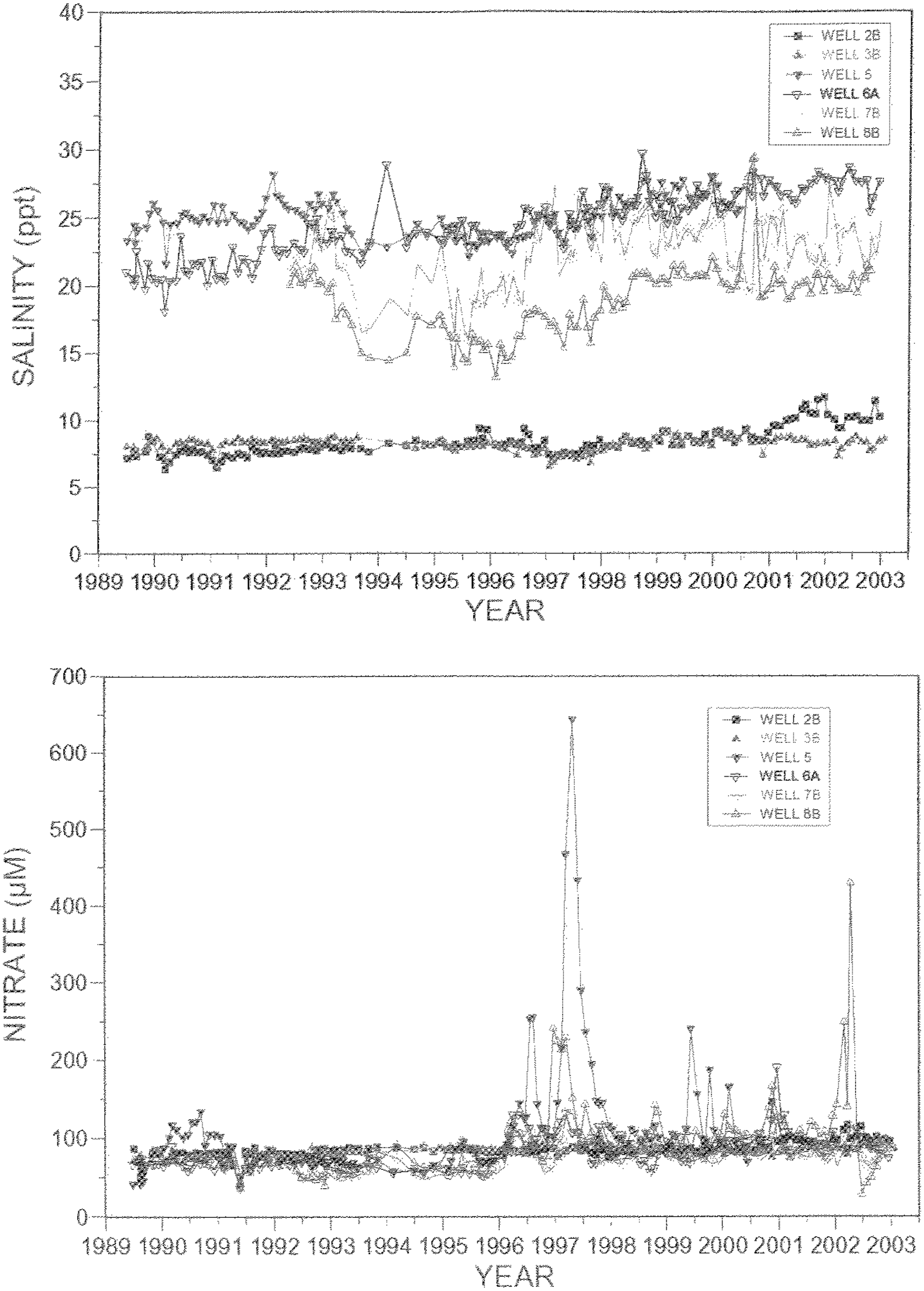


FIGURE 6. Concentrations of Silica (top) and nitrate (bottom) from shallow monitoring wells at NELH/HOST Park versus time over the course of the monitoring program from 1989 to 2003. Data from the NELHA Comprehensive Environmental Monitoring Program (CEMP).

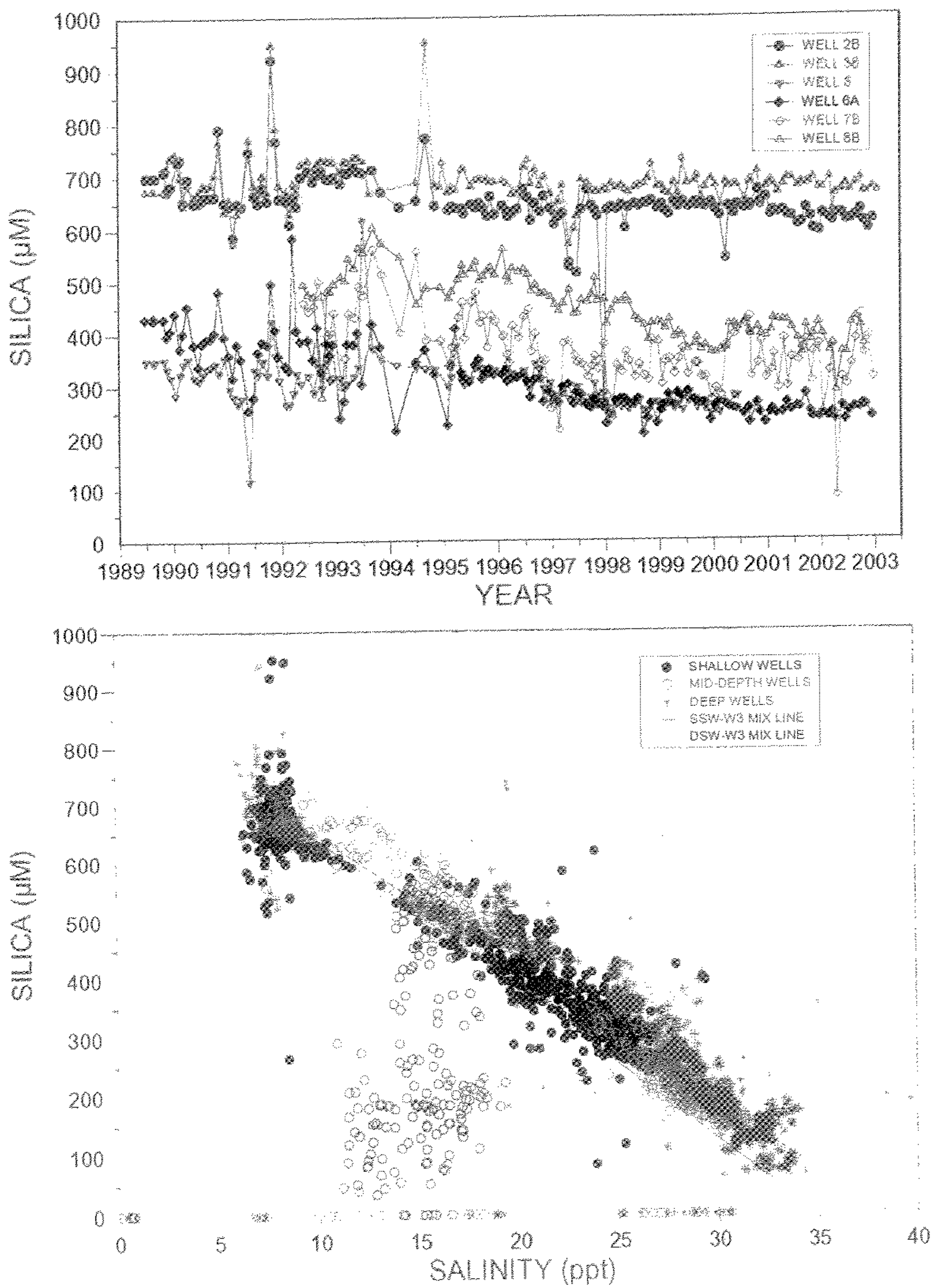


FIGURE 7. Concentrations of Silica in shallow monitoring wells at NELH versus time from1989 to 2003 (top). Mixing plot of Silica as a function of salinity (bottom) in water collected eight wells on the grounds of the Natural Energy Laboratory of Hawaii (NELH). Data from the NELHA Comprehensive Environmental Monitoring Program (CEMP).

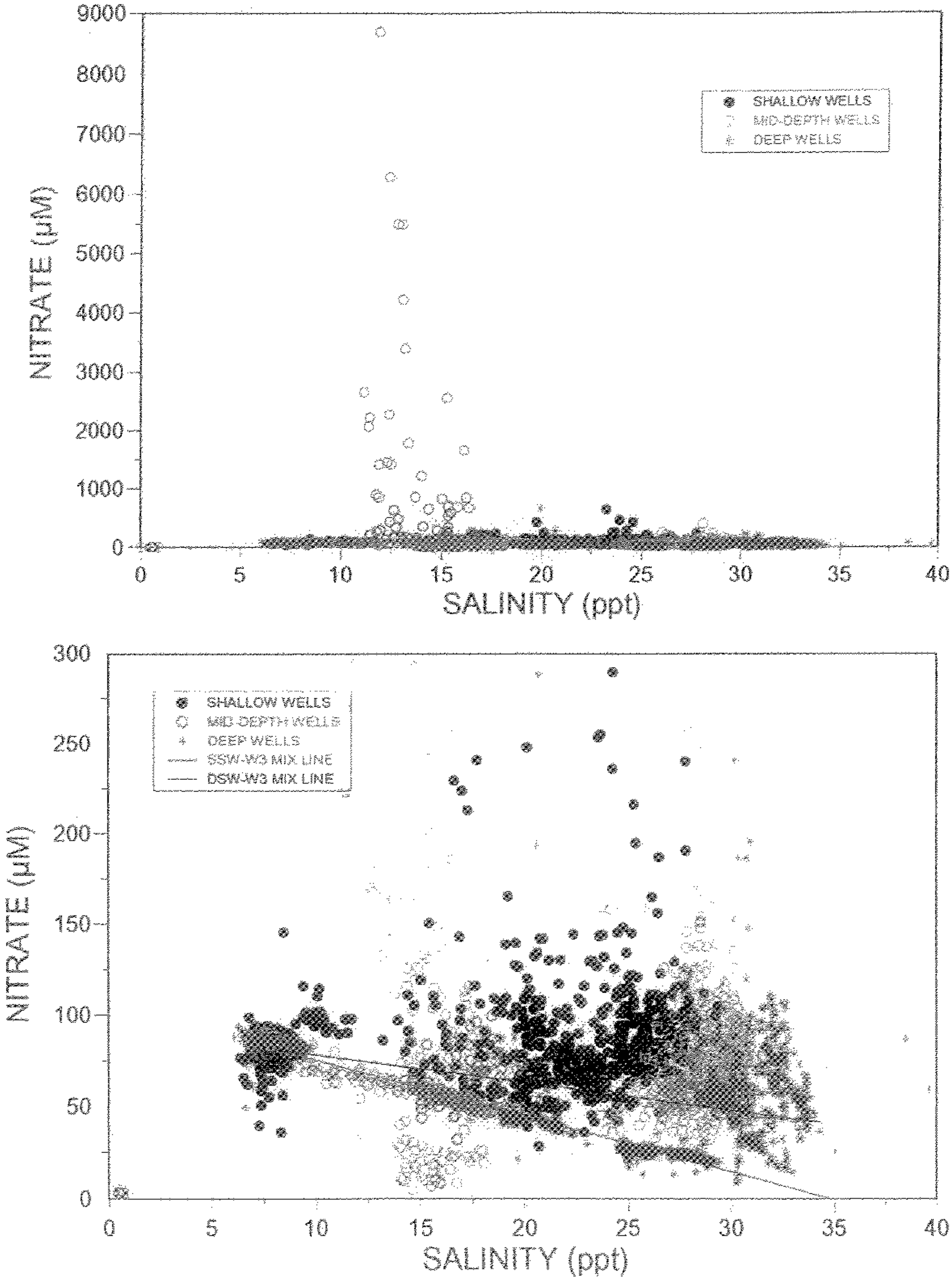


FIGURE 8. Mixing plots of Nitrate nitrogen as a function of salinity from water collected from eight wells on the grounds of the Natural Energy Laboratory of Hawaii (NELH). Top plot shows full range of measurements from zero to 9 mM. Bottom plot shows data with nitrate concentrations below 300 µM. Data from the NELHA Comprehensive Environmental Monitoring Program (CEMP) conducted from 1989 to 2003.

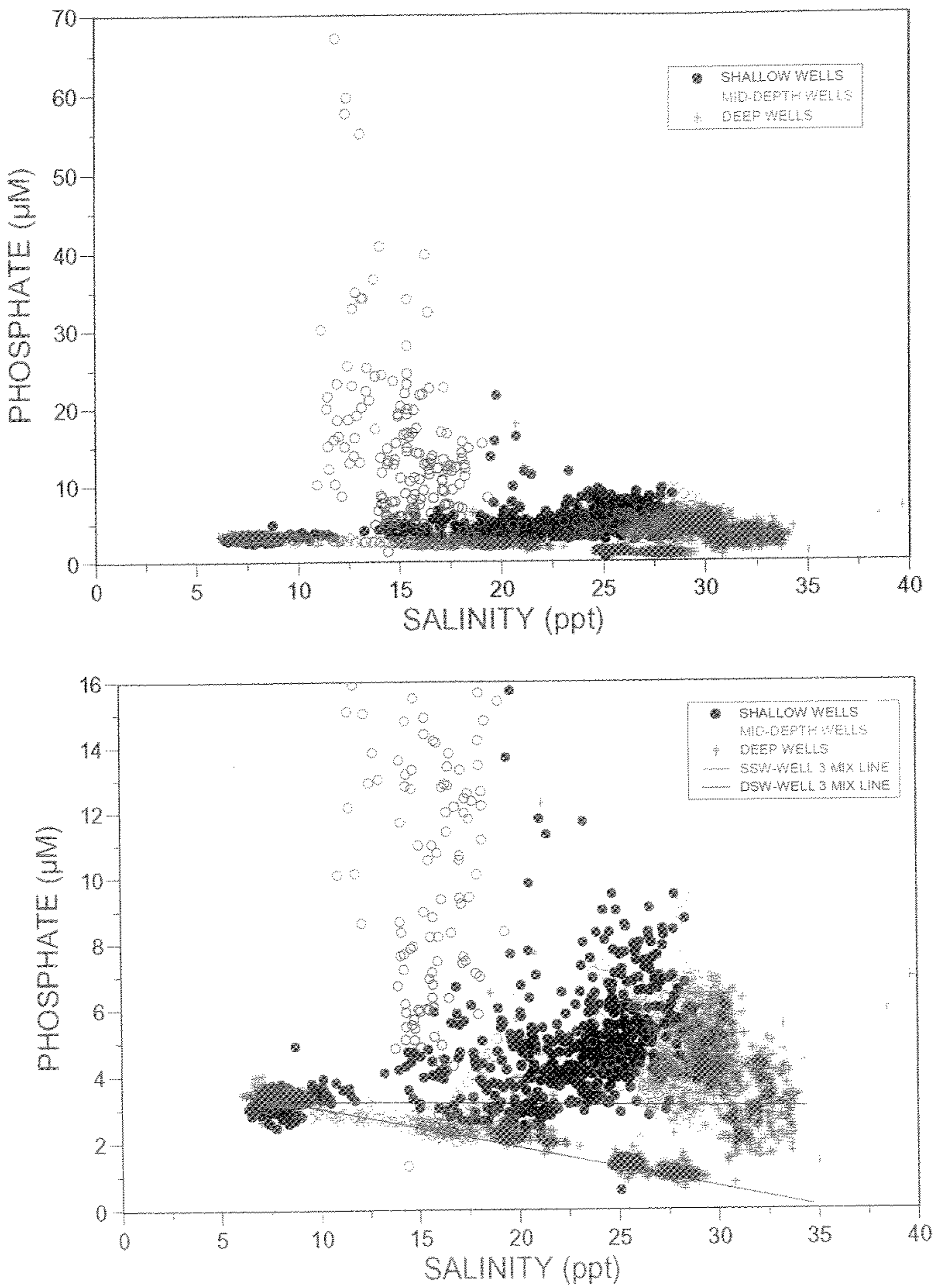


FIGURE 9. Mixing plots of phosphate phosphorus as a function of salinity from water collected from eight wells on the grounds of the Natural Energy Laboratory of Hawaii (NELH). Top plot shows full range of measurements from zero to 70 µM. Bottom plot shows data with nitrate concentrations below 15 µM. Data from the NELHA Comprehensive Environmental Monitoring Program (CEMP) conducted from 1989 to 2003.

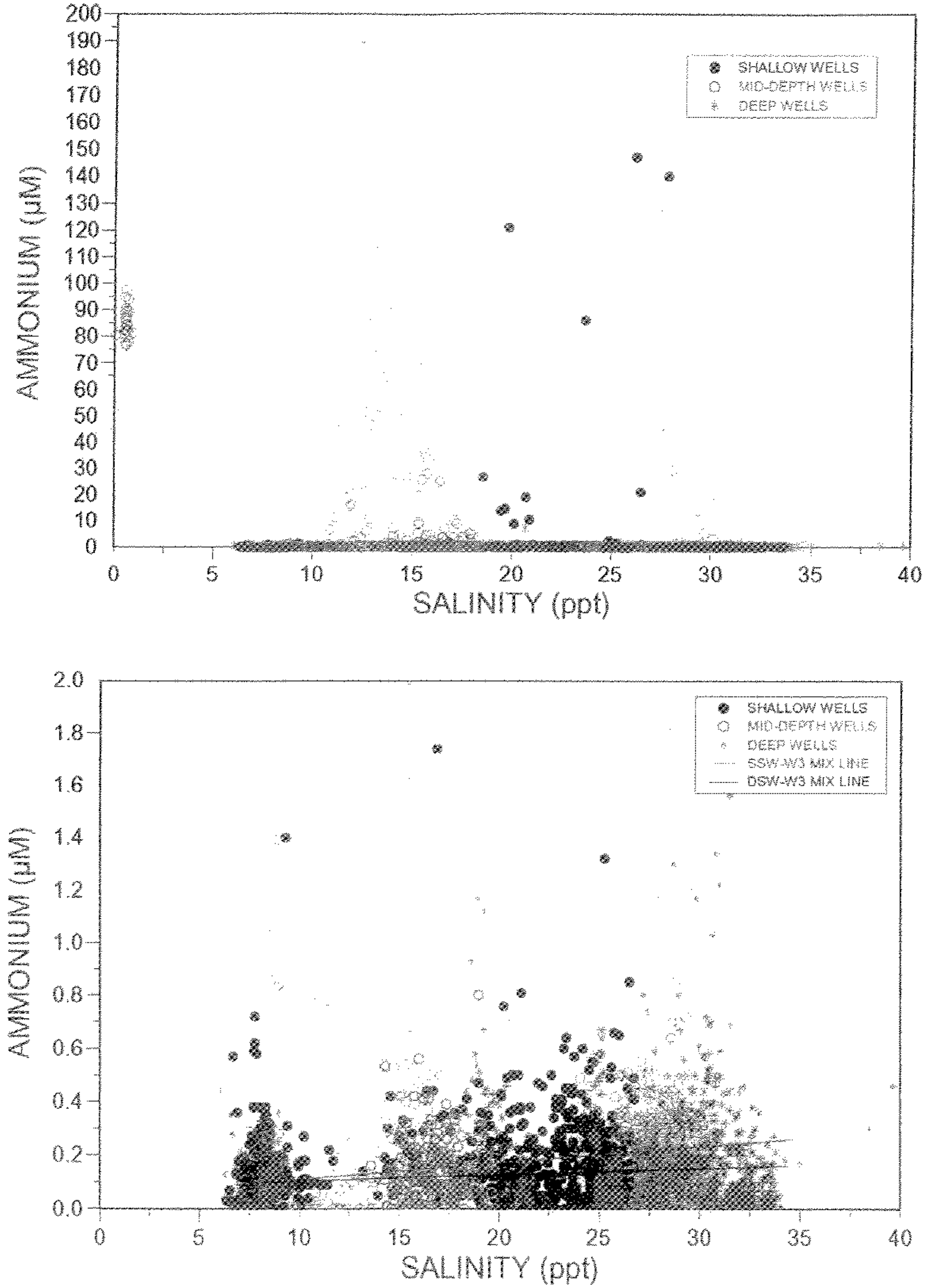


FIGURE 10. Mixing plots of ammonium nitrogen as a function of salinity from water collected from eight wells on the grounds of the Natural Energy Laboratory of Hawaii (NELH). Top plot shows full range of measurements from zero to 200 mM. Bottom plot shows data with nitrate concentrations below 2 µM. Data from the NELHA Comprehensive Environmental Monitoring Program (CEMP) conducted from 1989 to 2003.

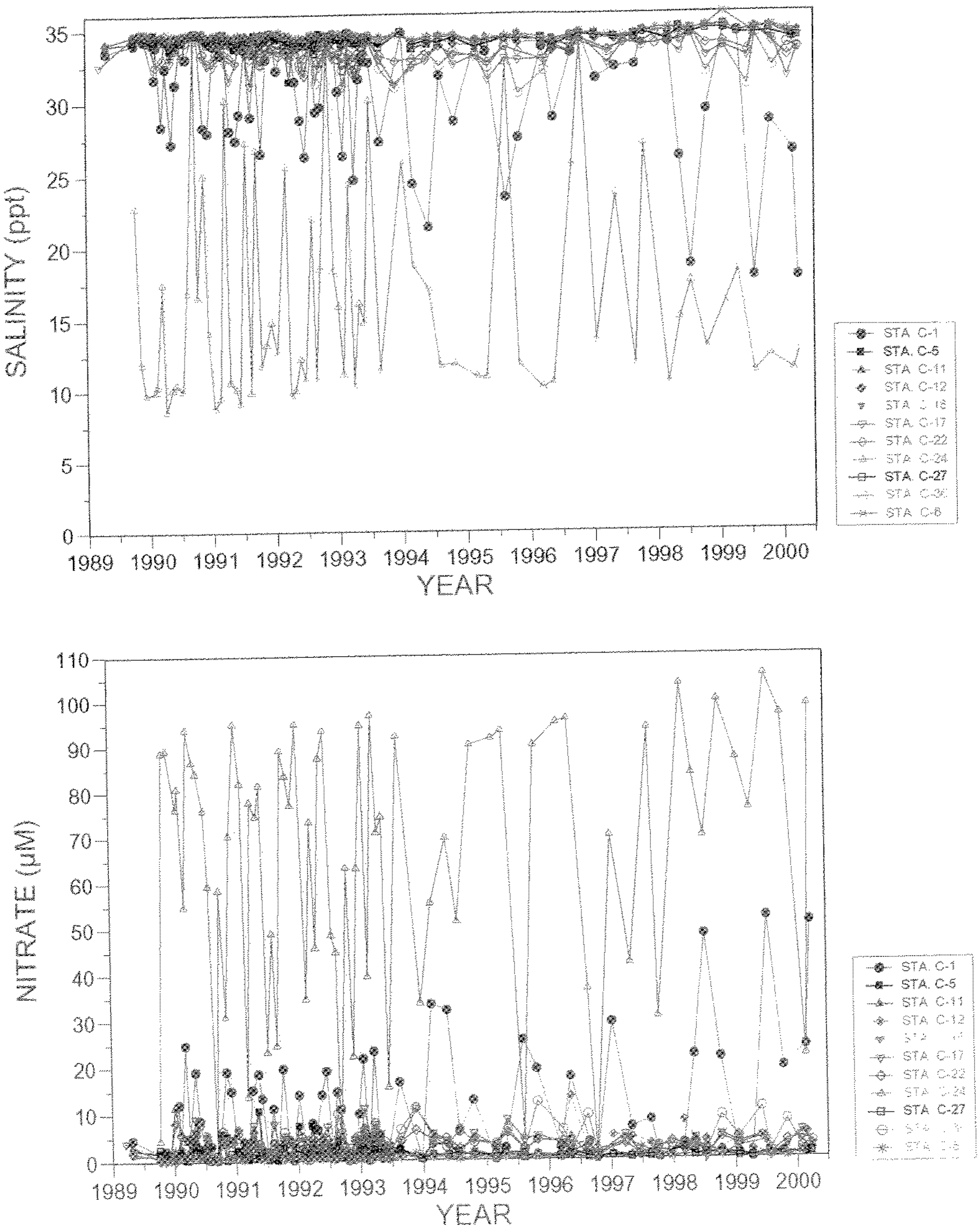
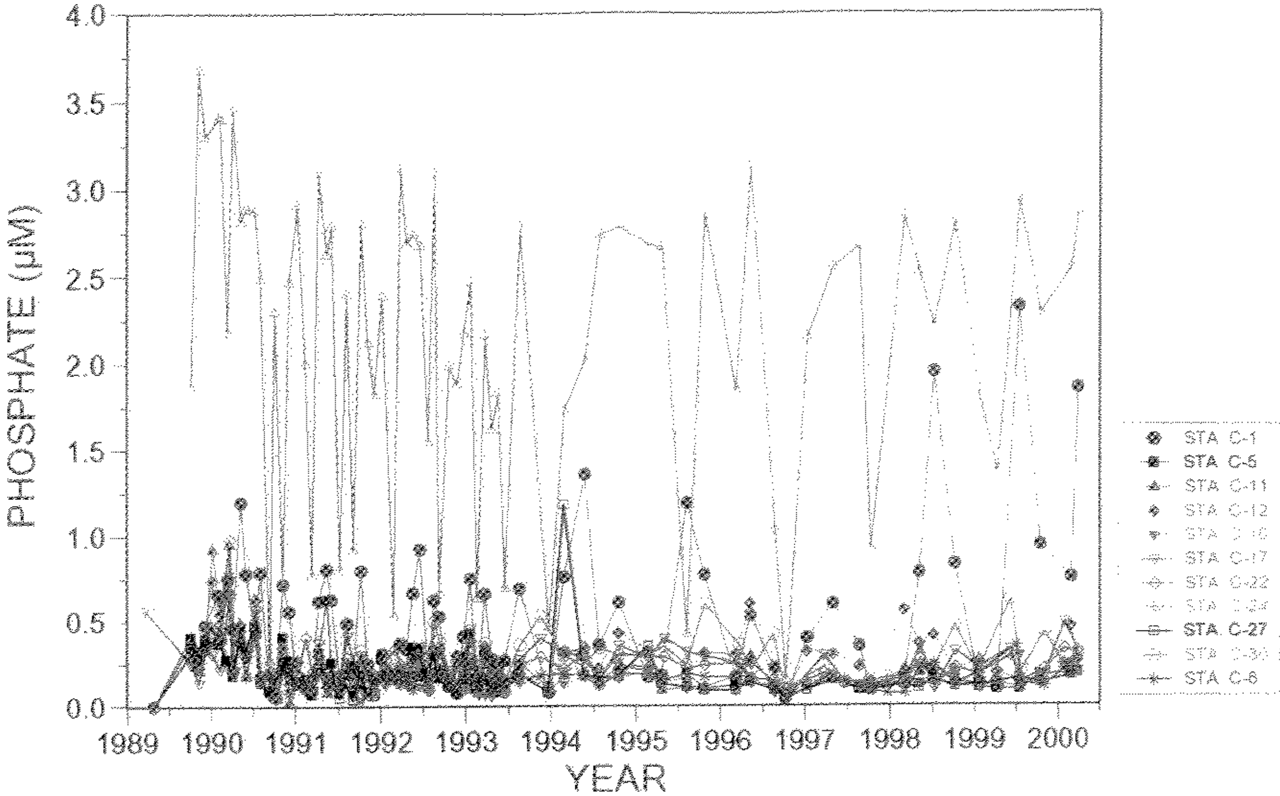


FIGURE 11. Plots of salinity (top) and nitrate nitrogen (bottom) from samples collected at ocean sampling stations offshore of the Natural Energy Laboratory of Hawaii (NELH). Data from the NELHA Comprehensive Environmental Monitoring Program (CEMP) conducted from 1989 to 2001.



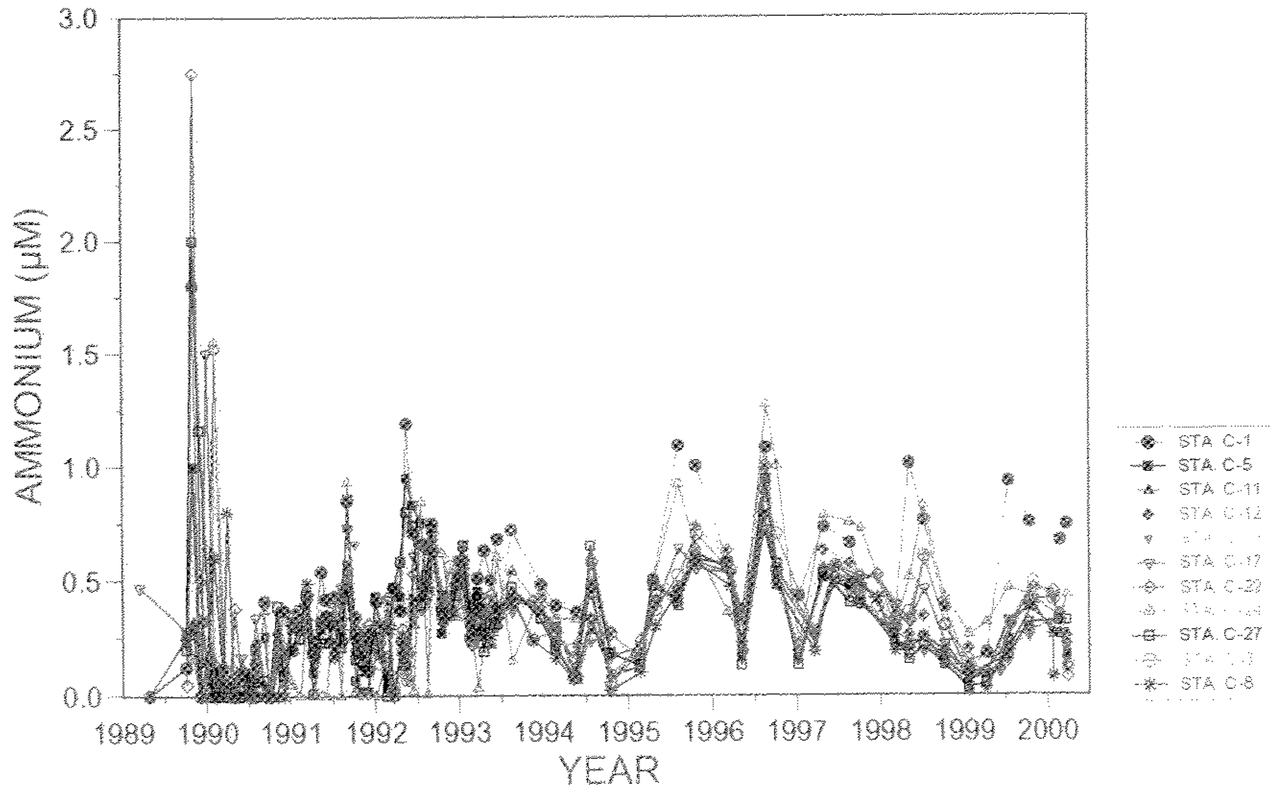


FIGURE 12. Plots of phosphate phosphorus (top) and ammonium nitrogen (bottom) from samples collected at ocean sampling stations offshore of the Natural Energy Laboratory of Hawaii (NELH). Data from the NELHA Comprehensive Environmental Monitoring Program (CEMP) conducted from 1989 to 2001.

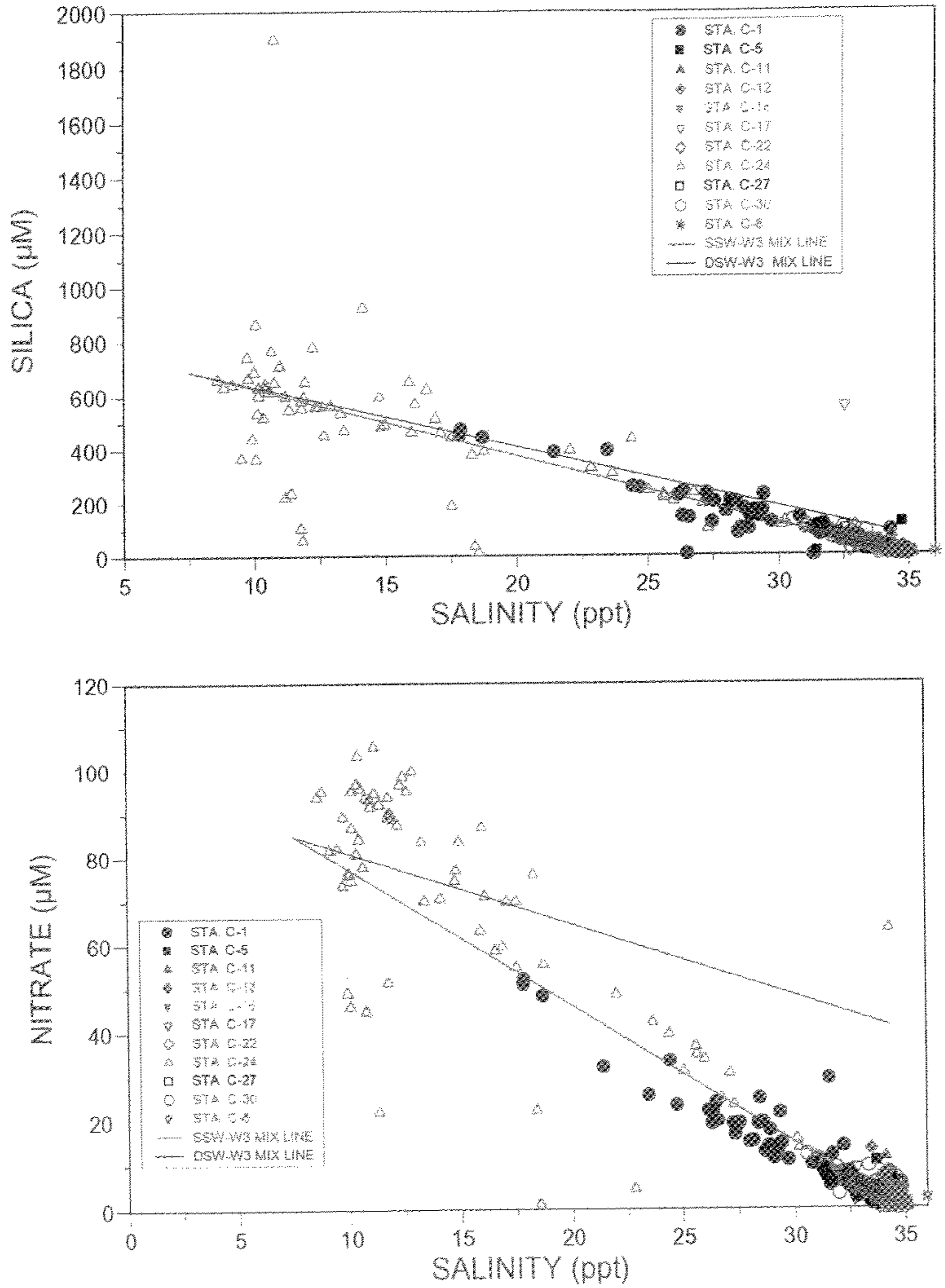


FIGURE 13. Mixing plots of Silica (top) and Nitrate nitrogen (bottom) as functions of salinity from ocean samples collected offshore of the Natural Energy Laboratory of Hawaii (NELH). Data from the NELHA Comprehensive Environmental Monitoring Program (CEMP) conducted from 1989 to 2001.

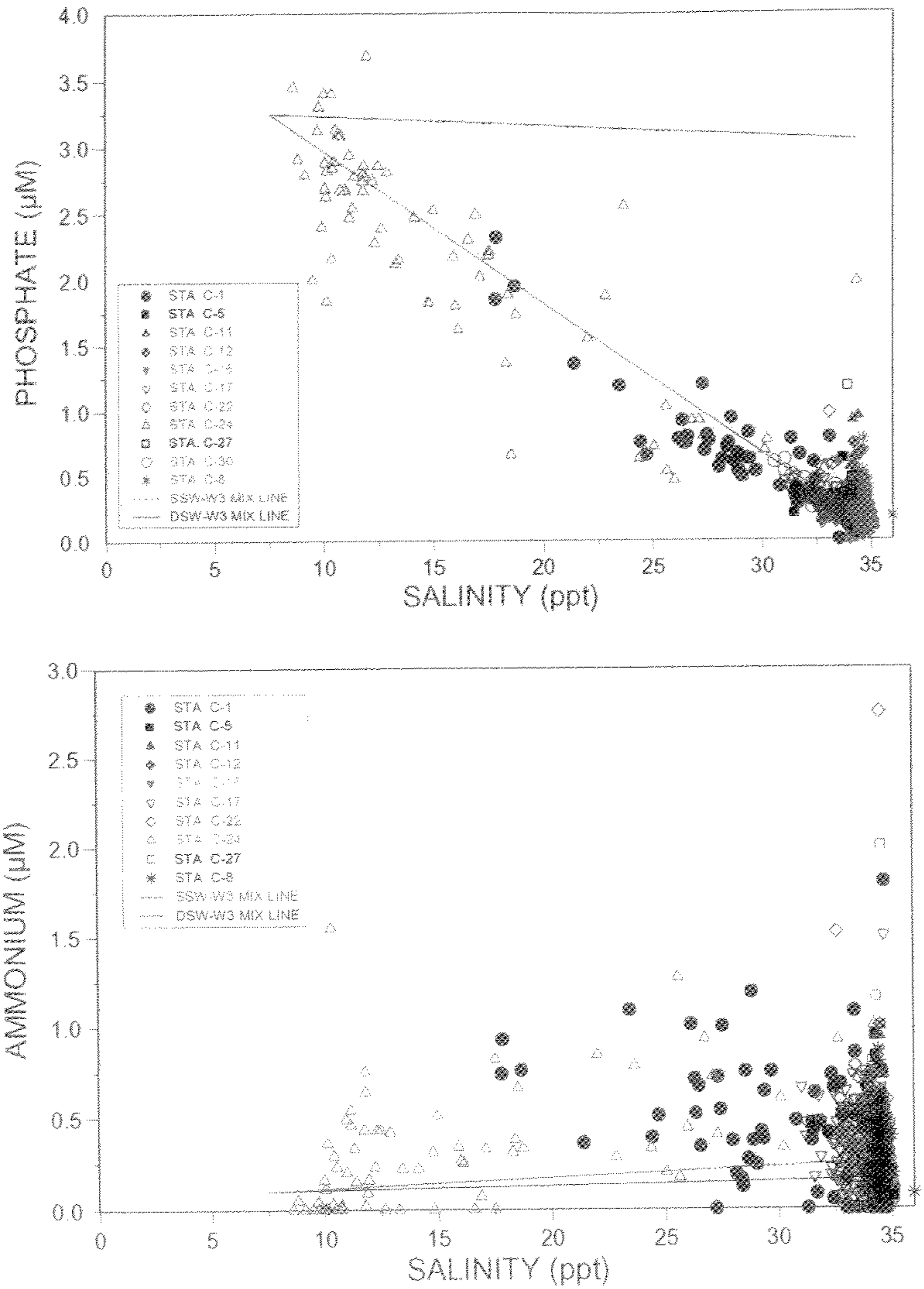


FIGURE 14. Mixing plots of phosphat phosphorus (top) and ammonium nitrogen (bottom) as functions of salinity from ocean samples collected offshore of the Natural Energy Laboratory of Hawaii (NELH). Data from the NELHA Comprehensive Environmental Monitoring Program (CEMP) conducted from 1989 to 2001

Report 2330/2331-021504

Archaeological and Cultural Impact Assessment Study

HELCO Keahole Generating Station Project

Lands of Kalaoa 1-4, North Kona District
Island of Hawai'i (TMK: 3-7-3-49:36, 37)

Technical Study for Chapter 343 Environmental Impact Study

PHRI
Paul H. Rosendahl, Ph.D., Inc.
Archaeological • Historical • Cultural Resource Management Studies & Services

SUMMARY

At the request of Belt Collins Hawaii Ltd. (BCH), and on behalf of their client, Hawaii Electric Light Company, Inc. (HELCO), Paul H. Rosendahl, Ph.D., Inc. (PHRI) prepared an Archaeological and Cultural Impact Assessment Study for the HELCO Keahole Generating Station Project. The 15.643 ac project site is located approximately 200 ft inland of Queen Kaahumanu Highway, at the northwestern corner of the Keahole Agricultural Park, in the Lands of Kalaoa 1-4, North Kona, Hawai'i Island (TMK:3-7-3-49:36,37). This archaeological and cultural impact assessment study was prepared as a technical study for an Environmental Impact Statement (EIS) being prepared in compliance with the requirements of *Chapter 343 (Haw.Rev.Stat.)* to support an application to the State Land Use Commission for a boundary amendment to reclassify the property to the State Urban District and subsequently seek a Change of Zone to General Industrial from the County of Hawaii.

In June 1992, PHRI conducted an archaeological inventory survey covering most of the present project site for the HELCO Keahole Parcel Project area. Four quarry sites consisting of seven component features–all pahoehoe excavations–were identified. Each site was recorded in detail. As there were no cultural deposits of any kind within the identified features, no subsurface test excavations were conducted. All four sites were assessed as significant for their information content; however, no further work or preservation was recommended for any of the sites, as the data collected during the inventory survey was considered adequate and sufficient mitigation of the potential adverse impacts of further development and use of the parcel. SHPD subsequently reviewed the final report on the inventory survey, concurred with the evaluation and recommendation of PHRI, and stated its determination on December 4, 1992 that proposed expansion of the existing power generation station would have "no effect" on historic properties. On September 22, 2003, PHRI inspected the present project site with regard to the three small additions, and confirmed that all three additions were fully developed elements of the project site.

No evidence of any potentially significant traditional cultural properties, natural resources, practices, or beliefs was identified within either the 1992 inventory survey project area or the three small additional project elements. The two TMK Parcels comprising the majority of the project site contain developed facilities surrounded by chain link fence, with the former being the site of the existing power generating station and the latter the site of an existing transformer station, while both access roadways are existing paved roads. The project site has been extensively modified and developed during historic times, as indicated by (a) the existing modified condition of the property, and (b) the negative findings of the both the 1992 inventory survey and the more recent 2003 inspection which yielded no evidence of the presence of any potentially significant cultural resources–properties, features, natural resources, practices, or beliefs–either within or directly related to the project site. Furthermore, there is no indication of any kind that the project site has any natural resources necessary to or currently being used by either Native Hawaiian cultural practitioners exercising traditional and customary access and use rights for any purposes or by individuals of any other cultural affiliation for any traditional cultural purposes. Based on the negative results of the both the 1992 inventory survey and the more recent 2003 inspection, and the absence of any evidence that the project site is currently being used for any legitimate traditional cultural purposes by either Native Hawaiian cultural practitioners or individuals of any other cultural affiliation, it can be concluded that the HELCO Keahole Generating Station Project should have no significant effects—much less any adverse impacts—upon any cultural resources, and that no mitigation measures of any kind are needed.

Based on the negative conclusions of both the present archaeological assessment and cultural impact assessment, it is believed appropriate for the SHPD to prepare and issue–in accordance with the general guidance provided by Chapter 284: Section 5(b) of the SHPD Rules Pertaining to the Historic Preservation Review Process (HAR Title 13, DLNR; Subtitle 13, SHPD) (DLNR 2003b), a formal written determination of "no historic properties affected" for the HELCO Keahole Generating Station Project Site.

Report 2330/2331-021504

Archaeological and Cultural Impact Assessment Study

HELCO Keahole Generating Station Project

Lands of Kalaoa 1-4, North Kona District
Island of Hawai'i (TMK: 3-7-3-49:36, 37)

Technical Study for Chapter 343 Environmental Impact Study

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FEBRUARY 2004

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INTRODUCTION

PROJECT BACKGROUND

At the request of Belt Collins Hawaii Ltd. (BCH), and on behalf of their client, Hawaii Electric Light Company, Inc. (HELCO), Paul H. Rosendahl, Ph.D., Inc. (PHRI) has prepared this Archaeological and Cultural Impact Assessment Study for the HELCO Keahole Generating Station Project. The project site is located in the Lands of Kalaoa 1-4, North Kona, Hawai'i Island (TMK:3-7-3-49:36,37), approximately 3,200 ft east of Keahole Airport *(Figure 1)*. More specifically, the project site consists of 15.643 acres of land situated approximately 200 ft inland of Queen Kaahumanu Highway, at the northwestern corner of the Keahole Agricultural Park *(Figure 2)*.

This archaeological and cultural impact assessment study has been prepared as a technical study in support of an Environmental Impact Statement (EIS) being prepared in compliance with the requirements of *Chapter 343 (Haw.Rev.Stat.)*. The owner of the property is the Hawaii Electric Light Company, Inc. (HELCO). The principal planning consultant for the project is Belt Collins Hawaii Ltd.; its address is: 2153 North King Street, Suite 200, Honolulu, HI 96819-4554; and its principal project contact is: Lee W. Sichter at (808) 521-5361. The EIS is being prepared to support an application to the State Land Use Commission for a boundary amendment to reclassify the property to the State Urban District and subsequently seek a Change of Zone to General Industrial from the County of Hawaii.

The basic objectives of the archaeological assessment were to determine the following: (a) the general nature, extent, and potential significance of any archaeological–historical remains present, (b) the historic preservation implications of such remains for the feasibility of proposed development and land use; and (c) the general scope of work and level of effort for any subsequent archaeological–historic preservation work that might be appropriate and/or required.

The basic objectives of the cultural impact assessment were to determine the following: (a) if the project area is currently being accessed by native Hawaiian cultural practitioners for any traditional and customary cultural uses; (b) if the proposed project would have any adverse impacts upon any identified current native Hawaii cultural uses of the area; and (c) what measures might be proposed to mitigate any adverse impacts the proposed project might have upon any identified current native Hawaiian uses of the area.

Based on discussions with Mr. Sichter of BCH, and with Dr. Patrick C. McCoy–State Historic Preservation Division (SHPD) Staff Archaeologist for Hawai'i Island, and PHRI familiarity with the specific project site as well as both the general project area and the current regulatory review requirements of the SHPD and the Hawaii County Planning Department, the following tasks were determined to be appropriate scope of work for the archaeological assessment survey and cultural impact assessment study:

1. Appropriate background literature review and research;
2. Archaeological update inspection fieldwork;
3. Data analysis and preparation of written report; and
4. Coordinate and consult with client, client representatives, agency staff, etc.

PHRI had previously conducted an archaeological inventory survey of most of the present project site in June 1992 (Dowden and Graves 1992). More recently, on September 22, 2003, PHRI Principal Archaeologist Dr. Paul H. Rosendahl inspected the small present project additions to the inventory survey earlier project area.

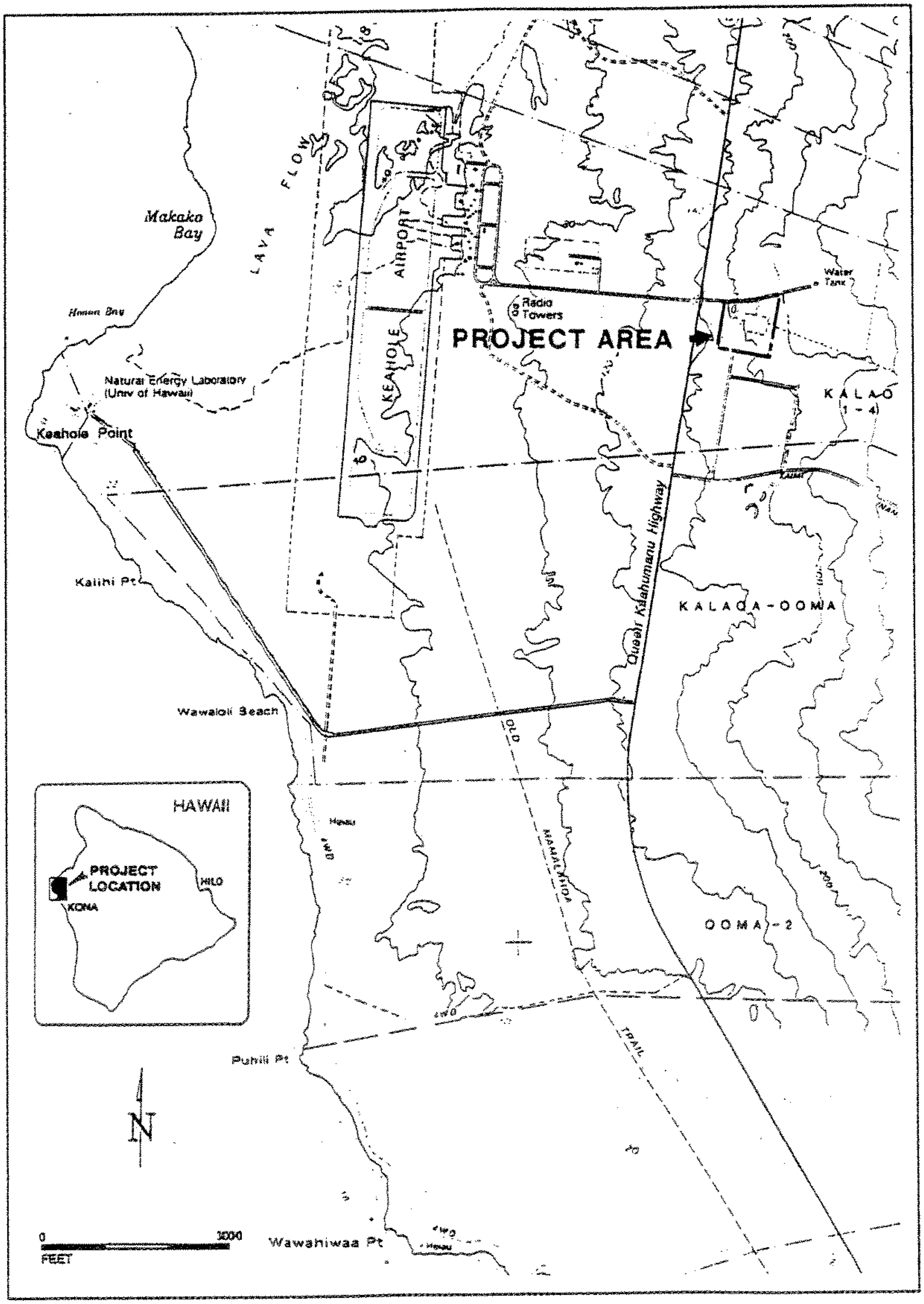

Figure 1. Project Location

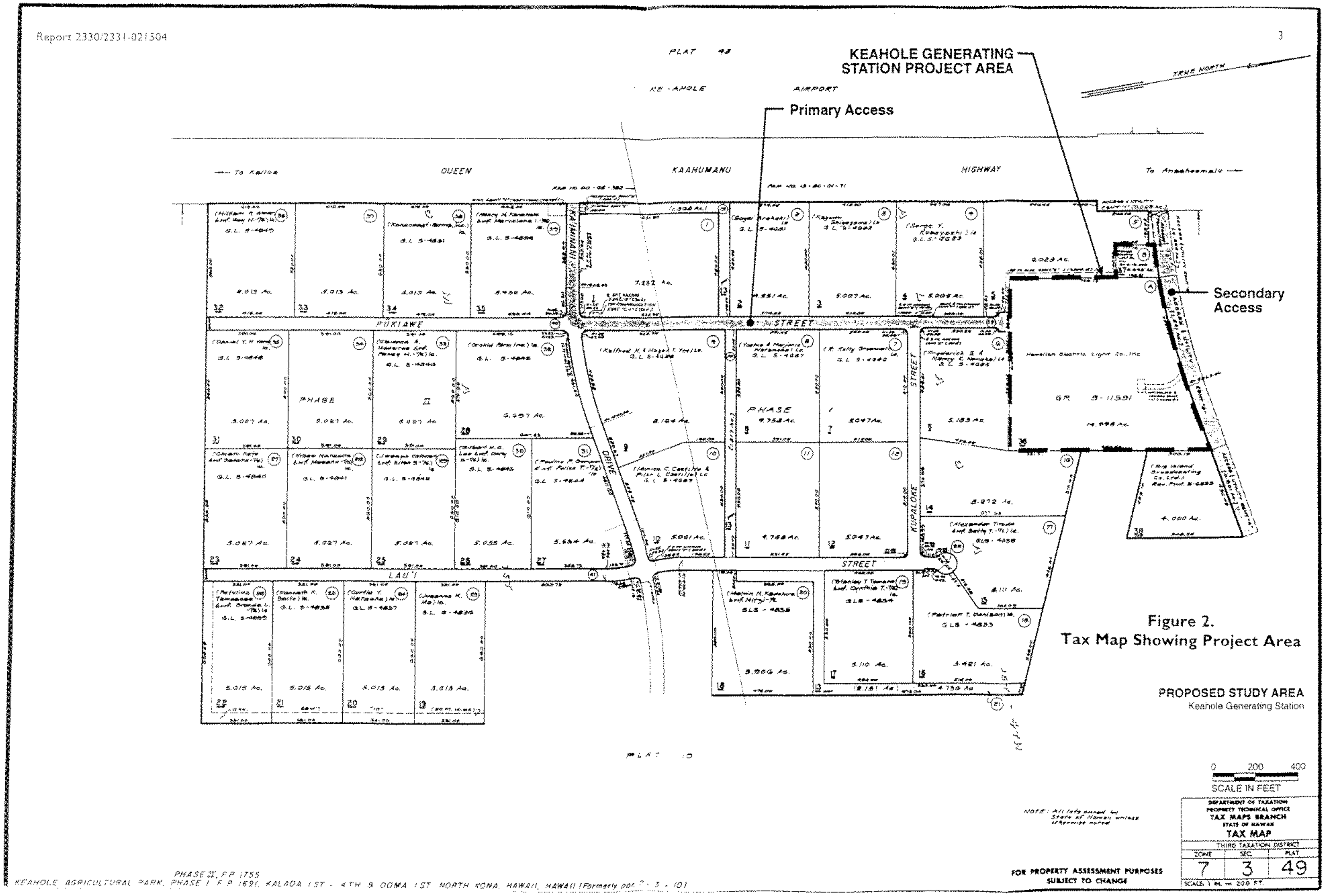

Figure 2.
Tax Map Showing Project Area

PROPOSED STUDY AREA
Keahole Generating Station

PROJECT AREA DESCRIPTION

The HELCO Keahole Generating Station Project site is located in the Lands of Kalaoa 1-4, North Kona, Hawai'i Island (TMK:3-7-3-49:36,37), approximately 3,200 ft east of Keahole Airport *(Figure 1)*. More specifically, the project site consists of 15.643 acres of land situated approximately 200 ft inland of Queen Kaahumanu Highway, at the northwestern corner of the Keahole Agricultural Park, and consists of four elements *(Figure 2)*:

- **TMK Parcel 36** – Parcel land area is 14.998 acres; surrounded by a chain link fence, this parcel is the existing site of the Keahole Generating Station, and has been developed with a 30-megawatt generating facility and portions of a 56-megawatt facility that have been constructed but are not operational
- **TMK Parcel 37** – Parcel land area is 0.645 acres; surrounded by a chain link fence, this small parcel is related the existing site of the Keahole Generating Station, and is occupied by an existing transformer station
- **Primary Access Road** – Primary access to the project site is by means of existing paved roadways within the Keahole Agricultural Park; by Pukiawe Street and Kaiminani Drive from Queen Kaahumanu Highway
- **Secondary Access Road** – Secondary access to the project site is by means of an existing paved access and utility easement from Queen Kaahumanu Highway and along the north boundary of the project site

The project area is part of the Kona Lava Plain, a low-cliffed volcanic coast defined by Armstrong (1983:37) as coastline with wave-cut cliff averaging about 20 ft in height along the shoreline. Basaltic lava flows of the prehistoric member of the Hualalai Volcanic Series of Hualali Volcano, which may be Late Pleistocene in age, formed the surface of the project area and immediate vicinity. In general, these lava flows are highly permeable, but brackish water is found only along the coast (Stearns and MacDonald 1946:139-140). Project area elevation rises from c. 200 ft (61 m) to c. 230 ft (70 m) AMSL. The terrain in the project area is gently undulating, and consists of soils included in the lava flows association, which includes "...excessively drained, nearly barren lava flows and somewhat excessively drained and well-drained, coarse-textured and medium-textured soils that formed in volcanic ash, pumice, and cinders. (Sato *et al.* 1973:4).

More specifically, there are two soils in the project area, Kaimu extremely stony peat and Punaluu extremely stony peat. Kaimu extremely stony peat (6-20% slopes), representing the Punaluu Series of well-drained, thin organic soils that have developed over lava bedrock, are found on uplands from sea level to 1,000 ft (305 m), and are rapidly permeable, with slow run-off, and a slight erosion hazard. These soils are generally used for pasture, macadamia nut, papaya, and citrus (Sato et al. 1973:22). Punaluu extremely stony peat (6-20% slopes), representing the Punaluu Series of well-drained, thin organic soils that have developed over pahoehoe lava bedrock, are found on uplands from sea level to 1,000 ft (305 m), and are rapidly permeable, with slow run-off, and a slight erosion hazard. These soils are generally used for pasture (Sato et al. 1973:48). Rainfall in the project area is c. 15 to 20 inches per year, and generally somewhat greater during the winter months, and the mean annual temperature is approximately 70 to 73 degrees F. (Armstrong 1983:63-64).

Prior to recent development, vegetation within the project area was generally very sparse and consisted primarily of fountain grass (*Pennisetum setaceum* [Forsk.] Chiov.), *noni* (*Morinda citrifolia* L.), *koa-haole* (*Leucaena glauca* (L.) Benth.), and *'ilima* (*Sida fallax* Walp.). Several ornamental were also present, including plumeria (*Plumeria acuminata* Ait.) and coconut palm (*Cocos nucifera* L.), and an unidentified shrub.

ARCHAEOLOGICAL INVENTORY SURVEY – 1992

BACKGROUND

In 1992, PHRI conducted an archaeological inventory survey of the HELCO Keahole Parcel project area (Dowden and Graves 1992) in connection with the preparation of an Environmental Assessment in support of a Conservation District Use Application (CDUA) amendment for proposed expansion of the then-existing power generation station situated within the project area. A copy of the final report on the survey is included here as Appendix A. The 1992 survey project area consisted of a single parcel, the approximately 15 acre parcel identified as TMK Parcel 36 (see *Figure 2*). Inventory survey fieldwork was carried out on June 29, 1992.

The basic objective of the survey was to provide information sufficient for compliance with all historic preservation regulatory review requirements of the State Historic Preservation Division (SHPD) and the Hawaii County Planning Department. The specific objectives of the survey were four-fold: (a) to identify all potentially significant archaeological remains present within the parcel; (b) to collect information sufficient to evaluate and document the potential significance of all identified remains; (c) to evaluate the potential impacts of any proposed development upon any identified significant remains; and (d) to recommend appropriate measures that would mitigate any adverse impacts upon identified significant remains.

FINDINGS

During the 1992 fieldwork, four quarry sites consisting of seven component features–all pahoehoe excavations–were identified. These sites ranged from poor to good in physical condition. Each site was recorded in detail. As there were no cultural deposits of any kind within the identified features, no subsurface test excavations were conducted.

CONCLUSION

The pahoehoe excavations identified within the 1992 survey project area were interpreted as quarry features related to prehistoric occupation of the general area, as evidenced by the presence of habitation and refuge cave sites previously identified to the south in the area of the Keahole Agricultural Park. All four sites were assessed as significant for their information content; however, no further work or preservation was recommended for any of the sites, as the data collected during the inventory survey was considered adequate and sufficient mitigation of the potential adverse impacts of further development and use of the parcel.

SHPD REVIEW AND DETERMINATION

The final report on the inventory survey (Dowden and Graves 1992) was reviewed by the SHPD. The SHPD review (Memorandum dated December 3, 1992; copy included here is Appendix B) determined the following:

1. The field survey had adequately covered the project area (i.e., had identified all sites present);
2. Data sufficient to determine and document the general significance of the four identified sites had been recorded;
3. All four sites were significant for their information content only;

4. Sufficient data had been collected from all four sites so that neither further work nor preservation of the sites was necessary or appropriate;
5. Therefore, no significant sites remained within the project area, and
6. The proposed expansion of the existing power generation station would have "no effect" on historic properties.

ARCHAEOLOGICAL ASSESSMENT: UPDATE INSPECTION – 2003

As indicated earlier, PHRI had previously conducted an archaeological inventory survey of most of the present project site–that c. 15 acre parcel identified here as TMK Parcel 36–in June 1992 (Dowden and Graves 1992). More recently, on September 22, 2003, PHRI Principal Archaeologist Dr. Paul H. Rosendahl inspected the project site with regard to the three small additions to the present project site. These three small additions are identified as (a) TMK Parcel 37, (b) the Primary Access roadway, and (c) the Secondary Access roadway (see *Figure 2*).

The field inspection of September 22, 2003 confirmed that all three additions were fully developed elements of the project site. Surrounded by a chain link fence, TMK Parcel 37 is occupied by an existing transformer station, and is related to the existing Keahole Generating Station site. Both the Primary Access roadway and the Secondary Access roadway consist of existing paved roads, with the former being paved roadways within the adjacent Keahole Agricultural Park, and the latter being a paved roadway within the access and utility easement immediately adjacent to the north of the present project site.

CULTURAL IMPACT ASSESSMENT

PURPOSE, BACKGROUND, AND OBJECTIVES

The purpose of this cultural impact assessment is to comply with the requirements of *Chapter 343 (Haw. Rev. Stat.)*, as amended by H.B. No.2895 H.D. 1 of the Hawai'i State Legislature (2000) and approved by the Governor as *Act 50* on April 26, 2000, and which among other things requires that environmental assessments (EA) and environmental impact statements (EIS) identify and assess the potential effects of any proposed project upon the "...cultural practices of the community and State...." *Chapter 343 (Haw.Rev.Stat.)* was amended by the State legislature because of the perceived need to assure that the environmental review process explicitly addressed the potential effects of any proposed project upon "....Hawai'i's culture, and traditional and customary rights." Guidelines previously prepared and adopted by the State Office of Environmental Quality Control (OEQC) 1997) provide compliance guidance. Both *Act 50* and the OEQC *Guidelines for Assessing Cultural Impacts* mandate consideration of all the different groups comprising the multi-ethnic community of Hawaii. This inclusiveness, however, is generally understated, and the emphasis—as indicated by a background review (see below) of the cultural impact assessment issue, and the intent and evolution of both the legislative action and the guidelines—is clearly meant to be primarily upon aspects of Native Hawaiian culture—particularly traditional and customary access and use rights.

Cultural resources include a broad range of often overlapping categories of cultural items –places, behaviors, values, beliefs, objects, records, stories, and so on. A traditional cultural property ("TCP") is one specific type of cultural resource that falls within the purview of the historic preservation review process. A "TCP" is a historic property or place that is important because it possesses "traditional cultural significance":

> "Traditional" in this context refers to those beliefs, customs, and practices of a living community of people that have been passed down through the generations, usually orally or through practice. The traditional cultural significance of a historic property, then, is significance derived from the role the property plays in a community's historically rooted beliefs, customs, and practices....
>
> A traditional cultural property, then, can be defined generally as one that is...[important/significant]...because of its association with cultural practices or beliefs of a living community that (a) are rooted in that community's history, and (b) are important in maintaining the continuing cultural identity of the community (Parker and King 1990:1).

In addition, it is important to realize that sometimes a traditional cultural property may not have a visible physical manifestation:

> Although many traditional cultural properties have physical manifestations that anyone walking across the surface of the earth can see, others do not have this kind of visibility, and more important, the meaning, the historical importance of most traditional cultural properties can only be evaluated in terms of the oral history of the community (Sebastian 1993:22).

There are at least two significant differences that distinguish traditional cultural properties as a subset within the larger sphere of cultural resources. First, while cultural resources such as practices and beliefs may be spatially associated with general types of geographical areas, such as the exposed lava lands of the Keahole Point area, a traditional cultural property is a specific physical entity or feature with a definable boundary, such as a specific location within the current project site. Second, while cultural resources such as practices and beliefs can include general cultural behaviors such as the gathering of various natural resources for general subsistence, industrial, or ceremonial uses, a traditional cultural property is a specific place or feature directly associated with specific behaviors the continuity of which over time, in either actual practice or remembrance, can be demonstrated.

Based on these two significant distinctions, it is possible to suggest three types of practitioner claims relating to cultural practices, beliefs, and features that are likely to be encountered in the course of conducting a cultural impact assessment study. These claims can be referred to as (a) traditional cultural property claims, (b) traditional and customary cultural practice claims, and (c) contemporary or neo-traditional cultural practice claims.

Traditional cultural property claims would be those which lie within the purview of the current historic preservation review process (DLNR 2001a,b); that is, they are claims involving the traditional practices and beliefs of a local ethnic community or members of that community that (a) are associated with a definable physical property (an entity such as a site, building, structure, object, or district), (b) are founded in the history of the local community, (c) contribute to the maintenance of the cultural identity of the community, and (d) demonstrate a historical continuity of practice or belief up to the present--through either actual practice or historical documentation. Furthermore, to qualify as a legitimate traditional cultural property within the historic preservation context, a potential traditional cultural property must be able to demonstrate its historical significance in terms of established evaluation criteria, such as those of the National Register of Historic Places and/or the Hawai'i Register of Historic Places.

Traditional and customary cultural practice claims would be those native Hawaiian claims which lie within the purview of Article XII, Section 7, of the Hawai'i State Constitution ("Traditional and Customary Rights"), and various other state laws and court rulings, particularly as reaffirmed in 1995 by the Hawai'i State Supreme Court in the decision commonly referred to as the "PASH decision," and as further clarified more recently in its 1998 decision in State of Hawai'i v. Alapa'i Hanapi and its 2000 decision in Ka Pa'akai o Ka 'Aina et al. v. Land Use Commission, State of Hawai'i et al. The notable points of the decisions in PASH and in Hanapi can be summarized as follows: (a) the reasonable exercise of ancient Hawaiian usage is entitled to protection under Article XII, Section 7 of the Hawai'i State Constitution; and (b) those persons claiming their conduct is constitutionally protected must prove that they are a native Hawaiian as defined in PASH, that the claimed right is constitutionally protected as a traditional or customary native Hawaiian practice, and that the exercise of the right is occurring on undeveloped or less than fully developed property. Ka Pa'akai generally reaffirms the same points as in the PASH and Hanapi decisions and, in addition, (a) indicates the explicit responsibility of the regulatory agency involved in any application review to arrive at affirmative and substantive conclusions regarding potential impacts upon traditional and customary native Hawaiian cultural practices and resources, and (b) suggests an "analytical framework" for the identification of and potential impacts upon any such cultural practices and resources.

Traditional native Hawaiian cultural practices can be categorized as two general types: (a) practices with active behaviors involving both observable activities with material results and their inherent values or beliefs; and (b) practices with more passive behaviors that seek to produce nonmaterial results. The former type of behaviors – practices with active behaviors, for example, would involve practices like the gathering and collecting of different animal and plant resources for various purposes, such as subsistence, medicinal, adornment, social, and ceremonial possibly other uses. Uses such as these usually have associated beliefs and values (both explicit and implicit) relating to a pervasive general theme that flows throughout traditional native Hawaiian culture and binds it together. To native Hawaiians, the natural elements of the physical environment--the land, sea, water, winds, rains, plants, and animals, and their various embodied spiritual aspects--comprise the very foundation of all cultural life and activity--subsistence, social, and ceremonial; to native Hawaiians, the relationship with these natural elements is one of family and kinship. The latter type of behaviors--practices with more passive behaviors--involves more experiential activities focused on "communing with nature"; that is, behaviors relating to spiritual communication and interaction that reaffirm and reinforce familial and kinship relationships with the natural environment.

While traditional cultural property claims, as defined above, would certainly fall within the general domain of traditional and customary cultural practice claims, not all traditional and customary cultural practice claims would necessarily qualify as traditional cultural property claims. Traditional and customary cultural practice claims subsume a broad range of cultural practices and beliefs associated with a general geographical area or region, rather than a clearly definable property or site--for example, the gathering of marine resources from along a section of shoreline for traditional subsistence or ceremonial purposes, in contrast to the gathering of a specific marine resource species for a specific use by current generation members of a family that had obtained the same resource from the same recognized site for several generations.

Contemporary, or "neo-traditional", cultural practice claims overlap with neither traditional property claims nor traditional and customary practice claims. Contemporary cultural practice claims would be those made by cultural practitioners relating to current practices or beliefs for which no clear specific historical basis in traditional culture can be clearly established or demonstrated; for example, the conducting of ritual ceremonies of uncertain authenticity at sites or features for which no such prior use can be demonstrated.

The specific purpose of the present cultural impact assessment study is to assess the potential impacts of the proposed project upon the cultural resources–the practices, features and/or beliefs–of native Hawaiians or any other ethnic group that might be associated with project area. To accomplish this purpose, several specific objectives were established:

1. Identify any native Hawaiian or other ethnic group cultural practices currently being conducted by individual cultural practitioners or groups;
2. Collect sufficient information so as to define the general nature, location, and authenticity of any identified cultural practices;
3. Assess the potential impacts of the proposed project upon identified cultural practices; and
4. Recommend appropriate mitigation measures for any potentially adverse impacts upon identified cultural practices.

Thus, the overall goal or objective of the present cultural impact assessment study was to identify any native Hawaiian or other cultural practices currently being conducted within or immediately adjacent to present project area that might potentially be in some manner constrained, restricted, prohibited, or eliminated if the proposed project were to be approved. The types of practices to be identified would be inclusive; that is, claims for all three types of practices–traditional cultural property, traditional and customary cultural practices, and contemporary cultural practices–would be identified and considered. More specifically, the objectives of the cultural impact assessment were to determine the following (a) if the project area is currently being accessed by native Hawaiian cultural practitioners for any traditional and customary cultural uses; (b) if the proposed project would have any adverse impacts upon any identified current native Hawaii cultural uses of the area; and (c) what measures might be proposed to mitigate any adverse impacts the proposed project might have upon any identified current native Hawaiian uses of the area.

CULTURAL IMPACT ASSESSMENT AND OEQC GUIDELINES

As indicated previously, the general purpose of this cultural impact assessment is to assess the potential impacts of the proposed project on any identified cultural resources in compliance with the requirements of *Chapter 343 (Haw.Rev.Stat.),* as amended by H.B. No.2895, H.D.1 of the Hawai'i State Legislature (2000) and approved by the Governor as *Act 50* on April 26, 2000. Among other things, this amendment requires that environmental assessments (EA) and impact statements (EIS) identify and assess the potential effects of any proposed project upon the "…cultural practices of the community and State…." Guidelines previously prepared and adopted by the State Office of Environmental Quality Control (OEQC 1997) provide compliance guidance. Both *Act 50* and the OEQC *Guidelines for Assessing Cultural Impacts* mandate consideration of potential cultural impacts upon all the different groups comprising the multi-ethnic community of Hawaii.

To understand the cultural impact assessment issue, particularly as it is addressed by the present study, a summary review of the intent and evolution of the OEQC guidelines is necessary. The guidelines evolved out of what are commonly referred to as "PASH/Kohanaiki" issues – issues relating to native Hawaiian traditional and customary access and land use rights as they were reasserted by a State Supreme Court decision in August 1995 and further clarified in its 1998 decision in State v. Hanapi – and the need for appropriate means to address these issues within the State environmental impact review process. For a good discussion of the issues and options involved, the "Report on Native Hawaiian Traditional and Customary Practices Following the Opinion of the Supreme Court of the State of Hawai'i in Public Access Shoreline Hawai'i v. Hawai'i County Planning Commission" prepared by the PASH/Kohanaiki Study Group (1998) should be consulted.

Initial attempts to address various issues relating to native Hawaiian traditional and customary access and land use rights within the framework of the State environmental impact review process were made in the form of proposed changes to the State EIS law as contained in Chapter 343 (HRS). These attempts to require a formal cultural impact assessment failed to pass the State legislature in 1996 and 1997.

A subsequent, second attempt to address various issues relating to native Hawaiian traditional and customary access and land use rights was made in the form of proposed changes in the "Administrative Rules" for compliance with Chapter 343 (DOH Title 11, Chapter 200). This attempt to require an explicitly defined cultural impact assessment also failed, as the governor declined to approve the proposed amendments.

The third attempt to address various issues relating to native Hawaiian traditional and customary access and land use rights within the State environmental impact review process resulted in the current OEQC "Guidelines for Assessing Cultural Impacts" (OEQC 1997b). Draft guidelines were initially issued for public review and comment on September 8, 1997. The Environmental Council formally adopted the guidelines in their final form on November 19, 1997.

The relationship of the OEQC guidelines to the State Supreme Court "PASH decision" was clearly stated on the front page of the September 8, 1997 issue of the OEQC bulletin, *"The Environmental Notice,"* when the draft guidelines were first issued for public review and comment:

> For years, a controversy has simmered over developer's responsibility to perform a "Cultural Impact Study" prior to building a project. The recent Supreme Court "PASH" decision reaffirmed the state's duty to protect the gathering rights of native Hawaiians. In light of these events, the Environmental Council has drafted a guidance document to provide clarity on when and how to assess a project's impacts on the cultural practices of host communities.

It should be noted that the guidelines for cultural impact assessment are meant to include consideration of all the different groups comprising the multi-ethnic community of Hawai'i; however, this inclusiveness is generally understated, and the clear emphasis is meant to be upon aspects of native Hawaiian culture.

More than 20 letters were received by OEQC in response to the publication of the draft guidelines, and relevant comments were said to have been incorporated into a final version of the guidelines (OEQC n.d.). The Environmental Council formally adopted the final guidelines (OEQC 1997b) on November 19, 1997. The final guidelines are virtually identical to the draft guidelines initially published on September 8, 1997, and the degree to which any of the received comments on the draft guidelines were considered prior to issuance of the final guidelines is uncertain. In fact, the overall process through which the guidelines were prepared and adopted brings out several important questions relating to such topics as (a) the source or basis utilized for the content of the guidelines, (b) the background and qualifications of the preparer(s) of the guidelines, (c) the criteria to be used for the adequacy of cultural impact assessment studies prepared in response to the guidelines, and (d) the legal question of how compliance can be required when the standards are guidelines.

According to the Chair's Report contained in *The 1997 Annual Report of the Environmental Council*, the Cultural Impacts Committee drafted the guidelines:

> The Committee drafted guidelines recommending a methodology to assess the impact of proposed actions on cultural resources, including Native Hawaiian cultural resources, values, and beliefs. The guidelines also specify the contents of a cultural impact assessment.
>
> To prepare the Guidelines, the Committee reviewed public testimony and solicited input from interested parties. Expertise from the DLNR's Historic Preservation Division as well as Federal regulations governing the "Protection of Historic Properties" were used to model the draft guidelines.
>
> The draft cultural impact guidelines were published for review and comment in the Sept. 8 *Environmental Notice*, and over 20 letters were received. Relevant comments were incorporated into a final draft version of the guidelines, which were adopted as a policy document by the Environmental Council on November 19, 1997 (OEQC n.d.:5).

Direct inquiries to OEQC (Gary Gill, then-Director) and SHPD (Dr. Holly McEldowney, then-Staff Specialist in the History and Culture Branch) provided additional background information relating to the formulation of the cultural impact assessment guidelines. The principal author or compiler of the guidelines was Arnold Lum, Esq., a member of the Environmental Council's Cultural Impacts Committee. Mr. Lum was also a staff attorney at the Native Hawaiian Legal Corporation. OEQC staff also assisted in the preparation of the guidelines. Several internal drafts were prepared, reviewed, and revised. Preparation of the guidelines relied to some degree upon National Register Bulletin No. 38, *Guidelines for Evaluating and Documenting Traditional Cultural Properties* (Parker and King 1990) for basic content information. Other sources, including the SHPD draft rules for conducting ethnographic surveys and dealing with traditional cultural properties (DLNR n.d.), were consulted; in fact, a copy of the SHPD draft rules was provided to OEQC and the Cultural Impacts Committee by then-SHPD Administrator, Dr. Don Hibbard. Professional staff in the SHPD-History and Culture Branch took part in the preparation and review of the guidelines. Certainly the inclusion of such professional anthropological and historical expertise in the preparation of the guidelines was appropriate; however, much of the professional advice on the extent to which detailed expectations--regarding study scope, content, methodology, documentation, and impact assessment--should be explicitly addressed in the guidelines was apparently discounted.

The most recent attempt to address various issues relating to native Hawaiian traditional and customary access and land use rights within the State environmental impact review process resulted in the amendment to *Chapter 343 (Haw.Rev.Stat.)*, as amended by H.B. No.2895, H.D.1 of the Hawai'i State Legislature (2000) and approved by the Governor as *Act 50* on April 26, 2000. While no specific administrative rules for the implementation of this amendment have been adopted, it is generally accepted that the *Guidelines* previously prepared and adopted by the State Office of Environmental Quality Control (OEQC 1997) are meant to provide general compliance guidance.

The OEQC *Guidelines* consist of three basic sections. The first section is an introduction which notes the various statutory and other bases for addressing potential impacts upon cultural resources within the context of the environmental assessment review process, and "...encourages preparers of environmental assessments and environmental impact statements to analyze the impact of a proposed action on cultural practices and features associated with the project area" (OEQC 1997:1). The second section of the guidelines discusses methodological considerations for conducting cultural impact assessments, and presents a recommended six-step protocol to be followed by the assessment preparers. The third section of the guidelines outlines eleven topics or "matters" that a cultural assessment should address; these topics basically represent the desired content and organization of a cultural impact assessment report.

As "guidelines," the OEQC *Guidelines* would seem to have neither the specific statutory authority of law, nor the regulatory authority of administrative rules. As guidelines, they can be regarded as providing general guidance; that is, they represent general suggestions and recommendations as to how to approach the assessment of potential cultural impacts. The guidelines provide little or no guidance relative to many important questions, perhaps the most significant of which would be the following:

1. How would project-specific determinations be made as to whether or not a cultural impact assessment study might even be necessary or appropriate--given the specific nature and location of a proposed project;

2. If a cultural impact assessment study is to be conducted, how does one determine what constitutes an appropriate project-specific level of effort – that is, the general scope of work or objectives for the study, and the specific tasks or activities required to accomplish successfully the scope of work or objectives;

3. What criteria are to be used for determining the credibility and reliability of potential cultural information sources (generally referred to as "informants" or "knowledgeable individuals");

4. If specific cultural practices, beliefs, or features are definitely identified as being associated with a project area, what criteria are to be applied for evaluating (a) the descriptive adequacy and (b) the cultural authenticity of the identified practices, beliefs, or features;

5. If specific culturally authentic practices, beliefs, or features are definitely identified as being associated with a project area, what criteria are to be used for assessing the nature and extent of potential impacts of a proposed project on the identified practices, beliefs, or features--that is, "no effect," "no adverse effect," or "adverse effect;"

6. If a project is determined to have potentially adverse impacts upon specific identified culturally authentic practices, beliefs, or features, what criteria are to be used for evaluating the adequacy and appropriateness of alternative potential mitigation actions;

7. Within the purview of what regulatory office or agency would the review and acceptance or rejection of a completed cultural impact assessment study legitimately fall; and

8. What standards or criteria are to be used to evaluate the overall adequacy or acceptability of a completed cultural impact assessment study?

Consideration of these questions, and their implicit implications, has direct relevance to the present cultural impact assessment study. These implications relate most importantly to (a) the level of study effort believed appropriate for the project-specific context, and (b) the rationale adopted for both the study overall, as well as for the identification and evaluation of any identified cultural practice claims, the assessment of potential project-specific impacts, and the formulation of any specific recommendations for further study or other mitigation actions.

BASIC GUIDANCE DOCUMENTS

Several references are available to serve as basic guidance documents for carrying out cultural impact assessment studies of various scopes and intensities. The principal sources are the following:

1. The OEQC *Guidelines for Assessing Cultural Impacts* (OEQC 1997);
2. The *Native Hawaiian Rights Handbook* (MacKenzie 1991), and more specifically the discussions of traditional and customary rights contained in the two chapters on access rights (Lucas 1991a) and gathering rights (Lucas 1991b);
3. The *Report on Native Hawaiian Traditional and Customary Practices Following the Opinion of the Supreme Court of the State of Hawai'i in Public Access Shoreline Hawaii v. Hawai'i County Planning Commission* prepared by the PASH/Kohanaiki Study Group (1998);
4. The text of several relevant decisions of the Hawai'i Supreme Court, including the decision commonly referred to as the "PASH decision" (1995), and the more recent decisions in State of Hawai'i v. Alapa'i Hanapi (1998) and Ka Pa'akai o Ka 'Aina et al. v. Land Use Commission, State of Hawai'i et al. (2000);
5. The federal regulations of the Advisory Council on Historic Preservation for the *National Register of Historic Places* (CFR 1981) and the *Protection of Historic Properties* (CFR 1986);
6. National Register Bulletin No. 38, *Guidelines for Evaluating and Documenting Traditional Cultural Properties* (Parker and King 1990); and
7. Recently approved versions of the State Historic Preservation Division (SHPD) administrative rules (effective December 11, 2003), including Chapter 275: *Rules Governing Procedures for Historic Preservation Review for Governmental Projects Covered Under Sections 6E-7 and 6E-8, HRS* (DLNR 2002a), and Chapter 284: *Rules Governing Procedures for Historic Preservation Review to Comment on Chapter 6E-42, HRS, Projects* (2002b), as well as an earlier draft Chapter 284--*Rules Governing Procedures for Ethnographic Inventory Surveys, Treatment of Traditional Cultural Properties, and Historical Data Recovery* (DLNR n.d.).

While the general nature and content of the first four referenced sources are self-explanatory, further comment should be made regarding the final three items. In the absence of any formally adopted administrative rule specifically addressing the treatment of traditional cultural properties, SHPD currently utilizes National Register Bulletin No. 38, *Guidelines for Evaluating and Documenting Traditional Cultural Properties* (Parker and King 1990), as its principal source of guidance for reviewing and evaluating the adequacy and acceptability of traditional cultural property study reports prepared in connection with various permit applications for which SHPD regulatory review is required. Bulletin No. 38 provides detailed guidance for the assessment of traditional cultural properties within the framework of the National Register significance criteria evaluation process (NPS 1990).

The SHPD draft administrative rule relating to ethnographic surveys and traditional cultural properties (DLNR n.d.) has existed in finalized draft version since at least early 1997; however, it has never been circulated openly, much less formally provided for public review, comment, and eventual adoption by the Department of Land and Natural Resources. This situation is unfortunate because the draft rule goes well beyond National Register Bulletin No. 38 in providing detailed guidance for conducting traditional cultural property studies, and more specifically for dealing with the identification, evaluation, and documentation of native Hawaiian traditional cultural properties and their associated cultural practices and beliefs.

In the absence of any formally adopted administrative rule specifically addressing the treatment of traditional cultural properties, SHPD can also be said to basically follow the federal regulations of the Advisory Council on Historic Preservation for guidance in the evaluation of significance--as contained in Section 60.4 ("Criteria for evaluation") of the "National Register of Historic Places" (CFR 1981), and for guidance in the assessment of potential effects--as contained in Section 800.9 ("Criteria of effect and adverse effect") of the "Protection of Historic Properties" (CFR 1986).

PRESENT STUDY SCOPE AND METHODOLOGY

The scope of work and methodology for the HELCO Keahole Generating Station Project cultural impact assessment is based on the general assumption that the level of study effort appropriate in any project-specific context should involve the consideration of several factors, the most relevant of which are the following: (a) the probable number and significance of known or suspected cultural properties, features, practices, or beliefs within or associated with the specific project area; (b) the potential number of individuals (potential informants) with cultural knowledge of the specific project area; (c) the availability of historical and cultural information on the specific project area or immediately adjacent lands; (d) the physical size, configuration, and natural and human modification history of the specific project area; and (e) the potential effects of the project on known or expected cultural properties, features, practices, or beliefs within or related to the specific project area.

Consideration of these factors within the specific nature and context of the proposed HELCO Keahole Generating Station Project, as well as prior general consultations with professional staff in SHPD, indicated that the most appropriate level of study for an adequate assessment of potential cultural impacts would be a relatively limited or abbreviated assessment study. Based on the location, small size, and the extensive recent historic period modification, development and utilization of the project site, this study assumes that (a) potential cultural impact assessment issues would be highly unlikely, (b) the negative results of the archaeological reconnaissance survey conducted for the project would confirm both the greatly altered physical nature of the project area and the absence of cultural resources within or related to the project area, and (c) in the unlikely instance that any legitimate cultural impact assessment issues should arise during the environmental review period, they could be addressed adequately within the framework of the review process (i.e., from Draft to Final Environmental Impact Statement).

Consideration of these factors within the specific nature and context of the proposed HELCO Keahole Generating Station Project indicated that the relatively greater levels of study effort that can be characterized as identification or documentation studies would be inappropriate and excessive. The distinctive characteristics of an identification study are that it would be restricted to (a) the identification of native Hawaiian or other ethnic group cultural practices, beliefs, properties, features, or exploitable natural resources associated with and/or present within or related to the specific project area that are currently being conducted by and/or known to individual cultural practitioners or groups, and (b) the collection of information reasonably sufficient so as to define the general nature, location, and likely authenticity of identified cultural claims. An identification study would not involve the considerably greater level of study effort--both calendar months and hours of labor--needed to carry out a full documentation study. The distinctive characteristics of the latter, which would commonly be referred to as a full ethnographic or oral history study, would be (a) the collection of detailed information regarding identified native Hawaiian or other ethnic group cultural practices by means of formal oral history interviews which are usually tape recorded and transcribed, and (b) the analysis and synthesis of all collected data--from interviews, as well as relevant historical documentary and archival research--within the general cultural-historical context of traditional native Hawaiian or other ethnic group culture and the defined specific geographical area of a specific project.

The overall rationale guiding the present limited assessment study has been that the level of study effort should be commensurate with the potential of the proposed project for making any adverse impacts upon any native Hawaiian or other ethnic group cultural practices currently conducted by cultural practitioners within the project area. The study presented here is believed to comprise a reasonable approach for the assessment of potential cultural impacts within this specific project area. The potential for the project to result in adverse impacts upon any current native Hawaiian or other ethnic group cultural practices, beliefs, or features would seem most likely to be minimal or indeterminate; that is, given the past land use history of the project area and the general nature and scope of the proposed project, it is very unlikely that the continued exercise of any current practices would be in any way constrained, restricted, prohibited, or eliminated.

The present limited cultural impact assessment study is based primarily on two sources of information, the archaeological inventory survey of TMK Parcel 36 conducted by PHRI in 1992 (Dowden and Graves 1992), and the more recent field inspection of the three small additional project site elements conducted in September 2003 by PHRI Principal Archaeologist Dr. Paul H. Rosendahl. The existing developed state of the project area was also taken into consideration, and no attempt was made to contact potential local informants regarding any potential knowledge of the project site.

FINDINGS

No evidence of any potentially significant traditional cultural properties, natural resources, practices, or beliefs were identified within either the 1992 inventory survey project area (TMK Parcel 36) or the three small additional project elements (TMK Parcel 27, and the Primary and Secondary Access roadways. Both TMK Parcel 36 and 37 are developed facilities surrounded by chain link fence, with the former being the site of the existing power generating station and the latter the site of an existing transformer station, while both the Primary and the Secondary Access roadways are existing paved roads.

CONCLUDING ASSESSMENT

The HELCO Keahole Generating Station Project Site has been extensively modified and developed during historic times, as indicated by (a) the existing modified condition of the property, and (b) the negative findings of the both the 1992 inventory survey and the more recent 2003 inspection which yielded no evidence of the presence of any potentially significant cultural resources–properties, features, natural resources, practices, or beliefs–either within or directly related to the project site. Furthermore, there is no indication of any kind that the project site has any natural resources necessary to or currently being used by either Native Hawaiian cultural practitioners exercising traditional and customary access and use rights for any purposes or by individuals of any other cultural affiliation for any traditional cultural purposes.

Based on the negative results of the both the 1992 inventory survey and the more recent 2003 inspection, and the absence of any evidence that the project site is currently being used for any legitimate traditional cultural purposes by either Native Hawaiian cultural practitioners or individuals of any other cultural affiliation, it can be concluded that the HELCO Keahole Generating Station Project should have no significant effects—much less any adverse impacts—upon any cultural resources, and that no mitigation measures of any kind are needed.

CONCLUSION

CONCLUDING COMMENTS

Based on the negative results of the both the 1992 inventory survey and the more recent 2003 inspection, it can be concluded that (a) no significant historic properties are present within the project site because of the developed condition of the project site–including both existing power generating and transformer facilities, and the paved access roadways–and the SHPD review and evaluation of the final report on the 1992 inventory survey, and (b) no further historic preservation work of any kind is needed. Therefore, the HELCO Keahole Generating Station Project should have no significant effects—much less any adverse impacts—upon any historic properties, and no mitigation measures of any kind are needed.

Based on the absence of any evidence that the project site is currently being used for any legitimate traditional cultural purposes by either Native Hawaiian cultural practitioners or individuals of any other cultural affiliation, it can be concluded that the HELCO Keahole Generating Station Project should have no significant effects—much less any adverse impacts—upon any cultural resources, and that no mitigation measures of any kind are needed.

REQUEST FOR SHPD DETERMINATION OF "NO HISTORIC PROPERTIES AFFECTED"

Based on the negative conclusions of both the present archaeological assessment and cultural impact assessment, it is believed appropriate for the SHPD to prepared and issue–in accordance with the general guidance provided by Chapter 284: Section 5(b) of the SHPD Rules Pertaining to the Historic Preservation Review Process (HAR Title 13, DLNR; Subtitle 13, SHPD) (DLNR 2003b), a formal written determination of "no historic properties affected" for the HELCO Keahole Generating Station Project Site.

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APPENDIX A

Archaeological Inventory Survey
Helco Keahole Parcel Project Area

Lands of Kalaoa 1-4, North Kona District
Island of Hawai'i (TMK: 3-7-3-49:36, 37)

PHRI Report 1265-063092

August 1992

Report 1265-063092

Archaeological Inventory Survey
Helco Keahole Parcel Project Area

Lands of Kalaoa 1-4
North Kona District, Island of Hawaii

PHRI

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Report 1265-063092

Archaeological Inventory Survey
Helco Keahole Parcel Project Area

Lands of Kalaoa 1-4
North Kona District, Island of Hawaii
(TMK:7-3-49:36)

by

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SUMMARY

At the request of Ms. Carol Thompson, Senior Planner with CH2M HILL, Paul H. Rosendahl, Ph.D., Inc. recently conducted an archaeological inventory survey of 15 acres in the HELCO Keahole Parcel Project Area. The parcel is in the Lands of Kalaoa 1-4, North Kona District, Island of Hawaii (TMK:7-3-49:36). The basic objective of the survey was to provide information sufficient for satisfying all historic preservation regulatory review requirements of the Hawaii County Planning Department, and the Department of Land and Natural Resources-State Historic Preservation Division.

The inventory survey was conducted June 29, 1992. During the field work, four quarry sites consisting of seven pahoehoe excavations were identified. The sites ranged in physical condition from poor to good. Each of the four sites was recorded in detail. Subsurface testing was not conducted, as there were no cultural deposits within the identified features.

All four sites are assessed as significant for information content. No further work is recommended for the sites, however, as the data collected during the present survey is considered adequate mitigation of potential effects of the proposed project.

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INTRODUCTION

BACKGROUND

At the request of Ms. Carol Thompson, Senior Planner with CH2M HILL, Paul H. Rosendahl, Ph.D., Inc. (PHRI) recently conducted an archaeological inventory survey of the 15-acre HELCO Keahole Parcel Project Area, Lands of Kalaoa 1-4. The parcel is in the North Kona District, Island of Hawaii (TMK:7-3-49:36). The overall objective of the survey was to provide information sufficient for satisfying all historic preservation regulatory review requirements of the Hawaii County Planning (HCPD) and the Department of Land and Natural Resources - State Historic Preservation Division (DLNR-SHPD).

The field work was conducted June 29, 1992 under the guidance of Supervisory Archaeologist James Head, B.A., and Crew Chief Sheryl Dowden, B.S. Crew members included Field Archaeologists Tom Carmody and Karen Wigglesworth, B.S. Principal Archaeologist Paul H. Rosendahl, Ph.D., provided overall direction for the project. The field work took 32 labor-hours to complete.

SCOPE OF WORK

The basic purpose of the survey was to identify—to discover and locate on available maps—all sites and features of potential archaeological significance. An *inventory survey* is an initial level of archaeological investigation. It is extensive rather than intensive in scope, and is conducted with the primary aim of determining the presence or absence of archaeological resources. A survey of this type indicates both the general nature and the variety of archaeological remains present, and the general distribution and density of such remains. It permits a general significance assessment of the archaeological resources, and facilitates formulation of realistic recommendations and estimates for any further work that might be necessary or appropriate. Such work could include further data collection involving detailed recording of sites and features, and selected test excavations. It might also include subsequent *mitigation*—data recovery research excavations, construction monitoring, interpretive planning and development, and/or preservation of sites and features with significant scientific research, interpretive, and/or cultural values.

The basic objectives of the present survey were fourfold: **(a)** to identify (find and locate) all sites and site complexes present within the project area; **(b)** to evaluate the potential general significance of all identified archaeological remains; **(c)** to determine the possible impacts of proposed development upon the identified remains; and **(d)** to define the general scope of any subsequent further data collection and/or other mitigation work that might be necessary or appropriate.

Based on a review of readily available background literature, familiarity with the general project area, extensive familiarity with the current requirements of review authorities, and based on discussions with Ms. Carol Thompson of CH2M HILL and Mr. Kanalei Shun, DLNR-SHPD Staff Archaeologist for Hawaii Island, the following specific tasks were determined to constitute an adequate and appropriate scope of work for the proposed inventory survey:

1. Review archaeological and historical literature relevant to the project area and conduct historical documentary research (emphasis on readily available literature and documentary sources) and interviews with any appropriate and available local informant sources;

2. Conduct 100% coverage, variable intensity ground survey of the project area, with **(a)** relatively higher intensity coverage of naturally vegetated and unmodified portions, and **(b)** relatively lower intensity coverage of areas that have been historically cultivated and otherwise modified;

3. Conduct limited subsurface testing of selected sites and features identified within the project area **(a)** to determine the presence or absence (and general distribution) of potentially significant buried cultural features or deposits, and **(b)** to obtain suitable samples for age determination analyses; and

4. Analyze field and historical research data, and prepare appropriate reports.

The inventory survey was carried out in accordance with the standards for inventory-level survey recommended by DLNR-SHPD. The significance of the archaeological remains identified in the project area was assessed in terms of **(a)** the National Register criteria contained in the Code of Federal Regulations (36 CFR Part 60), and **(b)** the criteria for evaluation of traditional cultural values prepared by the National Advisory Council on Historic Preservation. DLNR-SHPD and the Hawaii County Planning Department use these criteria to evaluate eligibility for the Hawaii State and National Registers of Historic Places. In addition, the significance of archaeological sites identified during the survey was evaluated in terms of the PHRI Cultural Resource Value Modes, which are described in the Conclusion section of this report.

PROJECT AREA DESCRIPTION

The project area comprises a single parcel of 15 acres, located just *mauka* (inland) of the Queen Kaahumanu Highway in Kalaoa 1-4 Ahupuaa, North Kona District, Island of Hawaii (Figure 1). Elevation of the project area is c. 200 ft (61 m) to 230 ft (70 m) AMSL (above mean sea level). The project area is part of the Kona Lava Plain, a low-cliffed volcanic coast, which is defined by Armstrong (1983:37) as coastline with wave-cut cliffs averaging about 20 ft. The project area surface was formed by Hualalai Volcanic Series flows, which may be late Pleistocene in age. The flows are highly permeable, but brackish water is found only along the coast (Stearns and MacDonald 1946:139-140).

The terrain in the project area is gently undulating, and the soils are composed of two series, the Kaimu extremely stony peat (6-20% slopes) and Punaluu extremely stony peat (6-20% slopes) (Sato et al. 1973). The Kaimu extremely stony peat represents the Kaimu series of well-drained, thin organic soils (about three inches thick) over fragmented aa lava. The Punaluu extremely rocky peat represents the Punaluu series of well-drained, thin organic soils (c. four inches thick) over pahoehoe bedrock.

Vegetation in the project area is generally very sparse and consists of fountain grass (*Pennisetum setaceum* [Forsk.] Chiov.), *noni* (*Morinda citrifolia*), *koa-haole* (*Leucaena glauca* [Lam.] de Wit), and *'ilima* (*Sida fallax* [L.]). Several recently planted exotics including plumeria (*Plumeria acuminata* Ait.), coconut palm (*Cocos nucifera* L.), and an unidentified shrub were noted.

PREVIOUS ARCHAEOLOGICAL RESEARCH

There have been numerous studies in the Kalaoa Ahupuaa 1-4 areas, these are summarized in Table 1. The earliest work was a reconnaissance survey of a section of the Kailua-Kawaihae Road in South Kohala, from Anaehoomalu Bay to Keahole Point, by Rosendahl (1973). He also conducted a general salvage of all endangered sites within and immediately adjacent to the highway alignment. There were 284 sites, including both those situated within the actual highway alignment and those of apparent value located adjacent to the alignment and within the original Road Corridor survey area. Most of the salvaged features were habitation (n=201), and low, C-shape shelters (n=149). According to Rosendahl, other types of habitation features included low, L-shaped shelters (n=5), natural depression shelters (n=12), small cave shelters (n=15), dwelling caves (n=7), platforms (n=10), a pavement (n=1), and surface midden areas (n=2). Other kinds of features Rosendahl encountered were enclosures of various sizes (n=14), cairns (*ahu*) (n=34), prehistoric foot trails (n=9), historic foot/cart trails (n=4), a cave burial (n=1), and a number of miscellaneous, unique, and/or minor types of features (n=21).

Cordy (1985) has also conducted surveys in the area and defined three environmental zones, based on location, elevation, bedrock, and present vegetation, that apply to archaeological work in the Ooma 1, Ooma 2, and Kalaoa 1-5 Ahupuaa. (1) The Coastal Zone is located 0-150 ft from shore, with elevations from 0-20 ft, and is characterized by low pahoehoe with some sand beaches and typical shoreline vegetation. (2) The Barren Zone, or Transitional Zone, according to Cordy, is located 150 ft to 1.5 miles from the shore with elevations from 20-430 ft above sea level. It is characterized by pahoehoe with pockets of aa, but contains no soil. Vegetation in the Barren Zone is extremely sparse in the seaward portion, but becomes denser in the upper regions, where grass and then lantana predominate. (3) The Upland Forest Zone is located 1.5 miles to 3.7 miles from shore, with elevations from 430 to 3,400 ft. It is characterized by a rough aa and soil terrain. Vegetation in the lower portion is dominated by *koa-haole* and Christmas-berry, and on the upper slopes by large forest trees.

While the HELCO Keahole Parcel project area is located at the northern border of Kalaoa 1-4, in the center of the Barren/Transitional Zone, previous studies within each of the environmental zones will be discussed in order to construct an *ahupua'a* settlement pattern.

A brief reconnaissance survey was conducted by Davis (1977) in portions of the various Kalaoa Ahupuaa for the Keahole Agricultural Park. The area of the survey included a narrow transect in the Kalaoa 4 Ahupuaa that ended at the 800 ft elevation level. Twenty-two site complexes and isolated archaeological features were identified. These sites included habitation caves, shelters, wind breaks, *ahu*, platforms, enclosures (one appears to be a historic homestead), walls, and an *ahupua'a* wall.

Hammatt and Folk (1980) conducted salvage excavation at 12 sites within the proposed Keahole Agricultural Park, in

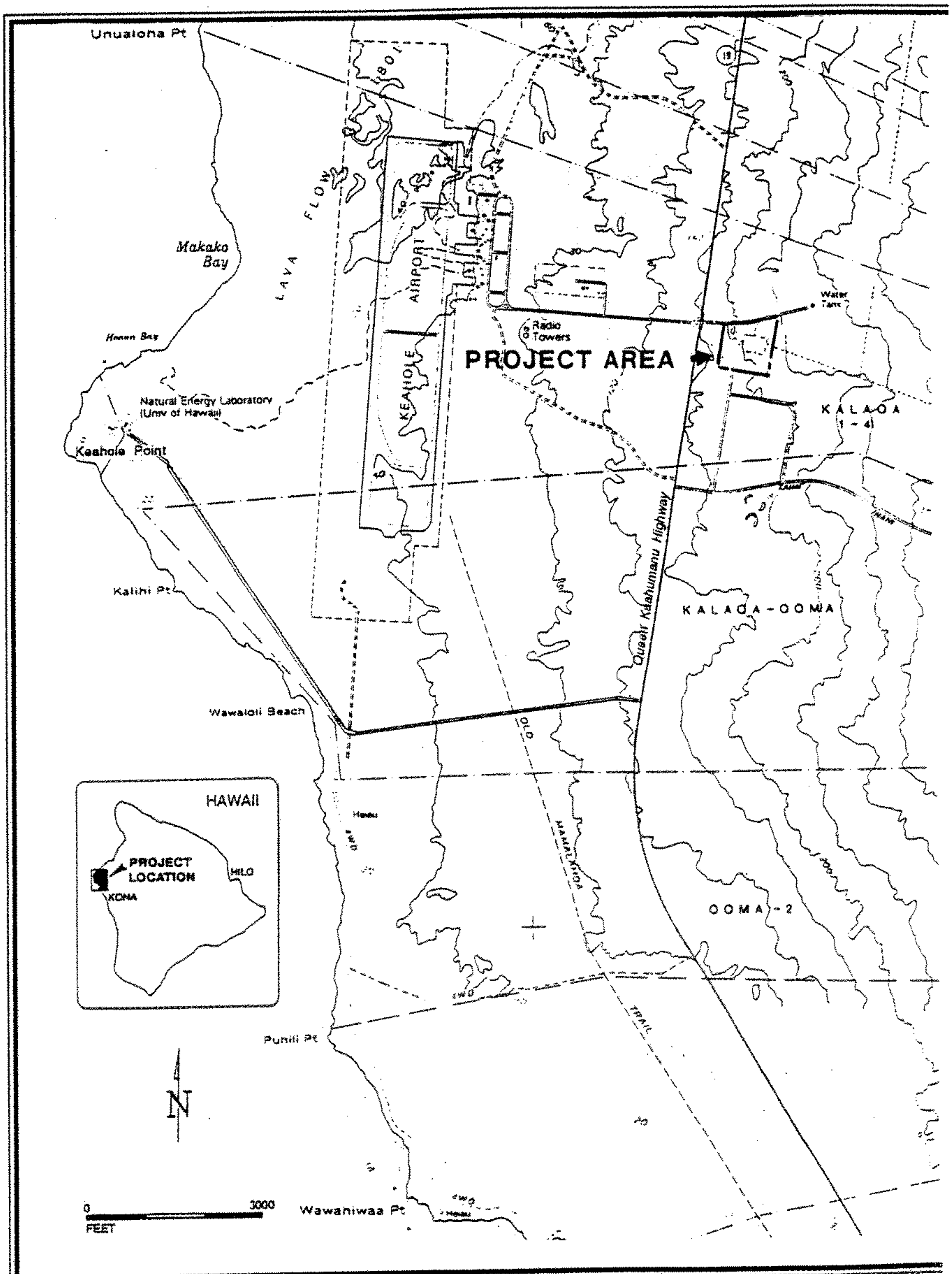

Figure 1. Project Location

Table 1.

SUMMARY OF PREVIOUS RESEARCH

Year	Author(s)	Type of Survey	Ahupua'a	Zone
1973	Rosendahl, P.H.	Reconnaissance Survey & Salvage	Hamanamana-Puuananulu	Coastal-Barren
1977	Davis, B.	Reconnaissance Survey	Kalaoa 4 & var. Kalaoa	Upland
1980	Hammatt, H.H. & Folk, W.M.	Reconnaissance Survey	Kalaoa-O'oma	Barren
1982	Soehren, L.J.	Reconnaissance Survey	Kalaoa 3-4	Barren-Upland
1985	Soehren, L.J.	Reconnaissance Survey	Kalaoa 3-4	Barren-Upland
1987	Cordy, R.	Field Check	Kalaoa 3-4	Barren-Upland
1987	Telea, L.J. & Walker, A.T.	Survey	Kalaoa 3-4	Barren-Upland
1987	Walker, A.T. & Haun, A.E.	Reconnaissance Survey	Kalaoa 3-4	Barren-Upland
1988	Walker, A.T. & Haun, A.E.	Data Recovery	Kalaoa 3-4	Barren-Upland
1989	Walker, A.T.	Inventory Survey	Kalaoa 5	Coastal-Upland
1990a	Walker, A.T. & Rosendahl, P.H.	Inventory Survey	Kalaoa 3-4	Barren-Upland
1990b	Walker, A.T. & Rosendahl, P.H.	Inventory Survey	Kalaoa 3-4	Barren-Upland
1991	O'Hare, C.R. & Rosendahl, P.H.	Inventory Survey	Kalaoa	Coastal
1992	Thompson, L.W. & Goodfellow, S.T.	Data Recovery	Kalaoa	Upland

Kalaoa-O'oma, and a reconnaissance survey of a parcel north of the park. The project identified 18 sites including *ahu*, a small wall partially destroyed by bulldozing, an enclosure, a platform, a trail, and lava tubes. Little evidence of occupation was found in the lava tubes in the parcel north of the park. The excavations conducted on the 12 sites in the Agricultural Park itself demonstrated prehistoric occupation within sheltered areas around natural sinks and lava tubes. It appears from the radiocarbon dates that domestic occupation in the area occurred from AD 1480 to AD 1700. Petroglyphs within several lava tubes appear to predate at least the upper part of this occupation. One cave site was extensively modified to create a large refuge wall with a constricted entrance and an interior passageway leading to two large tubes. This refuge phase is thought to post-date 1700 and probably corresponds to a period of chiefly rivalry and warfare on the Big Island. Three sites provided evidence of historic period occupation, goat corralling and a homestead.

Several surveys have been conducted in Kalaoa 3 or 4 at elevations of 430 ft or more. These include two reconnaissance surveys by Soehren (1982 and 1985), an archaeological field check by Cordy (1987), a reconnaissance survey and subsequent limited data recovery by Walker and Haun (1987 and 1988), a survey by Telea and Rosendahl (1987), and two inventory surveys by Walker and Rosendahl (1990a and 1990b).

During his reconnaissance survey of 6.8 acres at 1000 ft AMSL in the Kalaoa 4 Ahupuaa (TMK: 3-7-3-05:13), Soehren (1982) recorded two structures, a house platform and a square enclosure, that he interpreted as an agricultural *heiau*. In a subsequent survey of another parcel in the Kalaoa 4 Ahupuaa (TMK: 3-7-3-10:33), Soehren (1985) recorded several historic roads and a coastal-inland foot trail.

Cordy (1987) conducted a field check of a parcel in the proposed Kona Coast Subdivision in the Kalaoa 3 Ahupuaa (TMK: 3-7-3-28:5). He recorded one large platform/terrace, which he interpreted as either an agricultural *heiau* or a historic house platform.

Walker and Haun (1987) identified 17 features from four sites during a reconnaissance survey conducted by PHRI on a parcel of land in the Kalaoa 4 Ahupuaa (TMK: 3-7-3-05:87). These features included two agricultural complexes that were identified by Walker and Haun as part of a northern extension of the Kona Field System. A habitation/burial cave and a historic-period boundary wall were also recorded. Subsequent detailed recording was conducted at the sites and eight test units were excavated at three of the sites (Walker and Haun 1988). Limited midden remains and one bone fishhook were recovered from the test units and four radiocarbon dates ranging from AD 1280 to 1955 were obtained from recovered charcoal.

In 1987 PHRI conducted a reconnaissance survey of a parcel (TMK:3-7-3-05:86) in the proposed Kona Palisades Subdivision in the Kalaoa Ahupuaa (Telea and Rosendahl 1987). Fourteen features at six sites were identified. A full inventory survey was later conducted in this parcel (Walker and Rosendahl 1990a) and 18 additional features were recorded. Fifteen pits, five platforms, four walls, two caves, three mounds, two terraces, and one C-shape were recorded. They were assigned an agricultural, habitation, or boundary function. One cave and one mound were tested, and midden and indigenous and historic artifacts were recovered. Charcoal recovered from an excavation in one cave and from the surface of another cave yielded radiocarbon age ranges from AD 1552 to 1956.

In 1989 PHRI conducted an inventory survey of a parcel (TMK:3-7-3-10:Por.27) in the Kalaoa 5th Development Parcel. Forty-three sites containing 83 component features were identified within or immediately adjacent to the project area. Walker and Rosendahl (1989) identified walls, enclosures, overhangs, retaining walls, pits, terraces, lava tubes, C-shapes, alignments, mounds, platforms, trails, paved areas, cairns, pahoehoe excavations, and modified features. Limited subsurface testing and surface collection of artifacts and radiocarbon dating samples was conducted, however, the dating results were not included in the report. Indigenous portable artifacts collected from the project area included abraders (coral and echinoid spine), *Cypraea* sp. shell scrapers, a lithified sandstone pounder fragment, and an octopus lure; no volcanic glass artifacts were recovered.

An inventory survey of an adjacent parcel of land in the Kalaoa 4 Ahupuaa was conducted in 1990 (Walker and Rosendahl 1990b). Twelve features were identified at seven sites. Five terraces, two caves, two walls, one platform, one mound, and one water trough were recorded. They were assigned to the functional categories of agriculture, habitation, boundary, refuge, bulldozer-push, or animal water trough. The two caves were tested and midden and indigenous artifacts were recovered. Three radiocarbon dates ranging from AD 1470 to 1955 were obtained.

Data recovery was conducted in the Kona Palisades Subdivision parcel in 1991 (Thompson and Goodfellow 1992). No additional features were recorded, but detailed recording took place at four of the sites previously identified by Walker and Rosendahl (1990a). Twenty-five test units were excavated in 14 features and in two areas near features

Midden was recovered from seven of the features, indigenous artifacts were recovered from seven features, and historic artifacts from six. Eleven radiocarbon dates for seven features of the four sites were obtained from recovered charcoal (Thompson and Goodfellow 1992). These dates ranged from AD 1460 to 1955 for two temporary habitation cave shelters, from AD 1450 to 1950 for four permanent habitation platforms, and from AD 1410 to 1520 for one agricultural terrace. The sites and features were interpreted to be a northern extension of the Kona Field System.

O'Hare (in prep.) conducted inventory survey and testing in the Kalaoa View Estates Development Project, and identified seven sites consisting of 31 features. The 31 features comprised the following formal types: terrace, rock mound, cairn, C-shape, platform, enclosure, lava blister, and complex. The functional categories consisted of habitation, agriculture, boundary, trash pit and indeterminate. One temporary habitation feature, a C-shape, was dated to AD 1280-1430 and the other prehistoric temporary habitation, a modified lava blister, was dated to AD 1630-1890. The prehistoric permanent habitation feature, a platform, was dated to AD 1500-1680.

SUMMARY OF HISTORICAL DOCUMENTARY RESEARCH

PHRI Historical Researcher Lehua Kalima, B.A., conducted limited historical research on the HELCO Keahole Parcel project area. She reported that little information could be found on this area, specifically, and therefore she included information from the *ahupua'a* near Kalaoa 4, as well as more general information on the North Kona district. This information includes legends, early historic accounts, land use information and settlement patterns. Her work is presented in Appendix A, and is briefly summarized here with additional research from other sources.

Schilt (1984) wrote that in pre-contact times, an ancient chief, Umi-a-Liloa, used the numerous caves in the general vicinity of the project area as places of refuge. Cordy (1985) identified the Kalaoa area as home of the high priest, Kaluolapa, who presided over ceremonies in Haleohiu and Kalaoa. However, Cordy does not cite his source for this statement.

According to tradition, Kekaha was a region "valued by ruling chiefs, inhabited by attendant chiefs, and upon occasions abused by warring chiefs" (Kalakaua 1973:31). During the early 18th century there was war between Maui and Hawaii, and the Maui people were in the Kona area and "cut down the trees throughout the land of Kona." These acts of war were of no small consequence, for "to fell trees of such usefulness wa considered truly inhuman" (Springer 1985:23).

During the early historical period, Menzies was in Nort Kona and described the area as "barren and rugged" (1920:99 although it is assumed that he never made it to the project are itself. Also, Ellis noted the 1801 Huehue Flow from Hualala and how it destroyed villages, plantations, and fish-pond (Ellis 1963:30-31).

During the Great Mahele of 1848, Kalaoa 4 was set asid as Government Land (Board of Commissioners 1929). Thi land, as well as Kalaoa 1-3, the lands of King Kamehameh III, who passed it to the government. Most of the lan between the 1000 ft and 2400 ft elevation was soon sold, an from 1852 to 1864, a series of grants was issued in th *ahupua'a*. The grants were typically sold as lots of about 5 acres, and most of them were agricultural parcels (Cord 1985:6 and Soehren 1982:3).

When Handy began a study of the Hawaiian planter i 1930, there were still some taro plantations above Kalao (Handy and Handy 1972:523). Several methods of drylan planting practiced in the Kona area are described by Hand and Handy (1972:105-109), most of which involved clearin the vegetation by weeding or burning, clearing the plantin ground of stones, and mulching the ground over the plante crops with some type of vegetation (grass, ferns, sugar can tops, *kukui* leaves, etc.) (Ibid:108). The stones that had bee cleared from the fields were then piled into low walls c mounds. Garden areas at Kuakini (Schilt 1984:40) wer characterized by such clearing piles stacked against natur outcrops. These piles might also have acted as agricultur features themselves, as the stones would act as mulch an retain surface moisture (Yen 1974:5). Sweet potatoes wer grown on similar mounds (Ellis 1963:23), and although swe potatoes were not reported to have grown on this lan historically, they might have been grown here in prehistori times.

Coffee was first cultivated in the Kona area in the 1840 After the Great Mahele, foreigners were allowed to own land, an coffee plantations worked by Chinese and Hawaiian labore were established in the areas above Kona, at elevations abo 800 ft. Kelly (1971) reported that coffee was grown on thre acres in the Kalaoas in 1880. Coffee grew best on the fertil leeward slopes of Hualalai and Mauna Loa, at elevations c 800-1700 ft, the same area in which upland taro thrived (Go 1979:5). Coffee gradually replaced taro in these areas.

Coffee growers in the Kona area experienced booms a busts over the years. In the 1850s the coffee crop suffer through drought and blight. In 1880, the crop rebounded and an "abundance of fruit" was found "on the hills behind [Kailua] town" (Bowser 1880:549). Most of the coffee in this period was grown on large plantations. In 1889, the world coffee market collapsed. This resulted in a shift from large plantations owned by Caucasians to smaller plots that were frequently owned and operated by Japanese immigrants, individuals or families, who had completed their three years of service on the sugar cane plantations (Lind n.d.:19). In 1918, a frost killed the coffee crop in Brazil and prices for Kona coffee soared.

SETTLEMENT PATTERN

A general chronology for the North Kona area, north of the Honokohau/Kaloko area has been presented in Donham (1987:142-145). Donham's chronology, which includes data collected by Cordy (1981, 1985, 1986), Hommon (1976), and Kirch (1980, 1985) is generally summarized here.

Initial occupation of the northern end of North Kona occurred at Anaehoomalu in c. AD 900 (Barrera 1971). By AD 900 population growth in agriculturally favorable windward environments reached the point that exploitation of areas less favorable to agriculture (such as the northern portion of Kona) became necessary (Kirch 1985). Initial occupation of sites for areas environmentally similar to the present project area dates to c. AD 1030, which generally conforms to the above time scale. Kirch (1985) states that the overall population in West Hawaii appears to have been low, and remained fairly stable, until c. AD 1200 (1985:288), when a significant increase probably occurred. Due to the generally arid, rocky environment, and the lack of fresh water in the North Kona District, the increase was probably restricted to certain areas in the northern end of the district, such as Anaehoomalu and probably Kiholo, Kaupulehu, and Kukio.

Cordy's work suggests that as the population increased in certain parts of North Kona, substantial uninhabited buffer zones remained between established residential areas (Cordy 1981:173). Initial settlement of these uninhabited buffer zones, and probably along the entire coast as well, began c. AD 1400 at Kohana-Iki and Ooma II (Cordy 1981:168). During this period the population began to expand; it is suggested that it nearly doubled each century between AD 1200 and 1600; the expansion was followed by an eventual equilibrium and finally a decline (Kirch 1985:288).

Based on cartographic evidence, Cordy suggests that a shift from coastal to upland habitation took place during the nineteenth century in the North Kona area (Cordy 1985:35). Cordy's cartographic evidence indicated that during the Grea Mahele (c. AD 1848), significant concentrations of Kulean Awards were granted in upland areas, in contrast to coasta areas, of North Kona (Cordy 1986:36). Claimants to thes Kuleana Lands were required to provide evidence of residenc on the land or land use rights. Based on the presence of uplan habitation and agricultural sites in Kealakehe that date to c AD 1511-1638 (Walker and Rosendahl 1988), it seems likel that initial upland occupation of Kaupulehu may have occurre by AD 1550-1650. Agricultural sites, although not dated, ar also documented for upland Kalaoa 4 (Walker and Ham 1987). Upland expansion at Ooma II has been suggested t have begun c. AD 1650-1700 (Donham 1987:144)

In his study of prehistoric sites in the Ooma and Kalao Ahupuaa, Cordy (1985:38) proposed that populations wer small until AD 1500-1600 and that intensive agriculture wa not being developed in the area until AD 1500. Cord reviewed dates from 24 sites, and listed the earliest dat recovered from each *ahupua'a*. The earliest dates for Kalao 5 at that time were AD 1400 (for a temporary habitatio feature) and AD 1510 (for a permanent habitation feature) The earliest possible date for Kalaoa 4 was AD 1610, for temporary habitation feature, and AD 1680, for a permanen habitation feature. All of these dates were obtained fron coastal sites. One radiocarbon date of AD 1645-1950 wa recorded from a hearth in a habitation feature at Kealekehe b Hammatt (Hammatt et al. 1987). Dates recorded for habitatio sites in the Kahaluu area (Shun and Walker 1984) indicate that the Kona Field System in this area was established b 1420-1660.

IMPLICATIONS FOR THE CURRENT PROJECT

Expectations for the current project were formulate based on previous archaeological research and histori documentation. A variety of site types have been identified i the Barren Zone defined by Cordy (1985). Within the vicinit of the current project, these site types include shelter cave and modified lava-tube sinks, low stone platforms, low walled shelters, large *ahu*, enclosures, petroglyphs, cairn C-shapes, platforms, terraces, trails, and "hunting blinds. Thus, the inventory survey was expected to locate prehistori habitation and agricultural features as well as histori modifications to the landscape. It was also considered likel that the lava tube system identified by Hammatt and Fol (1980) would extend into the project area. More recer developments within the project area, i.e., an electrica generation facility, have altered at least three acres of th current project area and levelled most of the surrounding are

FIELD METHODS AND PROCEDURES

The present project was an inventory survey and consisted of pedestrian sweeps of the project area to locate all sites of archaeological significance. The sweeps were conducted by four persons in north-south and east-west transects, no more than 20 m (66 ft) apart. There was very little vegetation in the project area, and visibility was excellent. Survey transects were flagged to insure complete coverage, using red/white striped surveyor's flagging tape. The approximate locations of newly identified sites were plotted on a field copy of a scaled plan map of the project area, provided by the client.

All sites were described on standard PHRI site survey record forms and were photographed using 35 mm black-and-white film (PHRI Roll Number 4206). Detailed recording o sites included written descriptions, measurements, and pla maps. Each site, or the primary feature within each sit complex, was marked with pink-and-blue flagging tape, an with an aluminum tag bearing the site number, date, the letter "PHRI," and PHRI project number (92-1265). As an aid to sit reidentification, another piece of pink-and-blue flaggin tape, inscribed with the site number, was wrapped around rock and placed on the sites.

All new sites were assigned PHRI temporary fiel numbers prefixed with 1265- (beginning with 1265-1). Al sites were subsequently assigned permanent State Inventor of Historic Places* (SIHP) site numbers (Table 2).

Table 2.

CORRELATION OF SITE NUMBERS

SIHP Number	PHRI Number
18076	1265-1
18077	1265-2
18078	1265-3
18079	1265-4

**State Inventory of Historic Places (SIHP) numbers. SIHP numbers are five-digit numbers prefixed by 50-10-27 (50=State of Hawaii; 10=Island of Hawaii; 27=USGS 7.5' series quad map ["Keahole Point., Hawaii"]).*

FINDINGS

DISCUSSION

Four sites, with seven component features, were identified in the project area. Also, a modern house, which is occupied, is situated outside the project area on its western border. The locations of the sites are shown in Figure 2. The features and sites are described below. Sites consisting of more than one feature were considered complexes. All sites and features were pahoehoe excavations that probably functioned as quarries. A summary of identified sites and features is presented in Table 3.

The project area contained an abundance of recent trash, consisting of broken dishes, plastics, toys, metal, automobile tires, styrofoam, beer bottles, and other items, which may be associated with the house. A concentration of gourds and macadamia nut shells was found 13.0 m east of the house, within the project area. Some of the pahoehoe blisters near the house were filled with trash. At the north end of project area, 14.40 m north of the electrical facility and 20.0 m east of the dirt road, was a concentration of eight *opihi* shells on top of recent bulldozer push.

SITE DESCRIPTIONS

SITE NO.: State: 18076 **PHRI:** 1265-1
SITE TYPE: Pahoehoe Excavation
TOPOGRAPHY: Very gently sloping pahoehoe flows; exposed outcrops are common in the area.
VEGETATION: Fountain grass, *noni*, *koa-haole*, *'ilima*, plumeria, palm, unknown shrub.
CONDITION: Good
INTEGRITY: Unaltered
PROBABLE AGE: Prehistoric
FUNCTIONAL INTERPRETATION: Quarry
DIMENSIONS: 3.68 m by 2.53 m by 0.45 m
DESCRIPTION: Pahoehoe blocks have been broken out of a pahoehoe outcrop to form a small, shallow, amorphous blister. The excavated blocks (c. 0.10 to 0.40 m diameter each) are lying along the east side of the excavation.

SITE NO: State: 18077 **PHRI:** 1265-2
SITE TYPE: Complex (2 Features)

Table 3.

SUMMARY OF IDENTIFIED SITES AND FEATURES

Site/Feature Number	Formal Site/Feature Type	Tentative Functional Interpretation	CRM Value Mode Assess. R	I	C	Field Work Tasks DR	SC	EX
18076	Pahoehoe Excavation	Quarry	M	L	L	-	-	-
18077	Complex (2)	Quarry	M	L	L	-	-	-
A	Pahoehoe Excavation							
B	Pahoehoe Excavation							
18078	Pahoehoe Excavation	Quarry	M	L	L	-	-	-
18079	Complex (3)	Quarry	M	L	L	-	-	-
A	Pahoehoe Excavation							
B	Pahoehoe Excavation							
C	Pahoehoe Excavation							

Cultural Resource Management Value Mode Assessment
Nature: R = scientific research, I = interpretive, C = cultural
Degree: H = high, M = moderate, L = low

Field Work Tasks: *DR = detailed recording (scaled drawings, photographs, and written descriptions), SC = surface collections EX = limited excavations.*

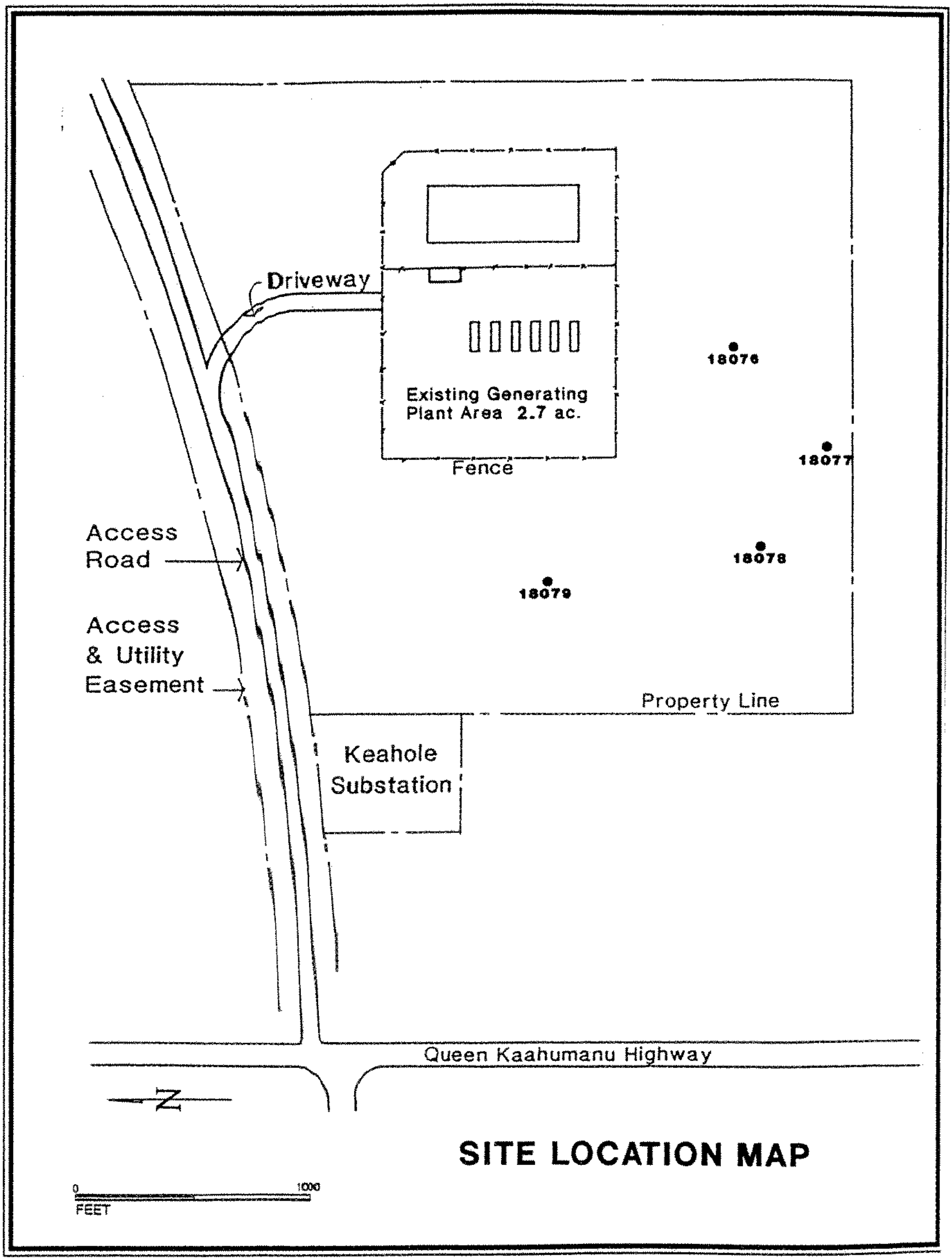

Figure 2. Site Locations

TOPOGRAPHY: Very gently sloping pahoehoe flows. Exposed outcrops are common in the area.
VEGETATION: Fountain grass, *noni*, *koa-haole*, *'ilima*, plumeria, coconut palm, unidentified shrub.
CONDITION: Fair
INTEGRITY: Unaltered
PROBABLE AGE: Prehistoric
FUNCTIONAL INTERPRETATION: Quarry
DIMENSIONS: 3.50 m by 3.5 m by 0.45 m (approx.)
DESCRIPTION: The site complex consists of two pahoehoe excavations.

FEATURE A: Pahoehoe Excavation
FUNCTION: Quarry
DIMENSIONS: 1.50 m by 1.60 m by 0.19 - 0.45 m
DESCRIPTION: Pahoehoe blocks have been broken out of pahoehoe outcrop to form a small, shallow, oval blister. The excavated blocks (c. 0.20 to 0.45 m diameter each) are lying around the excavation. Feature A is connected to Feature B by a strip of pahoehoe.

FEATURE B: Pahoehoe Excavation
FUNCTION: Quarry
DIMENSIONS: 1.70 m by 1.70 m by 0.21 - 0.44 m
DESCRIPTION: Pahoehoe blocks have been broken out of pahoehoe outcrop to form a small, shallow, circular blister. The excavated blocks (c. 0.15 to 0.35 m diameter each) are lying around the excavation.

SITE NO: State: 18078 **PHRI:** 1265-3
SITE TYPE: Pahoehoe Excavation
TOPOGRAPHY: Very gently sloping pahoehoe flows. Exposed outcrops are common in the area.
VEGETATION: Fountain grass, *noni*, *koa-haole*, *'ilima*, plumeria, palm, and an unknown shrub.
CONDITION: Poor to fair
INTEGRITY: Unaltered
PROBABLE AGE: Prehistoric
FUNCTIONAL INTERPRETATION: Quarry
DIMENSIONS: 7.0 m by 2.0 m
DESCRIPTION: Pahoehoe blocks have been broken out of a pahoehoe outcrop to form a long, narrow, shallow blister. The excavated blocks (c. 0.6 to 0.4 m diameter each) are lying around the excavation.

SITE NO: State: 18079 **PHRI:** 1265-4
SITE TYPE: Complex (3 Features)
TOPOGRAPHY: Very gently sloping pahoehoe flows. Exposed outcrops are common in the area.
VEGETATION: Fountain grass, *noni*, *koa-haole*, *'ilima*, plumeria, coconut palm, and an unknown shrub
CONDITION: Fair
INTEGRITY: Unaltered
PROBABLE AGE: Prehistoric
FUNCTIONAL INTERPRETATION: Quarry
DIMENSIONS: 6.2 m by 10.0 m by 0.4 m (approx.)
DESCRIPTION: The site complex consists of three pahoehoe excavations.

FEATURE A: Pahoehoe Excavation
FUNCTION: Quarry
DIMENSIONS: 3.10 m by 1.70 m by 0.45 m
DESCRIPTION: Pahoehoe blocks have been broken out of a pahoehoe outcrop to form an oval, shallow blister. Some of the excavated blocks (c. 0.10 to 0.40 m diameter each) are piled two-courses high along the west and north edge of the excavation, while other blocks are lying around the excavation.

FEATURE B: Pahoehoe Excavation
FUNCTION: Quarry
DIMENSIONS: 1.4 m by 1.0 m by 0.4 m
DESCRIPTION: Pahoehoe blocks have been broken out of a pahoehoe outcrop to form a circular, shallow blister. The excavated blocks (c. 0.1 to 0.3 m diameter each) are lying around the excavation.

FEATURE C: Pahoehoe Excavation
FUNCTION: Quarry
DIMENSIONS: 2.5 m by 2.0 m by 0.3 m
DESCRIPTION: Pahoehoe blocks have been broken out of a pahoehoe outcrop to form an oval, shallow blister. The excavated blocks (c. 0.15 to 0.60 m diameter each) are lying in and around the excavation.

CONCLUSION

DISCUSSION

Four sites, with seven component features, were identified in the project area. Feature types at the sites were limited to pahoehoe excavations, which were interpreted as quarry areas. These site types have not been previously documented in Kalaoa, although they are ubiquitous elsewhere in Kona, e.g., Kealekehe (O'hare, in prep.). How these quarry areas may have functioned is discussed here in the context of the larger settlement pattern.

Rosendahl (1973) has discussed the implications of barren-zone archaeological remains for understanding patterns of aboriginal Hawaiian settlement, particularly in the desolate section of North Kona extending from Kailua to Anaehoomalu. While discussion has concentrated on the nature of barren-zone residential occupation, the relationships between the coastal and upland occupation components are less well defined.

According to Rosendahl, the area of aboriginal Hawaiian occupation can be divided into three principal zones: **(a)** a very narrow and arid coastal zone associated with the exploitation of marine resources, **(b)** a sloping, barren intermediate zone of recent volcanics, almost devoid of soil or vegetation, and **(c)** an upland habitation zone associated with agricultural exploitation. The forest zone further *mauka* was exploited, but rarely inhabited.

The principal forms of occupation within the barren zone included **(a)** temporary shelter occupation by people traveling between the coast and uplands, and perhaps along the coast, and **(b)** temporary and extended residential occupation of larger, natural cave features by people engaged in various coastal zone marine exploitation activities. Other possible minor forms of occupation included special purpose temporary occupation, refuge functions, and use of caves as burial features. No direct evidence for other exploitative activities, such as scoria quarries and abrader manufacturing areas (such as those found in South Kohala), was apparent within the North Kona barren zone, according to Rosendahl (1973:66). All evidence encountered was related to activities within the adjacent coastal or upland zones.

Rosendahl also suggests (ibid:66) that while there is no direct archaeological evidence, it is possible that the *nene*, or Hawaiian goose (*Branta sandwichensis*) was hunted in the barren zone. Baldwin's study of the distribution and historic reduction of the *nene* indicates the endemic bird to have been at one time abundant in North Kona, especially in the area between Hualalai and Mauna Loa, and that it moved to the barren lowlands and coastal lava fields of Kekaha during the winter months (Baldwin 1945:28-31).

Much of the ethnohistoric and ethnographic information for North Kona refers to the area between Kailua and Honaunau; the area between Kailua and Anaehoomalu is similar, although here the coastal portion was more barren and had several fishponds, the upland portion was probably less densely populated, and is separated from the coast by a more extensive barren zone with more recent volcanic remains. During the historic period, most travel between Kawaihae and Kailua was by water, and this was apparently the case during the prehistoric period, as well (Rosendahl 1973).

The ethnohistoric and ethnographic sources offer almost no information on the relationship of the coastal and upland occupation components, but it can be assumed that a principal aspect of such relationships would have involved the exchange of marine resources for agricultural resources. This was the usual pattern of aboriginal Hawaiian social and economic interaction and integration (see Rosendahl 1972:7:462-469). This model has been called the *'ili-'ohana* model. A segment of the larger ahupua'a, the *'ili* was a land section extending *mauka* from the coastal waters and strand area through the agricultural lands and into the forest. The *'ohana* was the extended family group which occupied the *'ili* in dispersed, permanent residential units. This socio-economic model emphasized patterns of reciprocal exchange, of both subsistence products and other goods and services, between the *'ohana* members who lived on the coast and those who lived in the uplands. This validity of this model, however, is a matter of debate (Sahlins 1973, Hommon 1976).

Thus, the barren zone may have been used primarily for travel between coastal and upland areas. Temporary shelters and the *mauka-makai* foot trails evidence the movement of people, and presumably goods, between the coast and uplands. The findings in the current project do not support this hypothesis because no trail or temporary habitations were located. This, however, was due to the small size of the project area and to the recent modifications to it.

Evidence from the current project (i.e. the pahoehoe excavations), indicates that the barren zone may also have been the site of quarries that supplied materials such as scoria (which was utilized in the manufacture of abrading tools) and/or extracting basalt and volcanic glass products that were utilized as cutting implements. The excavations may have been used to create depressions for planting or water catchment. Further, the stones removed from the excavation may have been used as building materials. Thus, pahoehoe excavation may have served a variety of purposes. The pahoehoe excavations in the current project, however, appear to have been prospect pits rather than productive quarries. Perhaps, as Rosendahl suggests (1973:65), the type of lava in this area did not yield scoria or other usable raw materials. This could also account for the lack of pahoehoe excavations in the general vicinity.

It seems likely that the pahoehoe excavations are related to periods of prehistoric occupation, rather than the historic period, based on the presence of habitation and refuge caves in the area just south of the current project. These cave sites provide a temporal range of AD 1480 to 1700 (Hammatt and Folk 1980). It is also possible that during times of conflict, particularly during the late prehistoric, the exchange of materials such as volcanic glass and scoria was restricted, forcing people to seek alternative sources closer to home. Evidence to support this hypothesis has been presented elsewhere (Graves and Goodfellow 1992:74).

GENERAL SIGNIFICANCE ASSESSMENTS AND RECOMMENDED GENERAL TREATMENTS

General significance assessments and recommended general treatments for all identified sites are summarized in Table 4. Significance categories used in the site evaluation process are based on the National Register criteria for evaluation, as outlined in the Code of Federal Regulations (36 CFR Part 60). The Hawaii State Historic Preservation Division uses these criteria for evaluating cultural resources. Sites determined to be potentially significant for information content (Category A, Table 1) fall under Criterion D, which defines significant resources as ones which "have yielded, or may be likely to yield, information important in prehistory or history." Sites potentially significant as representative examples of site types (Category B) are evaluated under Criterion C, which defines significant resources as those "...which embody the distinctive characteristics of a type, period, or method of construction...or that represent a significant and distinguishable entity whose components may lack individual distinction."

Sites with potential cultural significance (Category C) are evaluated under guidelines prepared by the Advisory Council on Historic Preservation (ACHP), entitled Guidelines for Consideration of Traditional Cultural Values in Historic Preservation Review (Draft Report, August 1985). The guidelines define cultural value as "...the contribution made by an historic property to an ongoing society or cultural system. A traditional cultural value is a cultural value that has historical depth." The guidelines further specify that "[a] property need not have been in consistent use since antiquity by a cultural system in order to have traditional cultural value."

Table 4.

SUMMARY OF GENERAL SIGNIFICANCE ASSESSMENTS AND RECOMMENDED GENERAL TREATMENTS

SIHP	Significance Category				Recommended Treatment			
Site Number	A	X	B	C	FDC	NFW	PID	PAI
18076	-	+	-	-	-	+	-	-
18077	-	+	-	-	-	+	-	-
18078	-	+	-	-	-	+	-	-
18079	-	+	-	-	-	+	-	-
Total	0	4	0	0	0	4	0	0

General Significance Categories:

A=Important for information content, further data collection necessary (CRM value mode assessment = scientific research value
X=Important for information content, no further data collection necessary (CRM value mode assessment = scientific research value)
B=Excellent example of site type at local, regional, island, state, or national level (CRM value mode assessment = interpretive value
C=Culturally significant (CRM value mode assessment = cultural value)

Recommended General Treatments:

FDC=Further data collection necessary (further survey and testing, and possibly subsequent data recovery/mitigation excavations)
NFW=No further work of any kind necessary, sufficient data collected, archaeological clearance recommended, no preservatio potential (possible inclusion into landscaping suggested for consideration)
PID=Preservation with some level of interpretive development recommended (including appropriate related data recovery work) and
PAI=Preservation "as is," with no further work (and possible inclusion into landscaping), or minimal further data collection necessar

Based on the findings of the archaeological survey and test excavation field work, the archaeological remains found within the HELCO Keahole Parcel project area are assessed as significant solely for information content. These four sites have been measured, mapped, described, photographed, and plotted on a topographic map. No further work is recommended for these sites, as the information recovered is considered sufficient.

To assist the client in making decisions regarding the treatment of resources, the general significance of the archaeological sites identified during the current survey was also evaluated in terms of potential research value, interpretive value, and/or cultural value (PHRI Cultural Resource Management [CRM] value modes). *Research value* refers to the potential of archaeological resources for producing information useful in the understanding of cultural history, past lifeways, and cultural processes at the local, regional, and interregional levels of organization. *Interpretive value* refers to the potential of archaeological resources for public education and recreation. *Cultural value* refers to the potential of archaeological resources to preserve and promote cultural and ethnic identity and values. All sites identified during the current project were assessed as of low significance for research value, interpretive value and cultural value. CRM assessments for individual sites are presented in Table 3.

The assessments and recommendations presented here are based on the findings of an inventory survey of the project area, and they are subject to the limits of such surveys. There is always the possibility, however remote, that potentially significant, unidentified surface and subsurface cultural remains will be encountered in the course of further archaeological investigations or subsequent development activities. In such situations, archaeological consultation should be sought immediately.

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APPENDIX A

HISTORICAL DOCUMENTARY RESEARCH

by Lehua Kalima, B.A.

Historical information on Kalaoa Ahupua'a, in which the project area is situated, is extremely limited. For this reason, information concerning *ahupua'a* near Kalaoa 4 as well as more general information on the North Kona district are included within this report. The information presented here includes legends, early historic accounts, land use information, and settlement patterns.

Kalaoa Ahupua'a is said to be named for Kalaoa Pu'umoi, sister of Kapalaoa, the mother of the riddling expert Kalapana. The name Kalaoa literally translates as "the choker (as a stick for catching eels)" (Pukui et al. 1974:75).

The entire portion of North Kona which lies between Honokohau (sometimes referred to as Honokahau) and Kapalaoa was once known as Kekaha (Soehren 1963:1). These *ahupua'a* in Kekaha were often treated as a unit. Kekaha (where food does not grow) (ibid.) was a waterless land frequently ravaged by Pele. Hawaiians who lived there gave such epithets as "Kekaha wekaweka" (black Kekaha) and "Kekaha wai 'ole" (waterless Kekaha) to these barren lava fields (ibid.).

Hannah Springer, an authority on this area, writes that Kekaha (translated as barren, desolate) was the name given to that section of North Kona from Honokohau, north of Kailua, to Napu'u (the Hills), meaning Pu'uwaa'awa'a and Pu'uanahulu. That section continued along the coast to Anaeho'omalu, the boundary of South Kohala (Springer 1985:2).

Eliza Maguire, a resident of Hu'ehu'e at the turn of the century and a translator of Hawaiian legends, comments on the terrain of this area:

> One readily sees the great lava stretches of country, as one travels along the road. It is no wonder that the simple fisherfolks living along the sea-coast personified the volcano as a dreadful being with supernatural powers whose wrath bore down on them so much destruction, laying waste their gardens, and filling their fish-ponds with rocks, leaving them on a narrow strip of beach, the ocean on one side, and the lava fields on the other (Maguire 1966:5).

Pre-Contact History

Two legends relevant to the project area were found. One legend about the North Kona district concerns the god Lono, who was associated with life-giving resources such as rainfall: "...the story of the origin of the Makahiki rain and harvest festival...was to bring Lono from Kahiki, whither he returns," (Handy and Handy 1972:522-523). Another legend, included in Maguire's *Kona Legends* (1966), concerns a shoreline pool *makai* of the project area. The legend describes how a *kupua* (wizard) named Wawaloli entranced Malumaluiki, a beautiful girl from the uplands, who came to the shore to gather *limu* and shellfish. He taught her a chant, and every day when she came to the shore, Malumaluiki would call out this chant and bring him forth from his hole in the pool. Wawaloli would emerge from the pool and metamorphose from a *loli* (sea slug) into a man. The two would then devote the entire day to lovemaking, and Malumaluiki would neglect to gather food. Her parents wondered why she returned home tired and with no catch to show for her time at the beach. One day her father followed her and witnessed the transformation of Wawaloli and the couple's activities. The next day, carrying his trapping net, he arrived at the pool before Malumaluiki, and he called out the chant to bring forth Wawaloli. As the *loli* emerged from the hole in the pool, the father ensnared it and took it to the *kahuna* Papaapoo at Hoohila. Papaapoo advised the father to heat an *imu* and bake the *loli*. "When the loli is dead, your daughter will live on, and so will all the daughters of the families around here." This was done and Wawaloli perished but the pool and the hole that he once dwelled in remain.

Information relevant to the present project area was found in a number of archaeological reports. A passage concerning the ancient chief Umi-a-Liloa, found in Schilt (1984), refers to the numerous caves in the general vicinity of the project area and indicates that many of them were used as places of refuge:

> In Kona, 'Umi was said to have established craft and professional separations....This division of labor probably came at a time of rapid population increase and was aimed at increasing production and work efficiency. However, 'Umi's descendants apparently struggled without definitive success to maintain political control over the island. In fact, traditions dating probably from the 1500s to the mid-1700s tell of the stresses and battles between opposing district chiefs of Hawaii island, and Maui and the chiefs of leeward Hawaii. It was probably during this time that many caves in leeward Hawaii Island were extensively modified to become underground places of refuge (Schilt 1984:22).

Cordy (1985) identifies the Kalaoa area as that of the high priest, Kaluolapa, who presided over ceremonies in Haleohiu and Kalaoa. Unfortunately, he does not cite his source for this statement.

One saying about the Kekaha area comments on the life-sustaining qualities of the sea off Kekaha:

> *Ola Akula ka 'Aina Kaha, Ua Pua ka Lehua i Kai.*
>
> Life has come to the *Kaha* lands for the Lehua blooms are seen at sea.
>
> "Kaha Lands" refers to Kekaha, Kona, Hawaii. When the season for deep-sea fishing arrived, the canoes of the expert fishermen were seen going and coming (Pukui 1983:271).

Kekaha was, and is, famous for its offshore fishing grounds. The native historian, Samuel Kamakau, writes about the High Chief Umi-a-liloa fishing for *aku* off the coast of Maka'ula during the 15th century (Kamakau 1961:20). During the later years of his life (c. 1810), Kamehameha frequently enjoyed fishing expeditions along the shores of Kekaha (ibid:203).

John Papa I'i, a Hawaiian historian and member of Kamehameha III's court, notes the abundance of fish and trading done off the coast of Kekaha:

> The next day the ship arrived outside of Kaelehuluhulu, where the fleet for aku fishing had been since the early morning hours. The sustenance of those lands was fish... Soon the fishing canoes from Kawaihai, the Kaha lands, and Ooma drew close to the ship to trade for the *pa'i'ai* (hard *poi*) carried on board, and shortly a great quantity of *aku* lay silvery-hued on the deck (I'i 1973:109).

Hannah Springer writes about the climate of these Kekaha lands:

> Located on the leeward side of Hawai'i, Kekaha is less affected by the northeast tradewinds, which are distorted, if not blocked by the masses of Mauna Kea, Mauna Loa, and Hualalai, than are the regions of the windward side of the island. The land-sea breezes and other regional winds play an important part in determining the climate of, and affecting activities in Kekaha (Springer 1985:4-5).

Springer also notes that Robert Keakealani of Pu'uanahulu has described the winds of Kekaha as he learned them: The 'Eka wind is the "Waimea wind", the prevailing wind; the Kaumoku is the wind from Kona; the wind from Maui is called Ho'lua (Hoolua); and the Kuhonua is the wind from *mauka*.

The fishpond of Paaiea was a large pond extending from Kaelehululu in Mahaiula to Wawaloli on the southern boundary of Ooma, a distance of about three miles. This pond was not far from Keahole Point, and the fishermen going to Kailua and further south often took a short cut by crossing the pond in their canoes "thus saving time and the hard labor of paddling against the Eka, a strong sea breeze from the south, and also against the strong current from Keahole" (Maguire 1966).

This fishpond was destroyed in 1801 when it was inundated by the Hualalai lava flow.

Three poetic sayings referring to the 'Eka wind, mentioned by Robert Keakealani and Eliza Maguire, are found in Pukui's *'Olelo No'eau*:

> *Ka Makani kukulu pe'a nui, he 'Eka.*
>
> The 'Eka, the wind that sets up the big sails.
>
> When the 'Eka wind blew in Kona, Hawaii, the fishermen sailed out to the fishing grounds (Pukui 1983:159).

> *Ke 'Eka, makani ho'olale wa'a o na Kona.*
>
> The 'Eka breeze of Kona that calls to the canoemen to sally forth to fish.
>
> Refers to Kona, Hawaii (ibid:182).

> *Makani 'Eka aheahe o Makalawena.*
>
> The gentle breeze of Makalawena (ibid:228).

According to tradition, Kekaha was a region "valued by ruling chiefs, inhabited by attendant chiefs, and upon occasion abused by warring chiefs" (Kalakaua 1973:31). It was the object of contention during the late 16th century when Kamalalawalu, ruling chief of Maui, was at war with Lonoikamakahiki, ruling chief of Hawaii (Kamakau 1961:56

During the early 18th century, when Alapa'inui was at war with Kekaulike of Maui, the latter "abused the country people of Kekaha", cut down "the trees throughout the land of Kona", and "at Kawaihae he cut down all the coconut trees" (ibid:66). These acts of war were of no small consequence, for "to fell trees of such usefulness was considered truly inhuman" (Springer 1985:23).

Early Historical Accounts

The earliest written historical account of this part of the North Kona area is that of Archibald Menzies, who traveled with Captain George Vancouver in 1792. He wrote, "barren and rugged with volcanic dregs and fragments of black lava...in consequence of which the inhabitants were obliged to have recourse to fishing for their sustenance" (1920:99). It is assumed that Menzies never ventured beyond the coastline to the location of the project area.

John Papa I'i described Kalaoa as it appeared when he sailed past, "The gentle Eka sea breeze of the land was blowing when the ship sailed past the lands of the Mahaiulas, Awalua, Haleohiu, Kalaoas, Hoona, on to Oomas, Kohanaiki, Kaloko, Honokohuas, and Kealaheke, then around the cape of Hiiakanoholae, which was two long points of land. At first it seemed that these two were the only jutting points of land, but then more were seen, extending as far as Kapalilua" (1973:110).

William Ellis, during his around-the-island journey in 1823, noted the existing condition of the North Kona area, and also the extensive destruction by Hualalai's 1800-1801 flow. He wrote that the flow had "...inundated several villages, destroyed a number of plantations and extensive fish-ponds, filled up a deep bay twenty miles in length and formed the present coast...Stones walls, trees, and houses, all gave way before it; even large mass or rocks of hard ancient lava, when surrounded by the fiery stream, soon split into small fragments, and falling into the burning mass, appeared to melt again, as borne by it down the mountain's side" (Ellis 1963:30-31).

In 1840, Wilkes, an explorer with the American Expedition, made a few observations about this area:

> ...a considerable trade is kept up between the south and north end of this district. The inhabitants of the barren portion of the latter are principally occupied in fishing and the manufacture of salt, which articles are bartered with those who live in the more fertile regions of the south, for food and clothing (Wilkes 1845:91).

Evidence of this salt manufacture is still seen along the coast in the numerous basalt and concrete salt pans.

An early western description of a journey through the inland area was written by George Bowser in 1880 :

> From Kiholo the road southwards is rough and laborious. Perpetual travelling over lava is very hard upon our horses, and it is impossible to travel faster than the slowest walk. On the road we met with some awful chasms of unknown depth and numberless cracks and fissures in the lava (Bowser 1880:93).

Bowser also recorded the business operations in various areas of the islands. Here he relates his impressions of North Kona and mentions some of the luxuriant foliage he encountered:

> Presently I reached the ridge of the mountain, and had a fine view of the surrounding country. Fronting the sea for many miles in North Kona there is a rich tract of bottom land which might be turned to good account. Large areas of the mountain land might also be cultivated for coffee. It is a shame to see so many hundred square miles of country lying waste for want of enterprise on the part of its owners.
>
> I was astonished to see in this district how bananas, mangoes, oranges, pineapples, in short, all the fruits belonging to these islands grow in profusion and yield splendid crops upon the bare lava. Ferns it is not so surprising to see, for they will grow in all sorts of rocky situations, but the luxuriance of their growth is wonderful. In many places you may see them growing to the height of five-and-twenty feet. The ferns, except the variety which yields the pulu, are only food to look at, for if there is an edible fern here, as in New Zealand, the natives have had too many other more tempting fruits of the soil at hand to think of turning it to account. But the fruits I have just alluded to ought to be worth something if any one would but try to utilize them. They are so fine in quality and grow in such profusion that I feel sure some enterprising person will yet make a fortune by being the first to turn them to account (ibid.).

Land Tenure

During the Great Mahele of 1848 Kalaoa 4 was set aside as Government Land (Board of Commissioners 1929). This land and Kalaoa 1-3 were the lands of King Kamehameha III who passed it to the government. Most of the land between the 1,000 ft and 2,400 ft elevation was soon sold, and a series of grants was issued in these *ahupua'a* from 1852 to 1864. Typically sold in lots of c. 50 acres, most of them were agricultural parcels (Cordy 1985:6 and Soehren 1982:3).

Agriculture

The introduction of foreign plants and animals has changed cultivation and land use drastically in the Kona area and throughout the Hawaiian chain. Handy tells us that in the Kona area, where the rain for taro planting is seasonal, dry taro was planted in individual holes filled with mulch. Clearing the upland forest for this type of planting was termed *umoki* (Handy 1940:47-48). Kepelino, a native of Kona, gives a detailed account of methods of planting there (ibid:48).

In 1794, Captain Vancouver introduced goats and cattle to the Kona area, and for many years they were the mainstay of industry. The 1850s saw the development of large-scale commercial ranching and agriculture following the Mahele and an 1850 law permitting foreigners to own land. Coffee, grazing land, and sugar cane gradually replaced traditional subsistence crops such as taro and *'uala*. Chinese and Hawaiian labor was used on coffee plantations located in the fertile belt above the 800 ft elevation. At elevations of 500 to 3,000 ft, tobacco was grown commercially until about 1930 (Schilt 1984:24). Tobacco was not grown in the present project area, however, because of a lack of soil. Figure 1 is a map showing the project area vicinity as it appeared in 1888.

Land Settlement Patterns

The Kalaoa area has been described by early visitors as an arid and hot region. As in most of the Kekaha lands, the population of Kalaoa was largely concentrated on the coast, while most fields were in the upland forest. Trails (and associated shelters) connected the two areas (Cordy 1985:5). The 1801 lava flow effectively wiped out the coastal settlements in Kalaoa. According to Schmitt, the population decreased from 300,000 to 145,000 between 1778 and 1819, a reduction of 52% (Schmitt 1977:25).

In his 1985 report, Cordy discusses the conflicting views of Reinecke and Ching concerning the population in the project area vicinity. Reinecke (n.d.) thought there was once a large population, in the hundreds, and the reason for the "scarcity of remains" was that they were destroyed by man, cattle, and storms; were not discernible in sand areas; or were a short distance inland. Ching (1971) agrees, saying that legends suggest "[a] large population for the lands above the study area" (North Kona). He believes the trails in the Kalaoa area suggested inland permanent settlement in Kalaoa. He also argues that fishponds, fishing grounds, and the large number of archaeological sites, refuge caves, and *holua* slides in the North Kona area suggest a land of no little worth (ibid.). Cordy argues that population was always low, that the number of sites is not unusual for 400 years of occupation, and that the area contained only small villages of fishermen in a harsh environment. Counts of permanent house sites and conversion to population estimates (Cordy 1987:244-5) indicate tha the combined population of Ooma 1 and 2 and Kalaoa 4 and 5 never consisted of more than 102 people, and was at a maximum between c. 1750-1780. The population in North Kona declined to 1,753 in 1890 and then increased to 3,81[illegible] in 1900 (Schmitt 1977:13).

By 1866, most of the land flanking the Mamalaho[illegible] Highway had been sold (Soehren 1985). All the early grant had frontage on the "alaloa mauka" or upper belt road, nov known as the Mamalahoa Highway, which lies at about th 1,700 ft elevation. Another road at about the 1,100 f elevation, the Alanui Kauila, served the lower ends of thes grants (ibid.). Soehren notes that these arterial roads "connected the upland farm lots of the various *ahupua'a* with one another, with the port and urban center at Kailua and with the rest of the island" (ibid.). Portions of the Alanu Kauila are now part of Kauila Street in Kona Coast Viev subdivision, while Ahiahi Street in Kona Palisades follow approximately the route of the Alanui Kama, a lowe branch of the Alanui Kauila (ibid.).

Communication between different elevations withi the *ahupua'a* was provided by *mauka-makai* trails such a the Alanui Kauhini (probably Ka-'uhini, "grasshopper" [ibid.]). One of the trails in Kalaoa mentioned by Chin (1971) could be the Alanui Kauhini. It is a trail that run *mauka-makai*. In their survey of Kalaoa 4, Telea an Rosendahl (1987) state that the trail once served to transport people and produce between the upland agricultura and the coastal habitation zones.

Shortly after World War II, a jeep trail was bulldoze from Mamalahoa Highway to the shore near Keahole Poir (Soehren 1985). The upper portion of this road followed th Alanui Kauhini past private farm lands to the state land belo (ibid.). Over the years, the trail was maintained by periodi bulldozing until the Queen Kaahumanu Highway made ac cess to the shore easier (ibid.).

Today the Kalaoa area is well populated in the uppe forest zones, since the Kona Palisades Subdivision has devel oped much of that area. The intermediate zones are slowl becoming developed as part of the industrial and residentia areas which have been expanding out of Kailua. No perma nent human habitation was ever reestablished on the coa since the 1801 lava flow inundated much of the area. Th coastal area is now home to the Keahole Airport and OTEC the Natural Energy Laboratory of Hawaii.

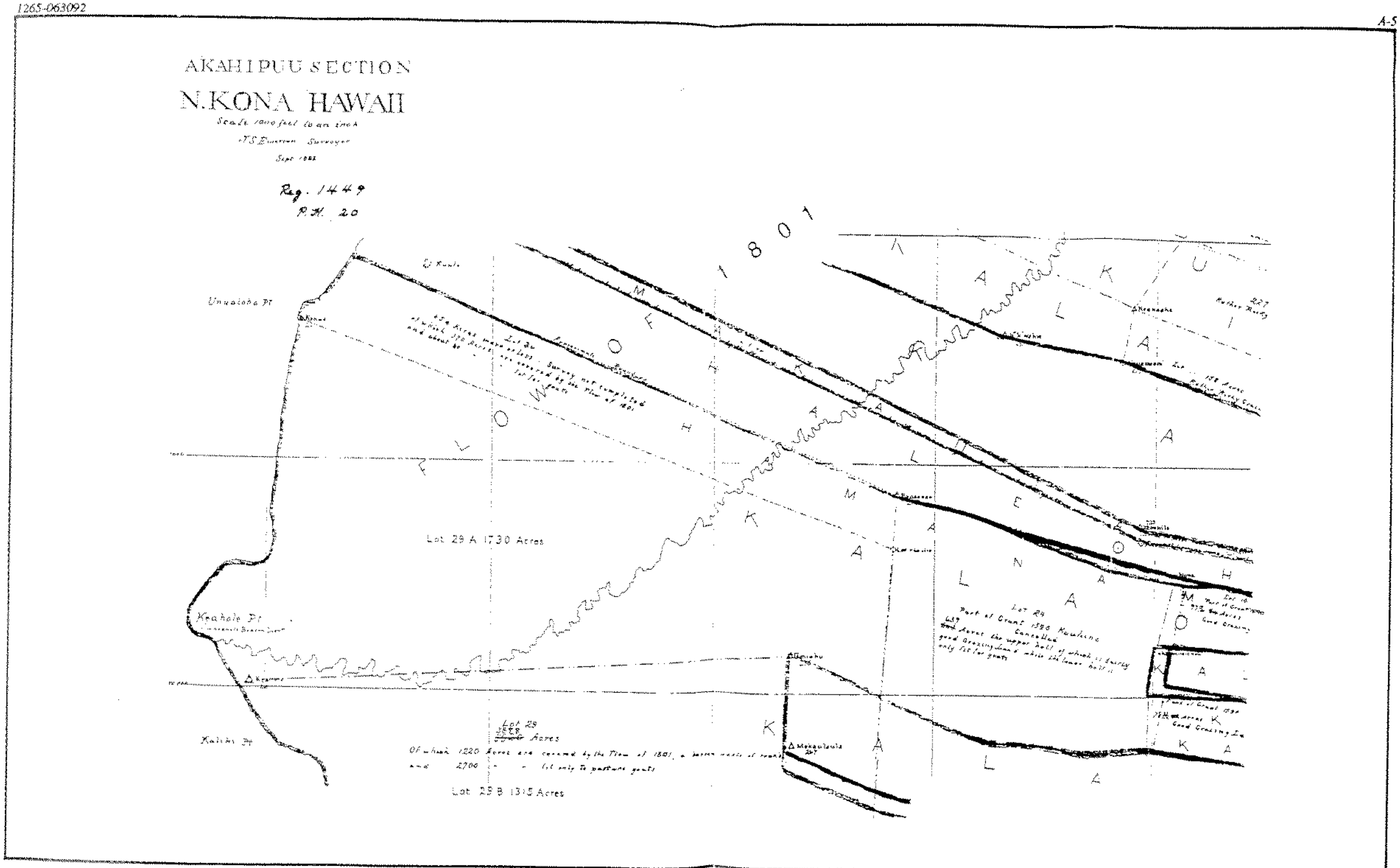

Figure A-1.
Map of Akahipuu Section, North Kona, Hawaii, by J.S. Emerson, Sept. 1888
Taken from State Survey Dept. Reg. Map No. 1449

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APPENDIX B

ILLUSTRATIONS

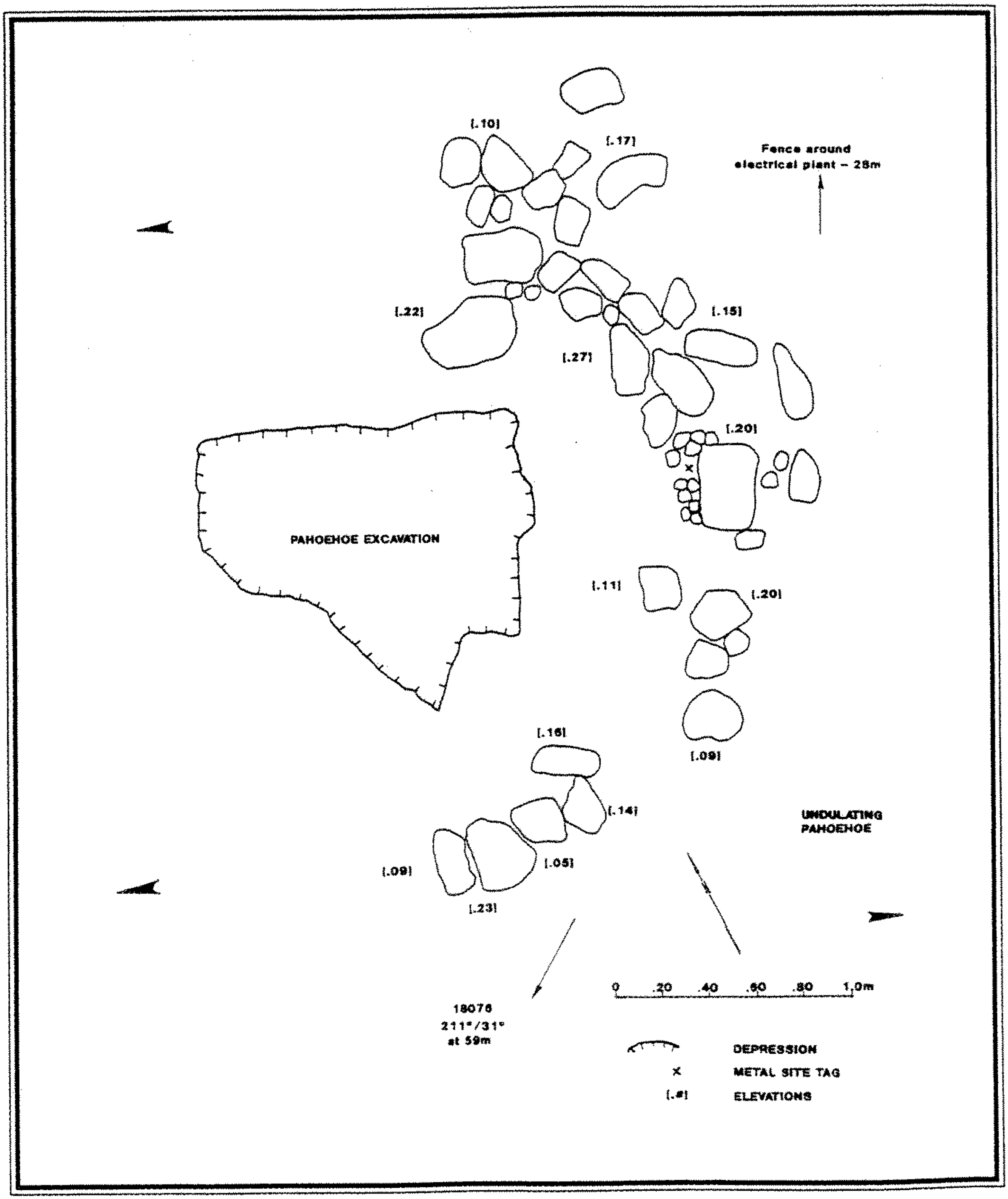

Figure B-1. Site 18076, Pahoehoe Excavation

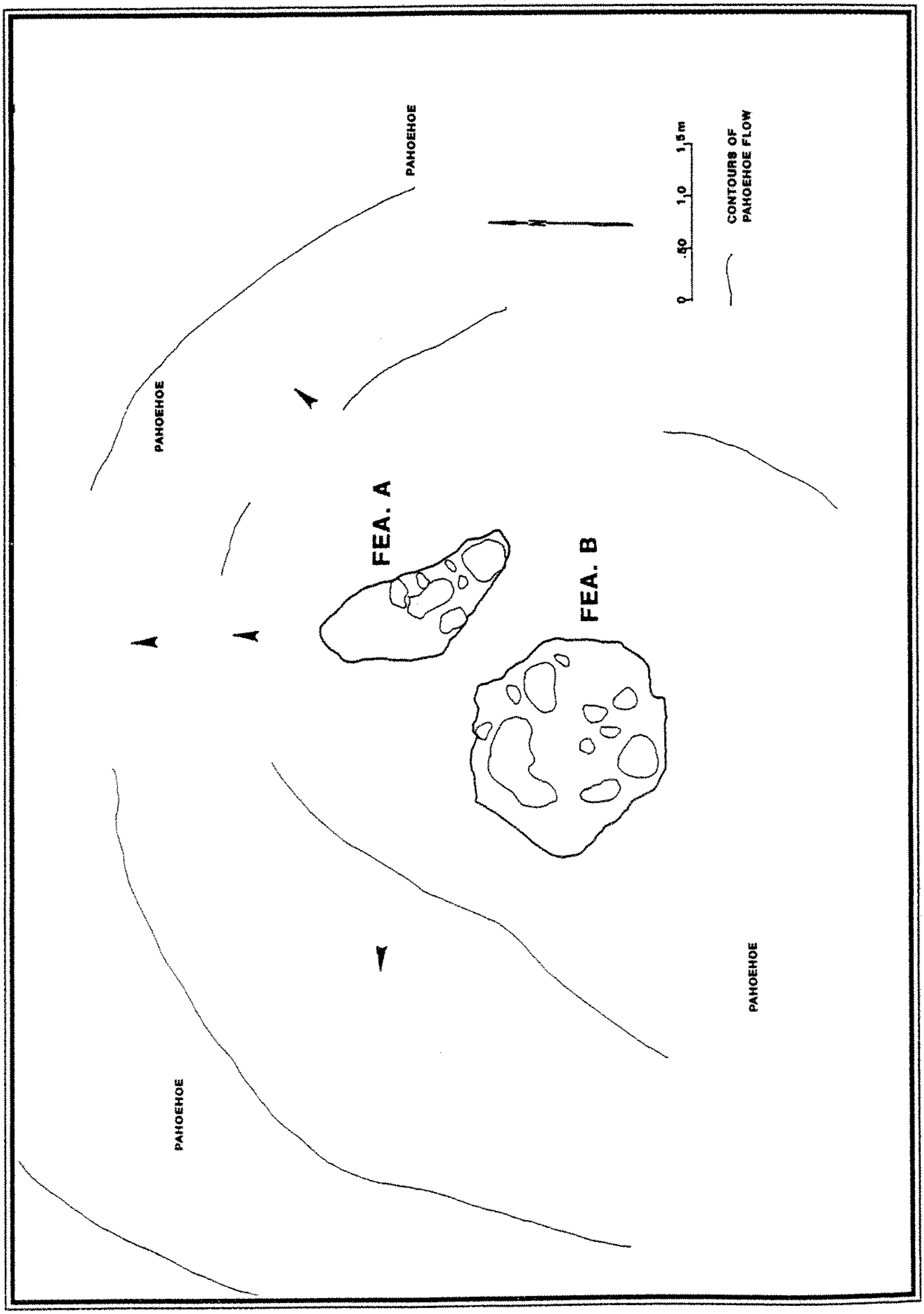

Figure B-2. Site 18077, Pahoehoe Excavation Complex

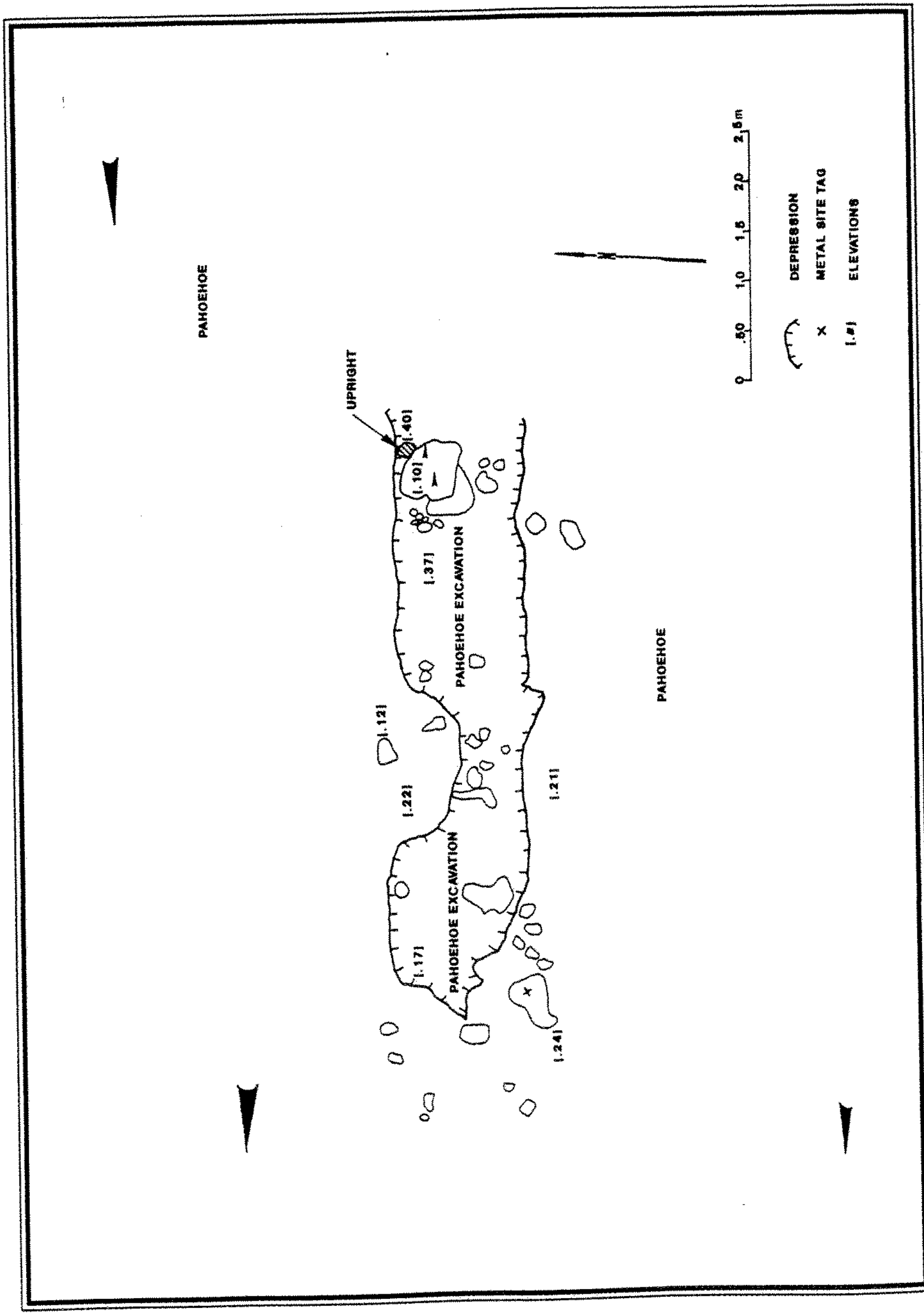

Figure B-3. Site 18078, Pahoehoe Excavation

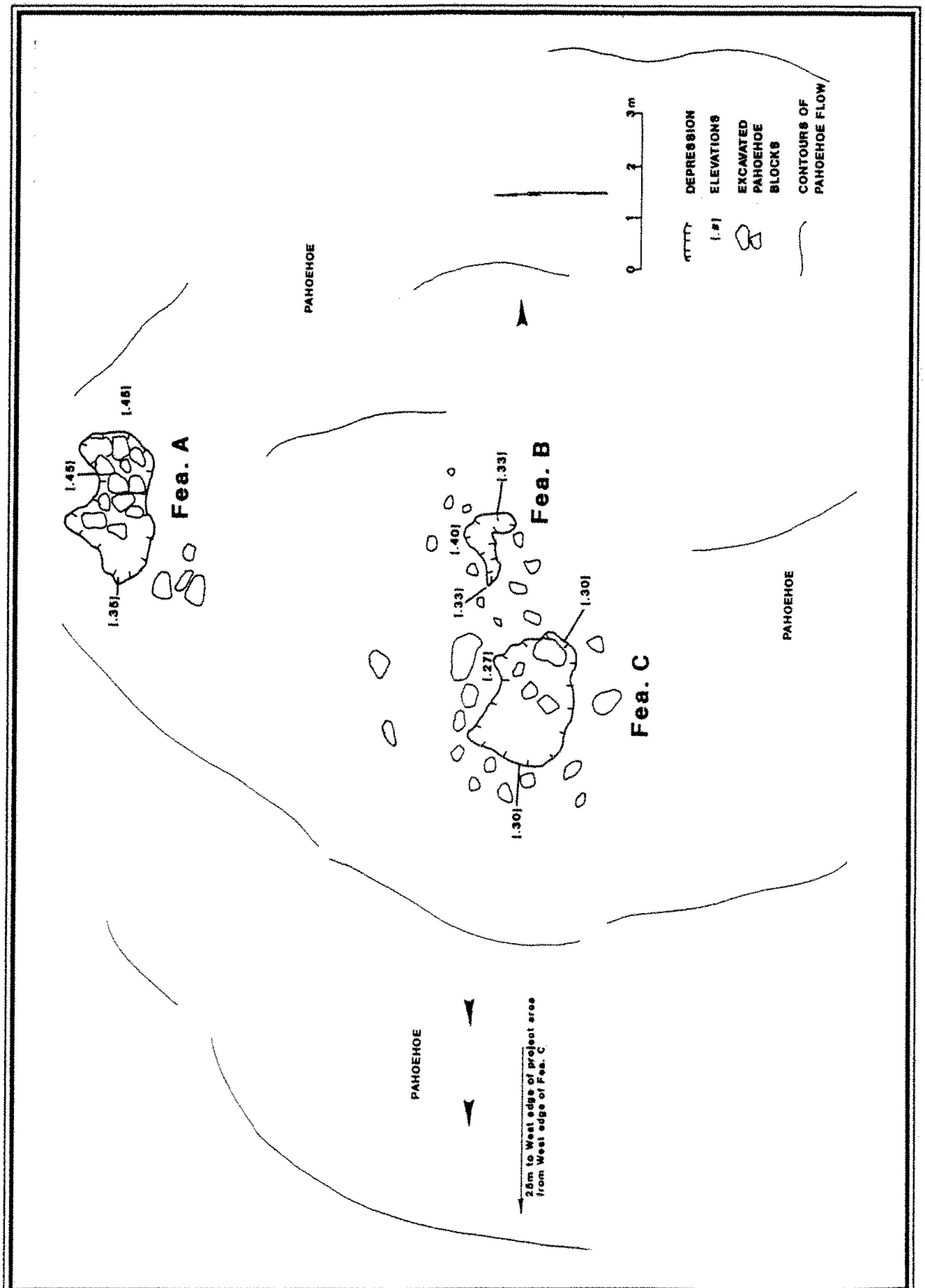

Figure B-4. Site 18079, Pahoehoe Excavation Complex

APPENDIX B

SHPD Memorandum Dated December 4, 1992

LOG NO: 6540; DOC NO: 9211KS29

To Roger Evans, Administrator, OCEA, from Don Hibbard, Administrator, SHPD

-HECD

December 3, 1992

LOG NO: 6540
DOC NO: 9211KS29

MEMORANDUM

TO: Roger Evans, Administrator
OCEA

FROM: Don Hibbard, Administrator
State Historic Preservation Division

SUBJECT: **CDUA HA-2600 -- HELCO, Meteorological Tower (File No. 92-2600)**
Kalaoa, North Kona, Island of Hawaii
TMK: 7-3-49: 036

HISTORIC PRESERVATION PROGRAM CONCERNS:

Our office reviewed the report by Dowden and Graves (1992) documenting the results of the archaeological inventory survey for the subject parcel (PHRI Report 1265-0603920-- "Archaeological Inventory Survey: HELCO Keahole Parcel Project Area, Lands of Kalaoa 1-4, North Kona District, Island of Hawaii (TMK: 7-3-49: 36)", Appendix D in the CDUA and Environmental Assessment documents). We find that the field survey adequately covered the project area, finding 4 historic sites (site numbers 18076, 18077, 18078 and 18079).

The description of these sites is sufficient to evaluate their significance. These sites are all very small excavations in the pahoehoe, probable very small prehistoric quarry sites. We agree that these sites were significant solely for their information content and that sufficient amounts of this information were recorded in the survey, making these sites "no longer significant". Therefore, no significant sites remain within the project area. Hence, the subject Conservation District Use Application will have "no effect" on historic sites.

If your office should have any further questions, please contact Kanalei Shun at 587-0007

KS:sty

bc: Paul Rosendahl, Ph.d.

Emission Studies - Impact on Keahole Agricultural Park

Report - 2004 June 27
Robert E. Paull
5393 Poola Street
Honolulu, HI 96821

Summary:

An evaluation was made of the potential effects of ethylene, sulfur dioxide (SO_2) and nitrogen oxide (NO_x) emissions from the expanded generating station on plants and crops in the Keahole area. Of these emissions, ethylene has the greatest potential to adversely impact plant growth and development, while SO_2 and NOx would cause phytotoxic symptoms on plants. Ethylene is a natural plant growth regulator used in agriculture in Hawaii and elsewhere to induce flowering of pineapple and ripening of bananas. The major urban and rural sources of ethylene are gasoline, diesel engines and fires. These sources lead to a localized increase in ethylene that may exceed the plant response threshold concentration influence plant growth. The other component of a plant's responsiveness to ethylene is the duration of exposure.

Based on my review, there will be no effect of the current operations or planned expansion at the generation plant on the plants growing in the agricultural park. This belief is based on the following:

The plume from the stacks are estimated to only impact the agricultural park an average of three 15 minute period per month with another 21 possible impacts of less than 15 minutes, giving a possible total of 24 per month.

The highest ethylene levels recorded for brief periods in the agricultural park are similar to those found in urban air in which the main source is automobile exhaust. The agricultural park would be exposed to ethylene from all sources in the area for 15 minutes at 1/10 of the concentration of the 8 hour recommended American Hygiene Association Rural Standard (0.05 $:L{\bullet}L^{-1}$). The American Hygiene Standard and the higher California Standard are commonly used measures to avoid crop damage.

There are no known published reports dealing with injury to ornamental plants including orchids, from ethylene, sulfur dioxide or nitrogen dioxide at the concentrations, frequency and exposure duration of gases from the generation plant impacting the agricultural park. The lack of published reports is due in part to the difficulty of performing these types of experiments and the lack of observable plant responses at these concentrations and exposure durations.

In summary, I anticipate no effect of the current or planned expansion at the generation plant on the agricultural park or surrounding area.

Report

This report is based on current studies on plant stress responses, the effects of ethylene and SO_2 on plants, and on the evaluation and review of the following documents:

1. Summary of Air Quality Studies - Keahole Agricultural Park. Prepared by CH2M Hill - 1993 November 08.
2. Plume Impact Study at Keahole Agricultural Park. Prepared by B. D. Neal & Assoc., - 1993 September.
3. Letter from Odgen Environmental and Energy Services. Dated 1993 March 31
4. Air Quality Study Acid Aerosol and Ethylene. Report. Prepared by J. W. Morrow Environmental Management Consultant - 1993 September 22.
5. Focused Ecological Risk Characterization - Three Short Reports. 1993 January 20 to 1993 October 29. Jennifer Holder & Alvin Greenberg.
6. Computer Search of Published Reports on the impact of ethylene, SO_2 and NO_X on plant growth development and toxicity.

For the purposes of this report, the findings of Mr. Frank Camp of Jim Clary Associates have been used and relied upon.

The estimated maximum emission rates for SO_2 and NOx for the CT-4/5 project are 221 lbs SO_2 per hour (964 tons SO_2 per year) and 93 lbs NOx per hour (371 tons NOx per year). These emission rates are documented in the Hawaii Department of Health's (DoH) September 28, 1995 Ambient Air Quality Impact Report, Table 1, page 31. Per DoH's July 30, 1997 Supplement B.1 to the Ambient Air Quality Impact Report, the NOx allowable emissions increases due to the project will be offset by contemporaneous NOx emissions decreases by shutting down diesel units D18, D19, and D20 and limiting operations of unit D21. This will result in a net NOx emissions increase for the project of 39.8 tons per year. Since this net increase is less than the 40 tons per year NOx Prevention of Significant Deterioration (PSD) significance level, project NOx emissions are not subject to PSD review requirements, including Best Available Control Technology.

The maximum impacts of project SO_2 emissions are shown in DoH's December 27, 2000 Ambient Air Quality Impact Report, Supplement D, Table 2, page 13. After adding modeled project SO_2 impacts to monitored area background SO_2 concentrations, the combined maximum impacts are 468 ug SO_2/m3 (3-hour average), 105 ug SO_2/m3 (24-hour average), and 18 ug SO_2/m3 (annual average). These impacts represent 36%, 29%, and 23% of the corresponding State Ambient Air Quality Standards, respectively, which are established to be protective of public health. Supplement D reports no NOx impacts since the project will have a net NOx emissions increase that is less than the PSD significance level.

Regarding ethylene, the January 1993 PSD Permit Application for the CT-4/5 project, Section 6.2 (Vegetation and Soils Impacts), page 6-2, reports a maximum predicted 24-hour ethylene concentration from the proposed project of 0.03 ug•m^3. The ethylene computer output files are contained in Appendix F of the January 1993 PSD Application. The ethylene emission rate used in the modeling was 0.0266 grams per second. Adding the 0.03 ug•m^3 value to the background ethylene concentration of 1.5 ug•m^3 reported in the June 1988 Keahole

Environmental Assessment report results in a maximum ethylene impact of 1.53 ug•m^3. The ethylene monitoring conducted by J.W. Morrow as reported in Attachment C (Table 3, page 6) to CH2M Hill's Summary of Air Quality Studies at the Keahole Agricultural Park (December 1993 Keahole Revised Final EIS, Section 9) reports a maximum ethylene concentration in one sample of 1.3 ug•m^3.

In summary, the studies indicate infrequent plume impact on the agricultural park at Keahole. The plume is estimated to impact the agricultural park an average of 3 times for a 15 minute period per month with another 21 possible impacts, giving a total of 24 per month. The highest value for ethylene recorded was 1.3 :g•m^{-3}, sulfur dioxide - 24.1 :g•m^{-3}, HCl - 0.4 :g•m^{-3}, HNO_3 - 14.2 :g•m^{-3}, and H_2SO_4 - 4.5 :g.•m^{-3}.

All of the components measured in the above Air Quality studies have been shown in studies to cause phytotoxicity. Injury is very dependent upon a number of factors, such as dose and exposure time, biological sensitivity and multiple pollutant interaction. A difficulty arises in extrapolating from laboratory, field and greenhouse studies to real world exposures. These studies are most commonly based upon continuous exposure at dose levels known to give phytotoxicity. The difficulty is compounded by lack of information of responses of many crops, such as orchids, to many atmospheric pollutants.

In reviewing the information provided, for ease of summarizing, I will address the most important pollutants measured, ethylene, sulfur dioxide and nitrogen dioxide. The sulfur dioxide and other components measured are also components of VOG that would be expected to have a regular impact on this area. It would be difficult to separate the effects caused by different sources.

1. Ethylene:

Ethylene (ethene) is a volatile gas that has considerable effect as a regulator of plant growth. This is one of many volatiles released by plants. Ethylene is an unsaturated two-carbon gas (MW 28.05) and, besides being biologically significant, it is used commercially (Abeles et al., 1992). For example, ethylene is used commercially to induce pineapple flowering and fruit coloring in Hawaii, to ripen bananas worldwide and to induce flowering in crops such as guava. Stress such as drought, disease, insect attack, cold or heat all can induce ethylene synthesis by plants. Ethylene produced by these stresses plays a crucial role in modifying plant development (Dolan, 1997).

Ethylene is flammable and colorless, with low solubility in water. Ethylene can be expressed as :L•L^{-1} or on a mass basis :g•m^3 that avoids temperature differences . The specific volume of ethylene is 861.5 mL•g^{-1} at 21C, the same as nitrogen, therefore 1 :L•L^{-1} ethylene equals 1.15 mg•m^{-3}. It has full biological activity at 1 :L•L^{-1} (Abeles, 1973). Its use as an anesthetic in operations was discontinued in the 1930s (Chipman, 1931) due to fires and explosions (Guthrie and Woodhouse, 1940).

The analogues of ethylene; acetylene and propylene, are also phytotoxic air pollutants (Lonneman et al., 1974). These olefins cause similar symptoms to ethylene, but require higher concentrations (100 to 1,000 fold) to produce similar injury as ethylene (Burg and Burg, 1967).

Three major sources of ethylene are fires, automobiles and industry (Abeles et al., 1992). Plants do not produce enough ethylene to alter levels in the air above the fields (Lonneman et al., 1974). High levels of ethylene (0.6 :L•L^{-1}) can be found in soil due to microbial activity associated application of organic compost and soil compaction (Perret and Koblet, 1984; Campbell and Moreau, 1979).

Fires lead to localized production of ethylene (Sandberg et al., 1975). The conversion factors can vary from 0.002% for efficient incinerators to 1.5% for open fires (Feldstein et al., 1963). Rice stubble smoke has 4 :L•L^{-1} ethylene near the fire, dropping to ambient levels within 1 mile of the fire (Sawada, 1985). Automobiles, trucks and other gas engines are the major sources of ethylene in the urban environment (30 to 75% of the total in the environment) (Lonneman et al., 1974; Mayrsohn et al., 1977). These engines also produce methane and other hydrocarbons (Nelson and Quigley, 1984). Car engines without catalytic converters produce about 300 :L•L^{-1}, a converter reducing this by 60% (Nelson and Quigley, 1984).

Stress ethylene is produced by plants and can confuse the effect of external ethylene sources (Abeles et al., 1992). This stress ethylene is produced in response to both environmental and biotic (disease and insects) stresses constantly impacting plants in the field (Abeles et al., 1971). Another source of ethylene is organic material applied to a field to improve soil condition (Perret and Koblet, 1984). This ethylene may play a significant role in root growth and development.

In rural unpolluted air, ethylene levels of from 0.001 to 0.005 :L•L^{-1} are found. Urban air levels are 10 to 100 fold higher. The recommended air quality standard for California (1962) are 0.5 :L•L^{-1} for 1 hour or 0.1 :L•L^{-1} for 8 hours. The American Hygiene Association rural recommendation for ethylene level is 0.25 :L•L^{-1} for 1 hour and 0.05 :L•L^{-1} for 8 hours. The residential standards are 0.5 :L•L^{-1} for 1 hour and 0.1 :L•L^{-1} for 8 hours. (1 ppm = 1 :L•L^{-1} = 1150 :g•m^{3}).

Ethylene is removed rapidly from the atmosphere by a number of mechanisms. The mechanisms include photochemical oxidation, photolysis, and reaction with other reactive species (Derwent, 1995). The lifetime of ethylene in the air has been variously reported of from 0.4 to 4 days. Plants also metabolize ethylene.

The highest levels recorded at Keahole are similar to those found in urban air in which the main source is automobile exhaust. Common sources in an orchid shade house would be gas engine exhausts (automobiles, carts, gas sprayers, tractors, etc.), rotting plant material and fires (including cigarettes). To determine if plume ethylene was involved in any phytotoxicity would involve eliminating other possible sources.

2. Sulfur dioxide and Nitrogen dioxide:

Sulfur dioxide (SO_2) is the main sulfur compound emitted into the atmosphere. This is oxidized to SO_3 that form sulfuric acid (H_2SO_4) when hydrated.

$$SO_2 \text{ ------oxidation------> } SO_3$$

$$SO_3 + H_2O \text{ ------> } H_2SO_4 \text{ ------> } \text{Aerosol} \text{ ------> } (NH_4)_2SO_4$$

The most common anthropogenic source of sulfur dioxide in the atmosphere is the combustion of fossil fuel, coal and oil. In parts of the Hawaiian islands, the major source is volcanism, where sulfur dioxide is the primary plant noxious gas in the plume (Winner and Mooney, 1980). Another source of sulfate in the atmosphere is sea spray and in Hawaii this is probably the single largest incessant source. Sodium sulfate is the second most abundant compound in dissolved seawater (Smil, 1985). The other major additional source of sulfur in the atmosphere are the numerous reduced forms that become oxidated to sulfuric acid. These volatile compounds are released by bacteria, algae and plants. In this evaluation, since the SO_2 released by the generating plant is less than the EPA significance levels of 5 :g•m^{-3}, it is assumed that all is converted to H_2SO_4 and none is converted to the more stable form such as $(NH_3)_2SO_4$.

Background concentrations of SO_4^{2-} over remote oceans and clean continental air are less than 5 :g m^{-3} (Smil, 1985). More common values in non-industrial areas over continents is 10 mg m^{-3} with many urban areas having a mean of 106 mg•m^{-3}. The values vary widely with weather, with rainfall reducing levels dramatically. These values are for total SO_4^{2-} that includes sulfuric acid whose contribution will depend in general upon the amount of SO_2 emissions and the rate of oxidation to SO_4^{2-}, without conversion to other salts ($(NH_3)_2SO_4$, $MgSO_4$, etc.). The acidity due to H_2SO_4 and a complex mixture of other acidic compounds have been monitored on Mauna Loa and have all been in the acid range (pH 3.3 to 6.7; median pH 5.0). In the Mauna Loa data, the rains coming from every quadrant were acidic. Rain at lower elevation (Kapoho - sea level) was less acidic (pH 5.6) (Sequeira, 1982).

Plants respond to both sulfur dioxide and sulfuric acid, with long term, low level exposures in some instances being beneficial, especially if the soil is deficient in sulfur. Sulfur, especially as the sulfate in sulfuric acid, is an essential plant nutrient. Ammonium sulfate is sold commercially as a plant fertilizer. It is also much easier to routinely measure SO_2 in the atmosphere that the amount of sulfuric acid aerosol (Smil, 1985). Sulfates are the leading aerosol in the fine size category in the atmosphere from H_2SO_4 to $MgSO_4$, the latter from sea spray, while the former is a secondary air pollutant derived from SO_2.

Sulfur dioxide and nitrogen dioxide will be considered together as the interaction tends to be more likely to be phytotoxic than the individual components separately. Unfortunately, the low plume impact duration would be unlikely to have any phytotoxic effects. Two days exposure has been shown to significantly reduce potato plant leaf area but not dry weight. No data is known for orchids. Continuous exposure to 0.05ppm (131 ug•m^{-3}) is regarded as a threshold for growth reduction, though some plants do show responses below 0.05ppm.

3. Ethylene and Sulfuric Acid Effects on Plants

Ethylene effects on plants had been described in detail from laboratory and green house studies (Abeles et al., 1992). In general, the adverse symptoms include general reduction in growth, stimulation of lateral growth, leaf chlorosis and abscission, bud and flower abscission, and fruit chlorosis and ripening (Heck and Pires, 1962; Heck et al., 1970). Acute rapidly appearing symptoms do not occur, symptoms are associated with chronic exposure to ethylene (Abeles, 1973).

Ethylene can inhibit or promote the elongation of growing stems, roots and other organs (Dolan, 1997). Inhibition of elongation by ethylene is the normal response in intact plants and is both rapid and reversible. Growth promotion occurs in stems, petioles and fruit peduncle especially in aquatic plants (Abeles, 1973). Epinasty, the downward curvature of leaves, is a reversible symptom of ethylene exposure. It is, however, not a common response. Of 202 species tested, only 72 exhibited marked epinasty (Crocker et al., 1932). When it does occur, it is rapid usually occurring within 6 hours (Palmer, 1972).

The symptoms of SO_2 damage on plants are well known. The injury appears generally on the leaves a bleached brownish or yellowish spots or blotches interveinal chloric with areas of dead tissue. Species variation in sensitivity to SO_2 is significant. For example, while beans are sensitive, celery, corn and potatoes are quite tolerant (Rennie and Halstead, 1977).

Sulfuric acid damage has only been described for acute injury. In this case, the symptoms include chlorosis and rapid death of leaves and stems that have been treated. The injury does not spread beyond the affected areas. Species differ widely in their response to lower concentrations (Glass et al., 1982). Crops grown to harvest exposed to 30 millimeters of H_2SO_4 rain per week at pH 3.0, 3.5 and 4.0, had yield reduction in 5 crops including tomato, green pepper and strawberry, variable results with potato and no significant response in 15 other plant species. Sulfuric acid aerosols did not damage soybean and bean plants (Herzfeld, 1982), while $(NH_4)_2SO_4$ aerosols cause chlorosis and necrosis of bean plants (Gmur et al., 1983). In these last two studies, the aerosol concentrations were orders of magnitude higher than ambient concentrations. Dicotyledonous plants are more sensitive than grasses (monocotyledons). This overall resistance of plants to H_2SO_4 bears out the older finding of Thomas et al. (1943) that SO_2 is 30 fold more toxic than SO_4^{2-} to plants.

4. Ethylene and Sulfuric Acid Concentrations and Time Responses

Ethylene response is dependent upon three major factors, dose, exposure time and biological sensitivity. A difficulty arises in extrapolating from laboratory, greenhouse studies to real world exposures. These studies are most commonly based upon continuous exposure at dose levels known to give phytotoxicity after a certain period.

Predicting response to ethylene is confounded by a lack of information on the sensitivity of many crops to ethylene (Heck and Pires, 1962). To indicate a range of sensitivity, cut dendrobium flower sprays are injured by exposure to 3 mg l^{-1} for 48 hours, while only 6-hour continuous exposure at 0.1 mg l^{-1} is necessary for the more ethylene sensitive *Cattleya* species (Goh et al., 1985). The half maximum effective concentration for most physiological effects is between 0.1 to 1 :L•L^{-1} (Abeles et al., 1992). The threshold concentration is about 1/10 of these values: 0.01 to 1 :L•L^{-1}, the saturation response occurs in the range of 10 to 100 :L•L^{-1} (Abeles et al., 1992). Additional ethylene to supra-optimal concentrations has no other toxic effects on plant cells. These values are obtained using continuous exposure to ethylene and from dose response curve studies of leaf and fruit abscission, epinasty, fruit ripening, flower senescence, hook closure, inhibition of root elongation and seed germination.

The duration of applied ethylene necessary for an effect decreases with plant age (Abeles, 1973). This reflects, in part, tissue sensitivity to ethylene, this sensitivity varies from plant species, tissue, stage of development and inherent stress response. Minimum exposure periods vary with concentration, for example 1 hour at 80 :L•L^{-1} , 2 :L•L^{-1} for 6 hours, or 0.3 :L•L^{-1} for 24 hours for iris flowering (Yue and Imanishi, 1988).

The threshold concentration for ethylene response is continuous exposure to 0.01 :L•L^{-1} and the half maximal response continual exposure concentration is between 0.1 to 1 :L•L^{-1} . The air standards for ethylene cited above should therefore prevent most injury to plants. Numerous plants have been ranked as to their ethylene sensitivity (Table 1 & 2) with the ranking based upon exposure to ethylene at up to 15 :L•L^{-1} for 24 hours to 10 days. For example, carnation, cucumber, lettuce, rose and tomatoes are all regarded as sensitive showing some effects to such exposure, while sugar cane, cabbages and onions are not sensitive.

Goh et al., (1985) showed a reduction in fresh weight of cut dendrobium flower sprays occurred with 3 parts per million (ppm) for 48 hours. The relationship of a cut spray to field responses of plants is unknown. The continuous 48-hour exposure that showed a fresh weight loss has not been shown to occur at Keahole. The dry sepal in orchids reported after 6 hours at 0.1 ppm is for the more ethylene sensitive *Cattleya* species, this is a 6-hour continuous exposure. Hence, continuous exposure (6 hours or more) does pose a risk, however, the absence to data, of any specific damage ascribable to the current generation facilities of the diesels with 20-foot stacks and the one turbine coupled with the very short duration of plume impacts makes ethylene related phytotoxicity most unlikely in the future. The ethylene concentration is ca. 5 :L•L^{-1} , if a 10,000 dilution occurs this would give a 0.5 nL•L^{-1} at the agricultural park. The American Hygiene Association has set a rural standard of 0.25 :L•L^{-1} for 1 hour and 0.05 :L•L^{-1} for 8 hours continuous exposure. The agricultural park would see 1/100 of the 8 hours exposure for periods less than 1 hour.

The difficulty with the above analysis is the infrequency and short duration of plume impact on the agricultural park and lack of any information on orchid phytotoxicity to these gases. The short duration of plume impact that is probably not continuous but intermittent makes extrapolation from research results extremely difficult, as most of the research is based upon continuous chronic exposure of 24hours or more. In addition, phytotoxicity would not be immediately obvious under these circumstances. Cumulative response would not be expected with the impact duration and dose levels expected to affect the agricultural park. There has always been great problems in the published studies and other research, of expressing dose so that it adequately measure biological response under intermittent situations of vary times and concentrations.

Plant responses to sulfate in the atmosphere depend very much on the cation. The secondary pollutant, sulfuric acid (H_2SO_4) being more reactive than the $MgSO_4$ derived from sea spray. Strong sulfuric acid causes rapid acute damage to plants, however, exposing plants to 95% H_2SO_4 aerosols for two weeks showed no toxicity symptoms (Wedding et al., 1979). Exposure of plants to SO_2 can cause damage with a threshold for growth reduction being 0.5 ppm (131 :g•m^{-3}) (Darrall, 1989). Dry deposition of sulfates on plants can cause serious damage. Many plants can also take a large share of their sulfur needs (25 to 50%) directly from the air (Noggle, 1980).

The difficulty with the work on H_2SO_4 and plant injury is to calculate a threshold. In the data cited above from Glass et al. (1982) a 30 mm rainfall of pH 3.0 H_2SO_4 per week translated to spray with 1¼" of simulated rate with about 1mM H_2SO_4. This acid strength is equal to 102 mg•l^{-1} H_2SO_4 (102 ppm) or 40.6 mg•m^{-3}.

There is one publication dealing with the effects of sulfur dioxide on Orchids (Nyman et al., Envir. Exp. Bot. 30:207-213). The work was done with two epiphytic Florida orchids using SO_2 and O_3. Exposure to 0.6 ppm SO_2 (2 hour) or 0.3 ppm O_3 plus 0.6 ppm SO_2 (2 hour) did not exhibit visible injury.

I found no citations dealing with orchids and NO_x. Bougainvillea and Hibiscus are regarded as most sensitive to NO_x. The symptoms are necrosis and defoliation after exposure to 10 to 250 ppm for 0.2 to 8 hours. Your expected stack emissions is 42 ppm, after a 1/10,000 dilution 0.0042 ppm.

5. Air Standards for Ethylene

The unpolluted air ethylene ranges from 0.001 to 0.005 :L•L^{-1}, with urban roadside levels of 10.8 :L•L^{-1} and remote maritime location being as low as 0.00004 :L•L^{-1} (Derwent, 1995). The concentration in the air varies with time of day and season (Dollard et al., 1995). Urban air levels are 10 to 100 fold higher than rural; 0.5 :L•L^{-1} California, 0.2 :L•L^{-1} Germany, 0.03 :L•L^{-1} New York City and 0.7 :L•L^{-1} Washington D.C. (cf. Abeles et al., 1992). There are no national standards; however, there are recommended levels. For example, recommended levels in California are 0.5 :L•L^{-1} for 1 hour or 0.1 :L•L^{-1} for 8 hours (Anon, 1962). The American Industrial Hygiene Association has set recommended levels of ethylene for rural air of 0.25 :L•L^{-1}, 0.5 :L•L^{-1} residential, both for 1 hour and 0.05 and 0.1 :L•L^{-1} for 8 hours respectively (Anon, 1968).

6. Conclusions

The difficulty with the above analysis is the infrequency and short duration of plume impact on the agricultural park and lack of any information on orchid phytotoxicity to these gases. The short duration of plume impact that is probably not continuous but intermittent makes extrapolation from research results extremely difficult, as most of the research is based upon continuous chronic exposure of 24 hours or more. In addition, phytotoxicity would not be immediately obvious under these circumstances. Cumulative response would not be expected with the impact duration and dose levels expected to affect the agricultural park. There has always been great problems in the published studies and other research, of expressing dose so that it adequately measure biological response under intermittent situations of vary times and concentrations.

The overall conclusion is of no anticipated effect of the current or planned expansion at the generation plant on the agricultural park. A reduction in ethylene levels and therefore potential impacts on the agricultural park in the future would be anticipated. This reduction would occur as the diesels generators are phased out and simple combustion cycle and combined cycle combustion turbines are used exclusively.

Table 1 . Sensitivity of selected plants to ethylene from Heck and Pires (1962), Goh et al. (1985) and Woltering (1987). These observations are based upon continuous exposure of up to 15 :L•L^{-1} ethylene from 24 hours. to 10 days. * Indicated crops potentially grown in the Keahole area.

Sensitive	**Immediate**	**Resistant**
Begonia	Azalea	Anthurium
Carnation	Broccoli	Cabbage
Cattelya Orchid	Carrot	* Cordyline
Cucumber	Cyclamen	* Dendrobium Orchids
Euphorbia keysii	* Gardenia	* Dieffenbachia
Fuschia	Pelargonin	* Dracaena marginata
Lettuce	Primula	* Oncidium Orchids
Marigold	Soybean	Onion
Philodendron	Squash	Radish
Rose		
Sweet Potato		
Tomato		
* Vanda Orchid		

Table 2. The sensitivity of flower petals to ethylene exposure, and the symptoms displayed.[x].

Species	Sensitivity[y]	Symptoms[z]
Abelia schumanii	4	a
Acanthus hungaricus	4	a
Acanthus spinosus	4	a
Achillea filipendula	0	w
Aconitum napellus	3	a
Aeschynanthus sp.	4	a
Agastachefoeniculum	4	a
Alisma parviflora	4	w
Alliaria petiolata	4	a
Allium caeruleum	1	w
Allium cernuum	0	w
Allium sphaerocephalon	0	w
Alstromeria pelegrina	2-3	wa
Althaea officinalis	3	w
Anagallis arvensis	3	a
Andromeda sp.	3	a
Anemone (hybrid) (cv. Elegans)	4	a
Anethum graveolens	0	w
Anigozanthos spp. (3 species)	0	w
Antirrhinum majus	3	a
Arabis caucasia	4	a
Armeria maritima	3	w
Armeria pseudoarmeria	4	w
Asclepias tuberosa	2	w
Asperula tinctoria	3	a
Asphodeline lutea	0	w
Asphodelus albus	0	w
Aster novi-belgii	0	w
Baldellia ranunculoides	4	w
Bergenia cordifolia	0	w
Bloomeria aurantiaca	3	w
Borago officinalis	4	a
Brassica napus	4	a
Brodiaea californica	0	w
Brunnera macrophylla	4	a
Buglossoides purpurocaerulea	4	a
Calceolaria sp.	4	a
Calluna vulgaris	0	w
Camassia leichtlinii	0	w
Camassia quamash	0	w
Campanula garganica	4	w
Campanula glomerata	3	w
Campanula pyramidalis	4	w
Canna hybrid (3 cultivars)	0	w
Cardamine pratensis	4	a
Carpathea pomeridiana	4	w
Cattleya (hybrid)	2-3	w
Centaurea cyanus	0-1	w
Centranthus ruber (cv. Albus)	3	a
Centranthus ruber (cv. Coccineus)	3	a
Cephalaria alpina	2-3	wa
Cephalaria gigantea	2	wa
Ceratostigma plumbaginoides	4	w
Chasmanthe aethiopica	0	w
Cheiranthus sp.	4	a
Chelidonium majus	4	a
Chelone barbatus	3	a
Chelone obliqua	1-2	a
Chrysanthemum maximum	0	w
Chrysanthemum morifolium	0	w
Chrysanthemum parthenium	0	w
Chrysanthemum segetum	0	w
Claytonia sp.	3	w
Colchicum autumnale	0	w
Colchicum speciosum	0	w
Columnea krakatau	4	a
Columnea nesse	4	a
Commelina sp.	4	w
Convolvulus arvensis	4	w
Conium maculatum	0	w
Convallaria majalis	0	w
Corydalis sp.	2	wa
Crassula falcata	0	w
Crocosmia x crocosmiiflora	1-2	wa
Crocus chrysanthus	0	w
Crossandra sp.	4	a
Cyclamen (hybrid)	4	a
Cymbidium (hybrid)	4	cyw
Cymbidium (hybrid)	4	cw
Cyrtanthus purpureus	2	w
Dahlia (hybrid)	1	w
Delospermum cooperi	3	w
Delospermum lyndenburgensis	4	w
Delphinium ajacis	4	a
Dendrobium phalaenopsis	3	w
Deutzia scabra >Macropetala=	4	a
Deutzia schneideriana	4	a
Dianthus barbarus	4	w
Dianthus caryophallus (spray)	4	w
Dianthus caryophyllus (standard)	4	w
Dicentra formosa	2	wa
Dicentra (hybrid)	2	wa
Dorotheanthus bellidiformis	4	w
Dracocephalum nutans	4	a
Echeveria setosa	0	w
Echium plantagineum	4	a
Edraianthus graminifolius	3	w
Eremurus (hybrid)	0	w
Erica gracilis	0	w
Erica hiemalis	0	w

Erica tetralix	0	w
Erigeron (hybrid)	0	w
Erysimum cuspidatum	3	a
Erythronium americanum	3	wa
Eschscholzia sp.	4	a
Eucomis bicolor	0	w
Euphorbia fulgens	1	w
Exacum affine	0	w
Forsythia intermedia	4	w
Freesia (hybrids)	0	w
Fumaria sp.	2	wa
Galanthus nivalis	0	w
Galium aparine	3	a
Galtonia candicans	0	w
Galtonia sp.	0	w
Gaultheria shallon	3	a
Gentiana dahurica	0	w
Gentiana kochiana	0	w
Gentiana sino-ornata	0	w
Geranium gracile	4	a
Geranium nodosum	4	a
Geranium sanguineum	4	a
Gerbera jamesonii	0-1	w
Geum (hybrid)	4	a
Gladiolus (hybrid)	0-1	w
Gloriosa superba (cv. Rothschildiana)	0	w
Gratiola officinalis	3	a
Gypsophila paniculata	4	w
Helianthus annuus	0	w
Helipterum manglesii	0	w
Helipterum roseum	0	w
Hemerocallis	0	w
Hemerocallis lilio-asphodelus	0	w
Hippeastrum ackermannii	3	w
Hosta lancifolia	0	w
Hosta latifolia	0	w
Hosta tardiana	0	w
Hosta undulata	0	w
Hyacinthus orientalis	1-2	w
Hyacinthoides non-scipta	0	w
Incarvillea delavayi	4	a
Iochroma (hybrid)	3	wa
Ipomoea alba	4	w
Iris (hybrid)	0-1	w
Iris germanica	0	w
Iris halophyta	0	w
Iris sibirica	0	w
Ixia flexuosa	0	w
Ixora (hybrid)	3	a
Jasmium officinale	4	a
Kalancho blossfeldiana	2	w
Kalmia latifolia	4	a
Kohleria (hybrid) (cv. Eriantha)	4	a
Kniphofia (hybrid)	1	w
Kirengeshoma palmata	4	a
Lachenalia sp.	0	w
Laurentia fluviatilis	3	w
Lavatera maritima	4	w
Leicesteria formosa	4	a
Leucothoe axillaris	3	a
Leucothoe walterii	3	a
Lewisia cotyledon	4	w
Liatris spicata	0	w
Ligustrum ovalifolium	4	a
Lilium (hybrid)		
(cv. Brunello - Oriental hybrid)	1	w
(cv. Montenegro - Oriental)	0	w
(cv. Star Gazer - Aseatic hybrid)	2	w
(cv. Woodruff Memory - Aseatic hybrid)	0-1	w
Lilium martagon	3	wa
Limonium latifolium	3	w
Lindolofia stylosa	4	a
Liriope koreana	0	w
Lithops dorothea	3	w
Lobelia cardinalis	3	w
Lobelia siphylitica	2-3	w
Lonicera heckrottii (cv.Goldflame)	4	a
Lunaria rediviva	4	a
Lychnis chalcedonica	4	w
Lycopersicon esculentum	4	wa
Lysimachia ciliata	3	a
Lysimachia clethroides	4	a
Lysimachia punctata	4	a
Malva alcea	4	w
Malva sylvestris	4	w
Matthiola incana	2	w
Mentha suaveolens	4	a
Mertensia paniculata	4	a
Mesembryanthemum productus	3	w
Monopsis sp.	3	w
Muscari armeniacum	0-1	w
Narcissus pseudonarcissus	0	w
Nerine mansellii	0	w
Nerine sarniensis	0	w
Nicotiana tabacum	4	wa
Nerine bowdenii	0	w
Nierembergia sp.	3	wa
Nigella damascena	4	a
Nothoscordum aureum	0	w
Omphalodes verna	4	a
Ornithogalum thyrsoides	0	w
Ornithoglossum parviflorum	0	w
Papaver rhoeas	4	a
Paphiopedilum (hybrid)	2-3	w
Patrinia gibbosa	3	a
Penstemon cobaea	4	a
Penstemon heterophyllus	4	a
Penstemon serrulatus	3	a

Pentas lanceolata	4	a
Petunia hybrid	4	wa
Phalaenopsis (hybrid)	3	w
Phlox paniculata	3-4	wa
Phygelius sp.	3	a
Physostegia virginiana	3	wa
Phyteuma scheuchzeri	2	w
Pieris japonica	0	w
Plumbago auriculata	4	w
Polemonium foliosissimum	2	wa
Polianthes tuberosa	0	w
Polygonatum odoratum	0	w
Portulaca grandiflora	4	w
Portulaca umbraticola	4	w
Potentilla (cv. Gibson Scarlet)	3	a
Potentilla grandiflora	4	a
Primula denticulata	2-3	wa
Primula rosea (cv. Grandiflora)	2-3	wa
Primula vialii	2	w
Pulmonaria officinalis	4	a
Quamoclit coccinea	4	w
Rhododendron brachycarpum	4	a
Rhododendron (hybrid) (several cvs)	4	a
Ribes aureum	3	a
Rosa (hybrid)(cvs. Amsterdam, Sonia)	3	a
Rosa (hybrid)(cvs. Betty, Director Riggers, Fanal, Friedrich Heyer)	4	a
Rubia tinctorum	3	a
Rudbeckia (hybrid)	0	w
Sabatia sp.	0	w
Sagittaria lancifolia	4	w
Saintpaulia confusa	4	a
Saintpaulia tongwensis	4	a
Salvia (cv. Mainacht)	4	a
Salvia superba	4	a
Sambucus nigra	4	a
Sandersonia aurantiaca	0	w
Sansevieria sp.	0	w
Saxifraga litacina	0	wa
Scabiosa caucasia	2-3	w
Sedum (hybrid)	0	w
Sedum spectabile	0	w
Sedum spurium	1	w
Sempervivum sp.	0	w
Sinningia cardinalis	4	a
Sisyrinchium angustifolium	4	w
Sisyrinchium californicum	4	w
Sisyrinchium laevigatum	4	w
Solanum dulcamara	3	w
Solidago (hybrid)	0	w
Streptocarpus (hybrid)	4	a
Succisella inflexa	3	w
Symphytum cordatum	4	a
Symphytum grandiflorum	4	a
Symphytum ottomanum	4	a
Syringa vulgaris	4	a
Thunbergia alata	4	a
Tiarella cordifolia	0	w
Tigridia pavonia	0	w
Torenia (hybrid)	4	a
Trachelium caeruleum	3	w
Tradescantia (hybrid)	4	w
Tricyrtis latifolia	0	w
Triteleia laxa	0	w
Tritonia crocata	0	w
Tulbaghia violacea	0	w
Tulipa gesneriana (cvs. Ad Rem, Gander=s Rhapsody, Rosario)	0	a
Cecreado, Yokohama)	1	w
(cvs. Golden Apeldoorn, White Dream)	1-2	w
(cv. Lucky Strike)	2	w
(cvs. Alba, Leen van der Mark, Lustige Witwe)	1	w/wa
(cv. Pink Impression)	2	w/wa
Vaccinium macrocarpon	4	a
Valeriana officinalis	4	a
Veronica longifolia (cv. Blauriesin)	4	a
Veronica orchidea	4	a
Veronica spicata (cv. Alba)	4	a
Satureja vulgaris	4	a
Saxifraga apiculata	0	wa
Saponaria (hybrid)	4	w
Saxifraga arendsii (cv.	0	wa
Schneeteppich)*Viburnum henryi*	4	a
Viburnum lobophyllum	4	a
Weigela florida	0	w
Weigela (cv. Gustave Mallet)	0	w
Zebrina pendula	3	w
Zephyranthes candida	0	w
Zinnia elegans	0	w

[x] After: Woltering, E.J. and W.G. van Doorn. 1988. J. Exp. Bot. 39:1605-1616; van Doorn, W.G. 2000. Ann. Bot. 87:447-456.

[y] Sensitivity: 0 = insensitive; 1 = low; 2 = intermediate; 3 = high; 4 = very high.

[z] Petal symptoms: w = wilting; a = abscission; wa = wilting and abscission; w/wa = wilting, sometimes wilting and abscission; c = coloration; y = yellowing.

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SOCIO-ECONOMIC IMPACT ASSESSMENT OF REDESIGNATION OF KEAHOLE GENERATING AND TRANSMISSION SITES

September 2004

Prepared for:

Belt Collins Hawaii

Hawaiian Electric Light Company, Inc.

SMS **Affiliations and Associations:**

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EXECUTIVE SUMMARY

Project: Hawaii Electric Light Company, Inc. (HELCO) is seeking redesignation of two adjacent parcels from Conservation to Urban, and rezoning as General Industrial. The sites are already occupied by the Keahole Generating Plant and Airport substation. With new designation and zoning, HELCO could install new equipment designed to minimize emissions and noise, and to increase both power generation and efficiency. With the redesignation, HELCO will be able to meet the terms of a settlement worked out with other parties who had been contesting HELCO's plans to expand generation at Keahole. (HELCO can go ahead under existing agreements and permits to bring on-line the new combustion turbines at Keahole.) The preferred alternative is "Plan 2" in this report

This report assesses direct, secondary and cumulative social and economic impacts of the proposed action and four alternatives.

Alternatives: If the redesignation is not sought and granted, HELCO can consider alternatives:

(a) No Action (Plan 1) – no further construction of new generating facilities, at Keahole or elsewhere. Under this alternative, Hawaii County will have generating capacity insufficient to meet demand as of about 2014;
(b) New generating capacity using fossil fuels in West Hawaii (Plan 3);
(c) New generating capacity using fossil fuels in East Hawaii (Plan 4); and
(d) New generating capacity using biomass, a renewable resouce (Plan 5).

All alternatives include the mix of power sources now being used by HELCO, including the new generators being put in service at Keahole. All the plans involving new generating capacity – i.e., all but the No Action alternative – bring on capacity in order to meet demand. The Preferred Action includes addition of a steam turbine (ST7) at Keahole about 2009, which would bring CT4 and CT5 into a dual train combustion cycle (DTCC) system.

Existing and Emerging Conditions: West Hawaii has seen continuing population growth and economic growth over the past years. It accounts for about 40% of the island population. However, most of the electrical energy generated in Hawaii County comes from East Hawaii, and must be transmitted across the island to its major users. Development of new power sources is a priority for HELCO; development of those sources in West Hawaii is favored as cost-effective and efficient.

Issues and Concerns: The current proposal arises after a decade in which HELCO has sought to expand its generating capacity at Keahole but faced considerable opposition and skepticism. That opposition was part of a general trend to seek increased empowerment for West Hawaii, while distrusting decisions made in Honolulu or Hilo. A strong concern over the pace of development has also been felt in West Hawaii. Currently, that latter concern is prompting many residents to seek to slow residential and commercial development until infrastructure improvements – above all, road projects – are made to relieve congestion.

Since the early 1990s, Hawaii County energy consumers have had to deal with blackouts when the grid could not produce enough power to meet demand. Many see additional capacity as needed now. Interest in use of renewable resources, rather than fossil fuels, is strong.

Most stakeholders interviewed by SMS had no strong reaction to redesignation and rezoning at Keahole. Most saw it in relation to the settlement worked out between HELCO and other parties, and saw the settlement as an important step for the community.

Economic Impacts: Impacts due to construction and operation of new generating capacity are similar for the three alternatives involving fossil fuel plants. The No Action Alternative (Plan 1) would involve no construction or new operations, and hence no new jobs. The Renewable Alternative (Plan 5) calls for a much larger workforce than Plans 2 through 4.

Construction employment was estimated for all alternative plans, to the year 2025, based on construction cost estimates by HELCO. Over a twenty-year period, the Preferred Alternative (Plan 2) would demand some 321 person-years of work by construction workers, compared to 295 for Plan 3 (West Hawaii alternative), 284 for Plan 4 (East Hawaii alternative); and 747 for Plan 5 (renewable energy alternative.). The No Action Alternative (Plan 1) would involve no construction work. Direct construction work would further support indirect and induced jobs. The total number of jobs in Hawaii County (including direct jobs, ones supported by construction firms' purchases, and ones supported by workers' spending) would come to 662 person-years for Plan 1, 608 person-years for Plan 2, 586 person-years for Plan 3. and 1,539 person-years for Plan 5. Incomes generated for this total construction-related workforce would total approximately $24 million (2003 dollars) over twenty years for Plan 2, $22 million for Plan 3, $21 million for Plan 4, and $56 million for Plan 5.

New operations jobs would be created due to expanded generation and transmission capacity. For the three alternatives involving fossil fuel plants (B through D) the total new operations-related jobs would be in the range of 50 to 60 jobs by 2025 (including direct, indirect and induced jobs). For the Renewable Alternative (Plan 5), total operations-related jobs would climb over time to nearly 640 jobs.

With new jobs, workers could support families and households. The population supported by operations-related jobs in Hawaii County for the Plans 2 and 3 comes to 107 persons by 2025. For Plan 4 (East Hawaii Alternative), the total comes to 122 persons by 2025. For Plan 5 (the Renewable Alternative) the total operations-related population would reach 453 by 2025. New housing demand associated with these jobs and families would come to about 11 units for the fossil fuel-based alternatives, and 136 units for the Renewable Alternative.

The largest impact on the island economy derives from the No Action Alternative, which would fail to assure island residents and firms of electric power adequate to respond to demand as of about 2015. Uncertainty about power generation would raise operating costs for many firms and could lower productivity. Large resorts would likely be less affected than other customers, since these tend to be adopting distributed generation systems, in which they produce some of the power they consume and sell to the grid any excess.

Costs of the various plans for new generating capacity vary due to plant, transmission and fuel storage costs. When the development and operations costs through 2025 are added up and then analyzed in terms of net present value, the Preferred and West Hawaii alternatives would cost about the same ($1,808.5 million in 2004 dollars), and the East Hawaii alternative would be slightly more expensive ($1,819.8 million). The Renewable Alternative's cost ($1942.3 million) would be about 107.4% of the Preferred cost. The increased cost for the Renewable Alternative could amount to about $50 per year per ratepayer.

The major fiscal impact associated with the proposed action would be construction-related tax revenues for the State of Hawaii. These would amount to about $4 million (over time, to 2025, in 2003 dollars) for Plans 2 through 4, and nearly $10 million for Plan 5.

Social Impacts: Under the currently permitted work, two new generators are being installed at Keahole and a new stack is in place. The Preferred Alternative would add a steam turbine and emissions controls mandated in the settlement. Those activities would give nearby residents increased assurance that HELCO is monitoring and controlling noise and emissions, and that electricity is being produced in a relatively efficient, cost-effective manner.

Concern has been expressed that the presence of a generating station could affect property values. This is extremely unlikely. Sales values in the Agricultural Park are well above assessed values. Existing residential areas are nearly a mile or more away from the site. SMS ran a large-sample analysis of residential property sales and assessed values, to learn whether location of homes uphill from the Keahole industrial area (including the generating plant, the airport, and the Natural Energy Laboratory of Hawaii) was a factor helping to explain value. No significant association was found between location above the Keahole site and residential values.

A potential alternative site in West Hawaii, at Puuanahulu, would be separated from neighboring residential and resort areas by distance and topography. Little or no impact on the one major user of the area near the site – the County landfill – is anticipated. However, community concern has been voiced about increased truck traffic to and from the landfill due to the planned closure of the East Hawaii landfill. In that context, a proposal to add an industrial facility at Puuanahulu could well become a matter of concern to South Kohala residents.

If new generating facilities were located at Hill Plant in East Hawaii, they would be in an industrial area that is visible to much of Hilo and is close to areas recently redeveloped for retail uses. In light of the visibility of the site, the number of neighbors who could be affected or concerned by emissions and noise from the plant would be much larger than for the other sites considered here.

CONTENTS

EXHIBITS

INTRODUCTION

1.1 THE PROJECT

Hawaii Electric Light Company (HELCO) is seeking redesignation of two adjacent parcels from Conservation to Urban and rezoning as General Industrial. The sites are already occupied by the Keahole Generating Station (TMK 3-7-3-49: 36, 14.998 acres) and Keahole Airport Substation (TMK 3-7-3-49:37, 0.645 acres).

HELCO has proposed expansion of the Keahole Generating Plant since 1992 in order to meet demand in West Hawaii for increased firm generation capacity. That proposal has been the topic of much argument and litigation. In an Order filed on November 12, 2003, Judge Ronald Ibarra recognized a settlement worked out between HELCO and other parties, which would allow HELCO to move forward with permit applications, construction, installation, and operation of the new generating facilities. As part of the settlement, HELCO agreed to ask for the State Land Use and County zoning changes to ones appropriate for industrial activity.

In sum, the project consists of obtaining land use and zoning changes on land already in use for power generation and transmission. With new designation and zoning, HELCO could install new equipment designed to minimize emissions and noise and to increase both power generation and efficiency. This would allow HELCO to meet all the terms of the settlement.

Exhibit 1-A: LOCATION MAP

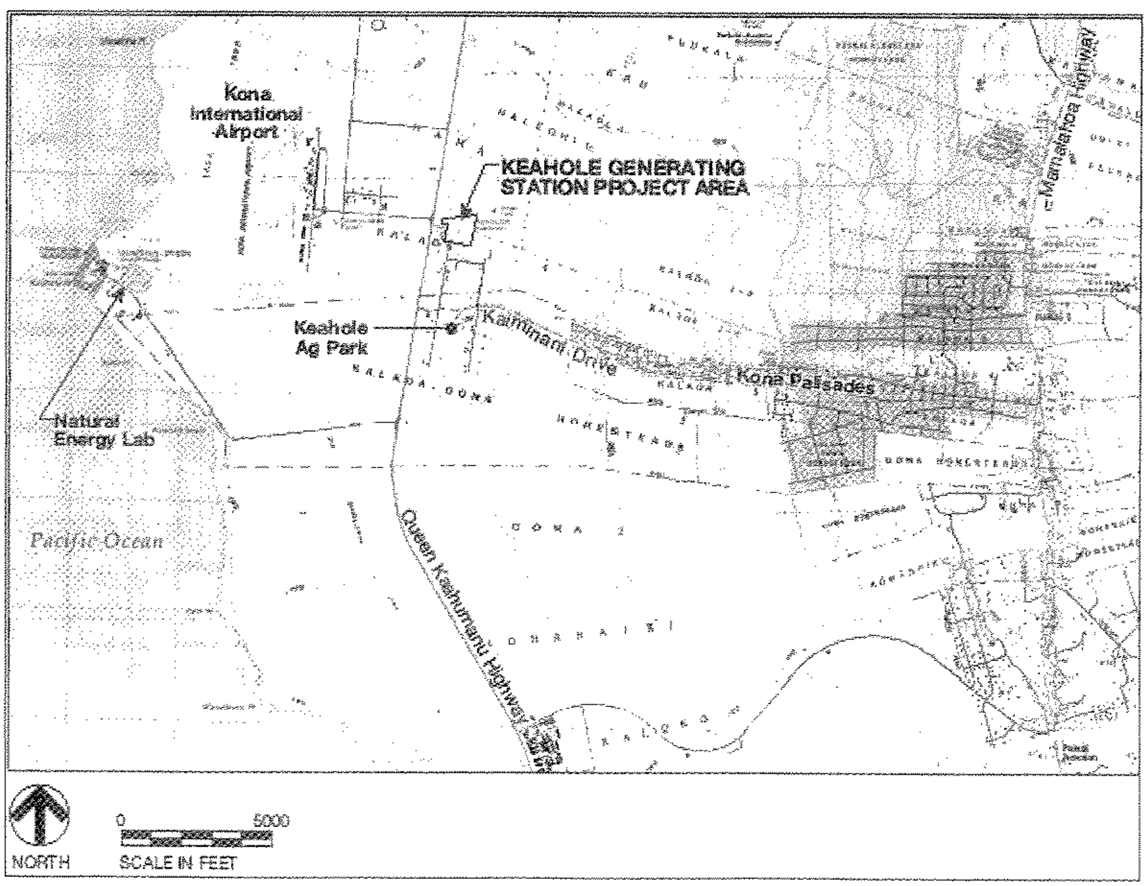
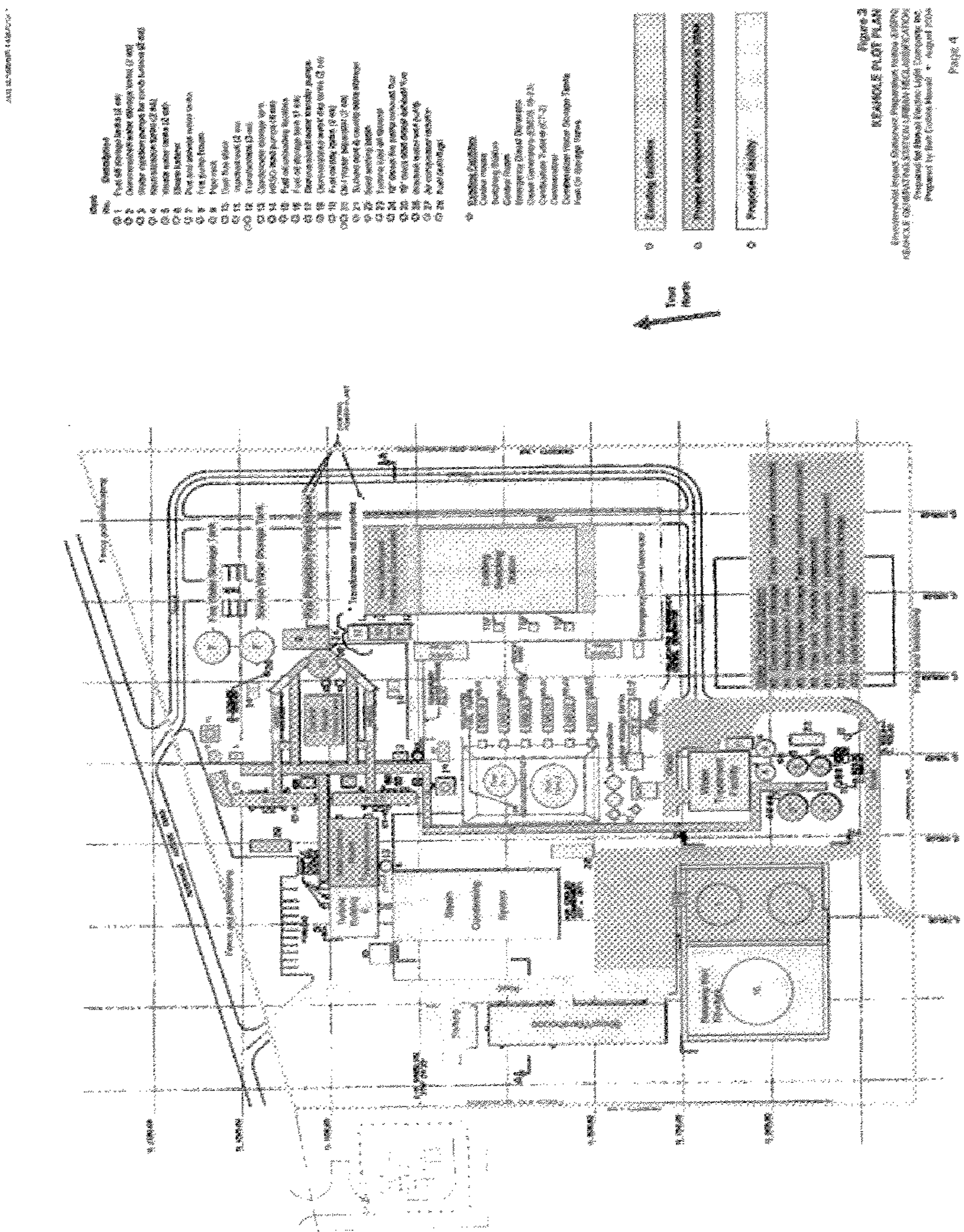


Exhibit 1-B: EXISTING AND PROPOSED FACILITIES ON THE KEAHOLE SITES



1.1.1 Existing Situation

As of the end of June 2004, the Keahole generating station had the following generators: Combustion Turbine (CT)2, CT4, and CT5 and Diesel Generating Unit (D)21, D22 and D23. CT4 and CT5 were installed and became available for commercial use in 2004. They will not be fully operational until 2005. (Designations are HELCO's, and are used to identify its various power sources. A Glossary is part of the Environmental Impact Statement, and is not repeated here.)

Including the two new turbines, the plant has a total capacity of 65.25 MegaWatts (MW). Three older generators, D18 through D20, were retired earlier in 2004.

The Hawaii Island electrical grid integrates power supplied by HELCO, Hamakua Energy Partners, Puna Geothermal Venture, Hilo Coast Power Company, and others.

1.1.2 Redesigation and Expansion of Generating Capacity

Hawaii County has seen much debate over whether generating capacity should be expanded at Keahole. That is not, strictly speaking, at issue here. With redesignation, HELCO can proceed to make planned changes at Keahole, including installation of emissions controls and eventual installation of a combined cycle generator using steam created by the waste heat of CT4 and CT5. These are industrial facilities appropriate on an industrial site. This next generator, ST7, is scheduled for 2009.

With or without redesignation, HELCO maintains that it can proceed with the installation of CT4 and CT5 under the "default entitlement" that occurred in 1996, when the Board of Land and Natural Resources failed to take action on HELCO's application, since CT4 and CT5 were named in HELCO's submittals. ST7, which would capture waste heat emitted by CT4 and CT5 and use it in a Dual Train Combined Cycle, was also included in the "default entitlement." However, the subsequent settlement included an agreement that ST7 would only be built with additional Selective Catalytic Reduction technology that was not in the submission for the default entitlement. Pursuant to the terms of the settlement, HELCO will build ST7 at Keahole under the conditions specified in the settlement.

In the course of interviews for this report (discussed in Section 3, below), Hawaii Island stakeholders were asked separately about what they understood to be the impacts of redesignation and the impacts of new generation capacity. In the impact analysis conducted by SMS, attention is paid to a No Action Alternative, mandated by EIS law, and to various ways to increase generating capacity in Hawaii County to meet anticipated demand. Those alternatives are described below.

1.2 ALTERNATIVES CONSIDERED

To assess the impacts of the project, alternatives were developed with HELCO's overall mission in mind, of supplying reliable power in an efficient, cost-effective way. Except for the No Action Alternative, the alternatives are different ways to approach maintaining firm generating capacity and reserve power to meet anticipated demand. The alternatives are listed in Exhibit 1-C.

At the end of May 2004, HELCO decided not to extend its contract for power with Hilo Coast Power Company (HCPC). That means that HCPC will no longer contribute to the grid after 2004. However, the two new generators at Keahole, coming on-line in 2004, will contribute nearly 40 MW, as compared to 22 MW from HCPC.

Under the **No Action Alternative**, the land would stay under current State Land Use Designation (Conservation) and zoning (Open). Work would proceed on CT4 and CT5. Construction of a new stack, designed to handle emissions from the new turbines, would be completed. Additional steps – installation of a steam turbine (ST7), integration of the two new turbines with ST7 into a dual train combined cycle system, and installation of emissions controls proposed in the Settlement – would not be possible at Keahole.

The remaining alternatives follow from the No Action Alternative. They sketch out different approaches to meeting the Big Island's need for firm generating capacity – electrical power that can be reliably supplied at any time of day, in all climatic conditions – to 2025. Actions described in the 2004 Evaluation of HELCO's 1998 Integrated Resource Plan (IRP) to assure Hawaii of an adequate power generating capacity through 2018 would be implemented as needed. (The time frame used here is adapted from the twenty-year horizon of the IRP [HELCO 1998, 2004].)[1]

The Preferred Alternative (Number 2) and the remaining alternatives (Numbers 3 to 5) all involve a portfolio of generating capacity, including fossil-fuel plants, geothermal energy, wind energy, distributed generation (with power being generated both by HELCO and others in the grid). In all cases, renewable energy is an important part of HELCO's resource plan.

The power generation and transmission system in the alternatives vary as follows:

- Location of *new* firm generating capacity;
- Mix of resources used to assure firm generating capacity; and
- Configuration of transmission system. (Since most demand is from West Hawaii, location of new generating capacity in other regions could involve some loss of capacity due to increased transmission distance and costs for improved transmission.)

These alternatives involve few assumptions concerning actions by others or decisions far in the future. For example, transmission improvement costs are viewed as necessarily part of an alternative with new generation in East Hawaii (No. 4), since the demand to be met is largely from West Hawaii. If a new biomass plant in East Hawaii is built, HELCO would again face transmission improvement costs, and these costs are estimated in the biomass alternative (No. 5). However, no further assumption is made here concerning the specific location of an eventual biomass plant.

[1] HELCO submits Integrated Resource Plans (IRPs) to the Public Utilities Commission on a regular basis. The recent IRP-2 Evaluation is based in part on planning assumptions in the 1998 report, in part on data gathered in the years since 1998.

Exhibit 1-C: ALTERNATIVE APPROACHES TO DEVELOPING NEW FIRM POWER GENERATION

Year	Alternative 1 No Action Addition/Retirements	Alternative 2 IRP Preferred Addition/Retirements	Alternative 3 West Hawaii Addition/Retirements	Alternative 4 East/West Hawaii Addition/Retirements	Alternative 5 Renewable Addition/Retirements
2004	Add Keahole CT4, CT5 Retire Keahole D18, D19, D20 Terminate HCPC	Add Keahole CT4, CT5 Retire Keahole D18, D19, D20 Terminate HCPC	Add Keahole CT4, CT5 Retire Keahole D18, D19, D20 Terminate HCPC	Add Keahole CT4, CT5 Retire Keahole D18, D19, D20 Terminate HCPC	Add Keahole CT4, CT5 Retire Keahole D18, D19, D20 Terminate HCPC
2005					
2006					
2007					
2008					
2009		Add Keahole ST7 (Keahole DTCC complete)			
2010					
2011					
2012					
2013					
2014					
2015	New generating units required		Add West Hawaii CT X1	Add Hill 5 Repower 1st CT	Add Biomass #1
2016					
2017		Add West Hawaii CT X1	Add West Hawaii CT X2		
2018				Add Hill 5 Repower 2nd CT Convert to Hill 5 Repower DTCC	Add Biomass #2
2019					
2020		Add West Hawaii CT X2	Convert to West Hawaii DTCC X1X2	Add West Hawaii CT X1	
2021					Add Biomass #3
2022		Convert to West Hawaii DTCC X1X2	Add West Hawaii CT X3		
2023				Add West Hawaii CT X2	
2024		Add West Hawaii CT X3	Add West Hawaii CT X4		Add Biomass #4
2025				Add West Hawaii CT X3	

NOTES: All alternatives start from mid-2004. At that time, CT4 and CT5, along with the new stack, are in place at Keahole. Under No Action assumptions, they will be brought on line, but no further development occurs at Keahole. Under the Preferred Alternative, new development occurs at Keahole as soon as practicable. The remaining alternatives were generated using a model that identifies when new capacity will be needed in order to deliver power reliably in response to demand. (The No Action Alternative does not, so it shows years in which the power in the grid is expected to be well below the level demanded by users. Those years are shaded in the exhibit.) For all alternatives, HELCO will continue to depend on a portfolio of power sources, including distributed generation, geothermal, wind and run-of-river hydroelectric power. In the table, "X" is used for future turbine, which would be assigned standard numbers (such as CT8) when they go into service. See EIS ***Glossary*** for abbreviations.

HELCO planners have assumed that fuel for Keahole and Waimea could be delivered via Kawaihae Harbor as of 2010; a Kawaihae Fuel Facility is included in the cost analysis of Alternatives 2 and 3. That facility is part of system planning independent of either the redesignation of the Keahole lands or expansion at Keahole. It is not considered here as an impact of actions at Keahole.

1.3 STUDY AREAS FOR THIS REPORT

The Preferred Alternative is located at a delimited site, but alternatives involve potential construction at sites throughout Hawaii County. Accordingly, the County as a whole must be considered the area of potential impact for the project. However, specific areas are potentially more affected by the project than others. These are:

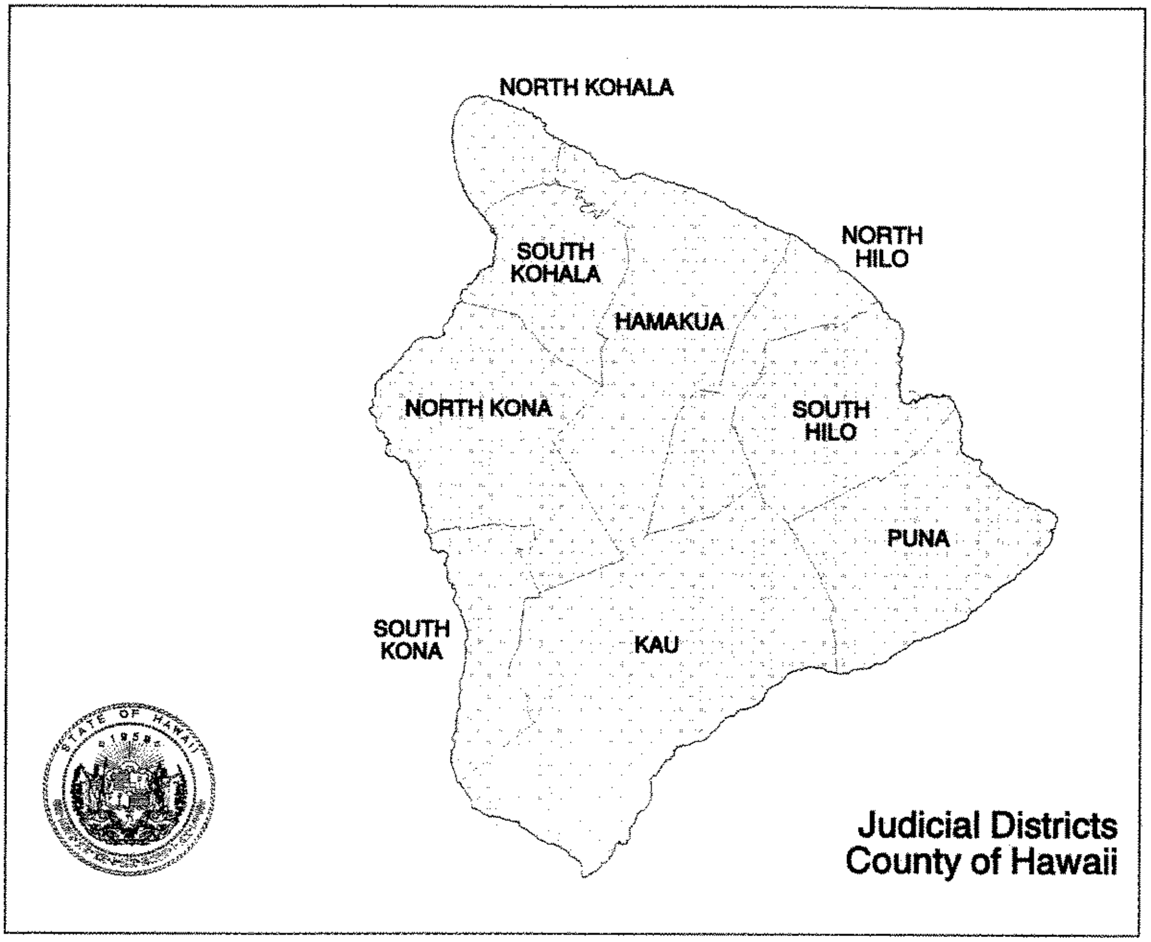
- Immediate vicinity: Keahole Agricultural Park (TMK 3-7-03:049);
- Neighboring areas: Kona Palisades, Kona International Airport, and the Hawaii Ocean Scientific Park/Natural Energy Laboratory of Hawaii as well as sites of proposed development by Department of Hawaiian Home Lands, the University of Hawaii and Hiluhilu Development (at Palamanui);
- West Hawaii (i.e., the districts of North Kohala, South Kohala, North Kona and South Kona) as a region with strong growth in energy demand; and
- Hawaii County as a political and economic entity, and as a unified power grid.

Communities near alternate sites for power generation or near transmission lines and supply routes needed for alternate sites, would be examined in detail if those sites were selected. For the current study, sites identified in earlier planning documents were considered:

- West Hawaii: on State land at Puuanahulu, near the land that has been dedicated to the West Hawaii sanitary landfill (within TMK 3-7-01-003-001);
- East Hawaii: at Hill Plant in Hilo (TMK 3-2-02-058:019).

SMS examined these potential alternate sites. No specific site for a biomass factory was identified. For all alternatives, the discussion deals with regional and islandwide impacts of alternate site choices.

Exhibit 1-D: DISTRICTS OF HAWAII COUNTY



EXISTING AND ANTICIPATED SOCIO-ECONOMIC CONDITIONS

2.1 EXISTING LAND USES ON THE SITES AND IN VICINITY

The project site is located at the north side of the Keahole Agricultural Park, near Queen Kaahumanu Highway. The Agricultural Park is fully occupied; all occupants have to demonstrate that they are using the land for agriculture, although some lessees also live on their lots. Crops grown in the Agricultural Park include flowers and local fruits. To the North are lands owned by the State of Hawaii, Department of Hawaiian Homelands. Queen Kaahumanu Highway connects Kailua-Kona, the major urban center of West Hawaii, with South Kohala resort areas and the commercial port of Kawaihae. Directly to the west *(makai*, or seaward) is the entry road to Kona International Airport. Commercial aircraft make daily scheduled stops at Kona International on flights from other Hawaii islands and from the US Mainland. International flights land there, but the airport does not currently have permanent facilities to handle international passengers. Further to seaward and to the south is the Hawaii Ocean Science and Technology Park, under the administration of the Natural Energy Laboratory of Hawaii Authority (NELHA). HOST Park is home to both research and commercial ventures. It pumps deep ocean water to the surface and in the park, providing cooling and a unique resource for many applications (including aquaculture and production of water for human uses).

The two parcels in the project site are both in current use by HELCO. The larger one (TMK 3-7-3-49:36) contains the only major generating facility in West Hawaii. The Airport Substation is located on the smaller parcel (TMK 3-7-3-49:37).

2.2 POPULATION

Hawaii County has seen continuing population growth during the last thirty years. The fastest growth has occurred in Puna, but West Hawaii has had large population increases, especially in North Kona and South Kohala. These two districts have developed a visitor industry that is staffed by residents from all over West Hawaii and even, when the economy is booming, from the rest of the island. (Puna's growth rate is more clearly attributable to the availability of inexpensive land and housing in that district.) Over the thirty-year span shown in Exhibit 2-A, the average annual growth rate in Puna has been 6.2%, while North Kona reached 6.1%, on average, and South Kohala reached 6.0%.

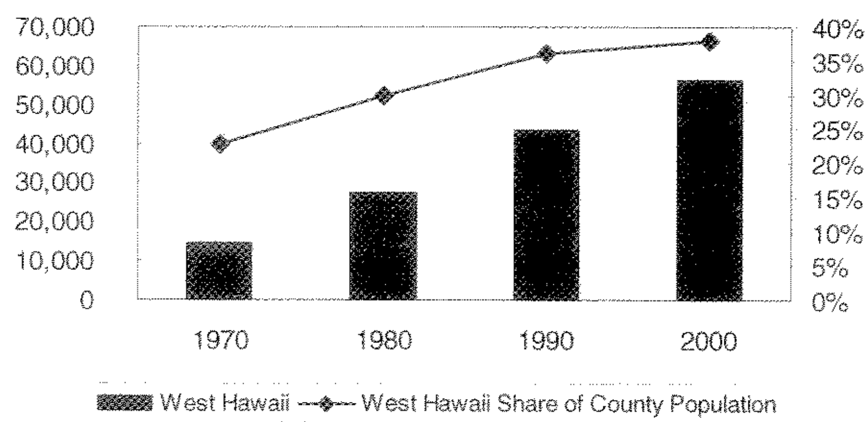
West Hawaii has come to be home to nearly 40% of the county's residents. (See Exhibit 2-B). It also has more than 80% of the island's visitor rooms (DBEDT, 2003a). In 2000, the average visitor count in Hawaii County was about 15% the size of the resident population. For West Hawaii, visitors numbered over 30% of the resident population.

Exhibit 2-A: RESIDENT POPULATION, HAWAII COUNTY AND DISTRICTS, 1970-2000

County and district	1970	1980	1990	2000
State total	769,913	964,691	1,108,229	1,211,537
Hawaii County	63,468	92,053	120,317	148,677
Puna	5,154	11,751	20,781	31,335
South Hilo	33,915	42,278	44,639	47,386
North Hilo	1,881	1,679	1,541	1,720
Hamakua	4,648	5,128	5,545	6,108
North Kohala	3,326	3,249	4,291	6,038
South Kohala	2,310	4,607	9,140	13,131
North Kona	4,832	13,748	22,284	28,543
South Kona	4,004	5,914	7,658	8,589
Ka'u	3,398	3,699	4,438	5,827

SOURCE: US Census, in DBEDT 2003b.

Exhibit 2-B: WEST HAWAII SHARE OF COUNTY RESIDENT POPULATION



NOTE: In this report, "West Hawaii" is the combined judicial districts of North Kohala, South Kohala, North Kona and South Kona.

Since 1990, West Hawaii has seen significant population growth. The median age has increased appreciably, and the very young have declined as a share of the population. (See Exhibit 2-C for demographics of the region and the two districts closest to Keahole.) In North Kona, less than half the population is Hawaii-born.

Exhibit 2-C: DEMOGRAPHIC CHARACTERISTICS, 1990 AND 2000

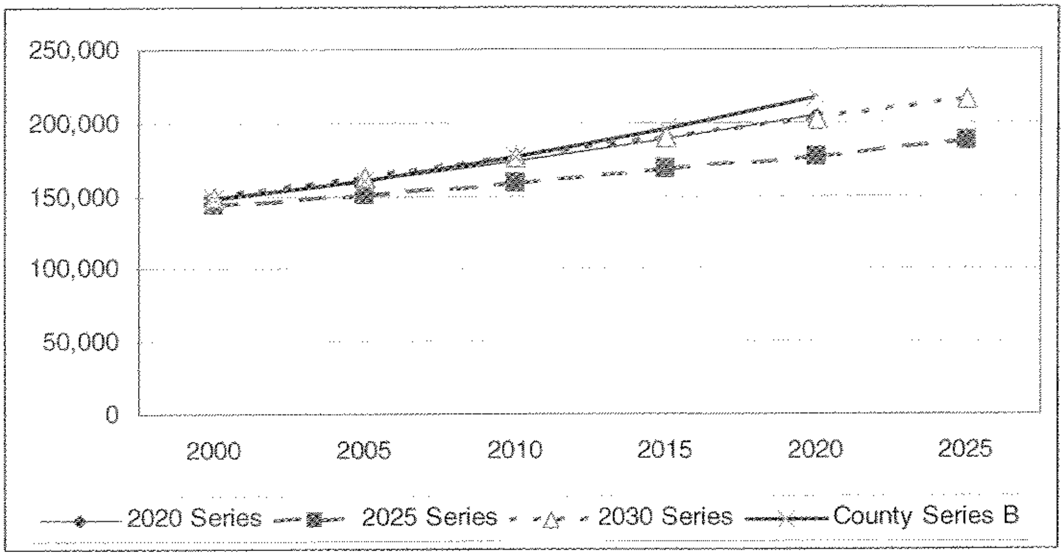
	County of Hawaii		West Hawaii		North Kona Dist.		South Kohala Dist.	
	1990	*2000*	*1990*	*2000*	*1990*	*2000*	*1990*	*2000*
Resident Population								
Total	120,317	148,677	43,373	56,301	22,284	28,582	9,140	13,131
Under 5 years of age	7.9%	4.6%	8.1%	6.3%	7.8%	6.4%	8.2%	5.3%
18 and over	71.3%	75.2%	71.9%	74.3%	73.6%	75.5%	70.3%	72.1%
65 and over	12.5%	14.6%	10.0%	11.5%	10.1%	10.8%	7.4%	10.8%
Median age	34.3	38.6	N/A	N/A	34.7	39.4	32.1	36.2
Visitor Population								
Annual Visitor Census	16,698	17,784	13,502	16,092	NA	NA	NA	NA
Hotel Rooms	7,846	9,774	7,423	8,278	4,096	4,295	3,327	3983
Housing								
Total housing units	48,253	62,674	18,693	25,190	9,990	13,960	4,235	5,794
Occupied	85.9%	84.5%	79.9%	79.5%	79.1%	75.4%	73.1%	80.2%
Vacant	14.1%	15.5%	20.1%	20.5%	20.9%	24.6%	26.9%	19.8%
For seasonal, recreational or occasional use	4.2%	8.7%	7.4%	15.4%	8.1%	19.7%	10.3%	15.3%
Households								
Number	41,461	52,985	14,935	20,034	7,898	10,522	3,095	4,648
Owner-occupied	61.1%	64.5%	55.4%	60.2%	54.6%	58.5%	52.7%	58.9%
Renter-occupied	38.9%	35.5%	44.6%	39.8%	45.4%	41.5%	47.3%	41.1%
Rental vacancy rate								
Average household size	2.86	2.75	2.85	2.81	2.75	2.7	2.91	2.81
Geographic Mobility								
Share of population born in Hawaii	65.8%	63.3%	53.9%	53.2%	45.5%	48.1%	54.6%	53.2%
Share from other states, territories	25.7%	26.4%	38.4%	32.5%	46.8%	41.5%	36.2%	34.1%
Foreign-born	8.5%	10.2%	7.7%	12.7%	7.6%	10.4%	9.2%	12.7%
Share living in same house for five years	53.1%	57.7%	42.9%	49.2%	39.4%	46.7%	37.4%	46.1%
Share same county, different house	25.7%	26.5%	26.8%	25.5%	26.8%	27.0%	27.4%	31.1%
Share same state, different county	6.7%	4.8%	7.2%	4.2%	6.8%	3.3%	10.0%	7.7%

SOURCE: US Census for 1990 and 2000.

Both Hawaii County and the State have developed population forecasts for planning purposes. These forecasts show continuing population growth for the County. Growth rates are expected to be higher than in the slow economy of the mid-1990s, but well below that experienced during the 1980s.[2] Exhibit 2-D shows the range of resident population growth estimates, while Exhibit 2-E deals with the visitor population. Exhibit 2-D shows an average annual visitor growth rate stabilizing well below 2% -- far smaller than that of earlier boom times.

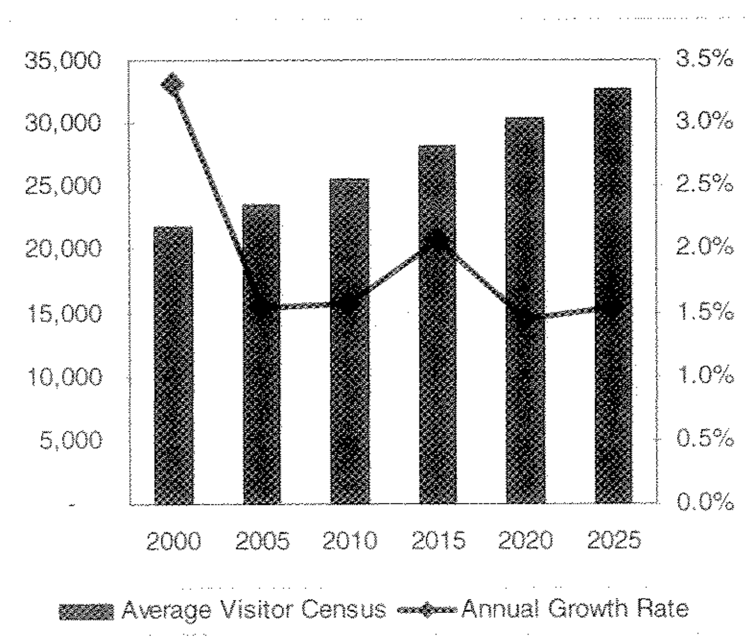
[2] A new forecast was recently issued for the State and Counties to 2030. For Hawaii County, it projects population trends very close to those in the 2020 forecast, i.e., not as conservative as the 2025 forecast (DBEDT 2004).

Exhibit 2-D: GOVERNMENT FORECASTS OF RESIDENT POPULATION GROWTH, HAWAII COUNTY



-SOURCES: DBEDT, 1996, 2000, 2004; Hawaii County General Plan Draft (www.co.hawaii.hi.us)

Exhibit 2-E: FORECAST VISITOR CENSUS, HAWAII COUNTY



NOTE: Average visitor census derived from forecast visitor days, divided by the number of days in the year.
SOURCE: DBEDT (2004).

Exhibit 2-F shows the overall relationship between population forecasts and energy demand forecasts. HELCO's estimates of growth in demand for electricity are somewhat higher than the population forecasts. This is reasonable in light of the combined effects of (a) renewed economic growth, (b) a tourism economy (in which visitor population is a significant contributor), and (c) a long-term trend for increasing demand for electricity, independent of population growth.

Exhibit 2-F: PROJECTED GROWTH OF POPULATION AND DEMAND FOR ELECTRICITY, TO 2030

	DBEDT 2030 Series		**Hawaii County Series B**	**HELCO Estimates of Peak Load (MW)**	
	Residents	*Visitors (1)*	*Residents*	*IRP2*	*IRP 2 Eval.*
A. Forecast Totals					
2000	149,261	21,831	148,677	168	170
2005	163,000	23,562	159,907	181	191
2010	176,750	25,479	176,938	202	218
2015	190,300	28,219	195,965	229	241
2020	203,050	30,328	217,718		
2025	216,150	32,740			
B. Average Annual Growth Rate for five year period ending in:					
2005	1.8%	1.5%	1.5%	1.5%	2.4%
2010	1.6%	1.6%	2.0%	2.2%	2.7%
2015	1.5%	2.1%	2.1%	2.5%	2.0%
2020	1.3%	1.5%	2.1%		
2025	1.3%	1.5%			

NOTE: (1) Visitor census derived from projection of total visitor days, divided by the number of days in the year.

SOURCES: Population forecasts shown in Exhibits 2-D and 2-E. The HELCO peak load for 2000 shown in the far right column is based on recorded data. Other items in the "HELCO Estimates" columns are forecasts in HELCO Integrated Resource Plan (1998) and recent IRP-2 Evaluation (HELCO 2004).

2.2 ECONOMIC CONDITIONS

2.2.1 Employment

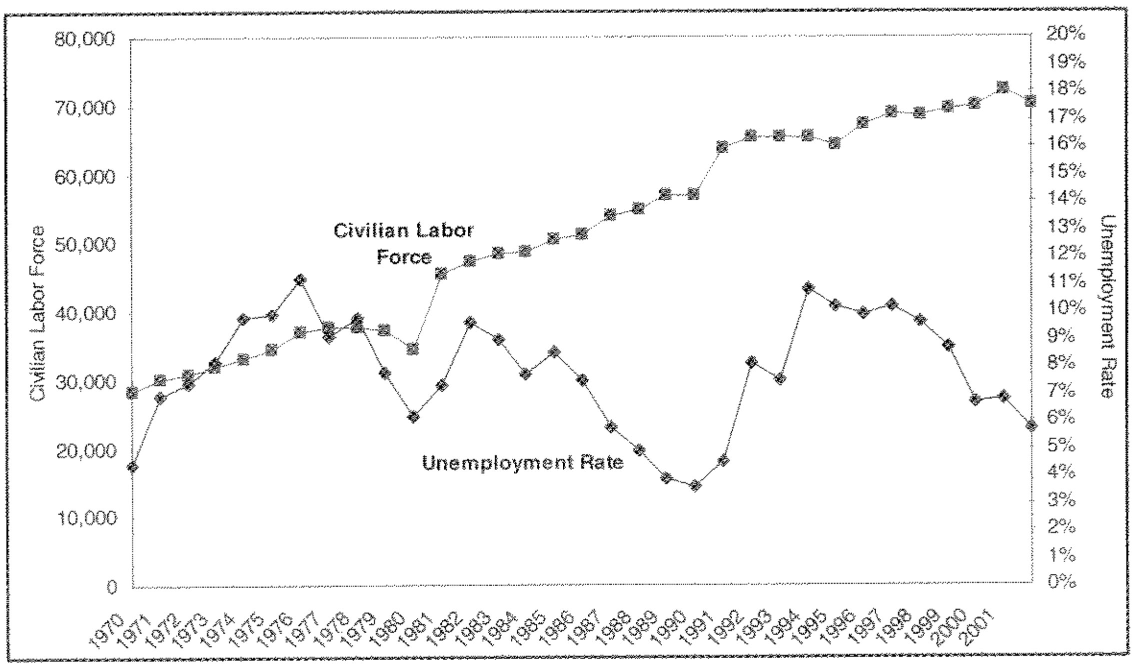
Hawaii County has experienced both bursts of job growth, when construction boomed and new hotels were hiring large numbers of workers, and serious times of job loss due to plantation closures. Plantation agriculture ended in the 1990s. At the same time, visitor numbers fell, and the result was a return to high unemployment (shown as of 1994, in Exhibit 2-G). More recently, the County unemployment rate fell below 5% -- well above the rates achieved in Maui and

Honolulu, but also well under the national rate (6.0% for March 2004). (Current data from Hawaii State Department of Labor and Industrial Relations website, http://www.state.hi.us/dlir/rs/loihi/.)

During the slowdown of the 1990s, many visitor industry workers had only part-time jobs. In times of economic growth, both unemployment and underemployment can be expected to decline.

The DBEDT 2025 forecast projects slow growth in wage and salary jobs (averaging 1.6% to 1.9% annually) in the coming years (DBEDT, 2000).

Exhibit 2-G: CIVILIAN LABOR FORCE AND UNEMPLOYMENT TRENDS



SOURCE: Hawaii State Department of Labor and Industrial Relations, in DBEDT, 2003b.

Census data show that West Hawaii has had a higher level of labor force participation than the County as a whole (in Exhibit 2-H). The level is falling, as the population ages and retirees form a larger group.

Exhibit 2-H: INCOME AND POVERTY, 1990 AND 2000

	County of Hawaii		West Hawaii		North Kona Dist.		South Kohala Dist.	
	1990	*2000*	*1990*	*2000*	*1990*	*2000*	*1990*	*2000*
Employment Status								
Population 16 years and over	88,999	114,647	32,201	43,473	16,836	22,390	6,613	9,708
Share in labor force	64.1%	61.9%	71.0%	67.5%	70.7%	69.2%	73.9%	70.7%
Civilian labor force	56,986	70,592	22,870	29,347	11,902	15,484	4,886	6,862
Unemployed	4.6%	4.9%	3.5%	2.8%	2.9%	2.7%	2.8%	2.3%
Class of Worker								
Private wage and salary workers	71.0%	65.4%	74.9%	72.8%	75.7%	73.6%	79.9%	78.1%
Government workers	17.6%	19.0%	10.4%	12.0%	9.1%	10.7%	7.4%	9.6%
Self-employed, not incorporated	10.7%	12.0%	13.6%	13.2%	13.9%	13.7%	12.2%	10.9%
Unpaid family workers	0.7%	0.7%	1.0%	0.7%	1.3%	0.9%	0.5%	0.3%
Poverty status, previous year								
Individuals								
Total below poverty line	16,776	22,821	4,343	5,581	2,032	2,756	922	1,100
Share of related children under 18	41.3%	35.9%	38.1%	33.7%	34.7%	32.7%	44.4%	41.9%
Share of persons 65 and over	8.2%	6.1%	5.8%	6.4%	4.9%	6.4%	4.1%	4.5%

While Hawaii County saw a major increase in the number of persons in poverty by the end of the 1990s, the increase was less severe in West Hawaii. However, the share of children in poverty was still high, although declining, in West Hawaii.

2.2.2 Industries in West Hawaii

As the center of Hawaii County's visitor industry, West Hawaii is the site of most of the County's jobs and employment growth. Exhibit 2-I makes the point clearly, inasmuch as nine of the 15 largest employers in the county are West Hawaii resorts, and the remaining six are countywide agencies. Within West Hawaii, the upscale South Kohala resorts (notably, Mauna Lani with some 2,000 employees) have larger staffs than the North Kona hotels and resort areas.

Hawaii County accounts for about 10% of the State economy (as estimated in Exhibit 2-J). It contains only a small manufacturing sector, while government, hotels, trade, and health services are major components. (In Exhibit 2-K, "Government" includes County, State and Federal agencies, including the Department of Education.)

While the visitor industry is centered in West Hawaii, major new sources of employment in East Hawaii have included a call center and University-related enterprises, such as headquarters for astronomical observatories, located in the University Park area. However, the Penncro call center recently closed, ending 172 jobs (Yamanouchi, 2004).

Even after the closing of Hawaii County's major plantations, West Hawaii has productive agricultural areas. South Kona is the heart of Hawaii's coffee industry. The Parker Ranch, based in Waimea, in the South Kohala uplands, is one of the largest ranches in the United States. Along the north coast of North Kohala are well-watered agricultural lands. The Keahole Agricultural Park provides about 190 acres of leased agricultural land near the airport and urban center, but it is only a small part of West Hawaii's agricultural area. (As of 2000, some 484,741 acres in West Hawaii were designated Agricultural [Hawaii County, 2003].)

Exhibit 2-I: THIRTY LARGEST EMPLOYERS, COUNTY OF HAWAII, 1999

Rank	Company	Employees	Business
1	State of Hawaii	7,450 1/	State government
2	County of Hawaii	2,250 1/	County government
3	C. Brewer & Co.	1,987	Holding company; agribusiness; land development; alternative energy; trucking; guava and macadamia nuts; Kona coffee
4	Hilton Waikoloa Village	1,200	Tourism
5	United States Government	850 1/	Federal government
6	Mauna Lani Resort (Operation), Inc.	800	Tourism
7	KTA Superstores	776	Supermarkets
8	Mauna Lani Bay Hotel	650	Tourism
9	Hapuna Beach Prince Hotel	579	Tourism
10	Orchid at Mauna Lani	554	Tourism
11	Mauna Kea Beach Hotel	543	Tourism
12	Four Seasons Hualalai	492	Tourism
13	Sure Save Supermarkets	455 2/	Supermarkets
14	Royal Waikoloa Hotel	374	Tourism
15	Kona Coast Resort	325	Tourism
16	Mac Farms of Hawaii Inc.	231	Grower, processor and marketer of macadamia nut products
17	Hilo Hawaiian Hotel	230	Tourism
18	HELCO	226	Utilities
19	Kona Surf Resort and Country Club	217	Tourism
20	GTE Hawaiian Telephone	203	Utilities
21	HPM Building Supply	200	Wholesale, retail and manufacturing; lumber and building materials
22	Kona Village Resort	186	Tourism
23	Keauhou Kona Resort Co.	180	General contractor
24	Royal Kona Resort	180	Tourism
25	King Kamehameha's Kona Beach Hotel	166	Tourism
26	Maryl Group Inc.	165	Land developer; general contractor
27	Life Care Center of Hilo	160	Healthcare
28	Jack's Tour Inc.	150	Tourism
29	Isemoto Contracting Co., Ltd.	140	General contractor
30	Suisan Group Inc. 3/	130	Wholesale frozen foods, dry groceries, produce, wholesale and retail fresh fish, fresh-fish auction

NOTES:

1/ Annual average job counts.
2/ Includes Wiki Wiki Mart and Wiki Wiki Video.
3/ Previously ranked as Suisan Co. Ltd.

SOURCE: Hawaii County, 2001.

Exhibit 2-J: COUNTY AND STATE ECONOMIES

	Hawaii County	State of Hawaii	Share
A. Indicators of County share of State Economy			
Employed Persons, 2002	66,150	557,400	11.9%
Wage and Salary Jobcount, 2002	58,250	562,600	10.4%
Personal Income, 2001 (Million $)	$3,335	$35,625	9.4%
Estimated Personal Income, 2005 (Million 1992$s)	$2,760	$31,794	8.7%
B. Estimated County Economy (based on recent State data and projections for 2003)			
Personal Income (Million $)	$3,690	$39,416	9.4%
Gross Domestic Product (Million $)	$5,063	$48,087	10.5%

SOURCES: DBEDT, 2003b, 2003c, 2000.

Exhibit 2-K: EMPLOYMENT IN HAWAII COUNTY INDUSTRIES, 2002

	Covered Employment, 2002	
	Average Employment	**Total Wages (Million $s)**
Goods Producing:	*7,575*	*$261.0*
Construction	3,846	$176.8
Manufacturing	1,406	$35.2
Agriculture, Forestry, Mining	2,323	$49.0
Distribution and Services	*39,275*	*$989.1*
Transportation, Utilities	2,414	$81.6
Trade	9,335	$241.4
Finance, Insurance, Real Estate	2,312	$75.4
Food Services	4,393	$58.5
Hotel, Accommodations	6,687	$188.1
Health Services	5,482	$151.7
Government	*11,016*	*$416.7*
Total	57,866	$1,666.8

SOURCE: DLIR, 2003

2.3 EMERGING TRENDS

West Hawaii has experienced both advantages and problems of economic growth. With recent prosperity have come new retail opportunities (with Costco, Wal-Mart, Home Depot and Lowe's all opening outlets in the Kailua area). On the other hand, traffic congestion, long a problem during rush hour on Palani Road, has worsened appreciably on Queen Kaahumanu Highway and on the Hawaii Belt Road between Kailua and South Kona. As a result, the Mayor has come to Kailua to explain that work is under way on highway improvements (Command, 2004). Both State and County roads are slated for improvements over the next few years.

During the 1990s, little new investment occurred in the visitor plant until the Hualalai Resort at Kaupulehu opened in 1998. That project was highly successful, and now includes several increments of resort housing along with a hotel and golf course.

Closer to the Keahole site, new and revived plans for urban growth have emerged:

- New development is being proposed for the Kohanaiki site, where disputes over Nansay Hawaii's proposals for a resort project led to the PASH decision, protecting native Hawaiian access rights. Rutter Development plans a golf course and housing project, while setting aside coastal lands for a public access beach park.

- At Honokohau, the State Department of Land and Natural Resources has requested proposals for marina redevelopment. Nearby, the Department of Hawaiian Homelands has entered into a lease agreement with a private development team for 200 acres, to include commercial uses, resort development, and a possible golf course (Viotti, 2004). The Department of Hawaiian Homelands also intends to increase its residential development in the Laiopua project, above the Queen Kaahumanu Highway near Honokohau, from 225 units to "more than double" that number.

- At Ooma, south of the HOST Park, the current owners have proposed developing some 400,000 square feet of commercial space, 400 hotel rooms, and 240 multi-family units. They have received approvals from the Hawaii Planning Commission (Command, 2003). When, however, the project came before the County Council, Mayor Kim requested that it be deferred until the timing of highway improvements could be clarified (Edwards, 2004). The Mayor's position was that this project and others like it that would create new traffic should not proceed until major nearby roadways are improved.

- At the HOST Park, a new Gateway Center is being developed to showcase new energy technologies.

- The 725-acre Palamanui project (Hiluhilu Development, LLC) would include commercial development, both single-family and multifamily housing, a golf course, and infrastructure in support of eventual construction of a University of Hawaii site on adjoining State land. (The University would rent space in the commercial area and then, presumably, later develop its acreage.) An access road for the private and public projects would join up with the Queen Kaahumanu access next to the HELCO Keahole sites (shown on Exhibit 1-B).

- The Department of Hawaiian Homelands acreage adjacent to the project site could benefit from the proposed access road. Those lands are shown in the Department's land inventory as largely residential, although part of the land, next to the highway and across the road from the project site, is identified as appropriate for commercial use (PBR Hawaii, 2002) No further plans are definite.

Further development is possible in existing resort areas, notably Mauna Lani and Waikoloa in South Kohala, Kaupulehu and Kukio at the north end of North Kona, and Keauhou at the southern end of North Kona. State Land Use Commission approvals make additional development eventually possible at additional sites, notably the State's Villages of Laiopua and the Queen Liliuokalani Trust's adjacent Keahuohu Lands.

In the near term – to about 2007 – new construction is bringing new resident housing to North Kona in single-family and townhouse subdivisions. Development of resort residential projects is very active in South Kohala and proposed for Keauhou in North Kona and for South Kona. These visitor-oriented projects will have little impact on population, but the higher density projects noted above would house more people and support more jobs in West Hawaii. Much of the development proposed in those projects could occur by the end of this decade.

2.4 ALTERNATE SITES

2.4.1 East Hawaii

HELCO's Hill Plant is located in Hilo, on Halekauila Street between Kanoelehua Avenue and Railroad Avenue. It is a few blocks south of the Hilo Airport. The site covers approximately 14.5 acres. HELCO has a generating plant and ancillary facilities (fuel storage, wells), a substation, the operating station for the island grid, offices for transmission and maintenance staff, and parking and equipment storage space on-site. Adjoining properties are industrial, and include the County baseyard and Hawaii Junk, Ltd. A few retail outlets are located within a block of the HELCO property.

The surrounding area is industrial, although some of the lots to the east (in the Department of Hawaiian Home Lands Panaewa industrial area) are not built out. To the south, commercial development has occurred along Kanoelehua Avenue at Makaala Street, where the Prince Kuhio Plaza shopping mall, a Wal-Mart store, and other stores are located. These are within a mile of Hill Plant. At about the same distance to the east is the East Hawaii Landfill, which is to be closed soon. County proposals call for location of a sort station for recycling and transfer of materials to be sent to the West Hawaii landfill at the site. However, the Hawaii County Council did not vote County funds for the project, and wants private firms to offer to build new waste reduction facilities (Thompson, 2004).

2.4.2 West Hawaii

The State of Hawaii owns a large parcel, including nearly 20,200 acres, in Puuanahulu, North Kona, just south of the boundary with South Kohala district. Puu Pohaku Street, a two-lane road runs inland from Queen Kaahumanu Highway to the West Hawaii Landfill, operated by Waste Management, Inc. under contract to the County of Hawaii. The landfill opened in 1992; it now occupies less than 25 acres of a 300-acre site. It is effectively screened from the highway by mounds of lava.

The County plans to reduce the amount of solid waste reaching the landfill significantly in the next few years. Allowing for diversion of 45% of the waste stream (compared to a current 15% level), the landfill is not expected to reach its capacity until 2049 (Hawaii County Department of Environmental Management, 2004).

A few oceanfront privately-owned parcels are located on the oceanfront to the west and slightly north of the West Hawaii site. Further north is the Waikoloa Beach Resort.

COMMUNITY ISSUES AND CONCERNS

3.1 SOURCES

SMS Research gathered information about community issues and concerns from several sources, including:

- Interviews with Hawaii Island stakeholders (listed in Exhibit A in the Appendix to this report);

- Review of newspaper articles on the Keahole project and the hearings, court filings, and controversy surrounding it; and

- Community input to the 1998 IRP process (in HELCO, 1998).

The interviewees were selected in an attempt to learn about the views of a wide range of HELCO customers and of those with a stake in the area surrounding the Keahole site.[3] Interviewees were asked to comment on the project, on generating more energy at Keahole, and on West Hawaii's current and future conditions. (See Exhibit B for the handout used in the interviews.) Interviews were semi-structured, and dealt with what the stakeholders saw as community views and concerns, not just those of the interviewees.

3.2 ISSUES AND CONCERNS INDEPENDENT OF PROJECT

Longstanding issues are important in shaping many people's responses to HELCO's current preferred action:

- **Quest for political empowerment:** Hawaii County residents often find that decisions affecting them are made in Honolulu with little regard to their views and little knowledge of their specific circumstances. They further tend to see State-level decision-making as focused on Honolulu. The resulting decisions may benefit Honolulu over other counties. At the County level, residents of West Hawaii and of Puna District have repeatedly argued that Hawaii County funnels resources to Hilo and ignores the concerns and needs of their areas. This perspective has led to proposals for home rule in West Hawaii; currently, it leads to requests for the County Council to meet in Kona when discussing local development issues. More generally, a sense that West Hawaii residents are ignored or disenfranchised recurs often in discussions of the area's present and future.

- **Concern over development/Concern for preservation of resources:** Much as in other areas of Hawaii, West Hawaii residents are concerned about the pace and

[3] To date, SMS has conducted interviews with fewer residents of Keahole Agricultural Park than originally planned, simply because most of those called were not interested in being interviewed. (SMS attempted to reach over 100 households in the Agricultural Park and Kona Palisades. SMS did not attempt to interview parties named in the settlement Those parties have agreed to support HELCO's petition, and could find a request to voice a wide range of community views as contrary to the spirit of the settlement.)

direction of economic growth and development. One strand of this concern is a wish to preserve community cohesion in many areas of West Hawaii. Another is a sense that valued resources must be protected and saved. This has fueled local protest against Nansay Hawaii's plans for the Kohanaiki property and support for state and federal protection of oceanfront areas.

Currently, opposition to development focuses on the failure of government-funded infrastructure to keep up with growth, notably with traffic congestion. Governrment agencies are seen as quick to give developers permits, but slow to fund improvements needed to cope with development.

An important result of the Kohanaiki protest was the PASH decision, whereby Native Hawaiian rights to gather traditional resources were recognized as applying on less than developed lands. While the immediate beneficiaries were few, others point to the decision as an example of developers' greed being checked, and local rights preserved.

West Hawaii's economy is based on tourism, and many residents enjoy recent improvements in access to stores and entertainment. The region is less insular and less opposed to economic growth than others. Still, residents are often wary of outside control over such growth.

3.3 ISSUES AND CONCERNS RELATED TO ENERGY GENERATION AT KEAHOLE, APART FROM THE PROJECT

A complex history of discussions over energy policy precedes the current proposal to redesignate the Keahole sites. Energy policy is a separate issue from redesignation of the land at Keahole, but it is clearly part of the context for residents' views of HELCO and the current Preferred Alternative. Much attention has been given to need for new power sources, whether new generating capacity should come from fossil fuels or other sources, the location and dispersal of power generating capacity, and to HELCO's ability to manage complex changes for the good of all.

HELCO's Integrated Resource Planning process has involved a wide range of stakeholders. It has dealt with generation, transmission and demand issues in the context of both developing demand-side management (DSM) programs and competing visions of an energy future. HELCO has dealt with agencies, other power producers, policy and planning specialists, and consumers with a clear understanding of their particular needs and policy agenda. Its plans have been scrutinized by environmental groups, neighbors, and local authorities.

Reviewing records from the IRP process and more recent controversies, SMS finds the following themes to recur in discussions of Hawaii island's energy future:

- **Reliability:** In the early 1990s, Hawaii County energy consumers had to deal with rolling blackouts when the energy grid could not produce enough power to meet demand. In the last year, outages have occurred when particular power suppliers had to suddenly reduce output.[4] Stakeholders see reliability as important – but at this point,

[4] For HELCO personnel, there is a crucial distinction between rolling blackouts in 1992 when the grid clearly could not meet peak demand on several occasions, and other cases, where emergency conditions forced a utility supplier off-line for a few hours or a day. For many customers, this distinction is less important.

many tend not to count on HELCO to assure it. Large consumers often have back-up generators. Residential customers and small businesses often do not believe that HELCO can provide enough power reliably, even with increased firm generating capacity.

- **Need for new power generating sources:** Interviews and comments in the newspapers suggest there is now (2003-2004) widespread agreement that additional capacity is needed. That is a change since the 1990s, when some critics argued that the Hamakua Energy Partners facility might meet HELCO's needs for many years, without new turbines at Keahole (Tummons, 1998).

- **Type of energy source:** The State of Hawaii and many on the Big Island are deeply interested in limiting dependence on fossil fuels. The Hawaii County energy grid stands out as a national leader, by producing about 23% of its power using non-fossil fuel resources (HELCO, 2004). HELCO has helped to make this trend possible, and is responsible for managing a complex, multi-source power grid. HELCO produces renewable energy at its Lalamilo wind farm and at a hydroelectric plant on the Wailuku River. HELCO contracts with power producers – both large producers under specific contracts and small ones who are credited for their contributions to the grid under net metering – for the bulk of renewable energy used in the Hawaii island grid.

  While many would like to see increased use of renewable resources, HELCO is obligated to provide reliable electricity at a reasonable cost throughout the island. Since such renewable energy sources as wind farms and solar cell arrays are climate-dependent, HELCO sees these as "non-firm" resources, providing varying amounts of power to the grid from moment to moment, and posing a serious management problem for HELCO.

- **Location of New Power Sources:** Two related issues are important for HELCO and for private power producers. HELCO stresses that most of the demand for electricity comes from West Hawaii, while HELCO generates power largely in East Hawaii. This adds to transmission costs and inefficiencies, so HELCO seeks to develop new capacity in West Hawaii. Next, major hotels have explored ways to produce electricity on-site, using solar panels and heat recovery systems to meet much of their own needs for electricity and to contribute to the grid. Distributed generation (DG), whereby customers become power producers in their own right while still remaining on-grid, minimizes transmission costs and encourages customers to assume some of the cost of new generating facilities. Accordingly, it is favored not only by those customers who have installed new facilities, but also by energy policy specialists on the Big Island.

- **Cost of energy:** Energy costs in Hawaii County are among the most expensive in the United States. Many HELCO customers complain about high rates and about rates based on peak, rather than actual, usage.

With regard to the specific plans to install new generators and other equipment at Keahole, some respondents mentioned the new stack as unsightly. Some thought tourists should not be confronted by an industrial site as soon as they leave the airport. They requested the use of landscaping to limit visual impacts.

3.4 ISSUES AND CONCERNS RELATED TO PROJECT

Most of the stakeholders interviewed for this project had no strong reaction to the specific action at issue in the EIS, the redesignation of HELCO's Keahole lands. HELCO's request for redesignation was described as part of the settlement. Nearly all had comments about the settlement process. They agreed on seeing the settlement as an important step for the community. The settlement was characterized as a win-win agreement, allowing HELCO to proceed while responding to neighbors' concerns. HELCO's agreement to a high level of emissions controls was viewed favorably by all who discussed the settlement at any length.

Informants uniformly saw reclassification as not being a concern, except as part of the settlement agreement.

Most stakeholders were glad to see the lengthy arguments over power generation at Keahole resolved and new generators being installed. They wanted to see more generating capacity in the Hawaii island grid soon, to serve customers and lower the likelihood of blackouts. (However, a few commented that they wished HELCO had shifted to another site some years ago.)

Most informants commented that they favored increased reliance on renewable resources.

The Keahole plant, with ST7 and the air emissions controls discussed in the settlement, was seen as valuable by some stakeholders not just as a contribution to near-term generating capacity but also as giving Hawaii Island the capacity needed to come to depend more and more on resources other than fossil fuels. They understand it as a bridge to a new system using technologies that are not yet well developed or fully viable in Hawaii today.

3.5 ISSUES AND CONCERNS RELATED TO ALTERNATE SITES

SMS did not conduct interviews to identify community concerns with regard to locating new generating capacity at the alternate sites. However, ongoing discussions of other development proposals suggest the following:

Within a mile or two of the East Hawaii site are new commercial areas and schools. The site is relatively low-lying, and the stacks are visible from far away, e.g. from the University Research Park on Komohana Street. It is reasonable to anticipate some community concern over increased industrial activity at the Hill Plant site.

The West Hawaii site is well buffered from coastal resort areas However, it is being scrutinized by South Kohala stakeholders now that the East Hawaii landfill is about to close, and large amounts of solid waste will soon be trucked to Puuanahulu through Waimea and on Waikoloa Road. Members of the Kohala Coast Resort Association have opposed the County's plan, on the grounds that the Puuanahulu landfill was not designated as a repository for the entire island's solid waste. This controversy bears on the possibility of a new power plant at Puuanahulu only indirectly: since solid waste traffic to the area has been a source of concern, it is likely that any further industrial activity at the site will be viewed as a possible threat to regional stakeholders' efforts to keep the region attractive to tourists. Transport of fuel for a new power plant at Puuanahulu will also likely be a concern.

IMPACT ASSESSMENT

4.1 APPROACH

This section deals with social and economic impacts associated with the Preferred Alternative, viewed in relation both to the No Action Alternative and to the alternative ways HELCO might try to provide adequate, cost-effective and reliable electricity for Hawaii County. Socio-cultural impacts can be of several types, notably:

- *Local, regional or general impacts:* A project can have local impacts because its construction or its operations affect the lives and community organization of neighbors and nearby groups. It can have regional impacts by providing services or employment for a region, or by withdrawing resources that would otherwise be used in the area. General impacts are more widespread or diffuse.

  In the present case, local social impacts of the Preferred Alternative mainly consist of the mitigation of potential nuisances discussed in EIS Chapter 3 (noise, emissions). The presence of additional generating capacity very close to the HOST Park and the new Energy Gateway Center will minimize the chance of transmission-related outages to these facilities. At the regional and island levels, assurance of generating capacity will support economic growth for West Hawaii and the County.

- *Direct, indirect or induced impacts:* These terms are used in input/output analysis. Direct spending (on construction or operations) leads to direct employment and incomes (for persons whose work contributes directly to the activity, whether or not they are actually on-site). Indirect jobs and incomes are created as goods and services are purchased for the activity from other firms in the economy. Induced jobs and incomes are created as direct and indirect workers spend their wages in the economy. The State Department of Business, Economic Development and Tourism has developed and refined a statewide input/output model, and these impacts can be calculated using industry multipliers in the model (DBEDT, 2002).

  Exhibits 4-A through 4-F identify direct impacts of construction and operations and go on to show indirect and induced impacts on employment and wages.

- *Cumulative impacts*: Cumulative impacts are the results of the insertion of a new activity in a developing context. They are the total impacts of the new activity and pre-existing factors. Cumulative impacts become especially important if a project adds to demand for limited resources that are barely sufficient without the project but less than adequate for the project plus all the other developments expected to exist ahead of the subject project.

  The key cumulative impact of the Preferred Alternative and Alternatives 3 through 5 is that they assure firm generating capacity to meet demand through the year 2025, while the No Action Alternative does not.

  In Exhibits 4-D and 4-G, the numbers of operations-related workers, their families, and their demand for new households are calculated. While some of these calculations rest on the Input-Output model, i.e., on a model of the entire economy, their cumulative impact is only seen when they are viewed in the context of the island workforce, population and housing demand when those workers take on their new jobs.

- *Symbolic impacts:* An action may have importance as much because of the way it is perceived as because of its tangible results. Symbolic impacts are not always easily classified as adverse or beneficial: If a project is viewed as a sign of unwanted impending changes, is that a signal of future disorganization or a spur to community organization to avert adverse impacts? Symbolic impacts deserve close study but, since they are matters of value and expectation, their importance and consequences are often uncertain.

  The Preferred Action allows HELCO to proceed with actions that have been identified by some of its neighbors as important to them. Under all the other alternatives, some change would be needed to the terms of the Settlement between HELCO and other parties. Even if these changes were resolved quickly, some of the goodwill generated by the settlement would be lost.

Two different approaches are used when dealing with monetary calculations in this report. When assessing the impact of different alternatives on incomes and government revenues, all calculations use constant 2003 dollars. Again, estimates of the impact of the No Action Alternative's low reliability after 2015 are phrased in constant 2003 dollars. This approach allows readers to judge impacts in relation to current experience. However, when developing alternatives, HELCO used a more complex model, since the eventual cost of development for ratepayers and investors will be affected not just by the cost of new facilities but also by the timing of their installation. Results of that model are shown in Exhibit 4-G and discussed in the section on the Hawaii Island Economy.

4.2 EMPLOYMENT AND INCOMES

The alternatives under study fall into three groups in terms of generating jobs:

- The No Action Alternative creates no jobs, either in construction or in operations.

- Alternatives 2 through 4 depend on the eventual construction of fossil fuel based generating facilities. Over the study period (2005 to 2025), these would involve some $30 to $36 million in construction costs.

- Alternative 5 depends on the construction of new biomass plants to process organic matter and create energy. These are estimated as considerably more expensive to build than diesel fuel-base plants. Also, they demand far more workers. Hence this alternative involves a considerably larger workforce (and population, and housing demand) than the others.

4.2.1 Construction

Construction employment can be estimated based on construction costs and historic ratios of workers to construction spending. Exhibit 4-A shows the workforce needed to put in place the various improvements needed to meet expected demand under the various alternative plans

(Alternatives 2 through 5). The No Action Alternative is not included since it includes no construction. Construction jobs are full-time equivalents in "person-years." One person-year may represent steady employment for a worker or shorter engagements by several contractors.

Next, the Input-Output model is used in Exhibit 4-B to estimate the additional jobs in Hawaii associated with construction. Construction jobs pay well, and construction typically involves materials and supplies from local sources, so more indirect and induced jobs are supported than direct ones. The State Input-Output model does not report county-level impacts; these have been estimated by SMS. County-level estimates are hence approximations.

Incomes can be estimated from industry averages (in DLIR, 2003), adjusted in proportion to increases in the Consumer Price Index (in DBEDT, 2003c). For indirect and induced jobs, average incomes for all wage earners are used. Incomes for the Hawaii County workforce were estimated first, on the basis of Hawaii County averages, and incomes for the remaining workforce associated with construction were estimated from Statewide averages. (See Exhibit 4-C.)

Exhibit 4-A: DIRECT CONSTRUCTION EMPLOYMENT

	2006-2010	2011-2015	2016-2020	2021-2025	CUMULATIVE
Construction Spending					
in Millions of 2004 $s					
2 Preferred	$11.7	$0.0	$14.9	$18.6	$45.2
3 West Hawaii	$0.0	$7.4	$17.5	$16.0	$40.9
4 East Hawaii	$0.0	$7.2	$17.4	$14.9	$39.4
5 Renewable	$0.0	$25.4	$27.3	$50.9	$103.7
Direct Construction Jobs					
Person-Years					
2 Preferred	85	-	107	134	326
3 West Hawaii	-	54	126	116	295
4 East Hawaii	-	52	126	107	284
5 Renewable	-	183	197	367	747

SOURCE: Construction cost estimates from HELCO, in 2004 $s. These estimates are for work by local contractors, and exclude the cost of turbines and other major equipment. Jobs were estimates by SMS, based on historic ratios of construction spending to employment.

Exhibit 4-B: DIRECT, INDIRECT AND INDUCED CONSTRUCTION EMPLOYMENT

	2006-2010	2011-2015	2016-2020	2021-2025	CUMULATIVE
Direct, Indirect and Induced Construction-Related Jobs *Person-Years*					
2 Preferred	210	-	267	335	812
3 West Hawaii	-	133	313	288	735
4 East Hawaii	-	129	313	267	708
5 Renewable	-	457	490	914	1,861
DII Construction-Related Jobs in Hawaii County *Person-Years*					
2 Preferred	174	-	221	277	671
3 West Hawaii	-	110	259	238	608
4 East Hawaii	-	106	259	221	586
5 Renewable	-	378	406	755	1,539

Exhibit 4-C: WORKFORCE INCOMES FROM CONSTRUCTION-RELATED EMPLOYMENT

	2006-2010	2011-2015	2016-2020	2021-2025	CUMULATIVE
Direct Construction Jobs *Millions of 2003 $s*					
2 Preferred	$3.9	$0.0	$5.0	$6.2	$15.1
3 West Hawaii	$0.0	$2.5	$5.8	$5.3	$13.6
4 East Hawaii	$0.0	$2.4	$5.8	$5.0	$13.1
5 Renewable	$0.0	$8.5	$9.1	$17.0	$34.6
Direct, Indirect and Induced Construction-Related Jobs *Millions of 2003 $s*					
2 Preferred	$7.7	$0.0	$9.8	$12.3	$29.8
3 West Hawaii	$0.0	$4.9	$11.5	$10.6	$26.9
4 East Hawaii	$0.0	$4.7	$11.5	$9.8	$25.9
5 Renewable	$0.0	$16.7	$18.0	$33.5	$68.2
DII Construction-Related Jobs in Hawaii County *Millions of 2003 $s*					
2 Preferred	$6.3	$0.0	$8.0	$10.0	$24.3
3 West Hawaii	$0.0	$4.0	$9.4	$8.6	$22.0
4 East Hawaii	$0.0	$3.9	$9.4	$8.0	$21.2
5 Renewable	$0.0	$13.7	$14.7	$27.4	$55.8

4.2.2 Operations

Direct operations jobs consist of power-generation jobs (whether for HELCO or another power producer). To estimate the impacts of these jobs for the larger economy and for incomes, SMS has treated the many jobs created in biomass plants as similar to those in sugar mills. Those jobs are, on average, not as highly paid as are power generation personnel. However, the economic impact of the mills has been very great. Not only is the direct workforce in biomass plants much larger than that needed to generate power using diesel fuel, but the ratio of indirect and induced jobs to direct jobs associated with a mill is also much higher than for fossil-fuel burning plants. (Exhibits 4-D and 4-E estimate the workforce and payrolls involved.)

The No Action Alternative creates no operations jobs. It is not shown in Exhibits 4-D and 4-E.

Operations jobs are, unlike construction jobs, long-term ones. At first, there is little employment associated with any of the alternatives, since the existing condition, with CT4 and CT5 on-line, will expand generating capacity. Over time, the direct job count for Alternatives 2 through 4 would climb above 20 jobs, while the job count for a system that relies on biomass for new generating capacity would exceed 100 jobs between 2005 and 2025.

Exhibit 4-D: DIRECT, INDIRECT AND INDUCED OPERATIONS EMPLOYMENT

	2010	2015	2020	2025
Direct Operations Jobs				
Cumulative New Permanent Jobs				
2 Preferred	4	4	12	21
3 West Hawaii	0	4	13	21
4 East Hawaii	0	4	16	24
5 Renewable	0	34	68	136
Direct, Indirect and Induced Operations-Related Jobs				
Cumulative New Permanent Jobs				
2 Preferred	12	12	37	65
3 West Hawaii	0	12	40	65
4 East Hawaii	0	12	50	74
5 Renewable	0	228	456	913
DII Operations-Related Jobs in Hawaii County				
Cumulative New Permanent Jobs				
2 Preferred	10	10	29	51
3 West Hawaii	0	10	32	51
4 East Hawaii	0	10	39	58
5 Renewable	0	160	320	639

NOTES: Direct employment estimated by HELCO planners. Indirect and induced jobs estimated by SMS based on the State Input-Output model (DBEDT

Exhibit 4-E: WORKFORCE INCOMES FROM OPERATIONS-RELATED EMPLOYMENT

		2010	2015	2020	2025
Direct Operations Jobs					
Millions of 2003 $s					
2	Preferred	$0.3	$0.3	$0.9	$1.5
3	West Hawaii	$0.0	$0.3	$0.9	$1.5
4	East Hawaii	$0.0	$0.3	$1.1	$1.7
5	Renewable	$0.0	$1.0	$2.0	$4.1
Direct, Indirect and Induced Operations-Related Jobs					
Millions of 2003 $s					
2	Preferred	$0.5	$0.5	$1.6	$2.8
3	West Hawaii	$0.0	$0.5	$1.8	$2.8
4	East Hawaii	$0.0	$0.5	$2.2	$3.2
5	Renewable	$0.0	$7.0	$14.0	$27.9
DII Operations-Related Jobs in Hawaii County					
Millions of 2003 $s					
2	Preferred	$0.5	$0.5	$1.4	$2.4
3	West Hawaii	$0.0	$0.5	$1.5	$2.4
4	East Hawaii	$0.0	$0.5	$1.8	$2.7
5	Renewable	$0.0	$4.7	$9.4	$18.8

4.3 POPULATION AND HOUSING IMPACTS

Population and housing impacts can be estimated from the job-creation associated with the project. To the extent that a project supports new permanent jobs, it may encourage in-migration. Again, with new jobs, resident workers may have enough income to form new households.

The number of operations workers involved in Alternatives 2 through 5 is small, as shown in Exhibit 4-F. (See Appendix C for calculations of impact for each alternative plan.) As many of the direct workers are specialized technicians, some new hires could come from off-island, and add to local housing demand when they begin work. A few more operations-related workers would amass the funds to set up separate homes after some time, and their eventual creation of new households is also shown in Exhibit 4-F.

Exhibit 4-F: POPULATION AND NEW HOUSING IMPACTS

	As of --			
	2010	**2015**	**2020**	**2025**
Population Supported, Hawaii County				
1 No Action	0	0	0	0
2 Preferred	20	20	61	107
3 West Hawaii	0	20	66	107
4 East Hawaii	0	20	81	122
5 Renewable	0	113	227	453
	On or, more likely, after --			
	2010	**2015**	**2020**	**2025**
Maximum New Housing Creation, Hawaii County				
1 No Action	0	0	0	0
2 Preferred	2	2	6	11
3 West Hawaii	0	2	7	11
4 East Hawaii	0	2	8	12
5 Renewable	0	34	68	136

NOTES: Population and housing impacts based on operations jobs, not construction, since the latter is limited in term. Number of persons per household (2.95) and ratio of jobs per household (1.41) estimated for 2000 from Census data, State DLIR job counts, and SMS estimates. New household creation estimated as 15% to 30% of households, based on past resort studies (Community Resources, 1987a, 1987b). New household creation occurs over time, not necessarily in the year for which operations jobs begin, since workers accumulate income and wait for other reasons to establish new households.

In West Hawaii, as in most of the State, affordable housing is very limited, so a major increase in demand for housing for an industrial workforce could be felt as a significant impact. The eventual increase in demand associated with the fossil fuel based alternatives is very small: less than one new house per year over twenty years. If biomass plants were built, housing demand would be greater, but likely spread over the island (given three separate plants).

4.4 IMPACTS ON THE ECONOMY

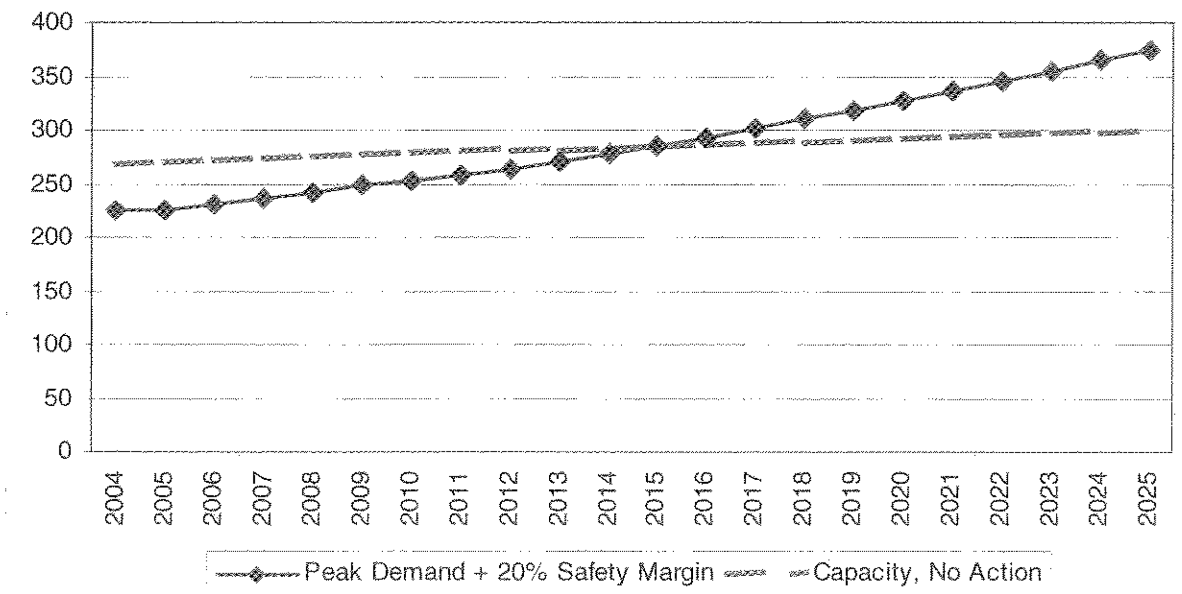
4.4.1 Implications of Alternative Plans for Energy Production and Cost

The alternatives considered by HELCO other than the No Action Alternative meet the requirements of a planning model intended to assure Hawaii County of adequate generating capacity to meet demand for electrical power. As a result, they do not vary in reliability of the power supply over the long term. They vary in cost and in local impacts.

In contrast, the No Action Alternative does not meet the demands of the planning model, and hence it involves less firm generating capacity than appears warranted. A shortfall in supply relative to demand could become problematic by 2015. Exhibit 4-G uses a planning standard – peak demand plus a 20% margin – against which the No Action Alternative would lead to shortfalls. (HELCO's capacity criterion calls for a reserve margin adequate to cover (a) peak demand, (b) one generating unit off-line for planned maintenance and (c) unexpected removal of the largest generating unit in the system. This criterion has been used since 1990 (personal communication, Ross Sakuda, Generation Development Planning, HECO, June 2004). Depending on which unit is on planned maintenance, the capacity needed over peak demand is in the range of 17% to 20%. HELCO uses 20% as a general planning version of the criterion.)

The No Action Alternative leads to an imbalance of demand and capacity similar to that seen in Hawaii County in the early 1990s – but that imbalance would be a continuing, worsening condition, not a short-term one. The cost of lowered reliability is discussed in the next section.

Exhibit 4-G: DEMAND FOR FIRM GENERATING CAPACITY AND CAPACITY AVAILABLE WITH NO ACTION ALTERNATIVE



The cost of supplying electrical power by different means can be estimated on the basis of forecasts of future costs. Exhibit 4-H shows the total costs of the various alternatives that would meet planning criteria for supplying firm power. (Cost estimates include equipment, construction, operations, and maintenance.) The dollar values represent the net present value of future costs and hence treat near-term costs as larger than similar costs occurring later.[5]

The No Action plans are not fully comparable to the others, since they do not involve facilities and operations at levels needed to meet expected demand. They are less expensive, but do not deliver the same service.

[5] Estimates of net present value include a discount rate and inflation rate that will affect future costs. The discount rate allows for the fact that future expenditure of funds is less expensive than saving now, and paying later (all other factors held equal), while the inflation rate allows for cost increases throughout the economy. With these rates used to adjust future investments and costs, the resulting calculations are in terms comparable to present day dollars.

Among the comparable plans, the Preferred Alternative and West Hawaii Alternative are the least expensive).[6]

Over time, the difference in cost among the plans with expanded reliance on fossil fuels is 0.6% or less. The difference in cost between dependence on biomass and on fossil fuels for a new firm energy-generating source is larger, ranges up to 7.4%.

Exhibit 4-H: FORECAST COSTS FOR ALTERNATIVE PLANS

Plan	Development Costs (Million $s) NPV to 2025	Comparison	Rank
1 No Action	$1,003.7	NC	
2 Preferred Action	$1,808.5	100.0%	1
3 New West Hawaii Plant	$1,808.5	100.0%	1
4 New East Hawaii Plant	$1,819.8	100.6%	3
5 Biomass	$1,942.3	107.4%	4

NOTES: Components of plans are shown in Exhibit 1-C. Cost estimates are expressed as Net Present Value 2004 dollars. Comparisons show relative cost of alternatives, expressed as percentages of lowest cost plan.
"NC": Not comparable.

SOURCE: HELCO estimates, 2004.

4.4.2 Impacts of Alternatives on the Hawaii County Economy

Hawaii County accounts for about 10% of the State economy and totals about $5 billion in gross domestic product (as shown in Exhibit 2-J). The Preferred Alternative (and the remaining alternatives designed to provide firm power adequate to support demand) would supply generating capacity to support anticipated economic growth. The No Action Alternative would subject Hawaii County customers to an increasingly inadequate power supply. Many customers would need to have back-up generating capacity.

No Action Alternative

The No Action Alternative would return Hawaii County to a situation in which generating capacity was inadequate to meet demand. (See Exhibit 4-G.). This would limit productivity and increase costs for firms.

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[6] The cost estimate for the Preferred plan is actually some $63,500 lower than for the West Hawaii alternatives. For this discussion, SMS viewed that difference, over a long-term analysis, too small to differentiate the two alternatives. Readers should note that the emissions controls accepted for Keahole under the Settlement were not seen as necessary to meet environmental standards. Hence, they were not included in the costs of development at other sites. Should other sites be chosen and should HELCO implement the control technologies requested and accepted for Keahole in the Settlement, then the cost of new plants elsewhere would rise.

When HELCO cannot meet demand, because generating capacity is less than needed, either unanticipated outages or planned rolling blackouts may occur. Rolling blackouts typically occur at peak demand times (around 6PM at night). Circuits at various places islandwide are removed from the grid. In 1991-1992, HELCO had to refuse service to customers on 22 different days because of a shortfall in capacity.[7] On average, about 15,000 customers lost power on those days. A total of 387 circuit interruptions occurred. While the average interruption was for about 45 minutes, the longest single interruption lasted nearly three hours.

When blackouts are possible, many firms must plan to protect their core functions and information systems. (Residential customers typically are resigned, but unhappy, about blackouts, reporting that they keep candles and flashlights handy. Some have home generators, even though they are on the grid.) Even occasional blackouts have important consequences for well-prepared customers:

- The HOST Park assures its tenants of a continuous supply of cold deep-ocean water. To do so, it maintains generating capacity and fuel to supply the pumps even if the local power supply fails for up to two weeks.

- The Keck Observatory can close its telescope dome using emergency power in the event of an outage. It does not have enough power to make and record observations, so viewing time is lost.

- At the North Hawaii Community Hospital, generators can supply offices and wards with power, but the operating theater is closed in the event of an outage.

In all these cases, uncertainty about power raises operating costs and can lower productivity. Under the No Action Alternative, rolling blackouts would come to be increasingly expected by 2015. This would make Hawaii County less competitive than other counties in attracting new investment, since firms would need to plan to supply their own power as a matter of course.

As noted earlier, residential energy demand per person has been consistently growing. While some of that demand is likely not productive, some, such as use of computers for work at home, clearly does support residents' income-producing activity. Under the uncertain conditions that the No Action Alternative would create, residents would not be able to depend on power for such activity, and hence would be less able to telecommute and otherwise work from home.

Not all customers would be affected the same way by a regime in which rolling blackouts occur often. First, HELCO tries to minimize interruptions for commercial areas, taking areas with largely a residential customer base off the grid rather than commercial ones. Next, the largest customers are increasingly being encouraged to develop their own power resources. At Mauna Lani, a major resort now draws on its own solar power sources to supply 800 kW for hot water and air conditioning, and even to contribute to the grid. While HELCO and customers such as the resort must negotiate fee structures and connection agreements, the clear result is that the largest customers are likely to be insulated from the uncertainties of outages in the case of the No Action Alternative. This alternative could increase third-party producers' interest in developing distributed generation capacity.

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[7] At that time, Puna Geothermal Venture had been contracted to provide 25 MW, but was not yet on line. Blackouts occurred when generating capacity was less than actual demand, because other units needed maintenance and went off-line.

Distributed generation is an objective of HELCO plans and included in all alternatives under study. The point being stressed here is that distributed generation is most cost-effective, and most likely to be implemented, by large customers. Those customers would in turn be protected from the risks that would arise under the No Action Alternative, while smaller customers would face both the risks and the reduced productivity associated with that alternative.

Alternative Plans

Alternative Plans 2 through 5 are designed to provide reliable service, and hence avoid situations in which rolling blackouts are scheduled. Service interruptions could still occur. While they vary in costs for ratepayers (discussed below), they all should involve capacity adequate for consumer demand. Hence they do not involve major impacts on the island economy due to reliability.

Alternative Plan 5 was included to address the feasibility of renewable firm resources as an alternative to fossil fuels. The obvious renewable resources capable of supplying firm power on a large-scale are geothermal energy and biomass. PGV has contracted to supply 30MW, although it is not consistently producing at that level. The Hawaii Island grid for many years depended on biomass in the form of bagasse burned by sugar mills. With the closing of the sugar plantations, biomass was no longer available, so HCPC is supplying power by burning imported coal, rather than a locally grown resource.

Should new biomass plants become viable, whether because of high fossil-fuel costs or energy policy, Hawaii Island would probably need to grow biomass expressly for this purpose, rather than as a byproduct of plantation agriculture. For each 25 MW biomass plant, approximately 6,300 acres would be needed to supply biomass. This alternative would, then, provide demand for nearly 20,000 acres of agricultural land over the next two decades. (That amount is 1.6% of Hawaii County's land designated as Agricultural by the State Land Use Commission.)

4.4.3 Impacts on Ratepayers

The cost of different alternative plans (2 through 5) can be compared as supplying generating capacity at the level forecast as needed by Hawaii County consumers. (The No Action Alternative is not comparable, since it does not involve provision of the same amount of power.)

Should the Biomass Alternative be pursued, ratepayers would likely cover the cost of this alternative. It would amount to about $50.50 per customer per year over the 21-year planning period. [8] (A few agricultural ratepayers would of course recoup this cost by supplying biomass for the plants.) When the Preferred Alternative and West Hawaii Alternative are compared, the cost difference is very small, and the Preferred Alternative is slightly less expensive.

4.4.4 Impacts on Stockholders

Hawaiian Electric reports to stockholders have repeatedly discussed the stalled development of the Keahole plant as a problem. Alternative 2 allows HELCO to generate power to meet demand and also to support a settlement that has been presented as a solution for the

[8] In 2002, HELCO had 66,411 customers (DBEDT, 2003). For this comparison, SMS assumed that HELCO would have, on average, 70,000 customers between 2004 and 2025.

community as a whole. In contrast, the No Action Alternative and the alternative plans (i.e., 3 through 5) fail to meet key terms of the settlement. Consequently, the Preferred Alternative offers stockholders a much less uncertain future than the other alternatives. In that future, continuing good relations between HELCO and its customers could well lead to less contentious planning and permitting processes, and hence more efficient actions by HELCO.

The Preferred Alternative develops a DTCC plant at Keahole in this decade. As a result, energy generation becomes more cost-efficient, and energy lost through waste heat will be reduced under the Preferred Alternative.

4.5 FISCAL IMPACTS

Fiscal impacts consist of changes in government costs and revenues due to a project. In the present case, direct impacts are small. For the No Action Alternative, major cumulative impacts could arise, inasmuch as the reduced generating capacity under that alternative would tend to limit economic activity, as discussed in Section 4.4.2 above. With reduced economic growth, government revenues tied to the economy (e.g., excise tax collections and property tax values) would be lower or grow more slowly.

4.5.1 State of Hawaii

Construction activities generate revenues for the state in the form of excise taxes, personal income tax, and corporate income tax. Exhibit 4-I shows that the State of Hawaii would gain approximately $4 million (2003 dollars) from cash flows associated with construction for Alternatives 2 through 4, and $9 million for Alternative 5. This exhibit draws on estimates of local construction spending (also used for Exhibit 4A). Estimates of specific revenue flows are shown in the Appendix to this report.

Exhibit 4-I: STATE REVENUES ASSOCIATED WITH CONSTRUCTION

State Tax Revenues, in Mill. 2003 $s	2006-2010	2011-2015	2016-2020	2021-2025	Cumulative
Alternatives					
2 Preferred	$1.1	$0.0	$1.4	$1.8	$4.3
3 West Hawaii	$0.0	$0.7	$1.7	$1.5	$3.9
4 East Hawaii	$0.0	$0.7	$1.7	$1.4	$3.8
5 Renewable	$0.0	$2.4	$2.6	$4.9	$9.9

The Hawaii State public service company tax is calculated on the basis of gross receipts of utilities. So long as HELCO is able to respond appropriately to demand (under Alternatives 2 through 5), no difference in receipts is anticipated.

Potentially, the No Action alternative could have a secondary impact on State revenues, to the extent that they would limit economic growth and hence income. While SMS finds this argument plausible, it cannot be quantified without making speculative assumptions about the share of growth that would be diverted to other Counties, rather than outside Hawaii.

4.5.2 County of Hawaii

The County of Hawaii's main revenue source is real property tax. Utilities pay only nominal real property taxes ($100/parcel). Consequently, no difference in County receipts is anticipated. Also, no difference in County costs is anticipated under Alternatives 2 through 5. For the No Action Alternative, with an important risk of outages, the County could anticipate lost work time and need to pay staff overtime due to disruptions associated with outages. (That cost would be part of the total impact on the Hawaii County economy discussed in Section 4.4.2.)

4.6 IMPACTS ON NEARBY AREAS AND ACTIVITIES

4.6.1 Agricultural Areas

The Keahole properties are at the north end of Keahole Agricultural Park. The Keahole Agricultural Park includes 36 lots (not counting the HELCO properties and an adjacent radio tower site). Of those, 25 have dwellings. Plants grown in the park include flowers and landscape plants. Currently, the agricultural park is fully leased.

The developers of the Palamanui project plan to build a roadway that will connect to the access road located on the north side of the HELCO property. It would then become the major road into and out of their project and the eventual State developments on adjacent land. If their plan moves forward, then HELCO could consider changes in access to the Keahole Generating Plant. At present, fuel trucks enter and leave by the north gate (to the access road currently used only by HELCO) but all other visitors and workers reach the plant by the south gate, traveling through the Agricultural Park. With a wider access road, HELCO can consider using the north gate for all traffic to and from the generating station, lessening the impact of the station on its neighbors in the Agricultural Park. This road plan is unrelated to the project and alternatives discussed here, except as part of the context for impact analysis.

Impacts on Activities and Occupants

In the past, neighbors have expressed concern that emissions from the Keahole plant might, in combination with vog, result in air quality harmful to those living and working nearby. This issue has been addressed in the Settlement and in Chapter 3 of this Environmental Impact Statement. To the extent that the Settlement is implemented (as planned under the Preferred Alternative), air quality will continue to meet or be better than current standards. Moreover, neighbors will have assurance that HELCO is taking steps to mitigate and monitor noise and emissions. Development of the ST7 unit will offer further reassurance, since it will use steam generated by the other combustion turbines to create additional power, thereby limiting emissions.

Under the other alternatives, the Keahole plant will have increased generating capacity, increased emissions, and a higher stack to disperse the emissions. HELCO would comply with environmental standards and regulations. However, under the other alternatives, not all the measures in the Settlement designed to address the concerns of the Keahole plant's neighbors would necessarily be implemented, either at Keahole or at other generating plant sites.

Impacts on Property Values

Land in the agricultural park is leased by the State Department of Agriculture. Lease rents are determined by independent appraisals. Leases may be sold to active farmers. When data on parcels in the agricultural park is compared with comparable leasehold agricultural parcels in West Hawaii, it turns out that sales values for land in the agricultural park are high, while the assessed values determined by County tax assessors are low:[9]

Exhibit 4-J: VALUATION OF COMPARABLE WEST HAWAII AGRICULTURAL PROPERTIES

	Total Sample	Keahole Agricultural Park
Parcels	642	36
Parcels with sales since 1/1/1998	121	15
Average land value/acre	$5,680	$1,845
Average sales price/acre	$6,786	$18,650

Clearly, the park's status and/or location tend to hold tax valuation down, but not sales values and the level of sales activity. It appears, then, that Keahole Agricultural Park has maintained high sales values, despite the presence of an active power plant to the north, and a major highway and airport to the west. In this situation, there is no obvious reason why the changes now underway, or the reclassification of the HELCO parcels (i.e., the project) can be expected to affect lease and resale values.

The Renewable Alternative would have an important impact on agricultural land, since it would involve production of fuel crops on some 20,000 acres by 2025. The consequences for valuation would depend on whether land used for biomass production had been valued previously as appropriate for high value crops or for little more than pasture. Agricultural values in Hawaii County range from $7/acre (for poor pasture land, dedicated to agricultural use) to $2,000/acre for land used for truck crops. Land for production of biomass or forage crops and dedicated to agricultural use would be valued at $250/acre.

Currently, there is much agricultural land in Hawaii County in large lots that is little used, and valued at about $150/acre or even lower amounts.[10] Use of such property for biomass production with long-term agricultural dedication would lead to higher valuations and taxes. The tax impact for the entire area involved in biomass production would likely be a gain for the County on the order of $20,000 annually.

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[9] Data were gathered using Hawaii Information Service records in November 2003. Sales are for the period from 1/1/1998 to the time of analysis. The comparable data are for leasehold agricultural parcels from three to ten acres in size.

[10] This claim is based on examination of values of some 20 properties in Hamakua and Kau over 500 acres, zoned for agricultural use. Since no sites for future biomass production are known, any sampling of potentially affected agricultural land is only preliminary.

4.6.2 Residential Areas

Currently, Kona Palisades is the only residential subdivision near the project and stretching below the 800 feet elevation. The closest homes are about 0.9 miles from the Keahole Generating Station by road. Eventually, additional housing could be located directly north and east of the Keahole site, in the Palamanui project and on State land, beginning about a mile away from the site. Additional housing could also be developed to the south of Kona Palisades.

Impacts on Activities and Occupants

With the Preferred Alternative, HELCO will be able to implement the mitigations and controls noted in the Settlement. Under all the other alternatives, residents would face a situation in which HELCO could not implement all the controls accepted under the Settlement. Consequently, they would know that while the precautions in place meet State and Federal standards, they are less stringent than the ones that some of the nearby property owners sought. Such a situation would be unsettling to some, and unlikely to encourage improved relations between HELCO and its local customers.

All the various alternatives would have no impact on the visual appearance of the generating station to the surrounding community.

Impacts on Property Values

Reclassification is not expected to affect property values, since value is estimated on the basis of market trends for similar properties, not the classification of very different ones. Residents may be concerned that plant development and energy production affect residential property values in the surrounding subdivisions. In the 1993 EIS for Keahole, an appraisal firm compared selected subdivisions and found no impact. For the present EIS, SMS ran a similar analysis for single family properties in much of North Kona (in TMK zones 3-7-3 through 3-7-5) between Queen Kaahumanu Highway and about the 1,200 foot elevation. The aim was to learn whether location of residential property uphill from the Keahole industrial area was an important component of value. Analyses were run on both appraised values and records of sales. In all cases, the uphill location was not significantly associated with value. In short, the presence of industrial activity and an international airport at Keahole does not now affect residential property values uphill. While we cannot rule out the possibility that the recently completed stack and new turbines will have a discernible impact on values, there is no evidence to suggest this. (As noted earlier, the new stack is included under all alternatives, as part of the construction currently permitted in advance of the proposed land use changes.)

4.6.3 Commercial and Industrial Areas

The alternatives considered here would have minimal impact on commercial and industrial areas. These are largely exempted from the rolling blackouts that could occur if the No Action Alternative is realized. As described earlier, improved reliability could lead to higher productivity and lower costs for Big Island businesses (under Alternatives 2 through 5), but this is not an impact on a specific commercial area.

The Natural Energy Laboratory of Hawaii is developing an Energy Gateway site along Queen Kaahumanu Highway south of the Keahole HELCO properties. That site will highlight energy research and development efforts in Hawaii and around the world. HELCO is an active collaborator in developing the site. However, no connection between activities at the Gateway site and the Keahole generating plant – beyond the need for reliable power – is obvious.

4.6.4 Other Areas and Activities in Hawaii County

The most immediate impact of the new facilities proposed for Keahole on Hawaii County in general is the provision of additional generating capacity.

In interviews, many residents commented that a visible industrial plant with a tall stack is undesirable at the intersection of the Queen Kaahumanu Highway with the road to and from the airport. They suggest that tourists' appreciation of Kona as a destination is lessened by the sight.

No increase in visibility is associated with the project, i.e., with reclassification of the site, so the question of whether the stack is obtrusive is not project-related. CTCT HELCO has undertaken to increase landscaping that would tend to mask the contours of the plant for observers on the highway

The Renewable Alternative could well have complex impacts on the areas surrounding biomass plants. Environmental impacts – water and air quality, noise – would likely arise. Traffic impacts associated with hauling biomass to the plant would need to be considered. These impacts could have important implications for nearby communities' quality of life. Those implications cannot be assessed here, for lack of detailed plans and siting decisions, but they must be acknowledged as issues to be faced if this alternative were to be implemented.

4.7 SOCIAL IMPACTS ON AREAS AND ACTIVITIES NEAR ALTERNATE SITES

The two sites considered here – Hill Plant and Puuanahulu -- are in many respects appropriate for further industrial activity. The first is in an industrial area, The site is already in use by HELCO, which has a generating plant on the property. The Puuanahulu site is accepted as the location of a locally unpopular land use. It is hard to see how a generating plant on Puu Pohaku Road could add appreciably to community impacts of the existing landfill

The East Hawaii site is in a changing urban area. The University of Hawaii at Hilo is increasing in size, new residential areas are being developed or proposed above it, and major retail development has already occurred on Kanoelehua Avenue. The Hill Plant site is visible, and operations there can be heard and, under some wind conditions, smelled by people in much of the surrounding area. Construction and operation of a new fossil-fuel plant at the site would not necessarily create significant new noise, visual and olfactory impacts. It is quite likely, however, that these activities will lead to increased community sensitivity to operations at Hill Plant. The choice of this site would, then, likely raise continuing problems in maintaining community relations.

As discussed earlier, local stakeholders are very concerned about the transport of solid waste to Puuanahulu. In the context of that ongoing controversy, stakeholders may want reassurance that (a) large numbers of fuel trucks will not be directed through Waimea, and movement of fuel trucks on local arterials will be carefully controlled to minimize congestion and assure safety.

MITIGATIONS

5.1 MEASURES TO MITIGATE ADVERSE IMPACTS IDENTIFIED IN THIS REPORT

The only adverse socio-economic impacts identified in this report for the Preferred Alternative are the higher cost for ratepayers and stockholders (as compared to the West Hawaii Alternative), shown in Exhibit 4-G. Those costs may be balanced against the gain in certainty achieved through the Settlement. Also, they are small in relation to the overall costs of power generation over the study period. No further mitigation measures seem necessary for socio-economic impacts of the Preferred Alternative.

The actions in the Settlement include specific responses to concerns of the parties to the agreement, notably the installation of Selective Catalytic Reduction (SCR) technology to deal with air quality, and use of landscaping and painting to minimize visual impacts. Leaving aside the technical question of how severe the impacts in question would have been, it is clear that these measures have served to demonstrate willingness of HELCO to work with its neighbors and have offered some reassurance that the Keahole plant will, under the Preferred Alternative, have less impact than feared. In this sense, the Settlement components can be seen as mitigating ongoing problems of community relations.

5.2 MITIGATION PROCESSES

Mitigation measures can be taken unilaterally or through a process in which key parties identify what they take to be important impacts, propose responses, and agree which response or set of responses most appropriately deals with the problem. The history of the Keahole proposal includes both types of decision-making process. HELCO has proposed and implemented some activities to limit impacts on neighbors, while others were proposed in the context of contested-case hearings and subsequent negotiations. The Settlement includes specific actions that respond to neighbors' concerns and hence mitigate both physical and social potential impacts.

The Preferred Alternative, as the implementation of the Settlement, continues this mitigation process. The No Action Alternative would set aside the settlement and offer no substitute. The alternative plans would also leave the implementation of the Settlement unfinished, and would hence likely demand reopening negotiations with the other parties to the Settlement.

APPENDICES

A PERSONS INTERVIEWED

Persons	**Affiliations** *(listed for the reader's information -- does not indicate any institutional stance with regard to project)*
Stan B. Berry	President and CEO, North Hawaii Community Hospital
Kathleen Kiss Damon	Director, University of Hawaii Center, West Hawaii
Fred Duerr	General Manager, Kona Village Resort
Kelly Greenwell	Keahole Agricultural Park resident Director, Kealakehe Ahupuaa 20/20
Roger Harris	Vice President, Planning, Pauoa Beach Consultant, Palamanui project
Paula Helfrich	Executive Director, Hawaii Island Economic Development Board
Pete Hendricks	Deputy Managing Director, County of Hawaii
Wayne S. Higaki	Assistant Vice President, North Hawaii Community Hospital
Jacqui L. Hoover	NELHA Gateway Manager, Natural Energy Laboratory of Hawaii Authority
Eddie Huihui	Kona Palisades Resident
Rosella Lampe	Kona Palisades resident
Wally Lau	Director, Kona Neighborhood Place Kona Palisades resident
Ronald L. Laub	Special Projects Administrator, W. M. Keck Observatory
Eric von Platen Luder	Owner/Manager, Huggo's Restaurant President, Kona Kohala Chamber of Commerce

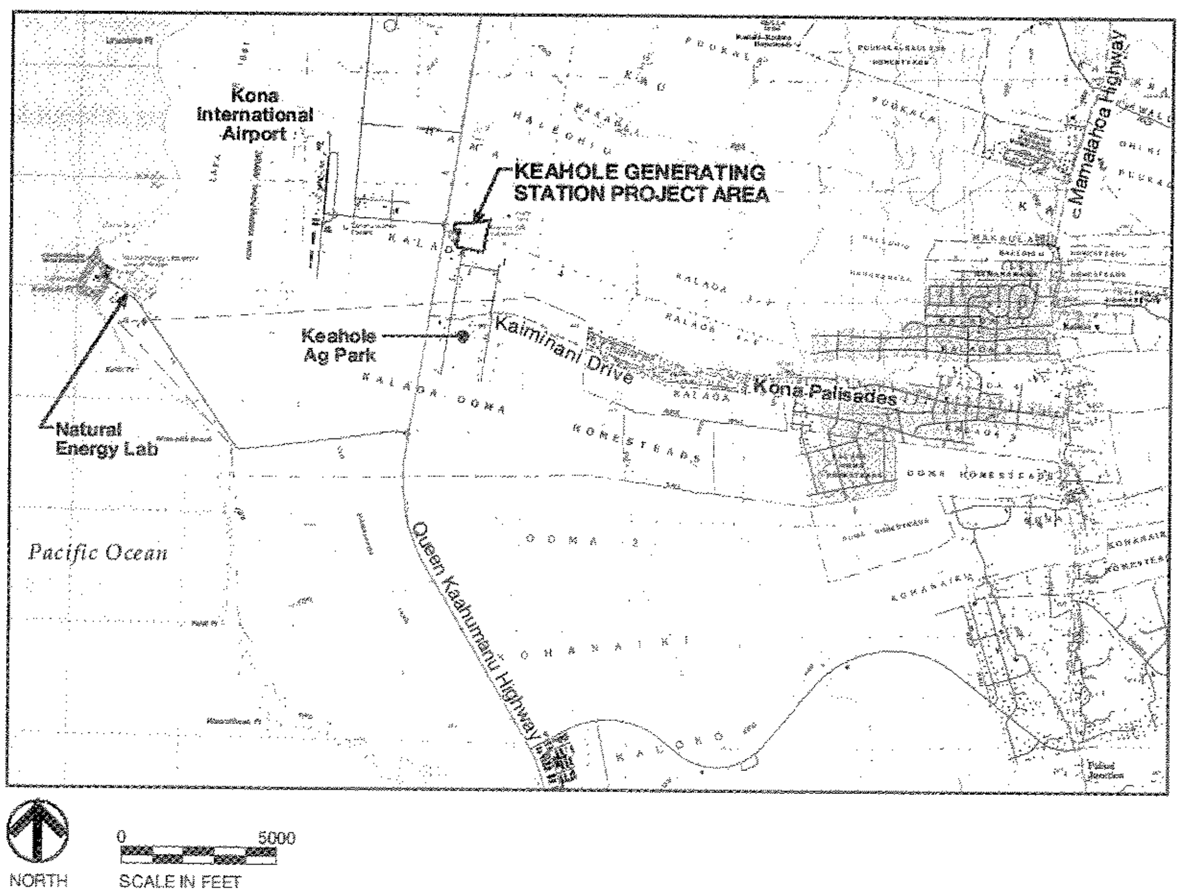
Persons	**Affiliations** *(listed for the reader's information -- does not indicate any institutional stance with regard to project)*
Dennis McBride	Facilities Engineering Manager, W. M. Keck Observatory
Larry McCullough	Kona Palisades resident
Mark McGuffie	General Manager, King Kamehameha's Kona Beach Hotel Corporate Director, Hotel Operations, HTH Corporation
Wilfred Murakami	Principal, Kealakehe High School
Glenn and Dassar Nojiri	Kona Palisades residents
Clyde Oshiro	Kona Palisades resident
John B. Ray	President, Hawaii Leeward Planning Conference
Linda A. Scheffler	Environmental Health Specialist, State of Hawaii Department of Transportation, Airports Division, Kona International Airport
Jeff L. Smith	Executive Director, Hawaii Ocean Science & Technology Park and the Natural Energy Laboratory of Hawaii Authority
Glenn Soma	Planning Branch, Hawaii State Department of Transportation, Harbors Division
Chuck Tipton	Kona Palisades resident
Ira F. Walton III	CEO, Kona Community Hospital

B INTERVIEW HANDOUT

Keahole Environmental Impact Statement

SMS Research is conducting interviews as part of work on a socio-economic impact study for the Environmental Impact Statement being prepared for the Keahole Generating Station. Our client is Belt Collins Hawaii, as planner for Hawaii Electric Light Company (HELCO). We are talking with people in West Hawaii to understand how the action studied in the EIS and HELCO plans are viewed by the community.

The EIS is to reclassify land from the State Conservation District to the State Urban District, and then to change zoning from Open to MG (General Industrial). The affected properties are the parcels under the Keahole Generating Station and the Airport Substation next to it. The generating station is about a mile east of Kona International Airport, and 750 feet east (mauka) of Queen Kaahumanu Highway.



HELCO has for many years proposed expanding the Keahole Generating Station, and HELCO still seeks to do so. HELCO started construction of the next phase in 2002, but stopped in response to a court order. Judge Ibarra recently vacated his court order, permitting HELCO to resume construction on the project. Judge Ibarra recognized a settlement worked out by HELCO with several parties who used to oppose the expansion.

Currently, the station has seven generators, with a total generating capacity of 30.25 MW (MegaWatts).[11] HELCO seeks to add three new generators and equipment, capable of generating 56 more MW. HELCO plans to mitigate anticipated impacts through emission controls, noise controls, and painting and landscaping.

For the EIS, we distinguish between land use changes (reclassification and zoning) and expansion of the plant. We will look at impacts of each.

SMS interviewers want to know how the West Hawaii community sees the Preferred Alternative and the proposed expansion. We will report our findings in the EIS, keeping individual opinions confidential.

For more information:

- About HELCO's plans – call Warren Lee at 935-1171 (wlee@hei.com)
- About the EIS process – call Lee Sichter at Belt Collins Hawaii (808-521-5361; lsichter@beltcollins.com)
- About SMS and this interview – call John Kirkpatrick at 1-877-535-5767 or, in Honolulu, 440-0703. (jkirk@smshawaii.com)

[11] This was true at the time of interviewing, in 2003. As of mid-2004, Keahole has a generating capacity of 21.25 MW, with three of its diesel generating units retired and the two new Combustion Turbines still in testing mode.

C CALCULATION OF POPULATION AND HOUSING IMPACTS, ALTERNATIVE PLANS

The following tables estimate population and housing impacts from the operations jobs forecast for the various alternative plans. (With no employment associated with operations under the No Action Alternative, no population and housing impacts are forecasts.)

2 Preferred	2010	2015	2020	2025
Operations-Related Jobs	12	12	37	65
Operations-Related Jobs, Hawaii County	10	10	29	51
Residents supported by Operations Jobs, State of Hawaii				
Persons	26	26	78	136
Households	9	9	26	46
Residents supported by Operations Jobs, Hawaii County				
Persons	20	20	61	107
Households	7	7	21	36
Potential New Household Creation, Statewide				
Low Estimate	1	1	4	7
High Estimate	3	3	8	14
Potential New Household Creation, Hawaii County				
Low Estimate	1	1	3	5
High Estimate	2	2	6	11

NOTES: Population and housing impacts based on operations jobs, not construction, since the latter is limited in term. Number of persons per household (2.95) and ratio of jobs per household (1.41) estimated for 2000 from Census data, State DLIR job counts, and SMS estimates. New household creation estimated as 15% to 30% of households, based on past resort studies (Community Resources, 1987a, 1987b). New household creation occurs over time, not necessarily in the year for which operations jobs begin, since workers accumulate income and wait for other reasons to establish new households.

3 West Hawaii	2010	2015	2020	2025
Operations-Related Jobs	0	12	40	65
Operations-Related Jobs, Hawaii County	0	10	32	51
Residents supported by Operations Jobs, State of Hawaii				
Persons	0	26	84	136
Households	0	9	29	46
Residents supported by Operations Jobs, Hawaii County				
Persons	0	20	66	107
Households	0	7	22	36
Potential New Household Creation, Statewide				
Low Estimate	0	1	4	7
High Estimate	0	3	9	14
Potential New Household Creation, Hawaii County				
Low Estimate	0	1	3	5
High Estimate	0	2	7	11

NOTES: Population and housing impacts based on operations jobs, not construction, since the latter is limited in term. Number of persons per household (2.95) and ratio of jobs per household (1.41) estimated for 2000 from Census data, State DLIR job counts, and SMS estimates. New household creation estimated as 15% to 30% of households, based on past resort studies (Community Resources, 1987a, 1987b). New household creation occurs over time, not necessarily in the year for which operations jobs begin, since workers accumulate income and wait for other reasons to establish new households.

4 East Hawaii	2010	2015	2020	2025
Operations-Related Jobs	0	12	50	74
Operations-Related Jobs, Hawaii County	0	10	39	58
Residents supported by Operations Jobs, State of Hawaii				
Persons	0	26	104	156
Households	0	9	35	53
Residents supported by Operations Jobs, Hawaii County				
Persons	0	20	81	122
Households	0	7	28	41
Potential New Household Creation, Statewide				
Low Estimate	0	1	5	8
High Estimate	0	3	11	16
Potential New Household Creation, Hawaii County				
Low Estimate	0	1	4	6
High Estimate	0	2	8	12

NOTES: Population and housing impacts based on operations jobs, not construction, since the latter is limited in term. Number of persons per household (2.95) and ratio of jobs per household (1.41) estimated for 2000 from Census data, State DLIR job counts, and SMS estimates. New household creation estimated as 15% to 30% of households, based on past resort studies (Community Resources, 1987a, 1987b). New household creation occurs over time, not necessarily in the year for which operations jobs begin, since workers accumulate income and wait for other reasons to establish new households.

5 Renewable	2010	2015	2020	2025
Operations-Related Jobs	0	228	456	913
Operations-Related Jobs, Hawaii County	0	160	320	639
Residents supported by Operations Jobs, State of Hawaii				
Persons	0	477	955	1,909
Households	0	162	324	647
Residents supported by Operations Jobs, Hawaii County				
Persons	0	334	669	1,337
Households	0	113	227	453
Potential New Household Creation, Statewide				
Low Estimate	0	24	49	97
High Estimate	0	49	97	194
Potential New Household Creation, Hawaii County				
Low Estimate	0	17	34	68
High Estimate	0	34	68	136

NOTES: Population and housing impacts based on operations jobs, not construction, since the latter is limited in term. Number of persons per household (2.95) and ratio of jobs per household (1.41) estimated for 2000 from Census data, State DLIR job counts, and SMS estimates. New household creation estimated as 15% to 30% of households, based on past resort studies (Community Resources, 1987a, 1987b). New household creation occurs over time, not necessarily in the year for which operations jobs begin, since workers accumulate income and wait for other reasons to establish new households.

D: CALCULATION OF STATE REVENUE IMPACTS ASSOCIATED WITH CONSTRUCTION

In the following tables, cash flows leading to revenues for the State of Hawaii are calculated for the alternative plans. (The No Action Alternative involves no construction, and hence no associated State revenues.)

2 Preferred	2006-2010	2011-2015	2016-2020	2021-2025	Cumulative
In Millions of 2003 $s					
Construction Spending	$11.7	$0.0	$14.9	$18.6	$45.2
Construction-Related Wages	$7.7	$0.0	$9.8	$12.3	$29.8
Revenues					
EXCISE TAXES on					
Construction Spending (1)	$0.5	$0.0	$0.6	$0.8	$1.9
Construction-Related Workforce Spending (2)	$0.2	$0.0	$0.3	$0.3	$0.8
CORPORATE INCOME TAX (3)					
Construction (3)	$0.0	$0.0	$0.0	$0.0	$0.1
PERSONAL INCOME TAX (4)					
Construction-Related Workforce Incomes	$0.4	$0.0	$0.5	$0.6	$1.5
TOTAL	$1.1	$0.0	$1.4	$1.8	$4.3

NOTES: Cash flows calculated by SMS based on spending estimates by HELCO.

(1) Excise tax estimated as 4.1666% of spending.
(2) Excise tax on workforce spending estimated as 4.1666% of disposable income. Based on historic spending patterns, 67.1% of workers' incomes are treated as taxable.
(3) Corporate income tax is calculated on profits, not gross revenues. Corporate taxes are estimated as 0.25% of gross revenues, based on historic patterns.
(4) The ratio of State taxes collected to workforce income is estimated as 5.05%, based on historical data.

SOURCES: Hawaii State Department of Taxation (1989), DBEDT (2003a) ...

3 West Hawaii	2006-2010	2011-2015	2016-2020	2021-2025	Cumulative
In Millions of 2003 $s					
Construction Spending	$0.0	$7.4	$17.5	$16.0	$40.9
Construction-Related Wages	$0.0	$4.9	$11.5	$10.6	$26.9
Revenues					
EXCISE TAXES on					
Construction Spending (1)	$0.0	$0.3	$0.7	$0.7	$1.7
Construction-Related Workforce Spending (2)	$0.0	$0.1	$0.3	$0.3	$0.8
CORPORATE INCOME TAX (3)					
Construction (3)	$0.0	$0.0	$0.0	$0.0	$0.1
PERSONAL INCOME TAX (4)					
Construction-Related Workforce Incomes	$0.0	$0.2	$0.6	$0.5	$1.4
TOTAL	$0.0	$0.7	$1.7	$1.5	$3.9

4 East Hawaii	2006-2010	2011-2015	2016-2020	2021-2025	Cumulative
In Millions of 2003 $s					
Construction Spending	$0.0	$7.2	$17.4	$14.9	$39.4
Construction-Related Wages	$0.0	$4.7	$11.5	$9.8	$25.9
Revenues					
EXCISE TAXES on					
Construction Spending (1)	$0.0	$0.3	$0.7	$0.6	$1.6
Construction-Related Workforce Spending (2)	$0.0	$0.1	$0.3	$0.3	$0.7
CORPORATE INCOME TAX (3)					
Construction (3)	$0.0	$0.0	$0.0	$0.0	$0.1
PERSONAL INCOME TAX (4)					
Construction-Related Workforce Incomes	$0.0	$0.2	$0.6	$0.5	$1.3
TOTAL	$0.0	$0.7	$1.7	$1.4	$3.8

5 Renewable	2006-2010	2011-2015	2016-2020	2021-2025	Cumulative
In Millions of 2003 $s					
Construction Spending	$0.0	$25.4	$27.3	$50.9	$103.7
Construction-Related Wages	$0.0	$16.7	$18.0	$33.5	$68.2
Revenues					
EXCISE TAXES on					
Construction Spending (1)	$0.0	$1.1	$1.1	$2.1	$4.3
Construction-Related Workforce Spending (2)	$0.0	$0.5	$0.5	$0.9	$1.9
CORPORATE INCOME TAX (3)					
Construction (3)	$0.0	$0.1	$0.1	$0.1	$0.3
PERSONAL INCOME TAX (4)					
Construction-Related Workforce Incomes	$0.0	$0.8	$0.9	$1.7	$3.4
TOTAL	$0.0	$2.4	$2.6	$4.9	$9.9

E. REGRESSION ANALYSIS OF RESIDENTIAL PROPERTY VALUES

To understand whether development of new electrical generating facilities (in all alternatives) or new controls over emissions and noise (in the Preferred Alternative), at Keahole would be likely to affect residential property values, SMS ran regression analyses of values for residential property in North Kona, comparing values of homes directly uphill from the Keahole generating plant and airport with others. The logic of the analysis is simply that if the presence of industrial facilities already affects residential values, then increased impact could (but might not) occur. If no impact is visible in current valuation data, then there is no basis for expecting such impact in the future.

SMS included both sales and valuation data for single family properties (Pitt Code 100) in Tax May Key areas 3-7-3 through 3-7-5. In addition to TMK data on value, sales, property description and building description, SMS coded each parcel for the following characteristics[12]:

- Elevation: Using elevation data transferred from USGS maps to TMK maps by Belt Collins, plats were coded as lying from 0 to 500 feet above sea level, 501 to 1,000 feet, 1,001 to 1,500 feet, 1,501 to 2,000 feet, and above 2,000 feet. Plats makai of Queen Kaahumanu Highway were coded separately, partly in order to distinguish oceanfront parcels from other low-lying ones. For the analysis, the makai plats, ones higher than 2,000 feet, and large ones that could not be identified as nearly all located within one of the elevation categories.

- Highway: Plats located next to Mamalahoa Highway, Queen Kaahumanu Highway or Palani Road were coded as more easily accessible than others.

- Uphill of Keahole: Plats along Kaiminani Road were coded as immediately uphill of Keahole Generating Station and the Airport; plats within 4,000 feet to the north or south were coded as near, but not directly uphill of Keahole; all other plats were coded as not uphill.

SMS proceeded to use regression analysis to identify concomitants of land value, total value and sales price, i.e., factors that can account for the value of the properties. The hypothesis being tested was whether a location uphill from the Keahole Generating Plant and Airport had a measurable association with value, either in the considered judgment of real property appraisers or in the sales record.

With the limits on sample noted above (e.g.., exclusion of parcels in plats that are too large to assign an elevation to all parcels in the plat), the resulting sample consisted of:

840 usable records of residential parcels;
340 records of parcels sold within the last five years; and
264 records of parcels sold within the last three years.

Sales for less than $10,000 were excluded as not reflecting market forces.

[12] Every parcel of land is uniquely identified by a string of numbers – the TMK number – as follows: Division (of the State: Hawaii County is Division 3); Zone (North Kona is Zone 7); Section (much of the area from Keahole to Keauhou is in Sections 3 to 5); Plat – often a subdivision or increment of one – and Parcel identifier. Condominium properties have an additional identifier for each condominium owner.

The dependent variables were:

- Total Value: This is the appraised value of the land and improvements, as established by Hawaii County Real Property assessors. The assessors take into account market data from the neighborhood and region. The mean value of the properties studied was $211,279.

- Land Value: This is the land value established by the assessors. The mean land value was $86,203.

- Last Price (for properties sold in the last five years): Since the market has risen, but not sharply, in the last five years, this period was chosen to maximize sample size. The mean price was $300,662.

- Last Price (for properties sold in the last three years): This period was chosen to have a tighter range of prices with some loss of sample size. The mean price was $279,212.

The key finding is very simple: It was possible to account for most of the values ascribed to the properties but in no case was the position of parcels uphill from the Keahole industrial zone significant. In other words, **this factor does not contribute to or detract from the value of the residential properties in any demonstrable way**.

Here the significant associations are noted:

Total value: The regression analysis was fairly robust ($R = .805$; $R^2 = .648$). The following variables were significant contributors to the dependent variable (i.e., explained the value of the properties):

Variable	p (significance)	B (contribution to dependent var.)[13]
Living area	.000	$84 per square foot
First floor area	.000	$10 per square foot
Age of house	.000	-$3,186 per year
Elevation	.000	-$3,179 per 100 feet elevation
Flooring material:		
Carpet	.000	
Hardwood	.000	
Building Type		
Wood House	.001	
Roof Material:		
Glazed Tile	.002	
Land area	.003	
Interior material		
Hollow tile	.010	
Single wall	.022	
Double wall	.035	
Highway	.047	
Full bathrooms	.048	

The "Uphill" variable was not significant (p =.179)

Land Value: This regression analysis was less strong than the one for total value, suggesting that the appraisers' procedures for distinguishing between land value and improved value are not as clear and consistent in practice as in theory ($R = .562$; $R^2 = .316$). The following variables were significant:

Variable	p (significance)	B (contribution to dependent var.)
Land area	.000	$2 per square foot
Area of first story	.000	$28 per square foot
Elevation	.000	- $2,689 per 100 feet
Roof Material		
Concrete Tile	.000	
Living area	.001	
Highway	.002	
Building Type		
Wood House	.003	
Masonry	.023	

The "Uphill" variable was not significant (p = .749)

[13] In this memo, B coefficients are noted for the strongest associations because these can be read as indicators of the contribution of each factor to value.

Sales over the Last Five Years (since 1/1/98): This regression was fairly robust (R = .773; R^2 = .598). The constant (point at which the regression line intercepts the y axis) was large and negative, making interpretation of the B coefficient unhelpful. The following variables were significant:

Variable	*p (significance)*
Living area	.000
Area of first story	.000
Exterior Wall	
Hollow tile	.000
Roof Material	
Concrete tile	.000
Elevation	.001
Flooring: Carpet	.001
Age of home	.012
Building type	
Wood	.012
Flooring: Tile	.002
Half baths	.037

The "Uphill" variable was not significant (p = .894).

Sales over the Last Three Years (since 1/1/00): This was the strongest regression analysis (R = .82; R^2 = .673). However, as in the last case, the constant was a large negative value, making interpretation of B coefficients unhelpful. Significant associations were:

Variable	*p (significance)*
Land area	.000
Exterior Wall:	
Hollow tile	.000
Flooring:	
Carpet	.000
Ceramic Tile	.000
Hardwood	.000
Roof material	
Concrete Tile	.000
Elevation	.003
Area first story	.003
Half baths	.004
Age of home	.009
Building type:	
Wood house	.026

The "Uphill" variable was not significant (p =.499).

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FINAL

Naphtha Fuel Study
Keahole Combined Cycle Plant

Hawaii Electric Light Company, Inc.
Hawaiian Electric Company, Inc.

Prepared by
Stone & Webster, Inc., A Shaw Group Company

February 2004

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Naphtha Fuel Study for Keahole Combined Cycle Plant

INTRODUCTION

The Hawaii Electric Light Company, Inc.'s (HELCO) Keahole Combined Cycle Project consists of the installation of a nominal 58 MW dual train (two combustion turbines, two heat recovery steam generators and one steam turbine) combined cycle electric generating facility at the existing Keahole Power Plant. The installation will utilize two General Electric LM 2500 combustion turbines each rated at 20 MW nominal. Each of the combustion turbines exhaust to a Heat Recovery Steam Generator (HRSG). Steam produced by the HRSGs supply a nominal 18 MW steam turbine.

Keahole combustion turbines CT-4 and CT-5 are currently configured to burn No. 2 diesel. In the event that fuel diversity or alternatives are sought for availability, reliability, or regulatory reasons, naphtha may be considered as one of the alternative fuel sources. This would require significant modifications to the fuel storage and handling systems, as well as the combustion turbine fuel supply, ventilation, and control systems. No. 2 diesel fuel would still be required for start-up and low output operation.

This report provides background information regarding naphtha as a fuel and details on the anticipated modifications required to convert Keahole CT-4 and CT-5 to naphtha as the primary fuel.

Naphtha Properties

The system design and process equipment required for operation with naphtha are dictated by the properties of the fuel, and specifically how they compare to diesel. The following sections describe key differences between naphtha and diesel, which must be addressed within the system design to allow the combustion turbines to safely and reliably operate with both fuels.

Flash Point: Naphtha, unlike diesel fuel, will more easily vaporize and produce ignitable gases at low air pressures, resulting in a low flash point for the fuel. The flash point is defined as the lowest temperature at which a fuel will produce flammable vapors capable of ignition. The flash point for naphtha varies with the specific blend, but is typically in the 20-55°F range. No. 2 diesel fuel, on the other hand, has a flash point of 126-140°F. Because of this bw flash point, naphtha requires an alternative fuel to add stability and prevent possible explosions during system start-up or low-load operation. The diesel fuel supply system would be retained for use as a start-up fuel for naphtha. Low flash point fuels also have a tendency to be highly volatile. Therefore, it is necessary to provide for draining of naphtha fuel between the manifold valves and fuel nozzles after transferring to the diesel fuel to avoid any build up of vapors.

Since naphtha has a tendency to flash to vapor at low pressures, it is very sensitive to reductions in manifold pressure and temperature. When the system begins to slow down to accommodate lower load demand, the decreased pressure can cause the turbine to flame-out (lose ignition ability). A flash point detection system would be required to switch fuels and operate on diesel at lower loads.

Ventilation Requirements: Naphtha vapors, which are heavier than air, require heavy gas fans in the bottoms of enclosures to remove them. The fuel skid and turbine compartment require special ventilation systems that vent the exhaust to an unconfined area to minimize the explosive hazard. The venting system must maintain a slight vacuum in the hazardous areas to assure against leakage of the combustibles into non-hazardous areas. Hydrocarbon detectors may be required in some applications in both the hazardous areas and in the vent lines.

The ventilation requirements for the present diesel fuel system require exhaust fans on top of the enclosures for the turbine and generator compartments with no special requirements for venting.

Temperature Considerations: Because naphtha is very sensitive to changes in temperature, the fuel and piping must be maintained between 68° F and 140° F. Below 68° F, the fuel may wax (thicken), and above 140°F, the fuel may flash. A naphtha cooler is required prior to the booster pumps if the naphtha cannot be maintained below 140° F. Heat tracing of piping will be required if the temperature range cannot be maintained.

Diesel fuel is less sensitive to temperature and pressure and does not have the same considerations required for naphtha.

A. NAPHTHA SYSTEM DESCRIPTION

The following modifications to the existing equipment are necessary for operation with naphtha.

Naphtha Unloading and Storage

Additional precautions are necessary for the transportation of naphtha due to its lower flash point and fuel volatility, but this fuel is routinely transported to an existing facility on the Island without major difficulties. A grounding system is required at the unloading facility to prevent static discharge that could be a potential ignition point and breathers are required on unloading lines to minimize the release of vapors. New unloading pumps will also likely be required for unloading naphtha from the fuel tanker to the storage tanks.

Because of its low density, the storage requirements for naphtha are greater than for diesel. The heating value of naphtha and diesel per pound is approximately the same, but naphtha has a lower specific gravity than diesel, and the heating value on a volumetric basis for naphtha is approximately 25% lower than diesel. For the same duration of storage time, naphtha therefore requires approximately 25 to 30 percent more volume of storage than diesel.

Naphtha is normally stored in tanks with floating roofs that eliminate any air space for vapors to collect. The tanks are equipped with gimbals for fuel loading, floating pump suction, and floating roof drain. A fixed roof storage tank with a vapor recovery system was evaluated, but determined not to be permittable for use with naphtha. Diesel storage tanks are typically fixed roof tanks with a floating suction. Diesel vapors, which develop in the open air space at ambient temperatures, are not a concern. The lined containment area for the tanks should be sized to ensure there is adequate secondary containment in the event of a tank breach. The cost of a floating roof tank typically is 20 percent higher than a fixed roof tank of the same capacity, thus the capital cost for fuel storage of naphtha is higher than for diesel storage.

Fire protection requirements for naphtha are also different from diesel due to its high volatility. An aqueous film-forming foam (AFFF) system is recommended for the fuel unloading and storage areas. Foam spray systems are recommended for the truck unloading area, with automatic foam chambers to dispense AFFF in the tank. Foam monitors, which provide foam coverage for a section of the containment area, would be located around the perimeter of the containment area.

For the Keahole facility, the existing diesel fuel storage tanks serving the diesel generators and CT-2, the diesel fuel centrifuge and diesel day tanks for CT-4 and CT-5 would still be required for startup and low load operating conditions. The planned diesel fuel storage tanks for CT-4 and CT-5 would be converted to naphtha storage tanks.

Naphtha Conveyance and Fuel Conditioning

Forwarding naphtha fuel from the storage tank to the combustion turbines also requires several modifications to the current system using No. 2 diesel. Naphtha is pumped directly to the combustion turbine fuel injection pumps rather than being centrifuged and delivered to day tanks like No. 2 diesel. Naphtha's high volatility and vapor pressure require that the forwarding pumps be mounted in a pit to prevent cavitation. Export grade naphtha does not require the centrifuge process. Instead, the fuel would be forwarded directly from the main storage tank to the fuel injection pump for each combustion turbine. A duplex strainer in the fuel line removes particulate matter and can be serviced on line.

Diesel fuel would still be required for low load operation and start-up. The day tanks, fuel forwarding pumps and fuel oil centrifuge would be retained for this function. Once the day tanks are filled with No. 2 diesel, the fuel is circulated continuously to maintain quality.

Since diesel has a higher level of lubricity, the diesel fuel system uses a more conventional application and does not require the special equipment that naphtha would for fuel control and flow division. The turbine fuel injection pump used for naphtha also differs in design from that used for diesel. Due to the low lubricity of naphtha, conventional fuel injection pumps are not suitable, and therefore new pumps would need to be purchased. A Roto-Jet pump, model 5400, is used for a similar application at another facility with favorable results. This pump has fewer wear parts and employs a speed increasing gear box to drive the high speed, single stage pump. This pump is VFD (variable frequency drive) controlled to deliver both naphtha and No. 2 diesel. A three-way valve is required on the pump feed to control the switch over of fuel. Control valves used in naphtha service require modifications to internal components, seats, and seals, due to the low lubricity of the fuel.

Fuel injection nozzle materials and design must also be modified to account for naphtha's greater potential for erosion. Fuel injection is accomplished by a pressure flow division system rather than a mechanical flow division system employed with No. 2 diesel. The pressure flow division system would be used for both naphtha and No. 2 diesel and would completely replace the mechanical flow division system. The equipment for this system is typically housed in the fuel pump enclosure adjacent to the turbine enclosure for fire protection reasons.

Performance Considerations

Attachment A shows the expected performance of the combustion turbine operating with naphtha and No. 2 diesel as fuel. Combustion turbine performance with naphtha will generate essentially equal power ratings as for No. 2 diesel. Naphtha's lower heating value is nearly identical to No. 2 diesel on a weight basis, at 18,400 Btu/lb, but requires approximately 25% more volumetric flow to achieve the same performance.

The sulfur content in naphtha is low in comparison to diesel fuel. Naphtha has less than 0.05 percent sulfur content, while conventional diesel fuel has a sulfur content of approximately 0.40 percent. Because of this, naphtha will burn cleaner than conventional diesel fuel and generate correspondingly lower sulfur dioxide emissions.

NO_x emissions for the two fuels are similar, with water injection the preferred reduction technique. Water is injected at approximately a 1:1 weight ratio for either fuel and total water consumption for NO_x reduction remains essentially unchanged. NO_x emissions for both naphtha and No. 2 diesel are expected to be at or below 42 ppm with water injection only.

Control Philosophy

Additional control functions are necessary to safely burn naphtha fuel. A system is required to monitor and control fuel switch-over to diesel at low loads due to naphtha's low flash point. A flash point detection system can be employed to optimize the switch-over point to diesel. During low demand conditions, one unit is switched to diesel and operates at minimum capacity. As a result, the second unit can operate at a higher capacity and continue to burn naphtha. This control approach maximizes the operation of the system with naphtha. The use of naphtha also requires different ventilation since its gas is heavier than air. Heavy gas exhaust fans are required for the combustion turbine enclosure and Lower Explosion Limit (LEL) sensors and control system are required for the turbine and generator compartments. Five LEL sensors are typically used on each turbine package. The addition of these control features would require an upgrade to the existing Woodward 503 turbine control system. Additional control modifications will also be required in the existing ABB/Bailey distributed control system for the balance of plant controls.

B. EQUIPMENT PHYSICAL ATTRIBUTES AND LAYOUT

Fuel Storage Tanks and Containment: The biggest impact to equipment layout is the increased size of the floating roof storage tanks required for naphtha. Increasing the storage volume by 25% requires a 12% increase in tank diameter, or a 25% increase in tank height (approximately 12 ft.). Because these tanks are of a ring wall foundation design, and are already partially installed, increasing the height is the preferred approach. The two 617,000 gallon No. 2 diesel fuel storage tanks (PLTLF-TK1A and PLTLF-TK2A) would increase in height from 42 ft. to approximately 54 ft with a volume of 775, 000 gallons for naphtha. Since the 1,579,000 gallon diesel fuel storage tank (PLTLF-TK1C) has not been fabricated, increasing the diameter may be the preferred approach. This would increase the diameter from 80 ft. to approximately 90 ft. with a volume of 2,000,000 gallons for naphtha. The volume of the containment area around the storage tanks would need to be increased accordingly by increasing the containment wall height approximately 4 ft.

Fuel Unloading Facility: The fuel unloading facility size and location would remain essentially unchanged from the current configuration, but would require some enhancements to safely handle naphtha. A grounding system for use during naphtha unloading is required, along with a breather system to minimize naphtha vapor release. The area should also be provided with an AFFF spray system.

Fire Fighting System: An AFFF fire fighting system is required for the storage tank areas. This system consists of a foam chamber for each storage tank (two required for the future TK1C), with foam spray systems in the truck unloading area. The foaming agent is stored is an 1,100 gallon horizontal bladder tank and is capable of producing a 3% AFFF solution per NFPA standards for volume and duration based on the tank sizes and coverage area. Foam monitors around the perimeter of the containment area would provide additional protection. The foam monitors would be supplied with 265 gallon totes of foaming agent which is educted into the monitor when in use.

Appendix C includes technical bulletins which provide additional information on the environmental impacts, expected shelf life, and disposal for one common AFFF product.

Fuel Forwarding Pumps: Naphtha forwarding pumps are ideally located in a recessed pit to provide sufficient suction head due to the high vapor pressure of this fuel. The pumps would be located in the containment in the same location as proposed.

Diesel Fuel System: It is preferable to use the existing diesel unloading and storage facilities for start-up and low power operation of CT-4 and CT-5. Diesel fuel from these storage tanks would be processed through the fuel centrifuge and stored in the 13,500 gallon day tanks. Diesel fuel would be continuously circulated and available for immediate switch over if needed.

Turbine Support Equipment: New fuel pumps and filters are required for delivery of naphtha to the combustion turbine. A three-way control valve is also required for fuel switch over. These pumps, filters, and control valves are housed in an enclosed area near the combustion turbine and the enclosure is equipped with a CO_2 fire protection system. Each set of pumps and filters occupy an area approximately 8'x 10'.

Turbine Enclosure Modifications: Additional LEL and fire detection sensors and control equipment are housed within the existing turbine enclosure. Heavy gas exhaust fans are relatively small (1 hp) and attach directly to the existing turbine enclosure.

C. WASTE PRODUCT PRODUCTION AND DISPOSAL

The cleanup of a diesel spill does not require any special precautions. Diesel is very stable at ambient temperatures and has a flash point of 126°F. Naphtha, due to its low flash point, will produce vapors at temperatures greater than 0°F and precautions need to be taken during cleanup due to this high flammability and its health classification. If left for a sufficient period of time, naphtha will completely vaporize. Since naphtha vapors are heavier than air, any containment would be filled with naphtha vapors and would be extremely hazardous to personnel.

Normal operation of the facility should produce no continuous waste streams containing naphtha. Small drips or leaks will typically evaporate before any spilled liquid can be collected or contained. Larger spills should be contained and collected for disposal at a suitable hazardous material waste facility.

Hazard classifications for diesel and naphtha are determined by the National Fire Protection Agency (NFPA). Naphtha has a more severe hazard classification for health and flammability than diesel fuel and has the same rating for the reactivity hazard classification.

Naphtha has a health classification of 1, which means that it is a material that, on exposure, would cause irritation, but only minor residual injury, including those requiring the use of an approved air-purifying respirator. Naphtha is only slightly hazardous to health and only breathing protection is needed.

Diesel has a health classification of 0, which means that, on exposure under fire conditions, it offers no hazard beyond that of ordinary combustible material.

Because of its low flash point, naphtha has a flammability classification of 4, which is the most flammable. The preferred method of controlling a fire is to stop the flow of material or to protect exposures while allowing the fire to burn itself out. Aqueous film-forming foam (AFFF) is preferred to water in controlling a naphtha fire.

Diesel has a flammability classification of 2, which indicates the material must be moderately heated before ignition will occur. Water spray may be used to extinguish diesel fires because the fuel can be cooled below its flash point.

D. REGULATORY AND PERMITTING REQUIREMENTS

Conversion to naphtha will have some effect on permitting and regulatory requirements associated with physical changes to the facility equipment, different emissions characteristics, and requirements associated with the use and storage of naphtha on site. The following permits will like require updates or resubmittal.

Land Use Permits: An updated Conservation District and Use Application, (CDUA) will need to be submitted and approved by the State of Hawaii Department of Land and Natural Resources (DLNR). This document is a comprehensive description of the facility. The DLNR will then reject, approve, or approve with conditions the application and issue a Conservation District Use Permit (CDUP) allowing engineering to proceed. Detailed design information is then submitted to the DLNR to ensure conformance with the CDUP.

Air Permit Modifications: An updated air permit will be required to verify that all requirements of the Clean Air Act (CAA) are satisfied, including National Ambient Air Quality Standards (NAAQS), State Ambient Air Quality Standards (SAAQS), New Source Review/Prevention of Significant Deterioration (NSR/PSD), and Good Engineering Practice (GEP) stack height provisions. Plant sulfur emissions (H_2S, SO_2) will be considerably lower with naphtha, with other emissions such as NO_x, CO, and PM_{10} remaining essentially unchanged from No. 2 diesel.

EPA Risk Management Plan: The plan will be revised to address emergency response requirements in the event of a fire or fuel spill and would be revised to reflect changes associated with storing and using naphtha as the primary fuel.

All other permits associated with noise generation, well water supply, waste water reinjection, etc., are unaffected by the conversion to naphtha and would not require modification.

E. NAPHTHA SUPPLY AND LOGISTICS

Naphtha is a light fraction fuel produced through refinement of crude oil. It is generally used by the chemical industry in the production of ethylene. The availability of naphtha in Hawaii is highly dependent on the type of crude oil processed by the refineries and the quantities of light products (gasoline, jet fuel, naphtha) desired. Lighter oils yield more light products, whereas heavier crude oils yield less light products and require more refining. The available supply will also be dependent on other users in Hawaii that have recently begun commercial operation using naphtha.

Currently all naphtha used in Hawaii is produced on Oahu. Specific data regarding available capacity, pricing, and future projections for naphtha are not readily provided by the local refineries and not fully known at this point. Prices for this product can increase dramatically if regional supplies are insufficient to satisfy local demand, requiring a net import of naphtha.

Naphtha is transported in barges from Oahu for delivery in Hilo, where an off-loading facility or terminal exists, but is not available for use by others. The existing Naphtha terminal is contractually dedicated for use by the Hamakua Energy Partner's (HEP) combined cycle facility in Honokaa. Consequently, new terminaling infrastructure would need to be installed to support Keahole's needs. Specifically, the facility would need storage tanks, a vapor extraction system, and a truck loading rack to load naphtha onto trator-trailers for transport. Additional storage tanks also need to be installed at the loading terminal on Oahu to accommodate additional volumes. Arrangements for storage and off-loading at the port would be part of a fuel purchase agreement arranged with HELCO and the fuel provider.

Estimates for fuel delivery indicate that transportation costs for naphtha are approximately equal to No. 2 diesel on a $/Btu basis. Naphtha is lighter and a greater volume of fuel can be carried in each load, but additional precautions reduce the number of trips carriers can make in a given shift. Naphtha and diesel fuel requirements are nearly identical on a mass basis. Additional volume is required due to its lower density as mentioned previously. Because it is lighter, more fuel (volume) can be carried in each truck load. The amount each truck can carry is weight limited, and the total number of trips required for fuel will remain essentially unchanged with naphtha.

F. ENVIRONMENTAL IMPACTS AND MITIGATION

Emergency response plans will need to be create in response to all foreseeable conditions where naphtha fuel spills, leaks or burns. Possible scenarios include, but are not limited to:

- Fuel leak from storage tanks at the Keahole plant
- Fuel leak or spill while off-loading a tanker at the plant
- Fuel leak or spill from a tanker en route to the facility
- Fuel leak or spill in delivery piping or CT enclosure

The impacts of all scenarios will be evaluated and an effective response that mitigates potential adverse impacts will be developed. The following mitigation features are currently envisioned for the scenarios identified above: 100% fuel containment volume provided with foam spray system.

- Fuel unloading area drains to tank containment area with foam spray system.
- Training a proper permitting of transportation company required.
- LEL detection system and CO_2 fire protection systems employed.

G. ENGINEERING, PROCUREMENT, AND CONSTRUCTION COST ESTIMATE

The following budgetary price estimate includes budgetary quotes for capital equipment where available and estimates for engineering and construction. The estimated cost reflects 2003/2004 labor and material rates and labor escalation factors and material cost changes should be considered for implementation of the project at some point in the future.

Engineering: This cost includes Mechanical, Electrical/I&C, and Civil/Structural engineering and design. It also includes Project Management, Project Services, and Construction and Startup support.

Capital Equipment: This cost includes the incremental cost to modify the existing and future fuel oil storage tanks (2-700,000 gallon tanks and 1-2,000,000 gallon tank) from fixed roof to floating roof and increase the storage and containment capacity by approximately 25%. A retrofit package is required for the combustion turbines and includes the cost of modifying the fuel injection systems, upgrading the control system and installing a new fire detection and heavy gas exhaust system. An AFFF fire fighting system is also required for the fuel storage area.

Construction and Startup: This cost includes all anticipated Civil, Mechanical, and Electrical/I&C construction and construction management costs associated with installing and commissioning the capital equipment described above.

Cost Summary:

	Qty.	Unit Price	Total Price
Engineering			$120,000
Procurement			
700,000 gal Floating Roof Storage Tank	2	$350,000	$700,000
2,000,000 gal Floating Roof Storage Tank (future) (Note 1)	1	$450,000	$450,000
GE LM2500 Modifications including: Naphtha pump/filter/fuel injection system Control System upgrade (Note 2) LEL System Heavy Exhaust System	2	$1,000,000	$2,000,000
Aqueous film-forming foam (AFFF) system	1	$100,000	$100,000
Construction and Startup			$1,500,000
TOTAL			$4,870,000
Note 1. The original estimate contained $400,000 for a 1,600,000 gallon tank. Note 2. Includes complete controls upgrade to a Mark VI. Per GE, controls upgrade is $650,000/unit.			

APPENDIX A

HEAT BALANCE CALCULATIONS

Estimated Average Engine Performance NOT FOR GUARANTEE

GE Aero Energy Products
A GE Power Systems Business

Performance By:	**ULF.KUTSCHERA**		
Project Info:	**Keahole Naphtha Fuel**		
Engine:	**LM2500 Standard**	Date:	**9/29/2003**
Deck Info:	**GE166A - PE.pip**	Time:	**1:47:32 PM**
Generator:	**167ER 60Hz, 13.8kV, 0.8PF (10807)**	Version:	**2.4.0**
Fuel:	**Liquid Fuel, w/ 0.0500% Sulfur, 18400 Btu/lb,LHV**		

Case #	100
Ambient Conditions	
Dry Bulb, °F	85.0
Wet Bulb, °F	76.9
RH, %	70.0
Altitude, ft	0.0
Engine Inlet	
Temperature, °F	85.0
RH, %	70.0
Conditioning	NONE
Tons or kBtu	0
Pressure Losses	
Inlet Loss, inH20	4.00
Exhaust Loss, inH20	6.00
kW, Gen Terms	22375
Est. Btu/kW-hr, LHV	10034
Fuel Flow	
MMBtu/hr, LHV	224.5
lb/hr	12202
Water Injection	
lb/hr	12492
Temperature, °F	100
Steam Injection	
lb/hr	0
Temperature, °F	0
CDP Injection	
lb/hr	0
Temperature, °F	0
Total Steam, lb/hr	0
Control Parameters	
LP Speed, RPM	3600
HP Speed, RPM	9575
CDP, psia	261.5
CDT, °F	891
T48, °R	1980
Exhaust Parameters	
Temperature, °F	1001

lb/sec	149.4
lb/hr	537840.0
Energy, Btu/s- ref 0 °R	56811
Cp, Btu/lb-R	0.2826

Emissions (NOT FOR USE IN ENVIRONMENTAL PERMITS, REF @ 15% O2)

NOx, ppmvd	42
NOx, lb/hr	39
CO, ppmvd	21
CO, lb/hr	12
HC, ppmvd	2
HC, lb/hr	1

Steam Production (lb/hr), psig@°F (4 inH2O condenser, 85% with 300°F Stack)

150 @ 367	86555
400 @ 650	76419
600 @ 750	73628
850 @ 825	71821

ST Power (kW)

150 @ 367	5525
400 @ 650	6743
600 @ 750	7125
850 @ 825	7534

Exh Wght % Wet (NOT FOR USE IN ENVIRONMENTAL PERMITS)

AR	1.2070
N2	70.7695
O2	14.0749
CO2	7.2578
H20	6.6813
SO2	0.0023
CO	0.0022
HC	0.0001
NOX	0.0050

Exh Mole % Dry (NOT FOR USE IN ENVIRONMENTAL PERMITS)

AR	0.9557
N2	79.9060
O2	13.9133
CO2	5.2164
H20	0.0000
SO2	0.0011
CO	0.0025
HC	0.0003
NOX	0.0050

Exh Mole % Wet (NOT FOR USE IN ENVIRONMENTAL PERMITS)

AR	0.8553
N2	71.5164
O2	12.4525
CO2	4.6687
H20	10.4993
SO2	0.0010
CO	0.0022
HC	0.0002
NOX	0.0045

Performance using Liquid Fuel

Estimated Average Engine Performance NOT FOR GUARANTEE
GE Aero Energy Products
A GE Power Systems Business

Performance By:	**ULF.KUTSCHERA**		
Project Info:	**Keahole No.2 Fuel Oil**		
Engine:	**LM2500 Standard**	Date:	**9/29/2003**
Deck Info:	**GE166A - PE.pip**	Time:	**1:42:56 PM**
Generator:	**167ER 60Hz, 13.8kV, 0.8PF (10807)**	Version:	**2.4.0**
Fuel:	**Liquid Fuel, w/ 0.4000% Sulfur, 18400 Btu/lb,LHV**		

Case #	100
Ambient Conditions	
Dry Bulb, °F	85.0
Wet Bulb, °F	76.9
RH, %	70.0
Altitude, ft	0.0
Engine Inlet	
Temperature, °F	85.0
RH, %	70.0
Conditioning	NONE
Tons or kBtu	0
Pressure Losses	
Inlet Loss, inH20	4.00
Exhaust Loss, inH20	6.00
kW, Gen Terms	22380
Est. Btu/kW-hr, LHV	10034
Fuel Flow	
MMBtu/hr, LHV	224.6
lb/hr	12205
Water Injection	
lb/hr	12520
Temperature, °F	100
Steam Injection	
lb/hr	0
Temperature, °F	0
CDP Injection	
lb/hr	0
Temperature, °F	0

Total Steam, lb/hr	0
Control Parameters	
LP Speed, RPM	3600
HP Speed, RPM	9576
CDP, psia	261.5
CDT, °F	891
T48, °R	1980
Exhaust Parameters	
Temperature, °F	1001
lb/sec	149.4
lb/hr	537840.0
Energy, Btu/s- ref 0 °R	56819
Cp, Btu/lb-R	0.2826
Emissions (NOT FOR USE IN ENVIRONMENTAL PERMITS, REF @ 15% O2)	
NOx, ppmvd	42
NOx, lb/hr	39
CO, ppmvd	21
CO, lb/hr	12
HC, ppmvd	2
HC, lb/hr	1
Steam Production (lb/hr), psig@°F (4 inH2O condenser, 85% with 300°F Stack)	
150 @ 367	86562
400 @ 650	76425
600 @ 750	73634
850 @ 825	71827
ST Power (kW)	
150 @ 367	5525
400 @ 650	6743
600 @ 750	7126
850 @ 825	7534
Exh Wght % Wet (NOT FOR USE IN ENVIRONMENTAL PERMITS)	
AR	1.2069
N2	70.7654
O2	14.0915
CO2	7.2341
H2O	6.6766
SO2	0.0181
CO	0.0022
HC	0.0001
NOX	0.0050
Exh Mole % Dry (NOT FOR USE IN ENVIRONMENTAL PERMITS)	
AR	0.9556
N2	79.8993
O2	13.9293
CO2	5.1993

H20	0.0000
SO2	0.0090
CO	0.0025
HC	0.0003
NOX	0.0050

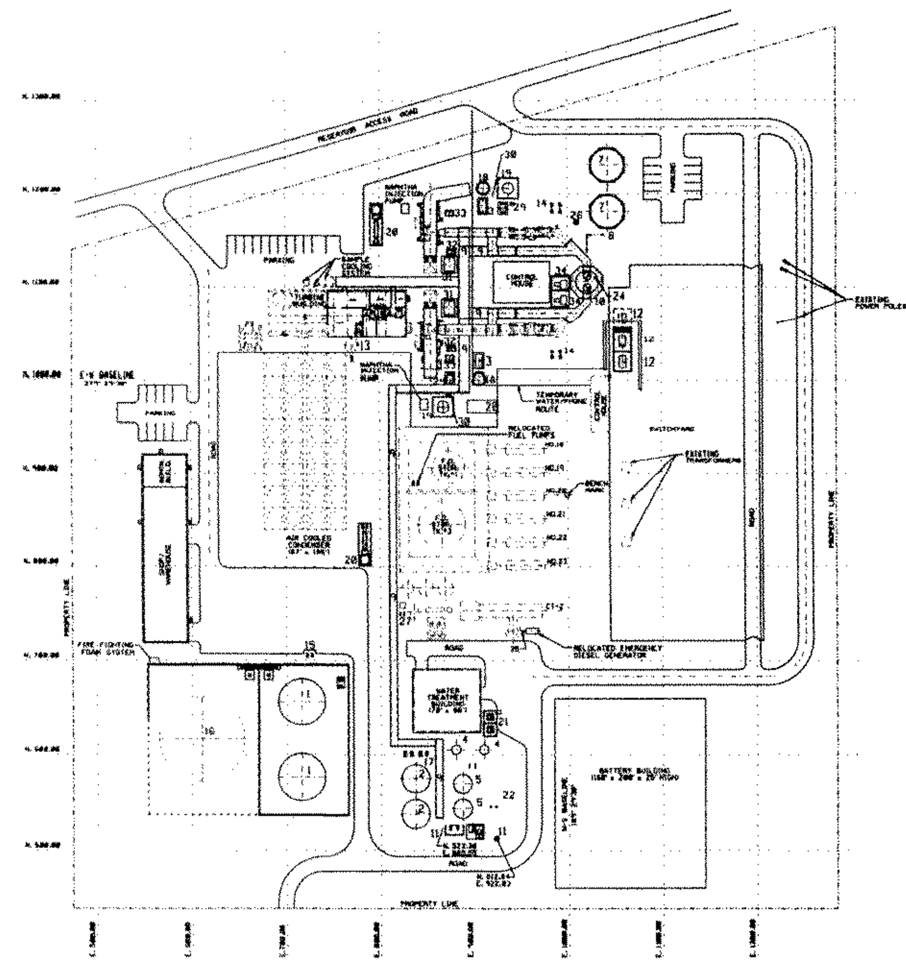
Exh Mole % Wet (NOT FOR USE IN ENVIRONMENTAL PERMITS)

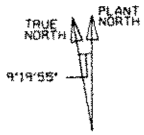
AR	0.8553
N2	71.5159
O2	12.4678
CO2	4.6537
H20	10.4925
SO2	0.0080
CO	0.0023
HC	0.0002
NOX	0.0044

Performance using Liquid Fuel

APPENDIX B

GENERAL ARRANGEMENT

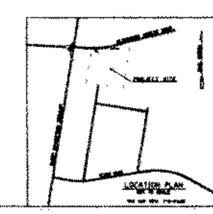




MARK NO.	DESCRIPTION
1	NAPHTHA FUEL OIL STORAGE TANK (80' DIA. x 48' H.)
2	DEMINERALIZED WATER STORAGE TANK (80' DIA. x 24' H.)
3	WATER INJECTION PUMPS FOR COMBUSTION TURBINE
4	NEUTRALIZATION TANK (20' DIA. x 18' H.) WITH CONTAINMENT WALL
5	WASTE WATER TANK (20' DIA. x 24' H.)
6	STEAM TURBINE (FUTURE)
7	FIRE / SERVICE WATER TANK (35' DIA. x 30' H.)
8	FIRE PUMP HOUSE (45' x 20' x 19' HIGH)
9	PIPE RACK
10	DUAL FLUE STACK (84' H.)
11	INJECTION WELL
12	MAIN TRANSFORMERS (ONE FUTURE)
13	CONDENSATE STORAGE TANK (12' DIA. x 16' H.) (FUTURE)
14	HRSG FEED PUMPS (FUTURE)
15	FUEL OIL UNLOADING FACILITIES
16	NAPHTHA FUEL OIL STORAGE TANK (90' DIA. x 48' H.) (FUTURE)
17	DEMINERALIZED WATER TRANSFER PUMPS
18	DEMINERALIZED WATER DAY TANK (12' DIA. x 18' H.)
19	FUEL OIL DAY TANK (12' DIA. x 18' H.)
20	OIL / WATER SEPARATOR
21	SULFURIC ACID & CAUSTIC SODA STORAGE
22	SOLID SETTLING BASIN
23	TURBINE LUBE OIL RADIATOR (FUTURE)
24	12" DIESEL FIRE PUMP EXHAUST FLUE (84' HIGH)
25	18" BLACK START DIESEL EXHAUST FLUE (24'-0")
26	BRACKISH WATER WELL PUMP
27	CT-3 NEUTRALIZED WATER PUMPS
28	FUEL OIL CENTRIFUGAL SEPARATOR
29	DUPLEX FUEL PUMP SKID
30	LIQUID FUEL PRE-FILTER
31	OIL COOLERS
32	TURBINE WASH SKID
33	HYDRAULIC START SKID
34	AUXILIARY TRANSFORMERS

NOTES:
1. SCALE: 1" = 40'-0"
2. PLANE GRID SYSTEM BASED ON EAST WEST BASELINE 271°29'30" BEING EQUAL TO N 1000.00 AND NORTH SOUTH BASELINE 181°29'30" BEING EQUAL TO E 1000.00.
3. MITIGATION MEASURES WILL BE DETERMINED THROUGH THE AIR QUALITY PERMITTING PROCESS AS ADMINISTERED BY THE STATE DEPT. OF HEALTH AND MAY INCLUDE MODIFICATIONS TO THE EMISSION CONTROL TECHNOLOGY REQUIREMENTS (e.g., SELECTIVE CATALYTIC REDUCTION, ETC.) AND SPECIFICATION OF FUEL PROPERTIES (e.g., NAPHTHA, LOW SULFUR DIESEL, ETC.).

SCALE: 1" = 40'-0"



STONE & WEBSTER ENGINEERING CORPORATION
DENVER, CO.

KEAHOLE CT-4 & CT-5
NAPHTHA STUDY

SK-01 0

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APPENDIX C

AFFF PROPERTIES AND HANDLING

Technical Bulletin

ANSUL®

Number 52

Environmental Impact of ANSULITE AFFF Products

ANSUL INCORPORATED
MARINETTE, WI 54143-2542

Background

With the advent of ever increasing environmental concerns, regulations and the increased use of ANSULITE AFFF products we have been receiving more and more requests on the environmental impact characteristics of the ANSULITE product line. There are four areas of interest with regard to the environmental fate of AFFF products. They are fish toxicity, biodegradability, sewage treatment plant treatability and nutrient loading. All of these are of concern when the end-use foam solutions reach natural or domestic water systems. Since the end-use foam solutions (i.e., after they have been proportioned with water), are all essentially equivalent with regard to levels of active ingredients, we may discuss the product lines as a whole rather than as individual concentrates.

Fish toxicity tests are normally run on both estuarine and fresh water species. The two most common test species are the Killifish, (Fundulus heteroclitus), and the Rainbow Trout (Salmo gairdneri). The Killifish is a tolerant, (eurytopic), fish while the Rainbow Trout is a sensitive, (stenotopic), fish. This combination gives an indication of the broad range over which various fish populations may be affected. The values are given as the 96 hour LC_{50} which is a measurement of the concentration which is lethal to 50 percent of the test population after 96 hours of exposure to that concentration. The units of measure are milligrams/liter or parts per million (ppm) which, in the case of water based solutions, are considered to be equivalent. Obviously, the higher the value, the greater the tolerance of the fish to the AFFF. Testing indicates that Rainbow Trout have a 96 LC_{50} for end-use ANSULITE AFFF solutions of from 4,000 – 6,500 ppm while Killifish have a 96 LC_{50} of from 26,000 – 36,000 ppm. It is evident from this broad range that fish toxicity is extremely dependent upon fish species. Other factors will also include water quality, water temperature, dissolved oxygen levels and general health of the fish population.

The biodegradability of AFFF solutions is a measure of how readily the chemicals in the AFFF are broken down by bacteria in the environment. As the bacteria use up the chemicals as food, (oxidizable carbon source), they also use up dissolved oxygen in the water as part of their metabolic process. To determine the theoretical biodegradability of ANSULITE AFFF, we use two different tests and compare the results. The first test is called a chemical oxygen demand test, (COD), and measures how much oxygen would be required to completely break down the chemicals contained in a given amount of AFFF to their most oxidized state. The second test is called a biological oxygen demand test, (BOD), and measures how much oxygen will be used up by bacteria, over a given time period, as they use up the chemicals contained in a given amount of AFFF as a food source. Normally, BOD tests are conducted over a five day period, however, for AFFF solutions, this period is extended to twenty days. The reason for this extension is that there is a lag phase in the bacterial population growth curve as the bacteria become acclimated to the chemicals in AFFF. After they become acclimated, they exhibit a logarithmic growth cycle as they use up the chemicals in AFFF. This long lag phase is actually an advantage in that it allows the AFFF time to reach "infinite" dilution before there is any substantial demand for dissolved oxygen. To determine the theoretical biodegradability, we look at the ratio of biological oxygen demand, BOD, to the total possible oxygen demand, COD, i.e., BOD_{20}/COD. Masseli et. al. from the Industrial Waste Laboratory of Wesleyan University conclude that a BOD/COD ratio above 50% for a chemical mixture is readily biodegradable while ratios below 15% show that the mixture is nonbiodegradable. ANSULITE AFFF products are well above the 50% level.

As far as sewage treatment plant treatability is concerned, ANSULITE AFFF products are not particularly toxic to the microbial populations normally found in treatment plants. However, a problem does exist with AFFF, (or any type of foam concentrate), entering a sewage treatment plant. That problem, especially if the plant uses the activated sludge process for secondary treatment, is in foaming, which tends to carry over suspended solids, and consequently, a rather large amount of BOD. Present data show that concentrations of AFFF up to 250 ppm can be handled without adverse effects. Often times, the normal volumetric dilution which takes place on the way to the sewage treatment plant will bring the concentration down below the 250 ppm level. If it doesn't, the use of a defoaming agent which is compatible with the treatment plant's flora may allow handling of concentrations above the 250 ppm level.

With regard to the nutrient levels of AFFF, the concern is that, if additional nutrients are added to a body of water which is already high in nutrients, an algal bloom may occur. Nutrients in water act to promote growth the same way that fertilizers do on land. Generally, only two nutrients are of concern in aquatic ecosystems, they are phosphates and nitrates. On very rare occasions, organic carbon may also act as a limiting nutrient. There is no need to worry about any nutrient loading when using ANSULITE AFFF products as they contain no sources of nitrates or phosphates and they are extremely low in total organic carbon when compared to other types of foam concentrates.

ANSULITE AFFF concentrates are formulated to provide maximum fire performance with minimal environmental impact. If additional information is required, contact Ansul at 715-735-7411. Fire protection is our only business.

Form No. F 82289-2

Technical Bulletin

ANSUL.

Number 54

Shelf Life of ANSULITE AFFF Concentrates and Their Premixed Solutions

ANSUL INCORPORATED
MARINETTE, WI 54143-2542

Shelf life is a term used to describe the length of time over which an AFFF concentrate or its premixed solution is stable and usable without a significant change in its performance characteristics. The shelf life depends upon the composition, the ambient temperature range encountered, and the container materials of construction. In the case of premixed solutions, it also depends on the type of water that is used to make up the premixed solution. For example, Ansul does not recommend that its ANSULITE concentrates be premixed in salt water. It recommends premixing of the ANSULITE concentrates only with potable water.

In the case of conventional AFFF concentrates (6%, 3%, or 1%) and polar solvent AFFF concentrates (3x3, 3x6, or ARC), the solids content (active surfactant content) is generally low compared with protein based foam agents and therefore much less likely to undergo stratification, sedimentation, or precipitation. Since the chemical surfactants are all synthetic as opposed to naturally occurring (protein foam), natural degradation of the concentrates does not occur. AFFF and polar solvent AFFF agents are capable of being premixed, but the stability of the resulting solution, as pointed out above, depends upon the type of water used to make the premix. It is generally advisable, therefore, to check the quality of the premixed solution on an annual basis during the normal maintenance procedures. (See Ansul Part No. 31274, AFFF Field Inspection Procedures Manual.)

A much more significant factor affecting shelf life is the ambient temperature range encountered. All ANSULITE AFFF concentrates and their premixed solutions are listed by approval testing agencies such as Underwriters Laboratories, Inc. This listing involves determining the usable temperature range for the ANSULITE AFFF concentrate or its premixed solution. The normal usable temperature range for ANSULITE 6%, 3%, 1%, and ANSULITE polar solvent AFFF is +35 °F (1.6 °C) to +120 °F (48.8 °C). There is also an ANSULITE 3% Freeze Protected concentrate that is available where low temperatures are likely to be encountered, which has a usable temperature range from –20 °F (–28.9 °C) to +120 °F (48.8 °C). Freeze protected concentrates are not usually used in a premixed solution configuration as this would destroy the most important feature of the product, i.e., its low freezing point. The usable temperature range is stated on the container in which the concentrate is sold. It is also stated on the operating nameplate of the equipment in which the concentrate or premixed solution is stored.

In the case of ANSULITE AFFF concentrates or their premixed solutions, temperatures below the lower minimum usable temperature represent more of a problem than temperatures above the maximum usable temperature. Since in both cases one is dealing with a mixture of water and high boiling point solvents, going below the minimum usable temperature limit could result in freezing of the solution, which would prevent its use, for example in proportioning equipment.

On the other hand, going above the maximum usable temperature, which should be avoided if possible, will not impair the ability of the concentrate to be proportioned or the premixed solution to be discharged. However, it may result in a decrease in the performance characteristics of the concentrate, its dilute solution, or the premixed solution, when compared to the concentrate or premix subjected to temperatures in the normal usable temperature range. Tests have been conducted with ANSULITE 6% and 3% AFFF agents and their premixed solutions for up to 300 days at 150 °F (65.5 °C) without a significant decrease in performance.

Going below the lower usable temperature of 35 °F (1.6 °C) will obviously result in freezing of the AFFF concentrate or its premixed solution over a period of time. However, because of the composition of AFFF concentrates or their premixed solutions, placing the storage container in an area normally heated to ambient temperatures (60 °F to 70 °F (15.5 °C to 21.1 °C)), will return them to their original condition with little or no change in performance characteristics.

As part of the listing or approval testing, the materials used in the containers for ANSULITE AFFF concentrates or their premixed solutions are tested over the usable temperature range stated on them. If the ANSULITE AFFF or polar solvent AFFF concentrates are stored in accordance with Ansul's recommendations, a shelf life of 20 to 25 years is reasonable to expect. However, because of the effect of the water type on premixed solution stability, annual inspection is recommended as part of the maintenance program and a shelf life of 3 to 5 years is to be expected. It is generally advisable to inspect any equipment containing ANSULITE AFFF concentrates or their premixed solutions on an annual basis. Part of this inspection should include the ANSULITE AFFF agent. If changes in the quality of the AFFF concentrate or its premixed solution, as outlined in the Field Inspection Manual (Ansul Part No. 31274), occur, a sample of the concentrate or premixed solution in a clear plastic bottle of 1 liter capacity should be sent to:

ANSUL INCORPORATED
ATTN: QUALITY ASSURANCE DEPT.
ONE STANTON STREET
MARINETTE, WISCONSIN 54143-2542

FINAL

SCR System Scope Study
Keahole Combined Cycle Plant

Hawaii Electric Light Company, Inc.
Hawaiian Electric Company, Inc.

Prepared by
Stone & Webster, Inc., A Shaw Group Company

February 2004

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SCR System Scope Study for Keahole Combined Cycle Project

INTRODUCTION

The Keahole Combined Cycle Project consists of the installation of a nominal 58 MW dual train (two combustion turbines, two heat recovery steam generators and one steam turbine) combined cycle electric generating facility at the existing Keahole Power Plant. The installation will utilize two General Electric LM 2500 combustion turbines each rated at 20 MW nominal. Each of the combustion turbines exhaust into a Heat Recovery Steam Generator (HRSG). Steam produced by the HRSGs supply a nominal 18 MW steam turbine. The combustion turbines fire No. 2 fuel oil and employ water injection for combustion based nitrogen oxide (NO_x) mitigation. NO_x emissions could be further reduced by utilizing a Selective Catalytic Reduction (SCR) system within the HRSG. This study will describe the SCR system operation and detail the modifications required to incorporate a SCR system into the Keahole Combined Cycle facility.

A. SCR SYSTEM DESCRIPTION

Nitrogen oxide emissions from combustion turbines are classified by their formation mechanisms as either thermal NO_x or fuel NO_x. Thermal NO_x is created by the high temperature reaction of nitrogen and oxygen in the combustion air. It is a function of the combustion chamber design and the turbine operating parameters, including the flame temperature, residence time at flame temperature, combustion pressure, and air/fuel ratios in the primary combustion zone. Fuel NO_x is formed by the gas-phase oxidation of fuel-bound nitrogen.

Selective Catalytic Reduction is a post-combustion NO_x control technology that has been extensively applied to natural gas-fired and to a very limited extent to liquid fuel fired, combined cycle CT operations. In this process, ammonia is injected into the turbine exhaust gas upstream of a catalyst bed. On the catalyst surface, the ammonia reacts with NO_x in the flue gas to form molecular nitrogen and water vapor. The general chemical reaction is given below:

$$4NO + 4NH_3 + O_2 \rightarrow 4N_2 + 6H_2O$$

The expected inlet concentration of the NO_x is 42 parts per million on dry volume (ppmvd) @15% O_2 with water injection mitigation measures. The maximum fuel bound nitrogen content per the fuel specification is 0.015% by weight. The 42 ppmvd @ 15% O_2 value accounts for this level of fuel bound nitrogen. The SCR system is designed to further reduce NO_x emissions from the stack to the desired or required levels. For this study, a reduction to 15 ppmvd @ 15% O_2 and 11.7 lb/hr NO_x from the inlet 42 ppmvd @ 15% O_2 is assumed and provides the basis of the estimates and calculations presented later in the study.

The SCR system controls will be designed to inject ammonia to meet the NO_x limit with a maximum ammonia slip of 3.5 lb/hr and 10 ppmvd @15%O_2.

The SCR catalyst would be located within the HRSG casing downstream of the high pressure evaporator tube section. This location in the HRSG is selected to provide optimum exhaust gas temperature for the reaction. Optimum NO_x reduction occurs at catalyst bed temperatures between 500° and 750° F for conventional base metal oxide (vanadium- or titanium-based) catalyst types. A catalyst designed for a specific system will exhibit optimum performance over a temperature range of ±50° F. Below this optimum temperature range the catalyst activity is greatly reduced, allowing unreacted ammonia to slip through. Above 850° F, ammonia begins to be oxidized to form additional NO_x. The ammonia oxidation to NO_x increases with increasing temperature.

Control Philosophy

The philosophy of the SCR control system is to inject ammonia (NH_3) into the turbine exhaust upstream of a reactor that contains catalyst to promote the reaction of NH_3 with NO_x and thereby limit NO_x emissions to concentrations at or below the regulatory levels described in the operating permit. Ammonia is delivered to the reactor using the inlet NO_x and oxygen concentrations and turbine-operating parameters for feed forward control and outlet NO_x concentration for feedback trim. For purposes of this study, it was assumed that approximately 65% of the NO_x is removed from the turbine exhaust with NO_x emissions limited to 15 ppm and NH_3 emissions (or slip) limited to 10 ppm (@ 15% O_2) or 3.5 lb/hr whichever is more restrictive.

According to the stoichiometry of the NO_x reaction for NO and NH_3, one mole of NH_3 reacts with one mole of NO producing nitrogen (N_2) and water (H_2O). Theoretically, an NH3/NO mole ratio of 0.65 would be required to accomplish 65% removal. In reality, a portion of the NOx is present as NO_2 (requiring slightly more NH_3) and some of the NH_3 will pass through the catalyst without participating in the reaction (ammonia slip). Therefore, the design NH_3/NO_x mole ratio will be slightly greater than the theoretical requirement. This molar ratio will tend to increase as the catalyst deteriorates.

The SCR will have a dedicated ammonia injection grid to distribute ammonia evenly across the catalyst face. The ammonia flow control to this grid anticipates the amount of ammonia flow required to achieve an outlet NO_x concentration of 15 ppmvd based on turbine operating conditions and the catalyst inlet NO_x and Oxygen concentrations. This ammonia demand approximates the required ammonia feed rate and anticipates changes due to turbine operation. The ammonia demand signal is then trimmed using a feedback controller that compares the measured SCR outlet NO_x to the operator controlled set-point. Finally, the resulting ammonia demand signal is compared to the measured ammonia flow rate, the difference is conditioned, and the resulting control signal is used to modulate the ammonia flow control valve. The control of the SCR system will be incorporated into the plant DCS, based upon input from the HRSG vendor.

Ammonia emissions, or ammonia slip, may be directly measured (using NH_3 analyzer), measured (using differential NO_x measurement), or calculated (using Predictive Emissions Monitoring) depending on the operating permit.

Direct ammonia measurement technology (using NH_3 analyzer) is available, but is still not considered a reliable method for measurement. The analyzers that are available use FTIR (Fourier Transform InfraRed) Spectroscopy as well as IM (Ion Mobility) Spectrometry.

The methodology for the determining the ammonia emissions using differential NO_x measurement (measured) is as follows:

- Convert NH_3 in the exhaust gas sample to NO prior to measurement with chemiluminesent analyzer
- Eliminate NH_3 from a second exhaust gas sample prior to NO_x measurement with chemiluminesent analyzer
- Calculate NH_3 concentration by difference between to two above measurements.

This also can be summarized as:

$$\text{Ammonia Slip} = (\text{Converted } NH_3 + NOx) - (NOx \text{ only})$$

The following is a description of the equipment required to complete the above calculation:

- Sample probe, High Temperature Converter, and sample transport and handling system that provide sample gas from the stack to a dedicated NO_x analyzer.
- Sample probe and sample transport and handling system (including NH3 filter) that provide sample gas from the stack to a dedicated NO_x analyzer.
- NH3 slip is the calculated difference between above two signals.

The methodology for the determining the ammonia emissions using Predictive Emissions Monitoring (calculated) is as follows:

- determination of the mass of NO_x removed in the SCR (physically measure inlet & outlet NO_x and Oxygen concentrations and fuel flow measured by flow meter)
- calculation of the amount of ammonia required to react with the amount of NO_x removed (using gas laws and chemical equations of reactions)
- subtraction of the above value from the measured amount of ammonia injected into the SCR (measured by flowmeter)

This can also be summarized as:

$$\text{Ammonia Slip} = \text{Ammonia in} - \text{Ammonia consumed}$$

The following information is required to perform this calculation:
Ammonia Injection Rate, lb. Ammonia / hr
Fuel flow rate, lbs./hr
NO_x inlet concentration, ppmvd
NO_x outlet concentration, ppmvd
Oxygen concentration (inlet & outlet), percent, dry (%)
Stoichiometric ratio of reaction(s) for ammonia with NO & NO_2 = f
Heat content of fuel
F factor from EPA 40 CFR 75, Appendix F

1. Ammonia (NH_3) In is continuously monitored using a calibrated flowmeter.
2. Ammonia (NH_3) consumed is calculated using the ammonia/ NO_x ratio (f) and the difference between the inlet and outlet NO_x concentrations corrected to 15% oxygen. Multiplying this value by appropriate constants and flue gas flow rate (FGF) will determine the mass rate of Ammonia consumed by reaction with NO_x (as NO_2). Flue gas flow rate is

calculated in the DAHS using measured fuel flow rate and higher heat content of the fuel multiplied by the 'F' factor supplied by EPA or determined by fuel analysis. This method calculates flue gas flow rate in DSCF/hr and is converted to DSCF/hr @ 15% O_2 using standard methods.

NH_3 Consumed (lb./hr) = [(f) * (NO_x in – NO_x out)] * [(17.03 lb.-mole /lb. NH_3) /(385 DSCF NH_3/ lb.-mole NH_3)] * [(DSCF @ 15% O_2 Flue Gas/hr)]

f = ratio of moles NH_3 to moles of NOx reacted (default = 1.00)
NO_x in = Inlet NO_x in ppmvd @ 15% O_2
NO_x out = Outlet NO_x in ppmvd @ 15% O_2
FGF (DSCF/hr) = F factor (DSCF flue gas/ MMBtu) * Heat Input (MMBtu/hr)
Heat Input = fuel flow rate (lb./hr) * fuel heat content (MMBtu/lb.)

Ammonia Supply

The ammonia supplied to the flow control skid can be one of several forms: 1) aqueous ammonia 2) anhydrous ammonia or 3) urea solution (using urea to ammonia technology).

Aqueous Ammonia

Aqueous ammonia is typically either 19% or 29% ammonia in solution with water. Although it provides some safety and economic advantages in storage and handling, the high cost of shipping the additional volume due to the water content will exceed the cost of additional safety equipment installation over the life to the units. The SCR also requires aqueous ammonia with high purity water to prevent poisoning of the catalyst, which adds to the cost. Additionally, a heat source is required to vaporize the ammonia, specifically to remove the water, which adds further cost to this option. It therefore was not considered in this study.

Anhydrous Ammonia

Anhydrous ammonia is a volatile and potentially dangerous form of ammonia that is transported as a liquified compressed gas shipped at its vapor pressure. For the application at Keahole, a 20,000 gallon pressurized storage tank is proposed, to maintain a one month storage of ammonia that will support both combustion turbines operating at full load in combined cycle mode.

The storage tank for the anhydrous ammonia will contain liquid and gaseous ammonia in equilibrium. The vapor pressure of the ammonia at 50° F is 75 psig. Even at this low temperature, there will be sufficient pressure to deliver the ammonia vapor to the control valve. During extremely warm days, at 100° F, the vapor pressure will be 197 psig. The control valve will be selected for high turndown capability, in order to accommodate this wide variation in pressure. In the event the storage tank supply pressure is not sufficient, an immersion heater would be provided to raise the saturation temperature/pressure. It is expected that heater operation will rarely be required. A pressure controller will control the heat input such that the vapor pressure is maintained at a minimum of 75 psig.

A system schematic for the anhydrous ammonia system is shown in Appendix B.

Urea

The hazardous nature of anhydrous ammonia has led to the development of urea systems. These systems convert granular urea or urea solution to ammonia. The systems are inherently safer than the anhydrous system and have been successfully demonstrated in several commercial installations.

Urea to ammonia systems are available in several designs. One design receives dry urea in pelletized form at the plant site. The urea is typically delivered by truck and unloaded by pneumatic conveying into a dry storage silo. The conveying blower is typically mounted on the truck. The capacity of the truck is approximately 25 tons. This would be approximately a one month supply for the Keahole plant. To allow complete unloading of the tank truck, a storage silo of approximately 1,000 cu ft is required. From the storage silo the urea is delivered to a mixing tank via a rotary feeder where the urea is mixed with demineralized water to produce a 40% urea solution.

Dry urea is delivered in pelletized form. Although this is a very commonly used fertilizer, the urea must be of industrial grade for this application. It is a solid under ambient conditions, is a non-toxic substance and presents essentially no danger to humans and the environment. Urea can be economically and safely shipped and stored in bulk quantities until it is eventually mixed with water.

An alternate design of urea to ammonia system receives a 40% urea solution at the plant site. The 40% urea solution would also be delivered by truck and would require a storage tank of approximately 7,000 gal to allow complete truck unloading. This would offer approximately a 3 week supply for the Keahole plant. The system is essentially identical to the dry urea system discussed above without the storage silo and its associated equipment. This system has a lower capital cost and operating cost compared to the dry urea system discussed above, however its viability depends on the availability of the urea solution.

In a typical urea to ammonia system, the ammonia solution is delivered to a pressurized vessel which is heated by an external source (steam or electric) to approximately 300° F. A level is maintained in the vessel and the heat input is controlled to maintain the pressure. The 300° F is the condition necessary to achieve decomposition of the urea into NH_3, CO_2 and water vapor mixture. As with the anhydrous system, this mixture is further diluted with air prior to discharge into the flue gas.

Other urea systems introduce ammonia into the flue gas by spray injection of ammonia solution into a hot flue gas bleed stream followed by a decomposition catalyst. The solution is mixed with compressed air to achieve atomization and the mixture is discharged into a hot flue gas bleed stream as a fine mist and subsequently vaporized. The flue gas and ammonia mixture is then injected into the main flue gas stream upstream of the SCR catalyst. The flue gas bleed stream mass flow is approximately 1% of the total combustion turbine exhaust flow.

A system schematic for the urea ammonia system is shown in Appendix B Sketch SK-03. The schematic is based on receipt of dry area via delivery truck.

Ammonia Injection
Prior to entering the flue gas, ammonia vapor from the ammonia storage tank is supplied to a flow control skid where the ammonia flow rate is controlled and also the ammonia is diluted with air below the lower explosive limit (LEL). The NH_3 is diluted with air to less than 3% by volume, which is considerably below the lower explosive limit (LEL) of 16.5%. The ammonia/air mixture is then delivered to an injection grid, which distributes the ammonia into the flue gas within the HRSG casing directly upstream of the catalyst.

B. EQUIPMENT PHYSICAL ATTRIBUTES AND LAYOUT

Ammonia Storage

<u>Anhydrous Ammonia</u>
The Anhydrous Ammonia System layout is shown on the site arrangement drawing (Appendix A Sketch SK-01). The major component is the storage tank and associated containment area (see Appendix A Sketch SK-02). A schematic of the Anhydrous system is shown in Appendix B, Sketch SK-03. These could be located north of the CT-5 HRSG, adjacent to the plant access road. On the north side of the containment area would be a curbed area for truck unloading. Ammonia flow control skids are located adjacent to each HRSG. An area for catalyst loading/unloading is also provided for each HRSG.

Anhydrous ammonia is delivered by truck in liquid form and delivered to an on-site storage tank utilizing ammonia vapor compressors located adjacent to the storage tank.

All piping and hose connections to the storage tank would be provided with excess flow valves, which prevent large quantities of ammonia from escaping in the event of a line break. A dual safety valve system is also provided which includes two 100% capacity relief valves. The relief valves are connected to a three way valve such one valve may be isolated for servicing while the other remains on line.

The unloading station includes an ammonia compressor to withdraw ammonia vapor from the top of the storage tank. The vapor is then compressed and the pressure forces the liquid ammonia from the isotainer (container used for ammonia transport) into the storage tank.
A containment area, which consists of a raised concrete curb, surrounds the storage tank. The containment area is designed to contain the liquid ammonia in the event of a catastrophic tank failure. The containment area would also capture water from the misting system in the event of an accidental release of ammonia vapor.

The truck unloading operation takes approximately 3 hours to complete. Plant personnel require respirators, protective clothing (front only – i.e. aprons) and rubber gloves for this operation.

Urea

The Urea System layout is shown on the site arrangement drawing (Appendix A Sketch SK-05). A Urea System schematic is shown in Appendix B Sketch SK-05. The major components are the urea storage silo, pneumatic conveying system for truck unloading, mixing tank, heat exchanger, hydrolyzer vessel and flash tank, a hydrolyzer feed pump and dilution air system. This equipment would be located in the same general area as shown for the anhydrous ammonia storage tank. See Appendix A sketch No. SK-04 for a detail of the urea to ammonia skid.

The urea system utilizes pelletized urea. It is a solid under ambient conditions, is a non-toxic substance and presents essentially no danger to humans and the environment. Urea can be economically and safely shipped and stored in bulk quantities until it is eventually mixed with water. Urea would typically be delivered by truck and unloading would be performed by a pneumatic conveying system using a blower and discharging into a storage silo. Conveying air would be discharged to atmosphere through a bin vent filter mounted on top of the storage silo.

HRSG/Catalyst

The HRSG design would need to be modified significantly to accommodate an SCR system, and will impact the cost of the HRSG. Modifications to the HRSG to incorporate the SCR system addition include an additional ductwork section to house the catalyst and the ammonia injection grid. Downstream of the catalyst, in low temperature sections, tubes may be subject to ammonium bisulfate deposition, specifically in the low-pressure economizer. All tubes subject to this should be of 409 SS material and a maximum fin spacing of 4 fins per inch should be used. A maximum of 10 rows of tubes per bank should be used and a minimum of 4 feet between tube banks is required to facilitate washing operations. Larger access doors should be provided to facilitate personnel entry and erection of scaffolding.

The SCR section of the HRSG is a duct section, which is filled with catalyst modules. Each catalyst module contains catalyst elements. The modules are designed for ease of installation and removal. An opening is provided in the top of the SCR duct to allow installation and removal of the catalyst modules with a monorail hoist system. The SCR section is located downstream of the HP evaporator. Clearances between catalyst modules and between the modules and the SCR housing are sealed to prevent any flue gas from bypassing the catalyst. The SCR system is typically designed to limit the gas side pressure drop to 2" w.c. Additional pitch of the catalyst will be required to minimize soot deposits associated with the diesel fuel.

CEMS

The CEMS will consist of all hardware and software required to measure and report regulated emissions. Included in the CEMS will be the ability to continuously measure and report NO_x and CO emissions (Oxygen will be measured as the diluent). NO_x will be continuously monitored at the SCR inlet as part of the control system for ammonia injection, in addition to the measurement at the outlet of the SCR, and this equipment will be included with the CEMS. If required by permit, ammonia emissions that may result from the installation of Selective Catalytic Reduction (SCR) to control NO_x emissions will be continuously reported. Ammonia may be measured (using differential NO_x measurement) or calculated (using Predictive Emissions Monitoring) depending on the operating permit.

The Data Acquisition and Handling System (DAHS) is the part of the CEMS that will provide real-time access to the data and produce regulatory reports as required by the various regulatory bodies. The DAHS will produce daily, weekly, quarterly, and annual reports and be used to provide necessary alarms should the CEMS monitoring functions become disabled or exceed allowed boundaries of calibration.

The monitors, controllers and associated sample handling equipment will be housed in a cabinet that will be located in an environmentally controlled shelter that will also house the DAHS. Calibration gases will be stored outside the shelter.

Ammonia Tank Misting System

A misting system would be installed for the purpose of controlling and mitigating an ammonia vapor cloud, in the event of an ammonia leak from the tank area. The misting system consists of a nozzle manifold located above and around the ammonia tank. The system is automatically activated upon detection of ammonia vapor by the Ammonia Detection System. Upon activation, a blanket of mist is spread over the entire potential release area. If a significant rate of change is detected in the level of the ammonia tank, indicating a major leak, the misting system will not be activated. Due to the high affinity of NH_3 with water, a large amount of ammonia vapor is absorbed, thus minimizing the ammonia vapor cloud downwind. Water supply for the misting system would be from the fire protection piping loop. The system can also be activated manually. Upon system activation, an alarm will sound locally and in the control room. A diked area is provided for the ammonia storage tank, which will contain the contents of the storage tank as well as any water discharged from the misting system.

Ammonia Detection

Ammonia detectors would be located in the vicinity of the storage tank. The detectors will activate alarms both locally and in the control room and will activate the misting system.

C. WASTE PRODUCT PRODUCTION AND DISPOSAL

Catalyst life can vary based upon several factors, but a three-year life was assumed for purposes of this report. End of catalyst life, or fouling of the catalyst, is usually indicated by an increase in ammonia slip. Because the catalyst has an affinity for heavy metals, it is reasonable to assume that spent catalyst will be treated as hazardous waste. Removal of spent catalyst is typically performed by a firm specializing in handling and disposal of hazardous waste. Using a hoist, catalyst modules are removed from the HRSG casing, wrapped with protective covering at grade and placed on a transport vehicle. At that time ownership and responsibility transfers to the disposal firm.

Water washing of the HRSG tubes will be required to remove corrosive deposits of heavy metals which accumulate on the tubes/fins. The main deposition is typically ammonium bisulfate containing heavy metals from the tubes/fins, and can be removed by water washing. It is anticipated that water washing will be performed twice a year, utilizing 1,000 gallons of water. This wash water waste is considered hazardous, and will need to be collected in the sump for pumping to a truck for off-site disposal.

D. AMMONIA SUPPLY LOGISTICS

In the interest of minimizing transportation costs, the ammonia delivered to the Keahole plant site will be in anhydrous form or as urea solution or pellets . Companies that typically deliver ammonia to jobsites in Hawaii are Gas Pro and BEI Hawaii. Based on two CTs base loaded, with NO_x at the CT exit of 42 ppmvd @ 15% O_2 with water injection, the ammonia consumption rate is expected to be approximately 1,000 gallons per week.

BEI was contacted regarding delivery of anhydrous ammonia to the Keahole site. The vessels that BEI utilizes are called "isotainers" which also contain pressurized liquid anhydrous ammonia. An isotainer contains approximately 6,000 gallons of ammonia. The isotainers are dedicated to this particular plant and delivered to the plant every three weeks. The isotainers are filled on the mainland (in the Los Angeles area), shipped to Hawaii and then transported by truck to the site and emptied into the plant storage tank. The empty isotainers are then returned to the mainland for re-filling. This entire cycle takes approximately 3 weeks.

Urea can be supplied to the plant site as a solid or in solution. As a solid, the urea is delivered in pelletized form. Typically a truck transports the urea container which has a capacity of approximately 25 tons. Dry urea cost (ex-works) is approximately $235/ton. The cost of the transport container and truck assuming delivery from mainland US is approximately $5,680 per delivery. The estimated annual cost of solid urea for the Keahole Plant is approximately $70,000.

If delivered in solution, the urea is supplied as a 40% solution. The urea container has a capacity of approximately 5,000 gal. Urea solution cost (ex-works)* is approximately $1.25/gallon. The cost of the transport container and truck assuming delivery from mainland US is approximately $5,680 per delivery. The estimated annual cost of urea solution for the Keahole Plant is approximately $275,000.

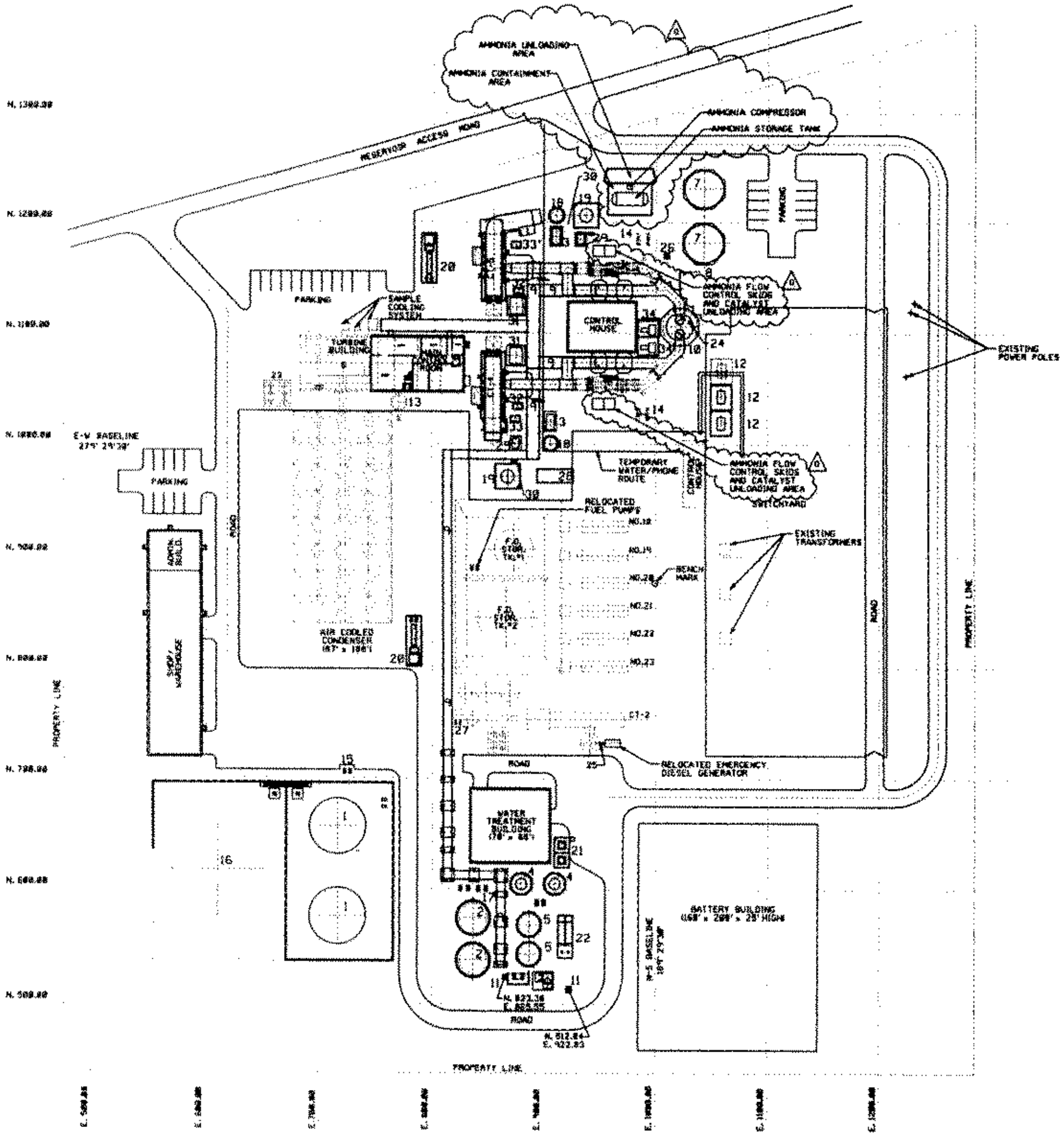
Costs above reflect urea supply from mainland US. We are continuing to investigate urea supply on the island of Hawaii.

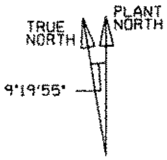
Urea systems which receive dry urea offer cost advantages for urea delivery. Initial capital cost and operating costs, however will be higher for this system when compared with the urea solution systems. A dry urea system would require a larger storage tank, would require demineralized water and a source of heat to dissolve the urea.

* Ex-works is a term defined as "the seller's only responsibility is to make the goods available at the seller's premises, i.e., the works or factory. The seller is not responsible for loading the goods on the vehicle provided by the buyer unless otherwise agreed. The buyer bears the full costs and risk involved in bringing the good from there to the desired destination. Ex works represents the minimum obligation of the seller."

APPENDIX A

SKETCHES

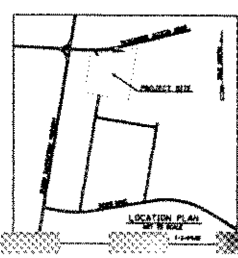




MARK NO.	DESCRIPTION
1	FUEL OIL STORAGE TANK (54' DIA. x 42' H.)
2	DEMINERALIZED WATER STORAGE TANK (38' DIA. x 24' H.)
3	WATER INJECTION PUMPS FOR COMBUSTION TURBINE
4	NEUTRALIZATION TANK (10' DIA. x 10' H.) WITH CONTAINMENT WALL
5	WASTE WATER TANK (20' DIA. x 24' H.)
6	STEAM TURBINE (FUTURE)
7	FIRE / SERVICE WATER TANK (35' DIA. x 30' H.)
8	FIRE PUMP HOUSE (45' x 20' x 19' HIGH)
9	PIPE RACK
10	DUAL FLUE STACK (184' H.)
11	INJECTION WELL
12	MAIN TRANSFORMERS (ONE FUTURE)
13	CONDENSATE STORAGE TANK (12' DIA. x 16' H.) (FUTURE)
14	HRSG FEED PUMPS (FUTURE)
15	FUEL OIL UNLOADING FACILITIES
16	FUEL OIL STORAGE TANK (80' DIA. x 42' H.) (FUTURE)
17	DEMINERALIZED WATER TRANSFER PUMPS
18	DEMINERALIZED WATER DAY TANK (12' DIA. x 16' H.)
19	FUEL OIL DAY TANK (12' DIA. x 16' H.)
20	OIL / WATER SEPARATOR
21	SULFURIC ACID & CAUSTIC SODA STORAGE
22	SOLID SETTLING BASIN
23	TURBINE LUBE OIL RADIATOR (FUTURE)
24	12" DIESEL FIRE PUMP EXHAUST FLUE (84' HIGH)
25	18" BLACK START DIESEL EXHAUST FLUE (74'-2")
26	BRACKISH WATER WELL PUMP
27	CT-2 NEUTRALIZED WATER PUMPS
28	FUEL OIL CENTRIFUGAL SEPARATOR
29	DUPLEX FUEL PUMP SKID
30	LIQUID FUEL PRE-FILTER
31	OIL COOLERS
32	TURBINE WASH SKID
33	HYDRAULIC START SKID
34	AUXILIARY TRANSFORMERS

NOTES:
1. SCALE : 1" = 40'-0"
2. PLANT GRID SYSTEM BASED ON EAST WEST BASELINE 279°29'30" BEING EQUAL TO N 1000.00 AND NORTH SOUTH BASELINE 189°29'30" BEING EQUAL TO E. 1000.00.
3. MITIGATION MEASURES WILL BE DETERMINED THROUGH THE AIR QUALITY PERMITTING PROCESS AS ADMINISTERED BY THE STATE DEPT. OF HEALTH AND MAY INCLUDE MODIFICATIONS TO THE EMISSION CONTROL TECHNOLOGY REQUIREMENTS (e.g., SELECTIVE CATALYTIC REDUCTION, ETC.) AND SPECIFICATION OF FUEL PROPERTIES (e.g., NAPHTHA, LOW SULFUR DIESEL, ETC.).

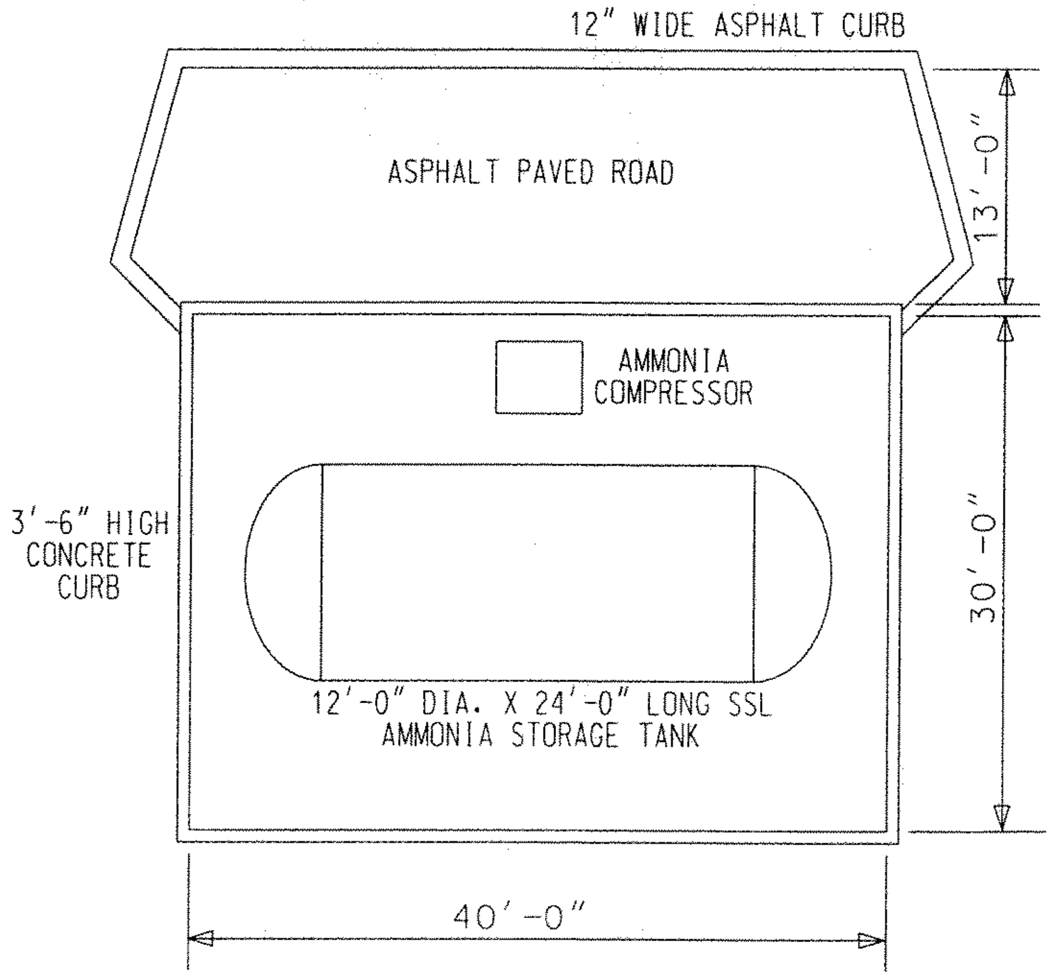
0 40 80
SCALE: 1"=40'-0"



STONE & WEBSTER, INC.
DENVER, CO.
02535

KEAHOLE CT-4 & CT-5
SCR STUDY
PROPOSED AMMONIA STORAGE LOCATION - ANHYDROUS

SK-01 | 0



ISSUE	DESCRIPTION	CHKD	CORR	APPR	DATE
4					
3					
2					
1	ORIGINAL ISSUE				

ISSUE

PRINTS

APP. CARD

12'-0" DIA. X 24'-0" LONG SSL
ANHYDROUS AMMONIA STORAGE TANK

DWG. NO. AMMONIA SKID SK-02

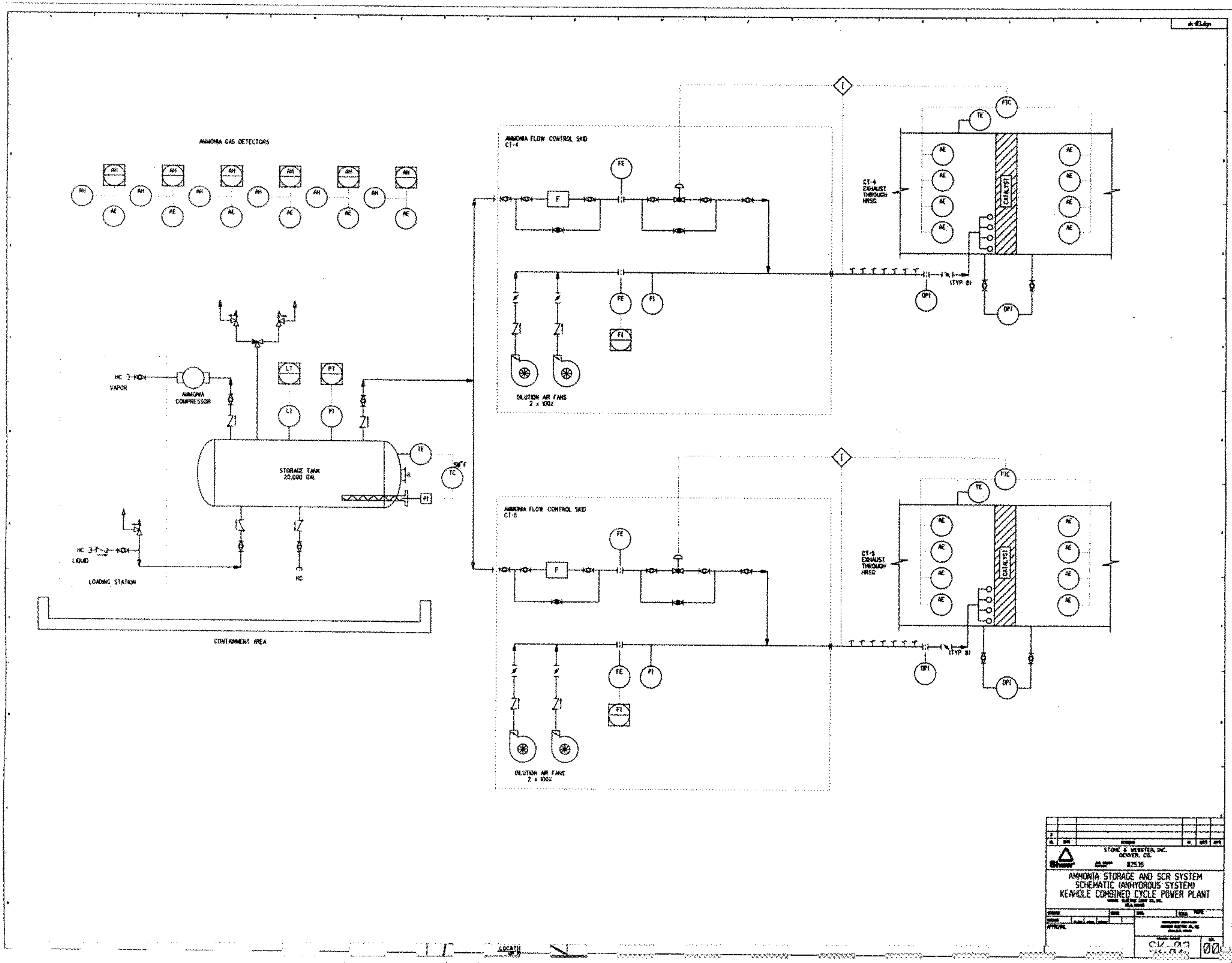
Shaw Stone & Webster, Inc.

DESIGNED BY DRAWN BY DSGN CHK'D BY CHK'D BY

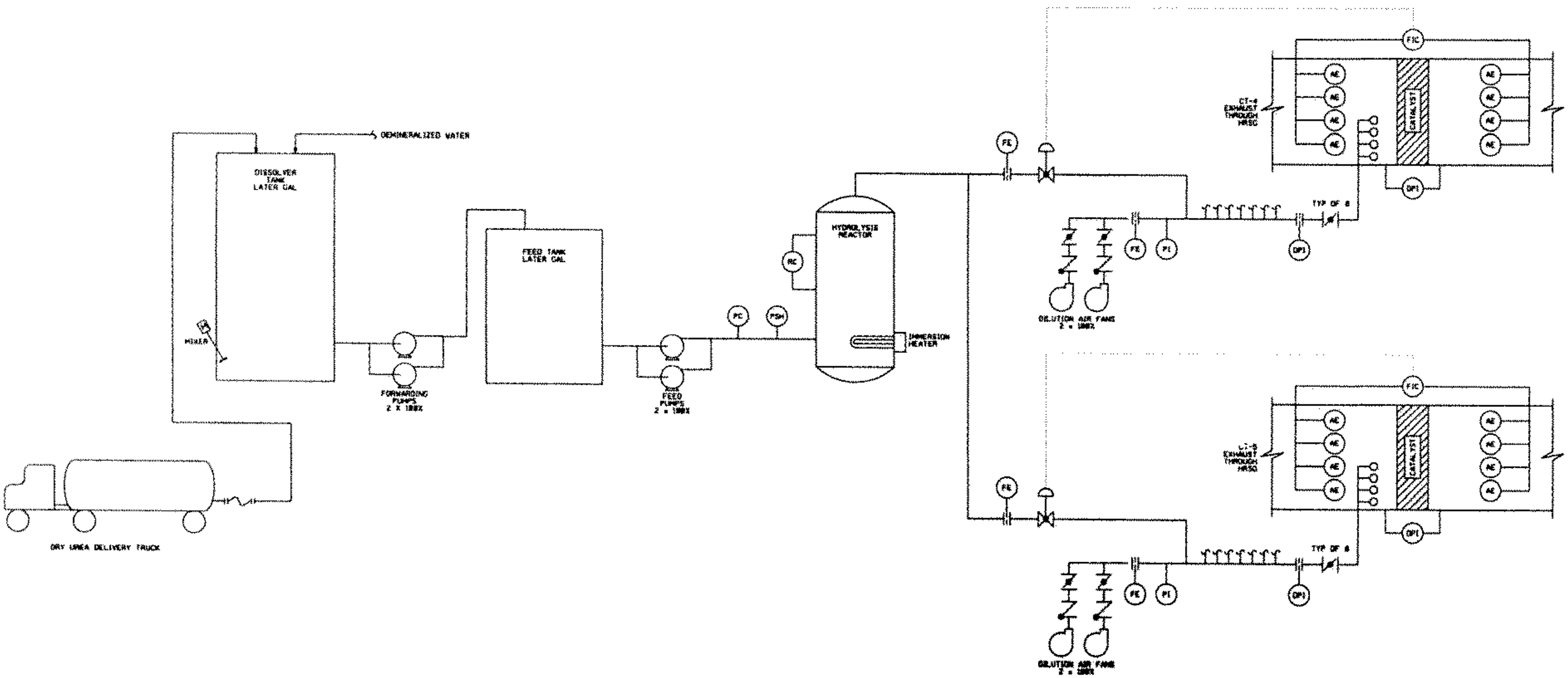
MODEL:

SUPV:

RESP ENGR:



AMMONIA GAS DETECTORS
AMMONIA FLOW CONTROL SKID CT-4
AMMONIA FLOW CONTROL SKID CT-5
CT-4 EXHAUST THROUGH HRSG
CT-5 EXHAUST THROUGH HRSG
CATALYST
(TYP 8)
DILUTION AIR FANS 2 x 100%
STORAGE TANK 20,000 GAL
AMMONIA COMPRESSOR
VAPOR
LIQUID
LOADING STATION
CONTAINMENT AREA
STONE & WEBSTER, INC. DENVER, CO.
82535
AMMONIA STORAGE AND SCR SYSTEM
SCHEMATIC (ANHYDROUS SYSTEM)
KEAHOLE COMBINED CYCLE POWER PLANT



STONE & WEBSTER, INC.
DENVER, CO.

UREA TO AMMONIA CONVERSION SYSTEM
AND SCR SCHEMATIC
KEAHOLE COMBINED CYCLE POWER PLANT

SK-05 | 00

Potential Impact on Water Resources of the Expansion of the Hawaii Electric Light Company's Power Generating Station at Keahole in North Kona, Hawaii

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Revised October 2004
December 2003

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Introduction

The Hawaii Electric Light Company (HELCO) is seeking a State Land Use reclassification of its Keahole power generation and Airport Substation sites in North Kona from Conservation to Urban. The reclassification would enable an expansion of the station's generating capacity to be implemented. This report presents an assessment of the potential impact on water resources that such an expansion is likely to have. The location of the 15-acre power plant site is shown on Figure 1. It is on the mauka side of Queen Kaahumanu Highway and directly across from the Keahole Airport access road intersection. Figure 2 is a site plan showing the location of features relevant to this assessment.

At present, power is generated by the CT-2 combustion turbine unit and all of the plant's water requirements are provided by the County Department of Water Supply (DWS) system. In the initial phase of expansion, which is expected to be on line in December 2004 or January 2005, two more combustion turbines, designated CT-4 and CT-5, would begin operation as simple cycle units. As a part of this expansion, use of water from an existing onsite brackish well, identified as State No. 4461-02, would begin. The supply of brackish water will reduce the amount of water supplied by DWS substantially. Finally, in about 2009, a steam turbine, designated ST-7, would be added and the three combustion turbine units would be run as combined cycle units. Heat recovery steam generator (HRSG) units would recover waste heat from the combustion turbines and produce the stream to drive the ST-7 unit. This future expansion would require a slight increase in supply from the onsite brackish well but no increase in supply from the DWS system.

Aspects of the Power Plant's Expansion Which Have the Potential to Impact Water Resources

The following aspects of the power plant's expansion have the potential to impact water resources: decreased use of the DWS' North Kona potable water system; draft of brackish groundwater from the plant's onsite existing well; disposal of the plant's various wastewaters in two existing disposal wells; and disposal of domestic wastewater in the existing septic tank and leach field system. Each of these is described below.

<u>Supply From DWS' North Kona Water System</u>. At present, the DWS system supplies approximately 40,300 gallons per day (GPD) for operation of the plant's existing combustion turbine and for other uses at the plant. About 30,800 GPD is used directly in the power generation process and the remainder is used for potable consumption by employees and for various service and washing uses. When use of the onsite brackish well begins with the addition of the CT-4 and CT-5 units, the required supply from the DWS system will be reduced to approximately 15,000 GPD. About 9200 GPD would be used for potable consumption and service and washing uses. Another 5800 GPD difference would be for new landscape irrigation. No potable water from DWS would be used directly for power generation.

<u>Supply of Onsite Brackish Groundwater</u>. HELCO's onsite brackish supply well was developed and pump tested in 1993 (its location is shown on Figure 2). When the CT-4 and CT-5 units are brought on line, the well will provide an average supply of 172,500 GPD. When the ST-7 steam generator and HRSG units are brought on line in about 2009, use of the brackish well would be increased at about 189,600 GPD.

<u>Subsurface Disposal of the Plant's Wastewater</u>. With only the CT-2 combustion turbine operating at present, the plant's onsite drain pit is used for industrial wastewater disposal. Under UIC Permit No. UH-1776, HELCO developed two 500-foot deep disposal wells in 1993 (their locations are shown on Figure 2). The wells will first be put into service when the CT-4 and CT-5 units are brought on line. Water directed to them will consist of the following: concentrate from reverse osmosis (RO) filtration units; backwash water from the RO plant, demineralizers, and dual media filters; and, after 2009, wastewater from ST-7 and the heat steam recovery generators (HRSG) units. All of the various wastewaters will be directed into a storage tank. When the water reaches a pre-set level in the tank, it will be pumped at 250 GPM through a filter medium and cartridge filter and then to disposal in the wells. Disposal in the wells will average 90,300 GPD in the interim period when the CT-4 and CT-5

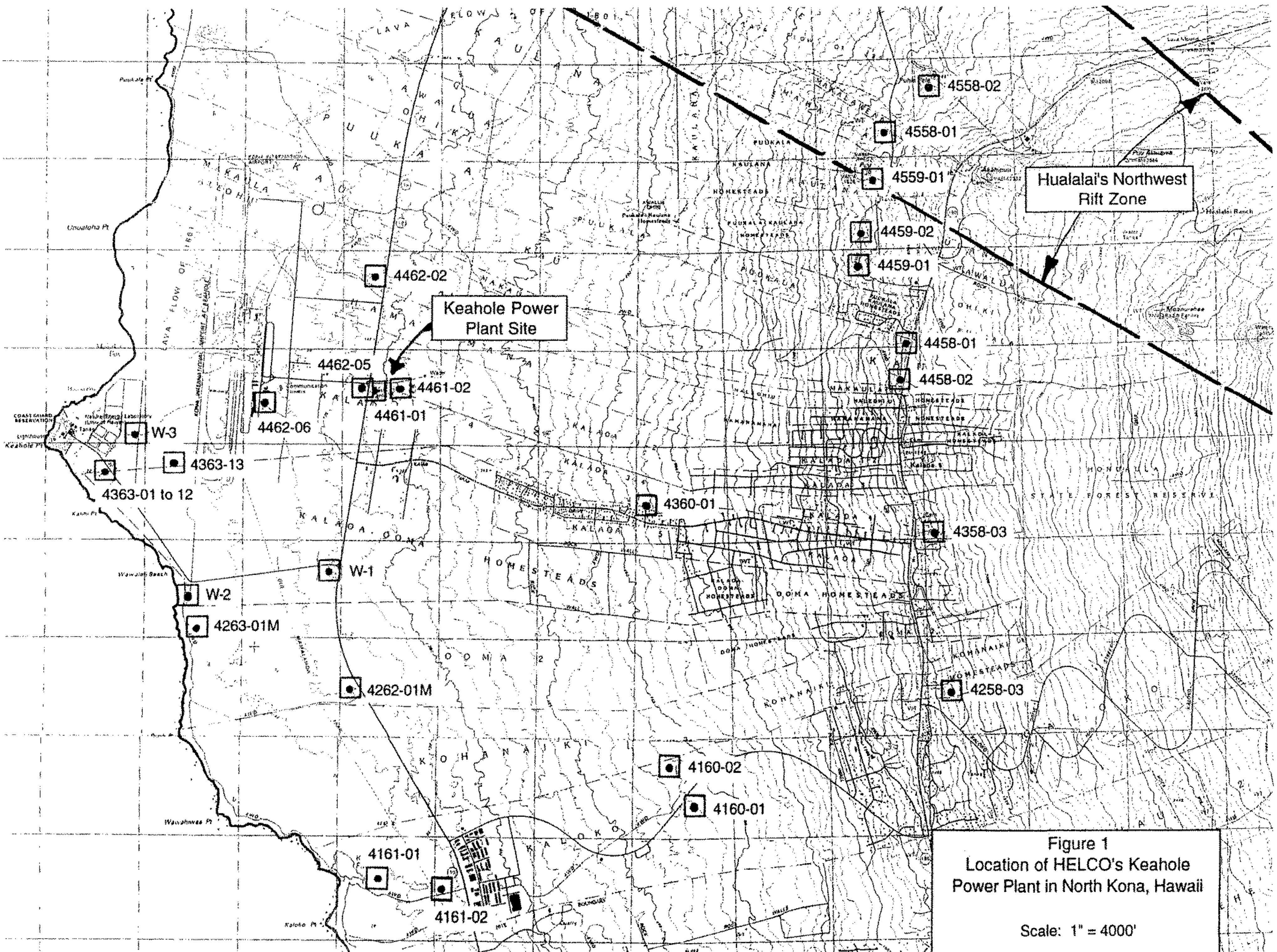

Figure 1
Location of HELCO's Keahole
Power Plant in North Kona, Hawaii

Scale: 1" = 4000'

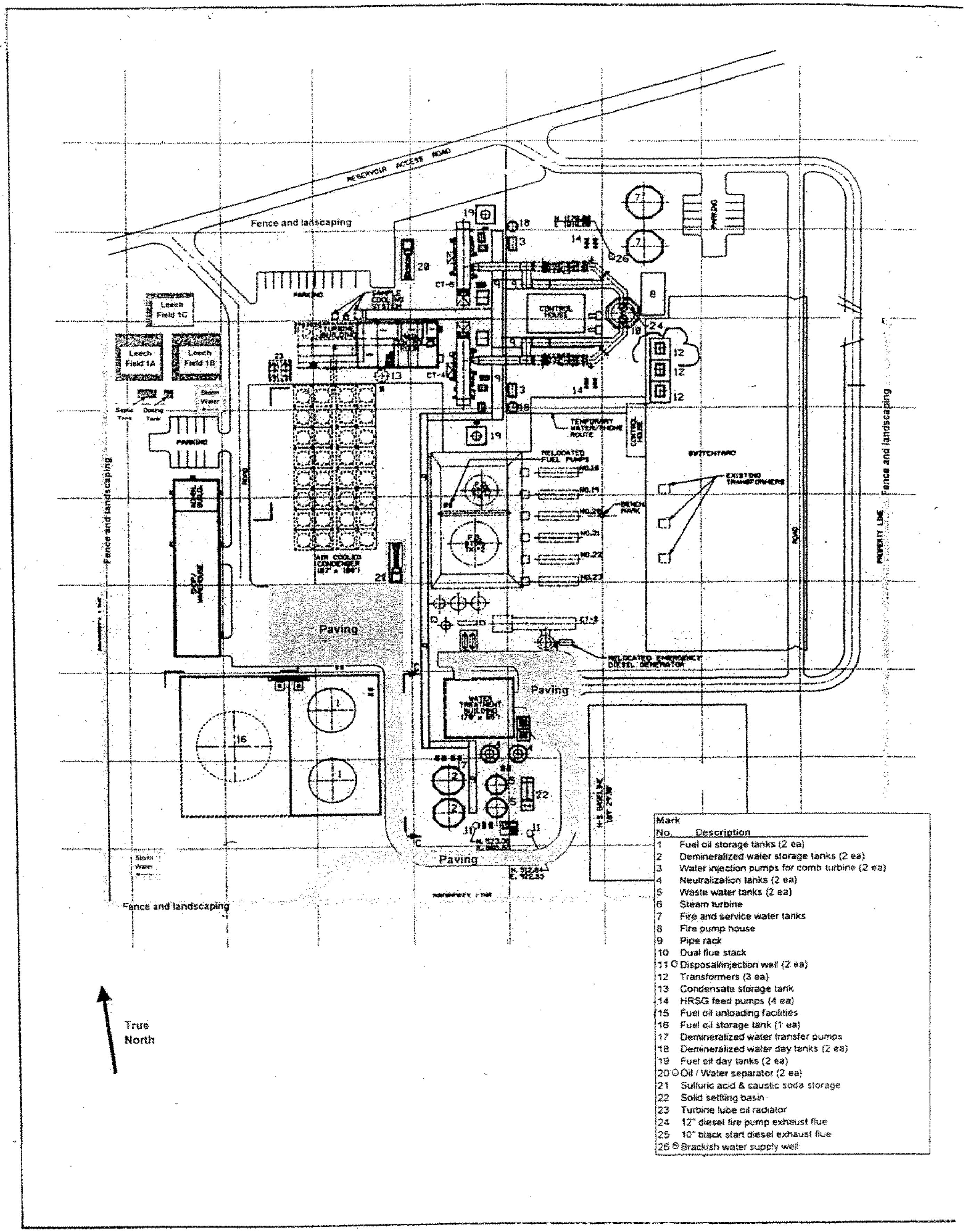

Figure 2

Site Plan of HELCO's Keahole Power Plant units are in service and it will increase to 107,300 GPD after the ST-7 and HRSG units are added in 2009. Use of the disposal wells will mean that the plant's onsite drain pit, which now receives about 22,200 GPD of the plant's wastewaters, will cease.

Treatment and Disposal of Domestic Wastewater. A 2325-gallon septic tank and leach field has already been constructed in anticipation of the plant's expansion. The estimated 2000 GPD present flowrate to this system is not expected to be changed by the plant expansion. Wastewater discharged from the septic tank to the leach field will ultimately reach the underlying basal groundwater. The locations of the septic tank and leach field are shown on Figure 2.

Summary of Water Uses and Wastewater Disposal. The tally below is a summary of the various water uses and wastewater disposal quantities described above. Virtually all of the difference between these supply and disposal amounts is or will be exhausted to atmosphere.

Summary of Water Use and Wastewater Disposal for the Keahole Power Plant

Status of Power Plant	Sources of Supply (GPD)		Wastewater Disposal (GPD)		
	DWS' North Kona System	Onsite Brackish Well	Septic Tank and Leach Field	Onsite Disposal Wells	Onsite Drain Pit
Existing: CT-2 Unit	40,300	0	2,000	0	22,200
2005 to 2009: CT-2, CT-4, and CT-5 (Simple Cycle)	15,000	172,500	2,000	90,300	0
After 2009: CT-2, CT-4, and CT-5 (Combined Cycle) and ST-7	15,000	189,600	2,000	107,300	0

Sources: Stone and Webster, 2004, 2004a, and 2004b.

Description of the Water Resources in the Vicinity of HELCO's Keahole Power Plant

Overview of Surface Water Resources. The power plant is located on the western flank of the Hualalai mountain. The surface lava flows at this site have been estimated by radiocarbon dating to be 2140±100 years old (Moore and Clague, 1991). There is almost no soil development and there are no natural gulches or eroded waterways. Due to the high permeability of the ground surface, stormwater runoff does not occur in any significant amount even during the most intense rainfalls. This being the case, this assessment of the impact of the power plant expansion on water resources focuses exclusively on groundwater.

Overview of Groundwater Resources. Knowledge of groundwater conditions in the vicinity of the power plant site comes from the wells shown on Figure 1 and on the mountain's surficial geology. Relevant data on the wells are listed on Table 1. The dominant aspect of the surficial geology is the linear band of cones and vents which comprise the mountain's northwest rift zone (also shown on Figure 1).

Two distinctly different modes of groundwater occur in the general vicinity of the Keahole power plant. Groundwater underlying the entire coastal zone occurs in a thin, brackish to saline basal lens which is underlain by saltwater at depth and is in hydraulic contact with seawater at the shoreline. Inland in the near vicinity of Mamalahoa Highway and extending some 20 miles from Kalaoa to Kealakekua, there is an abrupt change from basal to high level groundwater. The existence of high level

Table 1. Available Data on Wells in the Kaloko-Honokohau Area

Well		Owner or Developer	Year Drilled	Ground Elevation (Feet MSL)	Groundwater Level		Chloride Concentration		Water Temperature (° F)	Present Use
State No.	Name				Level (Ft. MSL)	Date Measured	Value (MG/L)	Date Sampled		
Basal Wells of Brackish Salinity										
- -	Makai Obs.	Kealakehe WWTP	1994	51	0.26	July 2001	- -	- -	68.9	Observation
- -	Mauka Obs.	Kealakehe WWTP	1994	47	1.19	July 2001	- -	- -	83.0	Observation
3960-01	- -	Queen Liliuokalani Trust	1982	40			3,400	1982		Irrigation
4059-01	Palani	DWS	1958	800	1.72	1958	3,475	1958	67.5	None
4060-01	Quarry			120			2,214	Nov. 1995	66.7	None
4061-01	Kalo-1	National Park Service	1996	38	1.20	May 2000			68.6	Monitoring
4160-01	Kaloko Irr. 1	TSA International	1985	566	2.59	3-31-93	940	7-16-85	64.3	None
4160-02	Kaloko Irr. 2	TSA International	1985	543	2.45	4-26-95	955	11-25-85	64.6	None
4161-01	Kalo-3	National Park Service	1996	24	1.37	May 2000			67.4	Monitoring
4161-02	Kalo-2	National Park Service	1996	57	2.37	May 2000			66.6	Monitoring
4262-01M	Ooma Mauka	Kahala Capital	1992	90	1.68	March 1996	2,500	1993	66.0	Monitoring
4263-01M	Ooma Makai	Kahala Capital	1992	12	- -	- -	5,500	Nov. 2002	70.0	Monitoring
4360-01	Kalaoa	DLNR-DOWALD	1968	863	2.54	4-26-95	740	9-27-68	69.2	None
4363-01 to 10	- -	Uwajima					15,000		68.0	Aquaculture
4363-13	Net Washing Well	Cyanotech								
4461-01	- -	Alika Cooper	1990	165			2,600		71.6	Irrigation
4461-02	- -	HELCO	1993	210	1.0	1-14-98	5,900	6-24-93	69.8	Future Cooling Water Supply
4462-02	- -	State DOT-Airports	1992	134	1.5	12-18-92	3,825	1-28-93		None
4462-05	W-11	State DOT-Airports	1996	140	1.4					Monitoring
4462-06	W-13	State DOT-Airports	1996	55	2.4					Monitoring
4462-07	W-14	State DOT-Airports	1996	55	2.4					Monitoring
	Well 1	HELCO	1993	195						Unused Disposal Well
	Well 2B	HELCO	1993	196						Unused Disposal Well
- -	W-1	NELHA	1988	105	0.81	6-18-91				Monitoring
- -	W-2	NELHA	1988	8	1.25	6-18-91				Monitoring
- -	W-3	NELHA	1988	21	0.95	6-18-91				Monitoring
Basal Wells of Potable Quality										
4458-01	Kau 1	Nansay	1991	1799	10.1	4-26-95	17	5-30-90	72.0	None
4458-02	Kau 2	Nansay	1992	1799	10.5	4-26-95	15	7-15-91	78.0	None
4459-01	HR-2	Huehue Ranch	1991	1534	7.3	3-23-91	150	3-23-91		Potable (Private System)
4459-02	HR-4	Huehue Ranch	1992	1532	7.0	6-4-92	110	6-4-92	74.8	Potable (Private System)
4558-01	HR-3	Huehue Ranch	1991	1519	7.0	7-29-91	20		73.0	Potable (Private System)
4558-02	HR-5	Huehue Ranch	1992	1529	22.5	10-5-92	35	10-5-92	73.0	Potable (Private System)
Wells Tapping High Level Groundwater										
3857-01	Walaha	DWS	1993	1542	62	1993				Pump stuck in well; to be Abandoned
3957-01	Keopu Mauka	HASEKO	1993	1674	47	1993	10	1-22-93	70.0	None
3957-02	USGS-Keopu	USGS/DWS	1991	1600	42.8	1-20-93				Monitoring
4057-01	QLT-1	Queen Liliuokalani Trust	1994	1720	189	1-19-94	5.6	5-26-00	69.4	DWS Potable Use
4158-02	Honokohau	DWS	1992	1675	98.2	4-26-95	6.7	5-26-00	72.3	DWS Potable Use
4258-03	Hualalai	DLNR-DOWALD	1993	1681	288.6	4-26-95	5.0	10-12-93		DWS Potable Use
4358-01	North Kalaoa	DLNR-DOWALD	1991	1799	236	1991	6.5	5-26-00	73.8	DWS Potable Use

groundwater was discovered in 1990. The geologic feature which creates this abrupt change has no surface expression and remains unknown. However, it creates a substantial reservoir of potable quality groundwater impounded behind it and it controls the location and manner of leakage into the downgradient basal lens in ways which are not yet understood.

Attributes of Basal Groundwater in the Vicinity of the Power Plant Site. Wells in the near vicinity of the power plant demonstrate that formation permeabilities at and below sea level where the basal lens resides are high, that the flow of groundwater through the lens is relatively low, and, as a result, the basal groundwater is relatively saline. These and other attributes of the basal groundwater are discussed in greater detail below.

- Modest Rate of Rainfall-Recharge. Based on the plausible assumption that the mountain's northwest rift zone is a hydrologic boundary, rainfall on the three-mile wide, mauka-makai strip centered on the power plant amounts to an average of eight (8) million gallons per day (MGD) per mile of width. The most applicable computations of the portion of rainfall which becomes subsurface groundwater recharge are in the range of 15 to 25 percent (Kanehiro and Peterson, 1977 and Oki, Tribble, Souza, and Bolke, 1999). That would approximate the flow of groundwater at 1.2 to 2.0 MGD per coastal mile at Keahole. Relative to other locations along the West Hawaii shoreline, this is a very small flowrate and it translates to low basal heads and high salinity (Table 2 summarizes water quality data for wells in the region). For example, chlorides of the three wells closest to the power plant (Nos. 4461-01, 4461-02, and 4462-02) are in the range of 2500 to 4000 MG/L. These levels are too saline for irrigation use without desalting treatment.

- Salinity Profile With Depth. As shown by the profiles on Figure 3, the basal lens beneath and near to the power plant is thin (ie. the sharp increase in salinity occurs at a shallow depth). Also, the transition zone where the salinity increases from brackish to saltwater is relatively broad. Both of these attributes are the result of the low rate of flow through the lens.

- Anomalously Cool Temperatures. The temperature profiles on Figure 4 depict an interesting regional anomaly. Basal groundwater in wells a short distance south of the power plant at Ooma is cold at the surface (66° to 67° F.) and gets progressively colder with depth (62° to 63° F. at 100 feet below sea level). This is significantly colder than the high level groundwater in wells which are directly upgradient (73.8° F. in Well No. 4358-01, for example). In fact, the temperatures 100 feet into groundwater are colder than in the ocean at 700-foot depth offshore (Figure 5). The source of the cool groundwater temperatures is the saltwater convection cell which exists at depth below the basal lens.

  Although groundwater temperatures beneath the power plant site are not quite as cool as in the area immediately to the south (Figure 6), they are still substantially cooler than wells which are nominally upgradient (72° to 78° F. in Nos. 4458-01 and 02, for example). Below 210 feet into groundwater, the temperature trend reverses and becomes warmer with increasing depth.

- Transmission of the Tidal Signal in Groundwater as an Indicator of High Formation Permeability. Figure 7 illustrates tidal attenuation and lag in wells at the power plant, both within the lens (the supply well, State No. 4461-02) and in the saline zone at depth (the Makai Disposal Well). Table 3 is a compilation of tidal amplitude and lag for these and other basal wells in the region. The ease which the tidal signal moves inland through the basal lens is an indicator of very high formation permeability. Tidal responses in the two wells at the power plant suggest that the permeability of lavas in the coastal zone are significantly greater than 5000 feet per day.

- Present Uses of Basal Groundwater in the Keahole Area. The saline nature of basal groundwater in the Keahole area limits its use. Well No. 4462-02 to the north of the power plant site was used for a time for dust control during construction at the airport, but it has been abandoned for a number of years (with the pump left in the well). Well 4461-01, located directly makai of the power plant, was drilled for potential irrigation use. However, it has

Table 2

Representative Groundwater Quality From Wells in the Keahole Area

Sampling Site	Date Sampled	Salinity (PPT)	Silica (µM)	Forms of Nitrogen (µM)				Forms of Phosphorus (µM)		
				NO_3	NH_4	TON	Total N	PO_4	TOP	Total P
High Level Potable Quality Wells										
4258-03	6-02-00	0.165	833	70.2	1.2	19.4	90.8	3.85	0.50	4.35
4358-01	3-22-96	0.256	856	75.2	0.1	3.6	78.9	3.50	0.08	3.58
	5-26-00	0.182	908	71.8	0.0	11.9	83.7	3.40	0.24	3.64
	7-20-01	0.116	831	79.2	0.0	35.3	114.5	4.32	3.68	8.00
Basal Wells of Brackish Quality										
4262-01M: Top	3-15-96	7.962	661	81.8	0.2	15.8	97.8	3.08	0.16	3.24
: Top	6-02-00	7.783	672	89.7	1.5	26.6	117.8	5.30	0.75	6.05
: Top	6-10-00	7.850	741	91.4	1.0	35.8	128.2	3.60	0.72	4.32
: Top	11-11-02	7.904	670	74.6	0.2	20.7	95.5	2.05	1.10	3.15
: Bottom	6-02-00	16.224	547	55.4	3.2	27.9	86.4	2.25	1.00	3.25
: Bottom	11-11-02	15.590	562	51.8	0.2	22.6	74.6	1.05	0.75	1.80
4263-01M: Top	11-11-02	9.738	625	64.2	0.1	20.0	84.3	1.10	1.55	2.65
: Bottom	11-11-02	18.937	479	43.6	0.2	19.0	62.8	1.15	0.50	1.65
4461-02	3-15-96	4.946	752	79.4	0.3	12.3	92.0	3.84	0.04	3.88
4462-05 (MW-11)	See Note 2	5.36	467	92.5	0.3	39.0	131.8	8.74	3.66	12.40
Basal Wells of Saline Quality										
4363-04	6-02-00	26.695	291	65.6	0.9	21.6	88.1	3.80	0.50	4.30
	6-10-00	26.836	287	72.3	1.4	32.8	106.5	4.08	0.56	4.64

Notes:
1. Except as noted below, all samples collected by Tom Nance Water Resource Engineering and analyzed by Marine Analytical Specialists.
2. The results for Well 4462-05, also known as Monitor Well No. 11 at the airport access road, are the average values of four semi-annual samples from November 2001 to May 2003. Samples were collected and analyzed by AECOS for DOT Airports.

FIGURE 3. SALINITY PROFILES IN THE BASAL LENS
AT KEAHOLE ON JULY 28, 2003

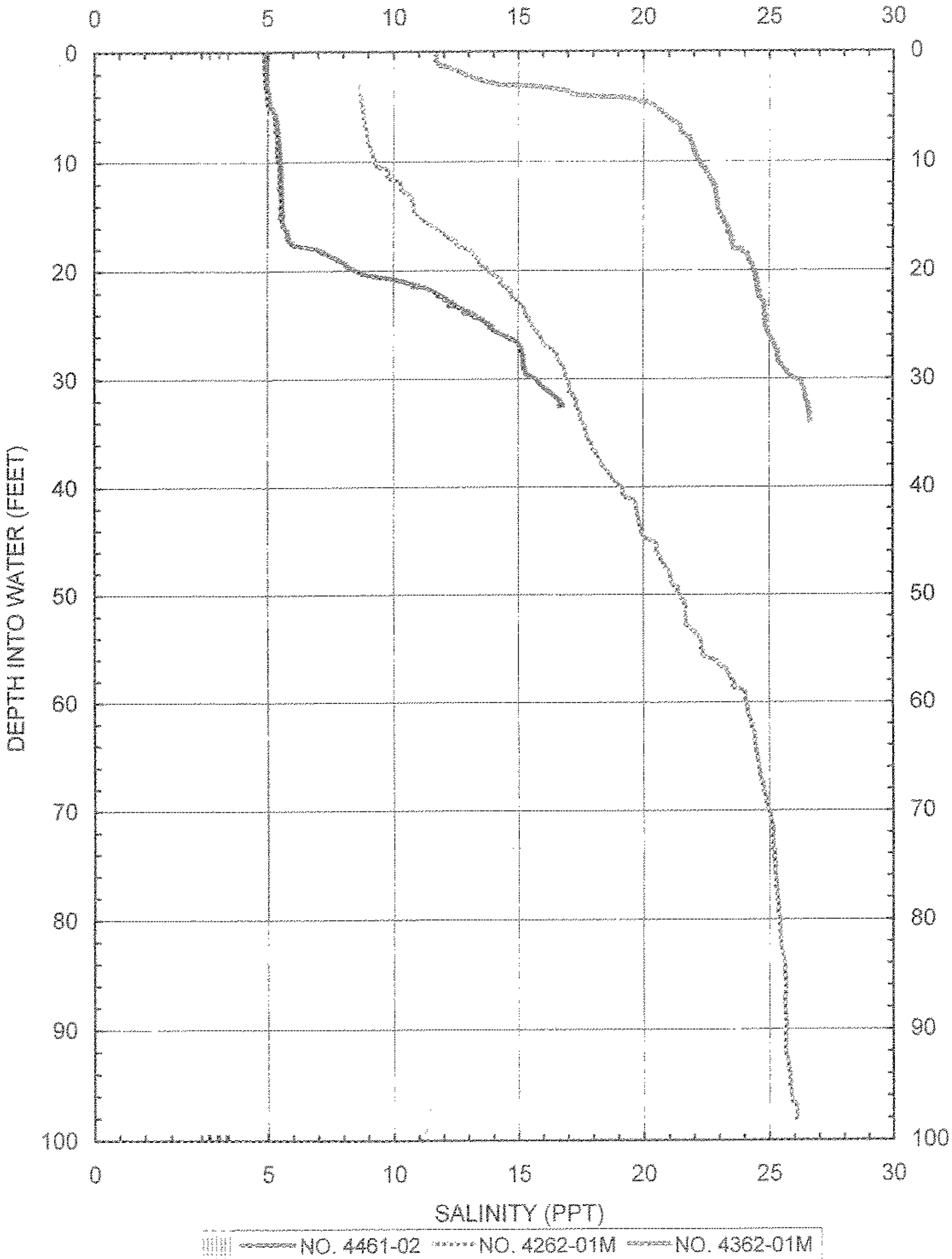

FIGURE 4. TEMPERATURE PROFILES OF THE BASAL LENS IN WELLS TO THE SOUTH OF KEAHOLE ON JULY 28, 2003

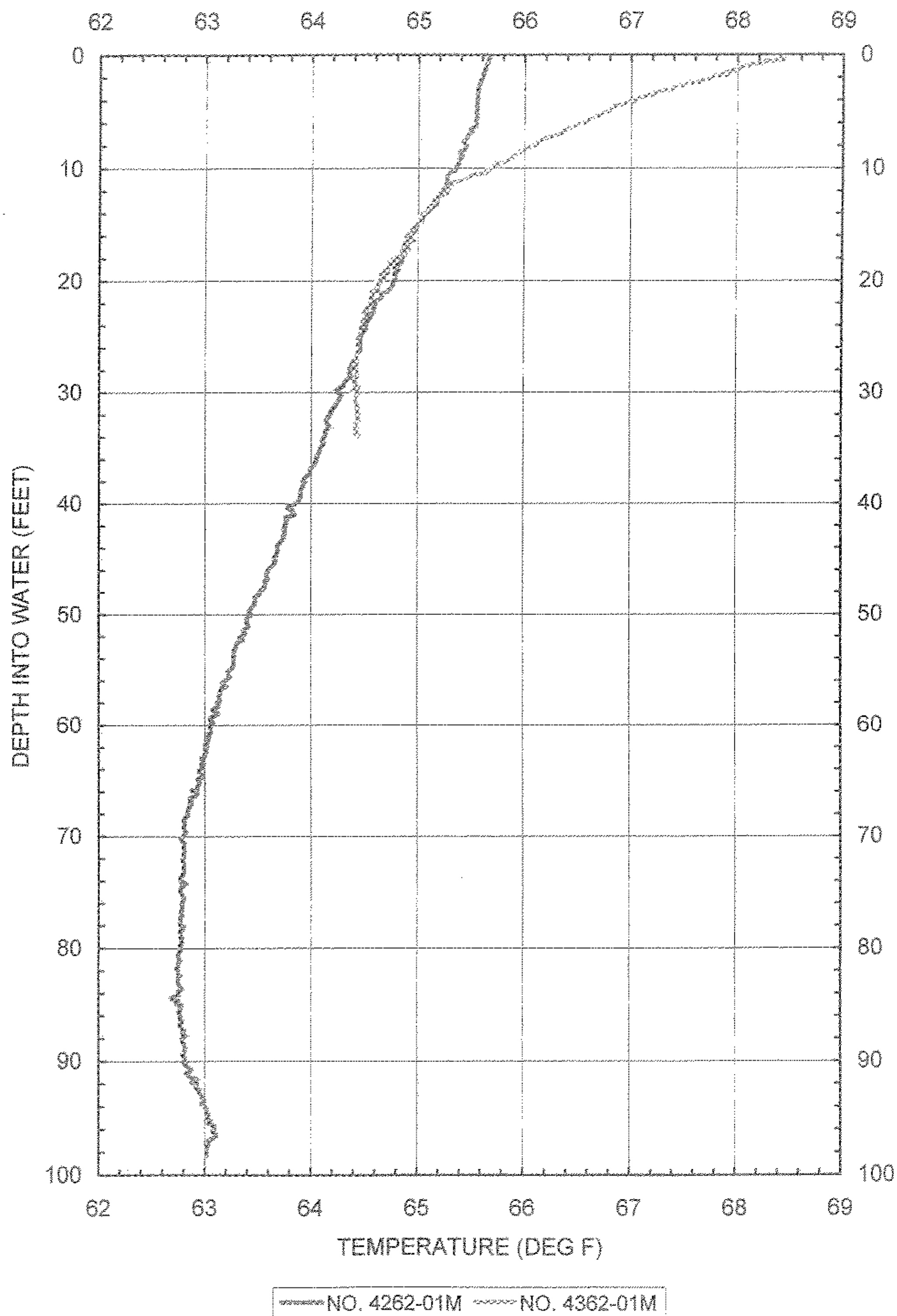

FIGURE 5. COMPARISON OF THE TEMPERATURE IN BASAL GROUNDWATER WITH THE OCEAN OFFSHORE

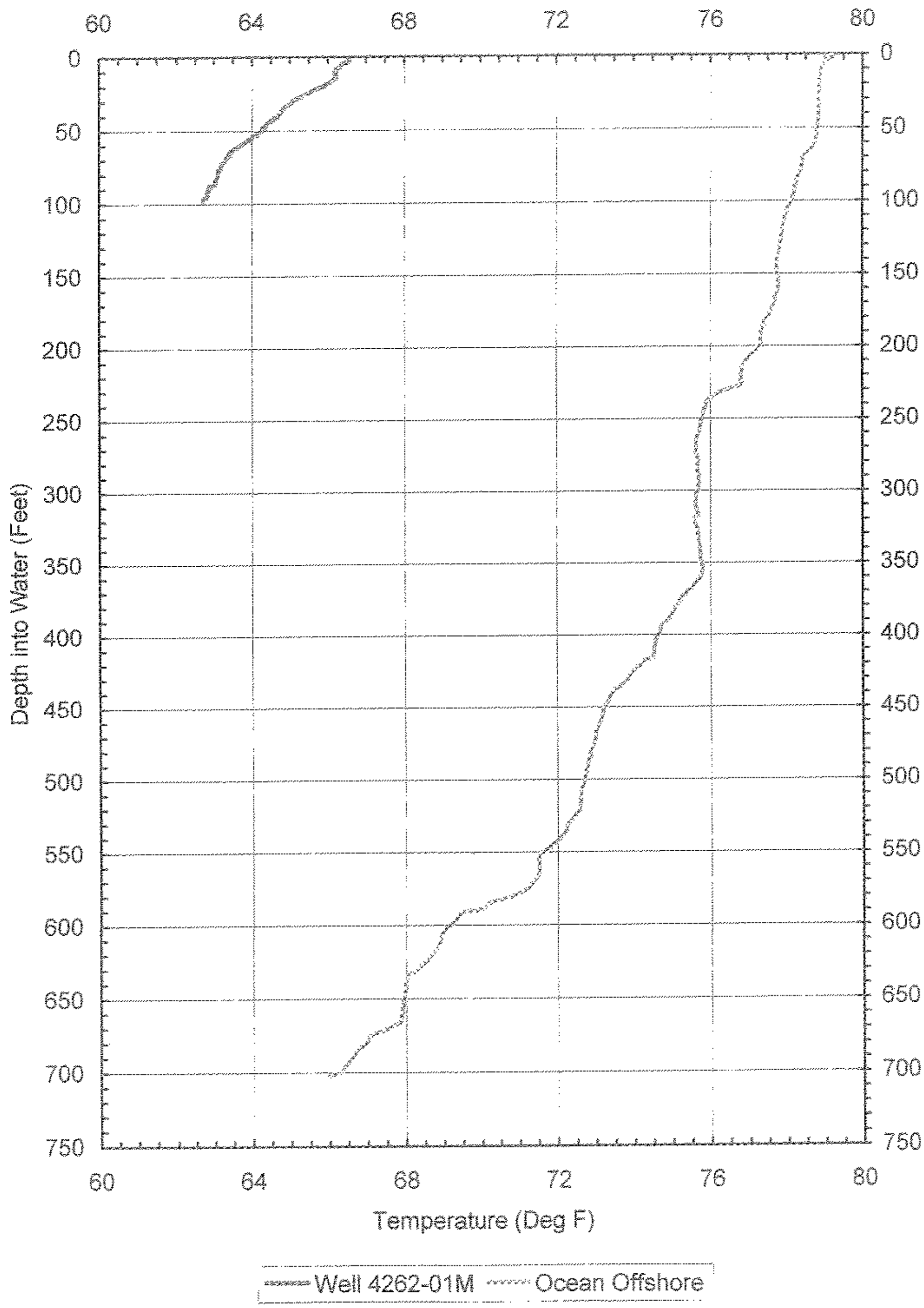

FIGURE 6. TEMPERATURE PROFILES THROUGH THE BASAL LENS BENEATH THE KEAHOLE POWER PLANT SITE ON JULY 28, 2003

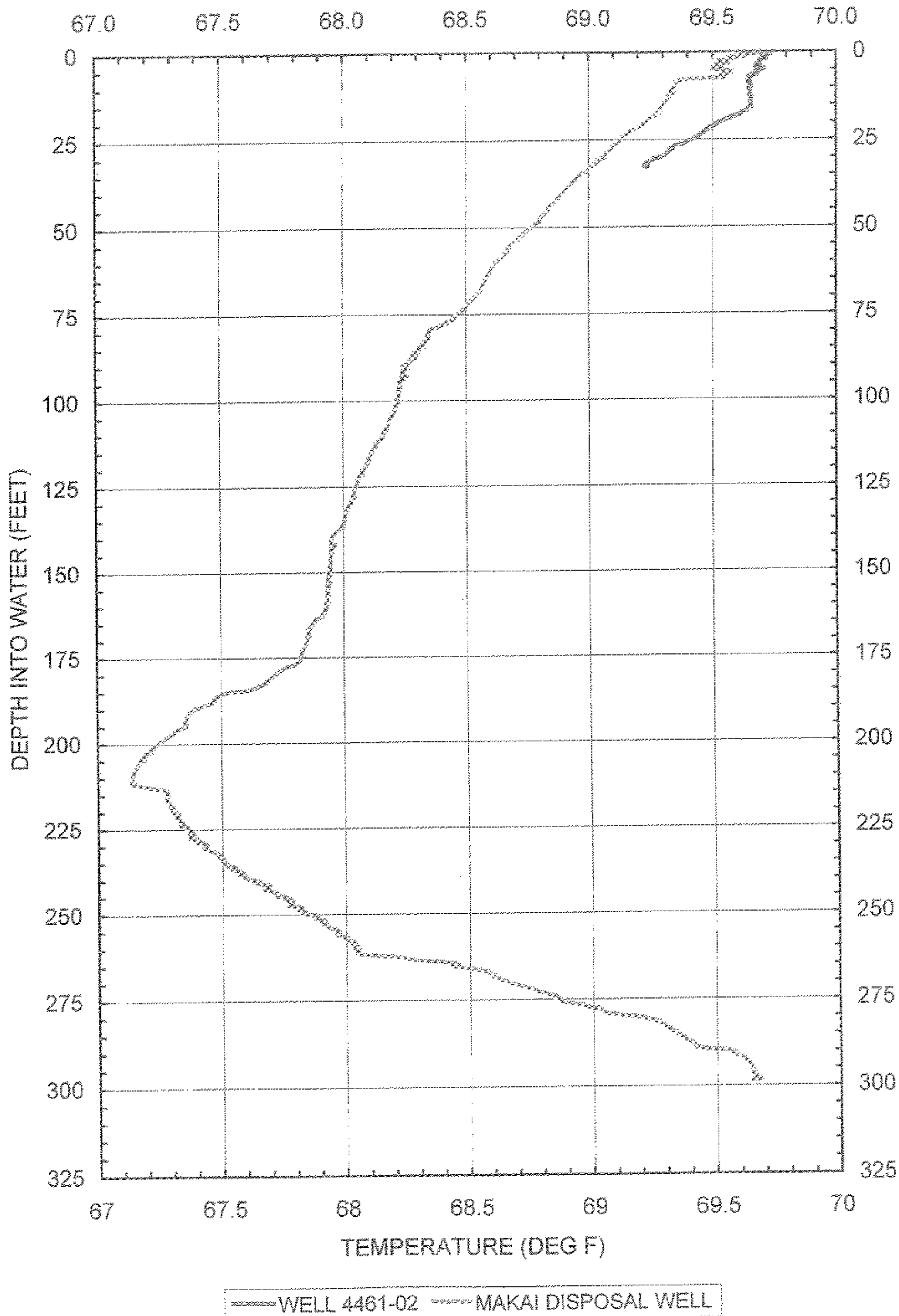

FIGURE 7. TIDAL RESPONSE IN GROUNDWATER BENEATH THE KEAHOLE POWER PLANT SITE ON JULY 22 TO 28, 2003

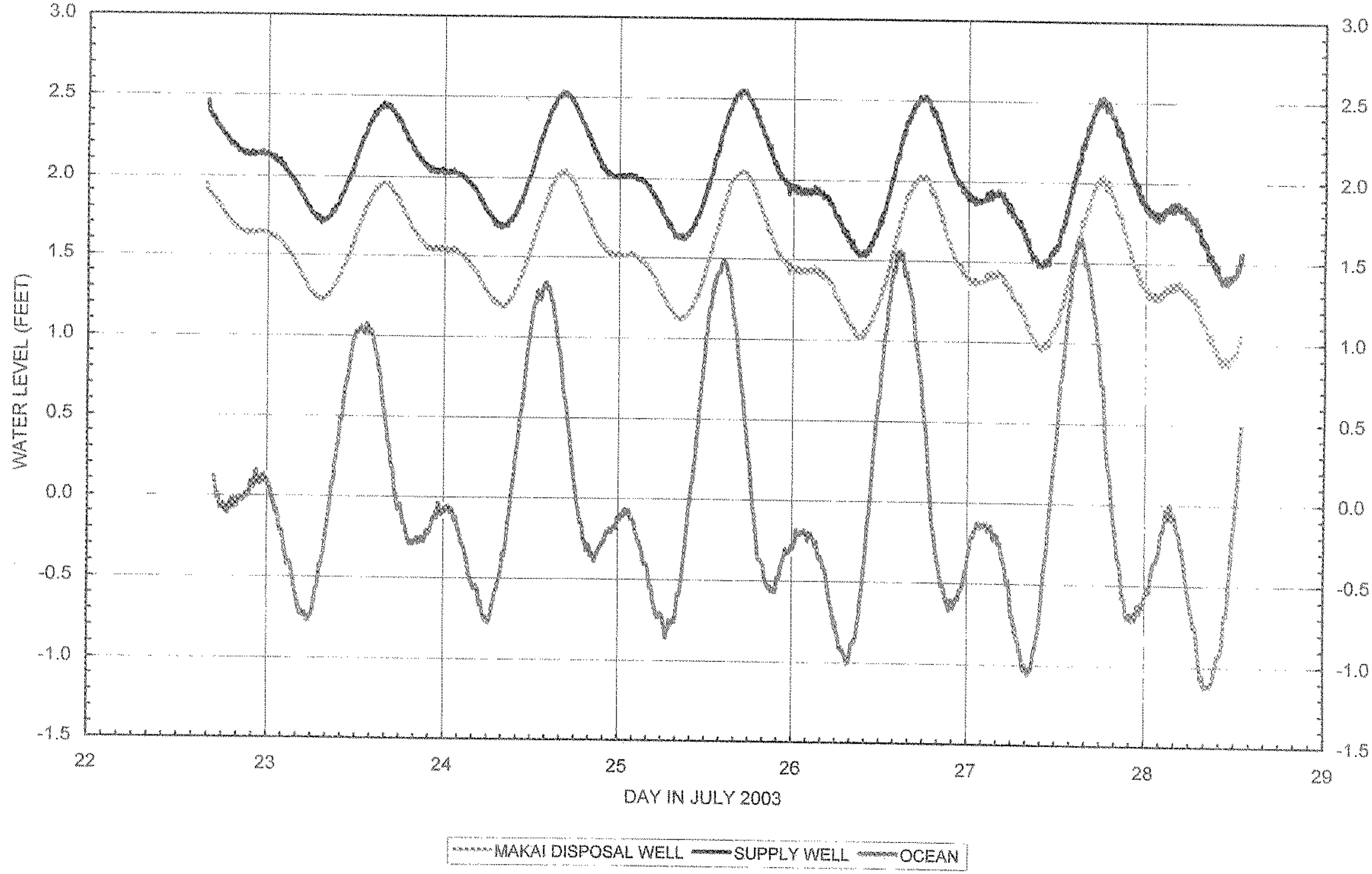

Table 3

Tidal Amplitudes and Lags of Basal Aquifer Wells Within and Around the Keahole Power Plant Site

Well		Distance From the Shoreline (Feet)	Period of Recording	Tidal Response	
State Number	Name			Amplitude as Percent of Ocean Tide	Lag Time (Hours)
• Wells Within the Power Plant Site					
4461-02	Supply	8,900	July 2003	35	2.65
--	Makai Disposal	8,600	July 2003	36	2.52
• Wells Nominally Downgradient From the Power Plant					
--	NELH No. 3	2,350	Oct. 2000	60	0.95
--	NELH No. 4	1,630	Oct. 2000	70	0.63
--	NELH No. 8	850	Oct. 2000	79	0.32
--	NELH No. 7	375	Oct. 2000	90	0.27
4463-01	DOT No. 14	310	Oct. 2000	78	0.22
--	NELH No. 6	200	Oct. 2000	85	0.23
• Wells to the South of the Power Plant					
4360-01	Kalaoa	16,000	March 1996	9	4.92
4262-01M	Ooma Mauka	5,500	Nov. 2002	44	1.50
--	NELH No. 1	5,050	Oct. 2000	48	1.35
4263-01M	Ooma Makai	400	Nov. 2002	70	0.70
	NELH No. 2	300	Oct. 2000	75	0.55

Note: All water level recordings compared to the ocean tide as recorded in Honokohau Harbor.

- Nitrogen and phosphorus removals by the septic tank and leach field system are conservatively assumed to be 50 and 20 percent, respectively. These relatively inefficient rates of removal were chosen because the leach field trenches were backfilled with gravel and crushed stone rather than with a loamy soil.

- Further nutrient removal will occur naturally during the wastewater's downward movement through the vadose zone and lateral movement with groundwater toward the shoreline. Based on the analyses in Nance (2002), these rates are conservatively assumed to be at 80 percent for nitrogen and 95 percent for phosphorus.

As shown in the table below, the above series of assumptions indicates that the disposal of 2000 GPD of domestic wastewater would add 0.066 pounds per day of nitrogen and 0.010 pounds per day of phosphorus to the flow of groundwater beneath the site. However, the nutrient load "naturally" in groundwater is many times greater than this. For example, using a low flux rate of 1.2 MGD per mile and the nitrogen and phosphorus concentrations in the underlying groundwater of 1.85 and 0.40 MG/L, respectively, (based on the level in Well 4462-05 immediately downgradient), the "natural" nutrient load in basal groundwater discharging into the marine environment along the 1.3-mile long shoreline between Keahole Point and Unualoha Point amounts to 24.0 pounds of nitrogen and 5.2 pounds of phosphorus. The power plant's addition would amount to just 0.5 to 0.3 percent of this, respectively.

Nutrient Concentrations and Loading From the Power Plant's Treatment and Disposal of 2000 GPD of Domestic Wastewater

Point in the Process	Nitrogen			Phosphorus		
	% Removal	Concentration (MG/L)	Loading (Lbs/Day)	% Removal	Concentration (MG/L)	Loading (Lbs/Day)
Raw Wastewater	- -	40	0.67	- -	15	0.25
After the Septic Tank and Leach Field Discharge	50	20	0.33	20	12	0.20
After Downward Travel Through the Vadose Zone and Lateral Travel in Groundwater	80	4	0.066	95	0.6	0.010

Summary Conclusions. This evaluation has identified and quantified four potential impacts on groundwater that the expansion of the Keahole power plant is likely to have. These can be summarized as follows:

- Use of potable water supplied by DWS' North Kona system would be reduced from 40,000 to 15,000 GPD. Until this water is used by other developments, it will allow DWS to reduce pumpage from its Kahaluu wells, if only slightly.

- Use of up to 0.19 MGD of brackish basal groundwater would reduce the natural flow of groundwater toward and into the marine environment by the same amount. However, the only downgradient use of this groundwater is by the Uwajima Fisheries saltwater wells in NELH. Because these are saltwater wells and because of the ongoing disposal of saltwater throughout the NELH facility, there will be no significant impact on these wells by the use of brackish groundwater at the power plant.

- Up to 0.11 MGD of the plant's industrial wastewater, about 70 percent of which will be concentrate from the reverse osmosis treatment system, will be disposed of into the saline groundwater between 250 and 300 feet below sea level. This water may tend to rise toward the bottom of the transition zone of the basal lens as it moves toward its discharge along the shoreline. The composition of the wastewater will generally be similar to dilute seawater.

- No increase in the wastewater disposed of in the septic tank and leach field will occur as a result of the plant's expansion. Disposal of about 2000 GPD of domestic wastewater in this manner adds nutrients to the underlying basal groundwater. However, this input is relatively negligible compared to the levels of nutrients "naturally" occurring in the groundwater.

Based on these results, it is reasonable to conclude that expansion of the Keahole power plant will not have a significant impact on water resources in the region.

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