VOLUME 2

DOCKET NO. 05-0315
HELCO 2006 TEST YEAR RATE INCREASE

DIRECT TESTIMONIES AND EXHIBITS

BEFORE THE PUBLIC UTILITIES COMMISSION

OF THE STATE OF HAWAII

In the Matter of the Application of HAWAII ELECTRIC LIGHT COMPANY, INC. For Approval of Rate Increases and Revised Rate Schedules and Rules.	)))))))	Docket No. 05-0315

HELCO
DIRECT TESTIMONIES
AND EXHIBITS

2006 TEST YEAR

BOOK 2 OF 5

May 5, 2006

T-5 D. V. Giovanni

HELCO T-5
DOCKET NO. 05-0315

TESTIMONY OF
DAN V. GIOVANNI

MANAGER
POWER SUPPLY O&M DEPARTMENT
HAWAIIAN ELECTRIC COMPANY, INC.

Subject: Production Other O&M Expense, System Reliability Improvements, Purchased Power, Production Inventory

1 INTRODUCTION

2 Q. Please state your name and business address.

3 A. My name is Dan V. Giovanni. My business address is: P.O. Box 2750,
4 Honolulu, HI 96840. My former business address was: 54 Halekauila Street,
5 Hilo, Hawaii 96720.

6 Q. By whom are you employed and in what capacity?

7 A. Since March 13, 2006, I have been the Manager of the Power Supply Operations
8 and Maintenance ("O&M") Department of Hawaiian Electric Company, Inc.
9 ("HECO"). Previously, from July 9, 2001 to March 12, 2006, I was the
10 Manager of the Production Department at Hawaii Electric Light Company, Inc.
11 ("HELCO" or "Company"). HELCO-500, page 1 provides my educational
12 background and work experience.

13 Q. Who is your successor as the Manager of the Production Department at
14 HELCO?

15 A. Mr. Norman Verbanic Jr. succeeded me and is the current Manager of the
16 Production Department at HELCO. He was promoted from Maintenance
17 Superintendent to Manager, Production Department effective March 13, 2006.
18 HELCO-500, page 2 provides his educational background and work experience.

19 Q. What is the scope of your testimony?

20 A. In this testimony, I will discuss the following:

21 1) overview of other Production O&M expense,

22 2) description of the HELCO system and its operation,

23 3) major changes in the HELCO generating system since 2000,

24 4) HELCO's improved reliability results, including reasons for reliability
25 improvements,

5) maintaining system reliability, safety and environmental controls in the 2006 test year,

6) discussion of other production "O&M" expense (other than fuel) in the 2006 test year,

7) purchased power expenses (including both purchased energy and capacity expenses), and

8) production stores inventory for test year 2006.

OVERVIEW OF OTHER PRODUCTION O&M EXPENSE

Q. Please provide an overview of HELCO's estimate of its test year 2006 other production O&M expense.

A. HELCO's normalized test year 2006 estimate for production expense other than fuel and purchased power ("other production O&M expense") is $23,040,000 as shown in HELCO-529. Of this total, $9,587,000 is for other production operation expense and $13,453,000 is for other production maintenance expense, as shown on HELCO-530.

Q. What makes up the 2006 test year estimate for other production operations expense?

A. As mentioned above, the 2006 test year estimate for other production operations expense is $9,587,000. Of this total, $6,054,000 is for labor expense and $3,533,000 is for non-labor expense. (See HELCO-531.)

Q. What makes up other production maintenance expense?

A. The test year 2006 estimate for other production maintenance expense of $13,453,000 is made up of $3,228,000 for labor expenses and $10,225,000 for non-labor expenses. (See HELCO-531.)

Q. What is the 2006 test year estimate for the production materials inventory?

A. The estimated test year 2006 production materials inventory is $1,062,000. (See HELCO-549.)

DESCRIPTION OF THE HELCO SYSTEM

Q. Please describe the location and classification of the generating units that supply power to the customers on the island of Hawaii.

A. HELCO-501 illustrates the locations of the firm and as-available (i.e., non-firm) power generating units interconnected to the HELCO grid on an island of Hawaii map. On the island of Hawaii there are 26 firm power generating units comprised of 24 HELCO units, an independent combined-cycle power plant owned and operated by Hamakua Energy Partners L.P. ("HEP"), and an independent geothermal power plant owned and operated by Puna Geothermal Venture ("PGV"). The total system capability, as reported in the Adequacy of Supply Report filed February 3, 2006, was 271.9 MW net, of which 90 MW is supplied by HEP and PGV.

HELCO-502 is a summary that provides a listing of these generating units with indications of whether each is HELCO-owned or owned by an Independent Power Producer ("IPP") and whether each unit is baseloaded, intermediate, or peaking. The summary also includes the respective generating capability, type of unit, intended operating mode, installation date, and age.

Q. Please explain how baseload, intermediate, and peaking units are brought online and dispatched to meet daily customer demand.

A. To provide generation to serve the load and regulating reserve, the system operator dispatches, as necessary, a combination of baseload, intermediate units, and peaking units. In general, the operation of these different types of units may be characterized as follows:

1) Baseload Units - Baseload units are operated 24 hours per day, seven days per week, except for periods when they are unavailable for maintenance or forced outage. Baseload units include Hill 5, Hill 6, Puna Steam Plant, PGV, and HEP (operating in a single train combined-cycle mode). With the exception of PGV, these units are dispatched at various output levels to minimize cost and follow the load changes.

2) Intermediate Units - Intermediate units are generating plants that are dispatched to meet demand beyond that satisfied by baseload units for daily or seasonal fluctuations. They provide intermediate capacity, that is, capacity intended to operate fewer hours per year than baseload capacity but more than peaking capacity. Intermediate units include Shipman 3, Shipman 4, Keahole CT-2, Puna CT-3, Keahole CT-4, Keahole CT-5, and HEP (operating in dual-train combined cycle mode). HEP is listed as both an intermediate and baseload unit, because the second CT is typically dispatched as an intermediate unit.

3) Peaking Units - Peaking units are operated only a limited number of hours per year. These units are operated during certain transmission configurations, certain times of the day, certain times of the year, or when demand for energy spikes. Most of these units can come online quickly (i.e., "fast start") and provide generation during periods of unexpected generation shortfall or for restoration following the sudden loss of a large generating unit. Peaking units include all of HELCO's diesel engines and one combustion turbine unit, Kanoelehua CT-1. There are 14 small diesel engines located at different locations on the grid, including: Kanoelehua D11, D15-D17, Waimea D12-D14, Keahole D21-D23; and dispersed

diesels D24-D26 (one each located at a HELCO substation).

4) As Available Units - As available units, such as run-of-river hydroelectric power plants or wind energy, cannot produce electric power on demand. This type of generation is not firm and is not dispatchable. The as-available energy is accepted onto the system, and firm power plants are correspondingly dispatched to lower loads, provided that doing so does not impact system reliability or power quality. On the HELCO grid there are six (6) as-available facilities comprised of Lalamilo Wind Farm (more than 100 wind turbine generators), Apollo Energy Corporation ("Apollo") Wind Farm (approximately 28 wind turbine generators at present), Hawi Renewable Development, LLC ("HRD") Wind Farm (14 wind turbine generators), Wailuku River Hydro (two hydroelectric generators), Puueo Hydro (two hydroelectric generators), and Waiau Hydro (two hydroelectric generators).

Q. How does HELCO's system compare to larger electric systems on the mainland?

A. On the mainland, electric utilities are interconnected to neighboring utilities and rely on this large interconnected power grid for generation reserves and system stability. An isolated island utility such as HELCO must independently operate and maintain its generating units, as well as coordinate operation and maintenance of the facilities of independent power producers ("IPPs"), such that there is sufficient generating capacity at all times to serve the system demand on the island. To meet this goal, HELCO coordinates scheduled outages of all generating facilities that are connected to the system to ensure there is sufficient reserve capacity to recover and meet the customer demand in the event the largest generating unit fails. This includes sufficient reserve capacity to meet

system load even if the largest generating unit is unexpectedly unavailable. This condition of having sufficient reserve margin is termed "loss of largest unit margin" condition.

Q. What does it mean to "recover" from the sudden loss of the largest single generating unit?

A. To "recover" from the sudden loss of the largest single generating unit implies that an event has occurred that requires a form of restoration. Because HELCO does not operate with sufficient spinning reserve to make up for the sudden loss of the single largest generating unit, the subject event would most likely result in a sudden decrease in system frequency and the interruption of service to customers. Units in reserve (e.g., diesel engines) would be started and then loaded to affect a "recovery" of power generating capability and restoration of service to customers.

Q. Are there other ways that HELCO operates which differ from a mainland utility?

A. Yes. HELCO operates with only enough generation capacity brought online to meet the present system demand and to provide sufficient regulating reserve to respond immediately to expected and typical changes in system demand. The regulating reserve is typically not enough to cover for the sudden loss of the larger generating units operating online. As a result, the unexpected sudden loss of a large generating unit on the HELCO system may result in customer service interruptions until enough of the offline reserve capacity is brought online to replace the lost generation. In contrast, mainland utilities and some larger island utilities such as at HECO on Oahu, typically have sufficient regulating reserve online (within its generating system or within that of the interconnected grid) to accommodate the sudden loss of large generating units without service

interruptions.

Q. Does the island of Hawaii present any unique challenges for electric system operation as compared to the other islands in the state?

A. Yes. Compared to the other islands, the island of Hawaii has a relatively large geographic area and a relatively small total system demand. HELCO's transmission system operates at a relatively low voltage (69 KV). There are two concentrated load centers: one in the east (Hilo) and one in the west (Kona). The majority of generating resources are located in the east side of the island, and thus, in general there is a net transmission of power from the east to the west to deliver power where it is being used. Due to these factors, the island of Hawaii presents technical challenges for system operations that include power transmission, power generation, fault protection, and voltage control.

OPERATION OF HELCO'S GENERATING SYSTEM

Q. How are power plant operations coordinated?

A. An energy management system ("EMS") monitors the power outputs of the as-available and firm power generating units and enables coordination of the power plant operations. Portions of the firm generating units have the capability to be placed under control by the EMS. The EMS dispatches these "controllable firm power" units to meet the instantaneous power demand on the grid, while satisfying cost and reliability criteria.

Q. Please explain the relationship between system demand, regulating reserve, and offline reserve capacity.

A. System demand is the sum of the electric energy consumed by customers at any point in time (load) and the power losses incurred transporting the power to the customers via the transmission and distribution system. Daily system demand

profiles vary over a 24-hour period from a minimum to a peak as shown in HELCO-503. To maintain system reliability and the system frequency at 60.0 hertz ("Hz"), online generation (i.e., "supply") must exactly match demand (load plus losses) at any point in time. If system demand exceeds the online generation, system frequency will decrease below 60.0 Hz. If the drop in system frequency is too severe it must be halted in order to prevent significant instabilities and possible collapse of the power grid. In a situation of excessive drop in system frequency, the system demand is reduced by shedding load from the system (i.e., interrupting service to customers) via automatic and/or manual means in an attempt to reestablish the balance between supply and demand. Customer interruptions will continue until the offline reserve can be brought online to meet or exceed demand. If the online generation exceeds the demand, system frequency will increase above 60.0 Hz. Generation would immediately be reduced by automatic or manual means to compensate for the high frequency.

Q. Please expand on the definition of regulating reserve.

A. Regulating reserve is that portion of the online generation capability that exceeds system demand and which is responsive to Automatic Generation Control ("AGC").

Q. What is AGC?

A. AGC is a standard industry term not unique to HELCO. AGC is a software program that is part of the energy management system (EMS). AGC dispatches load changes (up and down) on the respective units (the ones that are specified to the "on AGC") to meet system load demand. AGC dispatches loads among the units for minimum cost of generation. This is called "economic dispatch."

Q. How is regulating reserve utilized by AGC to maintain system frequency?

A. Regulating reserve is used to maintain the balance between supply and demand. It provides the reserve capacity needed to increase or decrease generation in response to typical changes in load demand or as-available power production. Thus, the regulating reserve capacity provides the generating margin required to maintain system frequency at 60.0 Hz under normal operating conditions. For example, if system demand decreases system frequency will increase. To return frequency to 60.0 Hz there will be a corresponding decrease in output from the online generating units and an increase in the regulating reserve on the system at that time. Conversely, if system demand increases, system frequency will decrease. To restore frequency to 60.0 Hz there will be a corresponding increase in online generation and a decrease in the regulating reserve on the system.

Q. Does HELCO have guidelines for the amount of regulating reserve it utilizes?

A. Yes. HELCO's present operating policy requires a minimum amount of regulating reserve for both up and down directions. Regulating reserve policy also requires three or more generating units to be online having this capability at all times. The minimum regulating reserve is met by operating these units between their respective full capacity and minimum capacity. The relationship of regulating reserve relative to system demand is illustrated in HELCO-504.

Q. How much regulating reserve did HELCO's system typically operate within the past?

A. Historically, HELCO was able to operate with a regulating reserve of 3 to 5 MW. Typical minute-to-minute imbalances between system supply and demand were relatively small. The HELCO customer base does not include industrial type loads which would create sudden and disruptive changes. Each

load is a relatively small percentage of total system demand. Accordingly, due to the characteristics of the load served and the daily profiles, it has been possible to operate with this relatively small amount of regulating reserve and maintain system frequency at desired levels.

Q. Were there ever conditions in the past which required higher levels of regulating reserve?

A. Yes. During periods of high as-available power generation from the Apollo Wind Farm, it was necessary to increase the regulating reserve to 7 to 10 MW in order to control system frequency. This was because the Apollo Wind Farm, which could produce up to 7 MW, commonly had sudden changes in output which caused rapidly occurring power imbalances between generation and load.

Q. What level of regulating reserve is HELCO operating with currently?

A. With the addition of 10.56 MW of wind energy at HRD in early 2006, HELCO plans to increase the regulating reserve above its historical levels when the HRD and Apollo wind farms are connected to the grid. Operational experience will be required to fully determine the regulating reserve requirement, but reports from utilities with similar high wind penetration suggest regulating reserve may need to be equivalent to 60% of the installed wind capacity (refer to HELCO-505 reference filing to the second Act 95 workshop regarding system integration issues). Thus, HELCO is planning to utilize a regulating reserve of 10 to 12 MW when both HRD and Apollo are operational.

Q. Does HELCO plan to increase regulating reserve further when more wind energy is connected to its grid?

A. Yes. Apollo has a Commission-approved purchase power agreement to repower its facility and increase its output from 7 MW to 20.5 MW. The repowering of

the Apollo Wind Farm is expected to be completed in 2007, and would result in a total of 34 MW of wind energy connected to the HELCO grid. At that time it may be necessary to increase the regulating reserve on the system to 15 to 20 MW.

Q. What happens if system demand suddenly exceeds the online generation capacity?

A. An event such as a trip of a large generating unit can cause system demand to suddenly exceed online generation capacity. Loss of a large generating unit would create a severe drop in frequency. The regulating reserve, designed to manage typical conditions, is usually insufficient to bring the system back into balance after such an event. If the loss is large enough, HELCO would shed load via automatic and/or manual means to reestablish the balance between supply and demand. The automatic means is called "under-frequency load shedding" and takes place very quickly (i.e., less than 0.2 seconds).

Q. Can you describe how automatic underfrequency load shedding works?

A. If system frequency suddenly drops to low levels, the automatic underfrequency load shedding scheme will open up to 10 blocks of load which could amount to more than 70.0 MW depending on the time of day. Automatic underfrequency load shedding is designed to occur at different frequency levels and time delays. The first block is shed at 59.0 Hz, and the last block is shed at 57.0 Hz. The customers affected by underfrequency load shedding remain out of power until the offline reserve generation can be brought online, or other equivalent loads are taken offline (e.g., through rolling blackouts). In most cases, fast-start diesel units and combustion turbines available as offline reserve capacity can restore service within several minutes to the customers affected by underfrequency load

shedding. The diesel units come online in one to two and a half minutes, and the combustion turbines in five to 12 minutes.

Q. What conditions can cause underfrequency load shedding?

A. Underfrequency load shed can occur when one or more generating units trip offline. The trips may be due to equipment failure, which may or may not occur in conjunction with a system event (such as a grid fault due to lightning or trees on a line). Grid faults place a strain on the firm and as-available power generating units and at times cause failure of critical equipment in the plants. Grid faults can isolate the generation from the grid through loss of transmission lines (refer to the testimony of Mr. Jay Ignacio, HELCO T-6).

Q. Can automatic load shedding always be depended upon to correct for an underfrequency event?

A. No. The most severe situations occur when multiple generating units trip offline within the same time period. In such cases, which typically occur during lightning and/or wind storms, the automatic load shed may not be enough to protect the system, and the system operator must manually open additional circuits to shed load in selected areas and stabilize the grid.

Q. How does HELCO operate if there is not enough generation to meet the system demand for an extended period?

A. If there is not enough generation to meet the system demand for an extended period, HELCO would interrupt service to selected customers for a period of time of 30 to 60 minutes. If the generation were still insufficient at the end of the period, then the service interruption would be shifted to other customers. Such an occurrence would be called a rolling blackout.

Q. What precautions does HELCO use to reduce the potential for the demand to exceed available generation?

A. HELCO coordinates the planned maintenance activities for all firm power generation on the system to maintain a generation margin in excess of expected demand, to allow for unexpected loss of generation.

Q. What conditions lead to a generation shortfall, if the planned maintenance activities are scheduled to allow for a margin over the system demand?

A. At any time forced outages of generating units may occur. If the forced outages plus scheduled maintenance outage are too high, then conditions may exist which would result in a generation shortfall. If significant then rolling blackouts may be necessary.

Q. Have there been recent rolling blackouts on the HELCO system?

A. No. The last rolling outage was on November 29, 2002. Today HELCO's system is much more resistant to conditions that could result in rolling blackouts.

Q. Why is HELCO's system much more resistant to rolling blackouts?

A. HELCO's system is more resistant to events that could result in rolling blackouts because the generation reserve margins have increased substantially in recent years and the generating units connected to the HELCO grid are operating more reliably.

Q. Can you describe how the reserve margins have been increased?

A. With the additions of 30 MW of firm power at PGV in the mid-1990s and 60 MW of firm capacity at HEP in 2000, the reserve margins increased substantially. Moreover, in 2004, HELCO commissioned CT-4 and CT-5 at the Keahole Power Plant resulting in a net addition of another 14.5 MW of

generating capacity and a further increase in the reserve margin. This latter net addition of 14.5 MW was a result of: (a) adding 44 MW of new combustion turbine capacity to its generating fleet (i.e., CT-4 and CT-5); (b) retirement of Keahole diesel engines D18, D19, and D20 for a combined reduction in capacity of 7.5 MW; (c) and the termination of the short-term purchase power agreement with Hilo Coast Power Company ("HCPC").

Q. What other generating capability improvements occurred in this same time period that made HELCO's system more resistant to rolling blackouts?

A. As shown in HELCO-506, PGV restored its output to 30 MW after a struggle for several years to sustain its firm capacity commitment to HELCO.

Q. Were these impacts on reserve margin reported to the Commission?

A. Yes. The March 2005 Adequacy of Supply ("AOS") Report to the Commission (filed on March 15, 2005) reflects all of the additions to HELCO's firm power generating capacity. In the February 2006 AOS Report to the Commission (filed on February 3, 2006), it showed an identical amount of firm power generating capacity. The increased reserve margins due to new firm power generating units are a primary reason why there is less concern for rolling outages today.

Q. What reliability improvements occurred in this same time period that made HELCO's system more resistant to rolling blackouts?

A. The reliability of HELCO's older generating units improved significantly in recent years. I will describe the work that was performed and the resulting reliability benefits later in my testimony.

Q. Is HELCO's forecasted reserve margin adequate to avoid rolling outages in the future?

A. Yes. As summarized in HELCO's annual submittals of the AOS Reports filed in 2005 and 2006, HELCO has sufficient reserve margins to avoid rolling blackouts for the near future. However, due to increasing load growth, the reserve margins for 2006 are approximately 6% lower than that anticipated and reported in the AOS filing submitted one year earlier.

Q. What other evidence is there that system load is growing at a rapid rate?

A. HELCO-507 is a plot comparing weekly system peaks for 2004 actual and 2005 actual. The system peaks are noticeably higher in 2005 and reached an all time high of 197.0 MW net on December 19, 2005.

MAJOR CHANGES IN THE HELCO GENERATING SYSTEM SINCE 2000

Q. What was the anticipated HELCO generation capability at the end of 2000?

A. The HELCO system firm power generating capability, as forecasted in the AOS Report filed on February 4, 2000, and revised on February 18, 2000, was expected to be 250 MW at the end of 2000. This included 112 MW of firm power generating capacity to be purchased from HEP (60 MW), PGV (30 MW), and HCPC (22 MW). As indicated in the same filing, HELCO anticipated that it would retire Shipman 1, Diesels 8 through 17, and Diesels 24 through 27 (distributed generation units), and that it would place Puna Steam, Shipman 3 and Shipman 4 on cold-standby.

Q. What were HELCO's corresponding O&M plans for this period?

A. As indicated in HELCO's 2000 rate case testimony, HELCO significantly reduced production O&M expenses (including O&M staffing) due, in part, to its plans to purchase more than half of its power needs from IPPs and to retire many of its own units. HELCO reduced overhaul costs of HELCO's remaining in-service units below historical levels due to the very low expected run hours.

Q. In 2000, what were HELCO's expectations for additional generation at Keahole Power Plant?

A. The HELCO 2000 AOS Report (filed on February 4, 2000) stated that HELCO's short-term plan included the installation of Keahole CT-4 and CT-5 at the estimated in-service dates of January 2002 and March 2002, respectively, and that the Keahole diesels D18 and D19 would retire with the installation of CT-4. Further, Keahole diesel D20 would retire and D21 would have limited run-hours with the installation of CT-5, as a condition of the Keahole air permit.

Q. What actually occurred in this time period?

A. HELCO's generating system evolved in a significantly different manner during the period from 2000 through 2004 than was anticipated. Plans to temporarily put certain units (Shipman 3 and 4, Puna Steam Plant) on hot and/or cold standby after HEP was added had to be cancelled and/or significantly modified given HEP's extended startup period problems, and PGV's extended derating (by up to 24.5 MW). For example, Puna Steam Plant has been baseloaded, and Shipman 3 and 4 are currently being used as intermediate units. These operating and reserve margin issues, as well as continued delays in adding generation at Keahole, the planned addition of substantial amounts of as-available wind energy, and higher than forecast load growth, led first to the deferral of planned generating unit retirements, and then to cancellation of plans to retire certain units even after CT-4 and CT-5 were installed. Only Shipman 1, D18, D19, and D20 were retired as planned, and the retirements of D8, D9 and D10 occurred years later than anticipated. These changes are discussed in the Generation Resource Contingency Plan, Update #7 (filed with April 2, 2001 in Docket No. 96-0029), HELCO's IRP-2 Evaluation Report (filed March 31,

2004 in Docket No. 97-0349, and in the annual AOS Reports filed by HELCO.

While the new units that HELCO planned to add to its system are now an integral part of its system, the peak load and energy demand to be served by the system are significantly higher than was forecast and, as a result, HELCO has retired fewer units than had been anticipated, and HELCO's own units are running more to make up the difference.

Q. How did the system peak grow during this period?

A. The system peak increased from 170.8 MW (net) in 2000, to 186.7 MW (net) in 2003 (versus the180.1 MW peak that had been forecast for 2003 in the April 9, 2001 AOS Report). The system peak grew to 197.0 MW (net) by 2005.

Q. How does HELCO's current generating capability compare to what it expected at the end of 2000?

A. As stated in HELCO's February 3, 2006 AOS Report, HELCO's firm power capability has been increased to 271,900 kW net. As discussed in HELCO T-4, the Company has implemented the following changes to its original year 2000 system plans:

- HELCO has increasingly relied on older generating units that it originally expected to retire or operate at reduced levels.
- Shipman 3 and 4 were not placed on cold-standby status, but instead were operated as intermediate units during HEP's initial operation in combined cycle operation. For a brief period of time, Shipman 3 and 4 then were placed in cold standby. With the load growth and capacity issues with PGV, Shipman 3 and 4 were taken out of cold standby and placed on warm standby, with periods of operation as required to maintain loss of largest unit margin. Given the current differences between the lower cost of

medium sulfur residual fuel oil (burned at Shipman) and diesel oil, HELCO operates Shipman 3 and 4 are now operated two shifts a day as intermediate units.

- Puna Steam Plant was not placed on warm-standby status, but instead has been and will continue to be maintained and operated as a baseload unit.
- Production O&M expenses have increased proportionally. More operators are required to sustain operations of HELCO's generating units. Maintenance costs have also increased since all firm power generating units require more comprehensive maintenance attention during planned outages. HELCO has implemented overhaul maintenance plans for all units, including the diesel generators.
- The Generation Asset Management ("GAM") program is being implemented to improve the reliability (i.e., reduce forced outages and number of failed starts of peaking units) of HELCO's older generating units. I will discuss the GAM program in detail later in my testimony.

Q. How does the increased reliance on HELCO's units impact other production O&M expense?

A. Other production O&M expenses have increased as units operate online more hours and wear faster. Consequently, variable operating expenses increase in proportion to operating hours and maintenance expenses increase as more wear and tear is experienced. The increase is reflected in O&M expense labor and non-labor categories. The increase is also reflected in the GAM Program costs, discussed later in my testimony.

Q. What has been the impact on other production O&M labor?

A. Production O&M labor has been impacted in three ways:

1) Increased O&M personnel at the recently expanded Keahole Generating Station to support operations two shifts per day, seven days per week. This has already occurred in late 2005.

2) Increased Hilo-based maintenance personnel to support increased operating hours for HELCO's firm power and as-available generating units in East Hawaii. This has already occurred in early 2006.

3) Increased operating personnel assigned to Shipman Power Plant to support Shipman 3 and 4 operations up to 14 shifts per week. This is in progress, mostly done, and is expected to be completed by May 2006.

I will discuss staffing in greater detail in the sections on other production operations labor expense and other production maintenance labor expense below.

Q. How will other production O&M non-labor expense be impacted?

A. Other production O&M non-labor expense will increase due to the need for outside services to supplement the workforce and provide specialized skills and services (e.g., generator, turbine and environmental consulting services).

HELCO'S IMPROVED RELIABILITY RESULTS

Q. How does HELCO assess the reliability condition of its generation system on a daily basis?

A. Each morning, HELCO estimates its peak load demand and compares this value to the firm capacity that will be available for dispatch on the system at the time of peak load demand. The difference is referred to as the "system margin." The reliability condition is labeled:

- GREEN if the system margin is greater than the capacity of the largest generating unit operating on the system that day,
- AMBER if the system margin is greater than zero but less than the capacity

of the largest generating unit operating on the system that day, and

- RED if the system margin is less than zero, indicating a generation shortfall at the daily peak and the potential for rolling blackouts.

Q. How has HELCO's system margins compared in recent years?

A. HELCO-513 presents a summary of the HELCO System Margins for 2003, 2004, and 2005. In 2003, there were numerous days of high risk, that is, reliability conditions AMBER and RED. In 2004, the number of AMBER days was significantly reduced and the red condition eliminated. In 2005, there were no AMBER or RED days, only GREEN days. This was due to a combination of factors including: restoration of PGV capacity to 30 MW, the additional capacity installed at Keahole Generating Station, and improvements in the forced outage rate (FOR) and availability factor (AF) from the latter portion of 2004 through 2005. Also shown on HELCO-513 are the annual peak load demand and the HELCO system capacity (with all firm power units being available). There was an increased firm capacity over the 3-year period of 15MW, and a corresponding increase in annual load demand of about the same amount. Nevertheless, the record indicates substantial improvements in daily reliability conditions in 2005. These improvements are not due to added capacity margin (or reserve margins) but are due to improved reliability of the operating units in the HELCO generating fleet. This conclusion is supported by a review of the reliability metrics for these years.

Q. What other metrics does HELCO use to measure the reliability of its generating units?

A. HELCO uses standard industry reliability metrics to measure the reliability of the generating units on the HELCO grid, including: Availability Factor ("AF"),

1 Equivalent Availability Factor ("EAF"), Forced Outage Rate ("FOR"), and
2 Equivalent Forced Outage Rate ("EFOR"). These are standard measures of
3 generating unit reliability which are regularly reported to the National Electrical
4 Reliability Council ("NERC") and compared with similar oil-fired utilities.
5 Q. What does AF measure?
6 A. AF measures the time a generating unit is capable of providing service, whether
7 or not it is actually is in service. This measure is expressed as a percent
8 available of the period under consideration. This measure does not take into
9 account if there is any deration in the capacity of the unit. It is considered
10 available if it is available at any capacity.
11 Q. What does EAF measure?
12 A. EAF measures the time a generating unit is capable of providing service at full
13 capacity, whether or not it is actually in service. The difference between AF and
14 EAF is that the latter includes a measure of the available time the unit is at
15 reduced capacity that is, "derated." The missing capacity is converted to a
16 reduction in available time.
17 Q. What does FOR measure?
18 A. FOR measures the percentage of time a generating unit is forced out of service
19 for emergency reasons. This percentage excludes the time during which the unit
20 experiences a planned service shutdown (i.e., scheduled maintenance). This
21 number reflects a facility's reliability.
22 Q. What does EFOR measure?
23 A. EFOR measures the percentage of time a generating unit is forced out of service
24 or is unable to produce full capacity for emergency reasons. The difference
25 between FOR and EFOR is the latter includes a correction for the period of time

1 the unit is available for service but at a reduced capacity, that is, "derated." The
2 missing capacity is converted to an increase in forced outage hours.
3 Q. What were the results of the AF and FOR data for 2002 through 2005?
4 A. HELCO-514 presents a summary of the Availability Factor (AF) and Forced
5 Outage Rate (FOR) for the HELCO generating units for 2004 and 2005,
6 HELCO-515 shows results for 2005, HELCO-516 shows results for 2004,
7 HELCO-517 shows results for 2003, and HELCO-518 shows results for 2002.
8 HELCO-514 illustrates significant improvement in reliability for 2005
9 compared to 2004, particularly in the Forced Outage Rate. Comparisons
10 between 2005 and earlier years show more pronounced levels of improvement.
11 Q. How does the improved reliability benefit the customer?
12 A. Low forced outage rates and high availability factors minimize the potential for
13 customer service interruptions. Further, greater availability of generating units
14 reduce the likelihood of extended outages to customers when the cause of the
15 outage is underfrequency load shedding due to loss of generation. If there is a
16 loss of generation on the grid causing underfrequency load shedding, the
17 duration of the outage to customers is of shorter duration if there is more
18 generation available offline, particularly if the standby generation is capable of
19 coming online quickly, and there are no startup failures when these generators
20 go online.
21 Q. How does improved generation reliability affect the System Average
22 Interruption Frequency index (SAIF)?
23 A. Improved forced outage rates and generation availability result in fewer
24 occasions of underfrequency load shedding and less potential for generation
25 shortfall. This will result in fewer customer interruptions, reducing the

1 component of SAIF that is attributable to generation interruptions, and tending
2 to reduce SAIF overall.
3 Q. How does improved generation reliability affect the Customer Average
4 Interruption Duration index (CAID) index?
5 A. Outages resulting from generation events are of short duration – only lasting as
6 long as it takes to bring online the standby generation in the case of
7 underfrequency load shedding; or in the case of generation shortfall, lasting as
8 long as the outage duration allocated for each circuit during a rolling blackout.
9 Transmission outages often require personnel to travel to the problem location
10 and make repairs, and thus typically longer average duration. Improved
11 generation reliability can result in a shorter CAID for those outages related to
12 generation loss; but there will be fewer generation-related outage events with
13 improved reliability. Thus the overall CAID index including both transmission
14 and generation outages may actually increase with improved generation
15 reliability since a smaller proportion of the outage events are the shorter
16 generation-related outages. Refer to the testimony of Mr. Jay Ignacio, at
17 HELCO T-6, for further discussion of related CAID and SAIF statistics.
18 REASONS FOR RELIABILITY IMPROVEMENTS
19 Q. Why were HELCO's AF and FOR statistics better in 2005 than in the previous
20 years?
21 A. HELCO's AF and FOR statistics were better in 2005 for two primary reasons:
22 (1) the Keahole CT-4 and CT-5 units were operational throughout 2005 and
23 exhibited excellent reliability in their first full year of operation on the system;
24 and (2) reliability of HELCO's older generating units were significantly
25 improved due in large part to the completion of certain GAM projects and

increased maintenance personnel. The resulting plant improvements and preventive maintenance measures reduced the number of equipment failures and unplanned maintenance occurrences and increased the amount of time HELCO's units were available for operation. I will discuss the impacts of the Keahole generating units, the GAM programs and other improvement factors below.

Keahole Generating Station

Q. What HELCO personnel are assigned to the Keahole Generating Station?

A. There are six operators, seven maintenance personnel, and three supervisors permanently assigned to the Keahole Generating Station. In addition, there is one Warehouse Attendant (from the T&D Department) and one Safety Administrator (from the Administration Department) permanently assigned to the facility. The facility is also supported by HELCO Production staff that is based in Hilo, including supervisory, engineering, and maintenance personnel.

Q. What are the operating hours of the Keahole Generating Station?

A. The facility is scheduled to operate from 6:00AM to 10:00PM each day with two operators on site. The facility can be operated 24 hours per day but this would require personnel to work on an overtime basis from 10:00PM to 6:00AM. In an emergency, the facility may be remotely operated from the System Operations Center in Hilo

Q. What generating units are located at Keahole?

A. The generating units located at Keahole include three combustion turbine units (CT-2, CT-4 and CT-5) and three diesel generators (D21, D22, and D23).

Q. Describe the significance of the Keahole Generating Station's power generation for the island of Hawaii.

A. The Keahole Station has been operating since 1973. It has a combined

generating capacity of approximately 65 MWs. Each of the units is firm and dispatchable at anytime unless they are on planned or forced outage. The Keahole Generating Station serves approximately 35% of the island-wide demand and up to 75% of the demand in West Hawaii. Keahole is at a location critical to the power stability and quality of HELCO's electric grid. It provides generation near the demand center in Kailua and thus helps sustain voltages in West Hawaii within acceptable tolerances. Generation at Keahole also relieves the necessity to transmit electricity from power plants in East Hawaii which results in lower transmission losses and lower operating currents on the transmission lines. Discussion regarding transmission losses and operating currents on the transmission lines is included in the testimony of Mr. Jay Ignacio, HELCO T-6.

Q. When were the most recent additions commissioned at the Keahole Generating Station?

A. CT-4 became commercially available on May 25, 2004, and CT-5 became commercially available on June 30, 2004. The related costs of the Keahole expansion are included in the testimony of Mr. Clyde Nagata, HELCO T-14, and Mr. Ken Fong, HELCO T-15.

Q. What do CT-4 and CT-5 add to HELCO's firm generation capacity?

A. CT-4 and CT-5 add approximately 44 MW to HELCO's firm power capacity units. However, as a condition of the CT-4 and CT-5 air permit, HELCO retired diesel engines D18, D19, and D20 prior to operation of CT-4 and CT-5. The retirement of these units reduced HELCO's firm power capacity by 7.5 MW. In addition, coincident with HELCO's successful commissioning of CT-4 and CT-5 in mid-2004, the purchase power agreement with HCPC for 22 MW was

terminated on December 31, 2004. In summary, the net increase to HELCO's firm capacity as a result of these combined actions was approximately 14.5 MW.

Q. Provide an example of a situation that signifies the need for the Keahole Generating Station expansion.

A. On September 12, 2002, HELCO experienced a generation shortfall and many customers had to be disconnected for a short period. During this incident, PGV was generating 5 MW instead of 30 MW, HEP was generating 28 MW instead of 60 MW, and HCPC (a former IPP) had a forced outage and was generating 0 MW instead of 22 MW. The IPPs were scheduled to produce a total of 112 MW but only delivered 33 MW to the system, a shortfall of 79 MW. This, in addition to a failed start at Puna CT-3 (a gas turbine rated at 21 MW), resulted in a generation shortfall and an interruption of service to HELCO's customers. If Keahole CT-4 and CT-5 were available the situation would have been avoided.

Q. Did CT-4 and CT-5 perform reliably during its first 18 months of operation?

A. Yes. CT-4 and CT-5 performed well during the first 18 months of operation. Of particular value to HELCO was that CT-4 and CT-5 experienced relatively few unit trips during their first 18 months of operation. As shown in HELCO-520, CT-4 and CT-5 experienced a total of 21 trips for its first 18 months of commercial operation (July 2004 through December 2005). By comparison, the two HEP combustion turbines, which are also LM2500 units, experienced 40 trips during its first 18 months of commercial operation.

Q. Please further explain the value of CT-4 and CT-5 to HELCO's reliability.

A. The additional capacity from CT-4 and CT-5 has enabled HELCO and the IPPs

to schedule critical maintenance outages on their units, while still maintaining the margin required for reliable service. For example, without the additional capacity from the Keahole expansion, HELCO would have reported negative loss of largest unit margin on 42 days in 2005, Condition AMBER. HELCO would have had to delay critical maintenance outages, operated Shipman plant more often, and would have been vulnerable to generation shortfall without the additional capacity provided by the Keahole expansion. This additional capacity is especially important to cover for maintenance outages of the HEP combustion turbines and PGV. Without the additional Keahole capacity these IPPs would be restricted to taking outages during the minimum load months of May and June. This is true because of the way system load demand varies throughout the year. There would only be sufficient margins in the early summer months to accommodate planned or maintenance outages for the largest IPPs if not for CT-4 and CT-5.

Q. Describe how the Keahole Generating Station contributes to lower transmission system losses.

A. The Keahole Generating station is located on the West side of the Big Island. Most of the generating resources are located on the East side of the Big Island while the customer demand is split between East and West sides of the island. Because of this, most of the power flow on the transmission system is from East to West Hawaii. This creates waste heat energy on the transmission system which is proportional to the square of the ampere flow on the transmission lines. The production of power at Keahole results in reduced ampere flow on the transmission lines and significantly reduced losses. The specific amount of transmission losses saved by Keahole generation is highly dependent upon

system load and the dispatch of the other generating resources on the system. For certain configurations, however, bringing a Keahole unit online can result in reduction of 2 MW of system losses for the first 10 MW of power into the system. Reactive power produced at Keahole supports local voltages and also tends to reduce ampere flow on the transmission lines, further reducing system losses.

Q. Describe how the Keahole Generating Station contributes to improved transmission reliability on the HELCO grid.

A. The additional firm power generating capacity at Keahole Generating Station is critical to support West Hawaii voltages and maintain electric current (i.e., ampere flow) within the rated limits on several major transmission lines. HELCO frequently dispatches the units at Keahole Generating Station to protect the system during planned and unplanned transmission line outages, and to maintain voltages and line current loading to within acceptable limits following a contingency. The following are examples of how generation at Keahole improves transmission reliability:

1) Provides voltage support during outages of 7700, 7600, 6300, 7100, 9100, 7300, 7400 transmission line outages. (Refer to HELCO-606.)
2) Prevents ampere flow overloads of the 7300, 7200, and 6800 transmission lines for single line contingency.
3) Allows closure of the 7700 transmission line. If HEP is dispatched at full load (which is typical under daytime loading conditions) and the 7700 transmission line is opened, the line cannot be closed without Keahole Generating Station having at least one combustion turbine online. This depends on load at the time as well as what other generating units are online.

It may also be necessary to reduce HEP output as well. This is due to the large phase angle difference created between the two ends of the 7700 line when it is opened.

4) Reduces system risk due to a second contingency on the transmission system when other critical transmission lines are out of service for planned or unplanned reasons. The HELCO system is presently at increased risk of line overload, abnormal voltages, low frequencies, and islanding of generation when any of several lines (including the 7700, 9100, 7100, 6600, 6300, 9600, 8600, 7600, 8200, 6800, 7300, and 7200 transmission lines) are out for maintenance or unplanned contingencies.

Operating generation at Keahole (the CT-4, CT-5 and/or CT-2 units) for reliability purposes, even if they are not the lowest-cost dispatch, helps to address these transmission system risks.

Q. Please identify specific instances when HELCO has used Keahole generation to increase grid reliability?

A. There are many instances when HELCO has dispatched generation at the Keahole Generating Station for purposes of grid reliability. Examples from 2005 include:

1) Keahole generation was operated until the early morning hours of December 19, 2005 during an unplanned outage of the 7600 line. This outage was the result of trees contacting the line during windy conditions.

2) Keahole generation was operated until the early morning of December 14, 2005 to allow a planned maintenance outage on the 7100 and 9100 lines. This was required to keep the 6800 line below the normal current rating of 270 amps during the outage and protect against possible voltage collapse

should the 6800 line fail.

3) Keahole generation was incrementally dispatched on December 2, 2005 to allow maintenance of the 8500 line.

4) Keahole generation was incrementally dispatched on November 27, 2005 to permit maintenance outages on the 7100 and 9100 lines. This was required to keep the 6800 line below the normal rating of 270 amps during the outage and protect against possible voltage collapse should the 6800 line fail.

5) Keahole generation was incrementally dispatched on November 22, 2005 to allow maintenance of the 6800 line.

6) On September 29, 2005, HELCO dispatched Keahole generation while it opened the 7700 line for maintenance. The switching was scheduled during a HEP planned outage to minimize the risk line loss. During the outage of the 7700 line, the 6600 line unexpectedly tripped due to a fault. The generation at Keahole enabled the system to survive the double outage of the 7700 and 6600 lines without experiencing unacceptable voltages and high line overloads. At the time, the two transmission lines that pass through the Saddle Road between Mauna Kea and Mauna Loa provided the only cross-island ties on the grid.

7) On September 27, 2005 incremental Keahole generation was dispatched for maintenance of the 7700 line.

8) Keahole generation was required for maintenance of the 8800 line on September 6, 2005.

9) On July 24, 2005, Keahole generation was required to support the system during an unplanned outage of the 7600 line. Later that day, an incident occurred causing the loss of the 7600, 7400, 9200, 8400 and 7800 lines.

Keahole generation was a key to protecting the system during this outage.

10) On July 22, 2005, Keahole generation was required and operated beyond normal shutdown to protect the system during a wild fire that threatened the 7200 line. This was required to protect the 7300 line from overload should the 7200 line open. Earlier the same day, Keahole generation was required to support the system during a maintenance outage of the 6600 line.

11) On July 18, 2005, Keahole generation was required to avoid overload of the 7200 line during a switching order on the 7300 line.

12) Keahole generation was required on July 14, 2005 to support the system, and operation extended beyond normal hours, during an emergency maintenance outage of the 8200 line to repair an overheating bus disconnect. This was required to reduce potential overload of the 6800 line in the event of a trip on the 8100 line.

13) Keahole generation was required to support 6600 line switching on May 27, 2005.

14) Additional Keahole generation was dispatched and the hours of operation extended through the night to support the system for an unplanned outage of the 8500 line due to a fault on April 26, 2005.

15) On February 28, 2005, Keahole generation was required to provide system protection during maintenance of the 8500 line. While the 8500 line was open, the 7600 line opened due to a fault. Due to Keahole generation being online, the system was able to survive the double line contingency and the 7600 line automatically reclosed.

16) Keahole generation was required to support switching of the 6600 line on January 25 and 26, 2005.

1 Generation Asset Management ("GAM") Program

2 Q. Please describe HELCO's GAM program.

3 A. HELCO's GAM Program is a combination of projects and maintenance
4 activities specifically organized and implemented to improve the reliability of
5 HELCO's firm power generating units.

6 Q. Please explain the genesis of the GAM program?

7 A. As discussed above, HELCO recognized that in contrast to its expectations at
8 the end of 2000, it would have to rely on its entire generating fleet, including the
9 older generating units to a much greater extent than previously forecasted. This
10 dependence on the older generating units would continue for many years. Thus,
11 it commissioned Sargent & Lundy to prepare an engineering study ("GAM
12 study") to determine the work requirements to enable HELCO's older units to
13 operate reliably into the future. Based on this study and HELCO's own
14 experiences with an assessment of its generating system, the HELCO
15 Production Department launched the GAM program in 2003.

16 Q. What are the specific objectives of the GAM program?

17 A. The objectives of the GAM program are to: improve the reliability of HELCO's
18 generating units, reduce the forced outage rates and increase availability factors
19 of individual generating units and the system as a whole; reduce the number of
20 failed starts of the diesel engines and CT-1 (the units used to restore generation
21 when a large unit trips and there is an underfrequency event), and reduce the
22 number of unit trip occurrences.

23 Q. What time period does the GAM Program cover?

24 A. Projects are spread over the 2003-2008 time period. At the end of 2005, the
25 GAM program was over 50% complete.

Q. Please provide specific examples of GAM program initiatives.

A. The following are examples of GAM program initiatives:

- Installation of new control systems and the overhauling and refurbishing of two diesel engine units per year in 2003, 2004, and 2005 directly reduced the number of failed starts and the number and duration of forced outages.
- Replacement of Shipman 3 and 4 boiler water wall tubes reduced the number and duration of forced outages due to tube leaks.
- Replacements of worn pumps and motors at Shipman 3 and 4 reduced the number and duration of forced outage due to ancillary equipment failures.
- Increases in the spare parts inventory shortened the duration of the forced outages.
- Increased maintenance of CT-1 combustion, electrical, and controls equipment reduced the number of failed starts and the duration of forced outages.
- Replacement of electrical switchgear at Shipman 3 and 4 reduced forced outages attributable to electrical problems.
- Rehabilitation of the Puueo Hydroelectric power plant
- Preventive measures on equipment prone to failure to reduce the forced outage rate and improve availability including:
  - Major turbine generator inspections and repair for Shipman 3 and 4;
  - Combustion turbine controls upgrade at CT-3, CT-4, CT-5 (completed in late 2005); and
  - Replacement of electrical switchgear, auxiliary transformer, and the motor controls at Hill Plant.

Q. What are the total GAM program costs for years 2003 through 2008?

A. The total GAM program costs for years 2003 through 2008 are as follows:

Capital	$18.2 Million
O&M	$17.4 Million
Total	$35.6 Million

The capital expenses do not represent plant adds in any given year alone. Projects are either completed in a given year or ongoing.

Q. What GAM program costs are in the test year 2006?

A. The GAM program costs in the 2006 test year are as follows:

Capital	$3.7 Million
O&M	$1.0 Million
Total	$4.7 Million

The capital expenses do not all represent plant adds in 2006. Projects are either completed in 2006 or ongoing into 2007 and beyond.

Q. What are examples of projects covered under the GAM program?

A. Examples of some of the larger capital projects and the associated costs for the 2003-2008 periods include:

- Shipman 3 and 4 Water Wall Replacement $2.4 Million
- Shipman Controls Upgrade $1.6 Million
- CT-3, CT-4, CT-5 Controls Upgrade $1.7 Million
- Puueo Hydro Rehabilitation $2.1 Million

Examples of some of the larger O&M projects include:

- Diesel Engine Overhauls $1.1Million

Q. What capital initiatives do these test year costs cover and provide costs for each.

A. Examples of some of the test year capital initiatives include:

- Hill Plant Demineralizer** $0.7Million

- Shipman Controls Upgrade $0.4 Million
- Shipman Plant Lighting $0.1 Million
- Shipman Operator Enclosures** $0.1 Million
- Puna Boiler Controls and Instrumentation $0.1 Million

Projects noted with "**" are plant adds in the test year. The others are not scheduled to be completed until a later year, and do not impact test year revenue requirements.

Q. Give an example of how the completed GAM projects (namely timely overhauls and general inspections) improved startup reliability of diesel generators and combustion turbines?

A. On May 16, 2005, CT-3 tripped at 9:51 a.m. resulting in the sudden loss of four (4) under-frequency circuits affecting approximately 6,000 customers. The system operator responded by issuing a fast start signal to all diesel engines not already online and CT-1. All 5 diesel engines on standby and all four dispersed units, as well as CT-1, came online with the initial start command. This successful startup of the standby diesels and CT-1 resulted in the timely restoration of service.

Other HELCO Initiatives to Improve Reliability

Q. What other initiatives has HELCO implemented to improve the reliability of its generating assets?

A. HELCO (1) investigated the benefits of fuel additives, (2) reorganized its maintenance division, (3) increased its critical spare parts inventory, (4) increased critical training of its personnel, (5) initiated an Asset Optimization ("AO") program, and (6) hired more maintenance personnel.

Q. Please describe the fuel additive investigation.

A. HELCO tested and qualified alternative fuel additives for use at Puna Steam, Hill 5, and Hill 6. The alternative, magnesium-based fuel additive is expected to significantly reduce the number of scheduled outages (to water wash the boiler internal surfaces) from approximately four per year per unit to two per year per unit. The water washing cleans ash deposits that otherwise catalytically convert sulfur from the fuel to SO3. The SO3 can result in high stack opacity and thus the fuel additives (and boiler water washings) assure compliance with environmental regulations (which are discussed below).

Q. Please describe the other initiatives that resulted in improved reliability.

A. HELCO implemented several other changes and new initiatives in the past three years that have contributed to its improved reliability, including:

1) The HELCO Production Maintenance Division was reorganized in 2002. The new organization is divided into two groups: (1) Steam and Hydroelectric Units; and (2) Combustion Turbine and Diesels (CT&D). Each group contains supervisory and craft personnel (i.e., electricians, mechanics, and instrumentation technicians). Each group is responsible for selected generating units of different types. The maintenance personnel develop a higher degree of specialization and familiarity with the generating units for which they are responsible, and as a result, perform maintenance work more efficiently and accurately over time.

2) HELCO increased the Production Department's inventory of spare parts, tools, and diagnostic test equipment. I will discuss the expense for spare parts inventory later in my testimony. The Asset Optimization program (discussed below) provides additional tools, test equipment, and analytical software for maintenance purposes. Other tools and test equipment

purchases are a capital expense, and are covered in the testimony of Clyde Nagata in HELCO T-14. This has resulted in more timely repairs of malfunctioning equipment and predictive maintenance (PdM) assessments of operating equipment.

3) The training budget (HELCO-521) for operations and maintenance personnel was increased over prior years to raise the level of proficiency of the HELCO staff.

4) HELCO initiated an Asset Optimization ("AO") program.

5) HELCO hired more full-time maintenance personnel.

Q. What is HELCO's AO program?

A. HELCO's AO program is a multiple-phase activity to evaluate its maintenance practices, identify the critical equipment components at each of its generating units, and develop optimal maintenance techniques, procedures, and resources for maintaining the condition of the critical equipment components. For Phase 1 of the AO program, HELCO utilized consultants from Emerson Process Controls ("EPC"), subject matter experts in maintenance and work process management to conduct such an evaluation. Phase 1 concentrated on HELCO Production's generalized maintenance work practices and the critical equipment components at its five steam-electric units and was completed in 2005. HELCO-522 provides EPC's Asset Optimization final project report.

Q. Why did HELCO initiate the AO program?

A. In 2002, more than 90% of HELCO's maintenance activities consisted of corrective maintenance ("CM", i.e., repair of equipment that unexpectedly broke or malfunctioned) and annual planned outages (e.g., annual overhauls and inspections). HELCO devoted less than 10% to preventive maintenance ("PM")

and predictive maintenance ("PdM")[1]. A maintenance assessment was performed by EPRI Solutions for the HELCO Production Department in 2003. The EPRI Solutions assessment suggested that for generating systems like HELCO's, PM and PdM should constitute the majority of the maintenance activities (HELCO-528). This would improve the reliability of the individual generating units and the system as a whole. As a result, HELCO initiated the AO program to review its maintenance practices with the goal of ultimately shifting its efforts from CM to increased PM and PdM.

Q. What were the objectives of Phase 1 of the HELCO AO program?

A. The objectives were multifold, including:

1) Evaluation of the existing maintenance practices and procedures;
2) Evaluation of the work process management system;
3) Classification of equipment components at Hill 5, Hill 6, Shipman 3, Shipman 4, and Puna Steam, and review of historical maintenance practices for each;
4) Identification of the most critical equipment components (from the listing developed in (3) above), and assessments of the condition of each utilizing PdM diagnostics techniques;
5) Modification of HELCO's Ellipse software used for work process management from the subsystem level to the equipment component level;
6) Development of recommended PM and PdM for each equipment component (from the listing developed in (3) above);
7) Development of recommendations for improved work process management,

[1] Predictive Maintenance (PdM) is that maintenance based on a conditional assessment of the equipment. Tests and measurements implemented to assess the condition of equipment are referred to as PdM tests and measurements.

1 improved outage and project planning, organizational changes, and
2 improved utilization of HELCO and contract resources;
3 8) Development of recommendations for immediate repair or replacement of
4 most critical equipment components that were found to be worn or at risk for
5 near-term failure; and
6 9) Production of a report summarizing all aspects of the work performed and
7 recommendations made.
8 Q. Has HELCO followed through with any recommendations from the Phase 1
9 report?
10 A. Yes. HELCO has followed through on many of the recommendations,
11 including:
12 1) Continuation of PdM diagnostic measurements of critical equipment
13 components on a time basis recommended by EPC;
14 2) Replacement or repair of critical components that were prone to failure;
15 3) Deferral of planned maintenance on critical components that were found to
16 be in good condition by PdM diagnostic testing;
17 4) Approval and recruitment for an additional Resource Planner within the
18 HELCO Production Department who would be primarily devoted to
19 maintenance planning and PdM activities;
20 5) Training of HELCO O&M personnel on the increased utilization of turbine
21 PdM supervisory instrumentation (i.e., vibration and temperature
22 monitoring instrumentation on rotating machinery); and
23 6) Implementation of Phase 2 of the Asset Optimization program.
24 Q. What is Phase 2 of the Asset Optimization program?
25 A. Phase 2 of the Asset Optimization program commenced in late 2005. In

Phase 2, consultants from EPC are being utilized to facilitate the refinement and improvement of HELCO Production Department's work practices and work process management system for planned outages (i.e., major overhauls of steam-electric generating units) and major projects (HELCO-528). Phase 2 will continue through 2006.

MAINTAINING SYSTEM RELIABILITY, SAFETY AND ENVIRONMENTAL CONTROLS IN THE TEST YEAR

Q. Please describe the different types of maintenance activities performed at HELCO.

A. HELCO manages the reliability and efficiency of its aging generating units through a complex process of identifying, categorizing, prioritizing and planning maintenance and project work. As stated earlier, maintenance work is classified as Preventive Maintenance ("PM"), Predictive Maintenance ("PdM"), or Corrective Maintenance ("CM"):

1) Corrective Maintenance - CM is also commonly referred to as "breakdown maintenance." CM often involves derating of the unit or a forced outage to perform corrective maintenance to repair or replace equipment that failed in operation.

2) Preventive Maintenance - PM is work that is organized on a scheduled basis and may or may not require an outage. It is often time-based and performed on a calendar schedule or based on operating hours (e.g., replacement of filters).

3) Predictive Maintenance - PdM is work that is organized and executed based on the assessed condition of the equipment. PdM diagnostic testing is typically performed as a precursor for PdM maintenance (e.g.,

thermographic testing of breakers, lube oil analysis, or vibration testing of rotating machinery). If the PdM tests indicate the subject equipment to be in good condition, PdM maintenance may be deferred. Conversely, PdM tests may indicate the immediate or near term need for specific repairs up to and including equipment replacement.

The specific scope of the PM, PdM, and CM may require an outage to be executed. In recent years the overwhelming majority of maintenance activities at HELCO have been CM. The efforts and programs described earlier in this testimony are leading to a shift away from CM towards PM and PdM to increase the reliability of the generating system.

Q. Please explain the difference between Preventive Maintenance and Predictive Maintenance.

A. Both PM and PdM are accepted industry maintenance practices that are intended to maintain equipment reliability and performance while minimizing direct and indirect costs due to corrective maintenance. The difference between PM and PdM may be best illustrated by example. Examples of PM include daily lubrication checks on rotating pumps and motors, periodic greasing of traveling screen chains and sootblower drives. PdM is a condition-based maintenance technique where routine monitoring and analysis of specific operating parameters are used to determine when and what type of maintenance should be performed. Examples of operating parameters that are routinely monitored include rotating equipment vibration analysis, lubrication oil chemical analysis, ultrasonic analysis, online infrared thermograph surveys, and pump performance tests. State-of-the-art instruments and software are used to monitor and track the condition of critical pieces of equipment that may otherwise result in forced

outages or unit deratings

Q. Does HELCO Production Department perform any other type of maintenance?

A. Yes. Other types of maintenance that HELCO performs include infrastructure repairs, grounds keeping, and repairs to portable tools and equipment used to maintain the generating assets.

Q. You stated that certain types of maintenance work may require or involve an outage. Please describe the different types of outages.

A. The different types of outages are as follows:

1) Planned Outages ("PO"). Planned outages (e.g., overhauls or major inspections) are time driven and planned months to years in advance. The timing of overhauls is usually driven by the need to perform a boiler internal inspection to renew the boiler operating permit on steam units. Combustion turbine POs are primarily driven by projected service hours. Planned outages are relatively long duration outages lasting four to more than 12 weeks depending on the scope and require the equipment to be offline. The scope of work during an overhaul normally includes both PM and CM (e.g., backlog of maintenance work orders produced since last outage), and capital projects. The planned work is based, in parts, on Original Equipment Manufacturer ("OEM") and universal industry guidelines, superheater and high-energy piping life assessment studies, and long lead items identified for correction at future outages. The 2006 test year overhaul schedule shown in attachment HELCO-527 represents a normalized overhaul year, where generating units are scheduled for PO based on the criteria mentioned above.

2) Maintenance Outage ("MO"). Maintenance outages are short duration

outages generally lasting several days to a few weeks. These types of outages are scheduled when system reliability conditions permit the loss of available capacity while maintenance is in progress. Although MOs do not require an immediate shutdown, shutdown delays generally exacerbate the unit's condition (i.e., performance may deteriorate and cost for repairs may increase). MOs typically require CM. While the unit is down for CM, PM may also be performed if the schedules permits and resources are available. MOs are generally unforecasted, and depending on system reserve margins, may trigger a delay of POs.

3) Forced Outage ("FO"). Forced outages are immediate unplanned outages where the unit is either automatically (i.e., protective relay trip) or manually (i.e., operator initiated) shut down depending on the nature of the problem. This is the most costly outage because it requires an immediate diversion of resources, expedited ordering of parts, materials and services, repairs performed to completion often with high labor overtime and penalty costs and the operation of less efficient intermediate and/or peaking units to meet the regulating reserve and fast start criteria. HELCO performs less critical shutdown-required backlogged maintenance work if time permits and if needed parts and materials are available at the time of the outage.

Q. Are maintenance outages difficult to plan?

A. Yes. Power plants are made up of thousands of pieces of equipment, controls and infrastructure, and every component that makes up a power plant wears and fails at a different rate. Maintenance is performed to inspect, restore and/or repair worn or broken pieces of equipment to maintain operating performance

1 and reliability. As a power plant and its associated infrastructure age, the scope,
2 cost and schedule to maintain each component becomes more complex and
3 dynamic. To illustrate this, HELCO-525 and HELCO-526 show the planned
4 versus actual maintenance schedules for 2004 and 2005, respectively.
5 Q. Has HELCO previously explained its decision to maintain its existing units
6 rather than installing new generation?
7 A. Yes. The cost effectiveness of continuing to maintain existing generation and
8 keep it running rather than installing new generation and retiring existing
9 generation was studied in HELCO IRP-2, Docket No. 97-0349. In the HELCO
10 IRP Plan (1999 – 2018) 2004 Evaluation Report filed on March 31, 2004,
11 HELCO states on pages viii and 43:
12 "...HELCO anticipates installing Keahole ST-7 (and converting CT-4 and
13 CT-5 to a dual train combined cycle) in the 2009 timeframe, which
14 necessitates that various older generating units that were previously targeted
15 for retirement will no longer be retired. These older units are already
16 permitted and grid-connected so that they can mitigate some of the
17 uncertainty in the schedule for adding new generation. Also, a 5-year
18 generation asset management program has been implemented in 2003."
19 "...the aging units could not be retired due to the difficulties encountered
20 in adding new generation at Keahole. HELCO's experience has
21 demonstrated that obtaining permits for adding new generating capacity to
22 the system is extremely difficult. Therefore, the retirement of units that are
23 already grid-connected and permitted must be carefully considered.
24 Additional expenditures to keep the units operating reliably are often
25 warranted, with the need for expenditures being considered on a case-by-case

1 basis."

2 Q. What else has caused production O&M costs to increase?

3 A. Other factors that have caused production O&M costs to increase include the
4 following:

5 1) Rapidly growing demand into the foreseeable future (HELCO-507 through
6 510). As a primary example, higher load demand growth has lead
7 HELCO to the re-staffing of Shipman Power Plant in 2006 and budgeted
8 wages of $759,000 is included in 2006. Further, costs to refurbish
9 Shipman Plant (i.e., GAM and other) are reflected in Production O&M,
10 and are budgeted at approximately $654,000.

11 2) The need to increase staffing (discussed below) as part of an overall plan
12 (HELCO-535 through 539, 542, 543) to improve and maintain availability
13 and reliability of existing HELCO generating units.

14 3) The need to comply with increasing regulatory and environmental
15 requirements (HELCO-523) has contributed to the increase in other
16 production O&M expenses. Significant capital and O&M labor and non-
17 labor resources are required to comply with all regulations impacting the
18 operation and maintenance of HELCO's generating units and the disposal
19 of wastes generated from the process, and to ensure employee and public
20 safety. HELCO-523 illustrates the number of environmental regulations
21 affecting production and includes both State and Federal level compliance
22 and enforcement. Compliance with the Federal Occupational Safety and
23 Health Division ("OSHA") regulations supports employee safety. The
24 Company must also comply with other regulations such as those
25 administered and enforced by the Department of Transportation Office of

Pipeline Safety (for fuel pipeline maintenance and inspection) and the Department of Labor and Industrial Relations , Hawaii Occupational Safety and Health Division, Boiler and Elevator Inspection Branch (for boiler code compliance).

OTHER PRODUCTION O&M EXPENSE

Q. What is HELCO's estimate of its test year 2006 other production O&M expense?

A. HELCO's normalized test year 2006 estimate for production expense other than fuel and purchased power ("other production O&M expense") is $23,040,000 as shown in HELCO-529. Of this total, $9,587,000 is for other production operation expense and $13,453,000 is for other production maintenance expense, as shown on HELCO-530.

Q. What is included in other production O&M expense?

A. Other production O&M expense includes expenses incurred to ensure reliable, efficient, safe and compliant operation and maintenance of HELCO's five steam, five combustion turbine, 10 diesel generating units and four distributed generation units at five power plants and associated support facilities, as well as the non-firm units made up of four hydroelectric generators and one wind farm.

Q. Has the level of other production O&M expenses changed in recent years?

A. Yes. HELCO-524 shows that actual other production O&M expenses almost doubled from 1996 to 2005.

Q. What has caused the rise in other production O&M expenses?

A. There are a number of reasons, which are discussed later in my testimony. A major cause of the rise in these expenses was the increasing age of HELCO's generating units and the need to run them harder. In the industry, fossil fuel generating stations have traditionally been replaced every thirty years or so with

new units. Due to escalating construction costs, difficulties in securing new sites and new environmental compliance requirements, HELCO has recognized the economic and generating system advantages of continuing to maintain existing plants, particularly those units that provide ancillary services to the grid (i.e., load regulation, frequency regulation, voltage regulation, and regulating reserve). As shown in HELCO-502, the average age of HELCO steam units is 40.6 years, 30.4 years for HELCO diesel engines, 14.8 years for HELCO combustion turbine units, and eight years for HELCO distributed generation units. The age of the IPP facilities is 19 years for PGV and six years for HEP. Portions of the Shipman Power Plant infrastructure in use today date back to 1955. The Puna Power Plant infrastructure dates back to 1968. The relative increase in the scope of repairs and projects required for power plants and associated infrastructures, and the need for more comprehensive planned outages are, in part, attributable to the age of the units. Moreover, increased maintenance is required of the HELCO steam and combustion turbine units because these units are utilized for load regulation and system frequency control. This regulative duty places increased stress on these older units. As HELCO adds to its grid, more as-available power (e.g., wind energy) that does not provide load and frequency regulation, the duty and the associated maintenance requirements on the older units will increase.

Q. What HELCO departments contribute to other production O&M expense?

A. The majority of other production O&M expense is incurred by the Production Operations, Maintenance, and Technical Services Divisions, and the administrative staff in the Production Department. Other HELCO departments (such as the Distribution, Engineering, and Information Services departments)

1 contribute smaller amounts to other production O&M expense. Also included
2 are costs from HECO's Environmental Department, Generation Planning
3 Department, and Energy Services Department via intercompany billings. For
4 further discussion on intercompany billings, refer to the testimony of Mr. Paul
5 Fujioka, in HELCO T-9.
6 Q. Why do expenses from these HELCO and HECO departments go to other
7 production O&M expense?
8 A. These expenses are incurred for the efficient operation and maintenance of every
9 HELCO unit. The HECO departments provide functions that currently do not
10 reside with any department in HELCO. This allows HELCO to avoid costs
11 associated with setting up redundant departments within its own company.
12 Q. Please provide an example of a HECO department that contributes costs to
13 HELCO's other production O&M expense?
14 A. The HECO scientific laboratory provides testing of waste water and other toxic
15 substances for environmental disposal purposes. Intercompany billings of
16 $421,000 are budgeted in the test year to be incurred for the use of HECO's
17 Environmental Services. There is not enough laboratory related activity at
18 HELCO alone to justify having its own laboratory on the island of Hawaii.
19 Budget Preparation
20 Q. How did HELCO develop its other production O&M expense estimate for the
21 2006 test year?
22 A. The budget amounts were developed as part of the regular Company-wide
23 detailed budgeting and management review process from April to January 2006.
24 The planning and budgeting instructions and assumptions used in developing the
25 operating budget are provided at HELCO-WP-902. During the

1 process, detailed estimates of O&M expenses were prepared by line supervisors
2 and managers throughout the Company. The detailed estimates, called
3 responsibility area ("RA") budgets, were then summarized to produce the initial
4 2006 O&M expense budgets. HELCO recycled this initial operating budget
5 during August – January 2006, to update certain assumptions included in the
6 initial operating budgets for 2006.
7 Q. What adjustments are made to the Production accounts in the 2006 operating
8 budget to determine the test year estimates?
9 A. There are two forms of adjustments that may be appropriate: (1) budget
10 adjustments, and (2) normalization adjustments.
11 Q. What are the budget adjustments?
12 A. The budget adjustments applicable to the production accounts are discussed in
13 the next section of my testimony. Certain adjustments were made for rate case
14 purposes to reflect consistent assumptions in the rate case. For example, an
15 adjustment was made to Account No. 502210, for "Shipman Steam Expenses",
16 to reflect the shift of costs for start-up propane, which is to be included fuel
17 expense (refer to HELCO T-4). Refer to the testimony of Mr. Paul Fujioka at
18 HELCO T-9 for further discussion of budget adjustments.
19 Q. What are normalization adjustments?
20 A. These are ratemaking rather than budget adjustments. Normalization
21 adjustments are intended to make the test year results of operation more
22 representative of a normal, on-going level of operations, or of the operating
23 conditions that are expected to be in effect during the period that the rates set in
24 this docket will be in effect. For example, it may be appropriate to amortize an
25 unusual, non-recurring expense over a period of several years for ratemaking

purposes if rates are not adjusted on an annual basis.

Budget adjustments and normalization adjustments made to the Production accounts will be addressed below.

Budget Adjustments

Q. What is the effect of the budget adjustments on other production O&M non-labor expense for HELCO's 2006 test year?

A. The budget adjustments decrease the amount for other production O&M non-labor expense by $357,000 as shown in HELCO-532, Column C.

Q. What is the basis for the adjusted decrease in other production O&M non-labor of $357,000?

A. The $357,000 net decrease is the result of a $200,000 increase in other production operation non-labor and a $557,000 decrease in other production maintenance non-labor expenses. (See HELCO-532.)

Q. What makes up the other production operation non-labor adjustment?

A. The $200,000 increase in other production operation non-labor expenses is attributed to:

1	Outside Services - General	$	(100)
2	Hill Boiler Draw Engineering Docs		150
3	Shipman Boiler Draw Engineering Docs		100
4	Puna Boiler Draw Engineering Docs		50
5	TOTAL	$	200

Q. What is the basis for the Outside Services – General adjustment?

A. The decrease of outside services – general of $100,000 is not a true decrease in cost but rather a reclassification or shift of Shipman Plant start-up propane cost from the Production budget to HELCO's fuel inventory. (See HELCO-532.) Further discussion on this topic is covered by Ms. Lisa Giang in HELCO T-4.

Q. What is the basis for the Shipman, Puna and Hill Draw Boiler Engineering Documents adjustments?

A. The net $300,000 increase in Shipman, Puna and Hill Draw Boiler Engineering Documents is attributed to the fact that Shipman, Puna and Hill Plants currently do not have accurate Piping & Instrumentation Diagrams (P&ID). Sketches of plant's sub-systems have been made. These sketches do not graphically represent the entire plant's process piping and do not include instrumentation. P&ID's need to be developed to represent the plant's actual piping and instrumentation. These P&ID's will capture "what is actually out there" and may be used for project design engineering, operations and maintenance troubleshooting, process documentation, operator training, and documentation control. The need for this was identified after the budget was complete. A firm price was not received until early 2006. It should be noted that we are adjusting and seeking recovery for this P&ID project. It is further normalized as discussed in the section on normalization adjustments.

Q. What makes up the other production maintenance non-labor adjustments?

A. The $557,000 decrease in other production maintenance non-labor expenses is attributed to:

1	Predictive Maintenance Program	$ 18
2	Maintenance of DG Unit	(171)
3	Abandoned Capital Projects	1
4	Outside Services - Temp Help	62
5	Hill 6 Hydrogen Dryer & Controls	100
6	Hill 6 Boiler VFD Upgrades	150
7	CT-1 Low Smoke Fuel Nozzles	268
8	Waiau Penstock Repairs	150
9	Puueo Penstock Repairs	200
10	CT-2 Major Field Inspection 2006	(700)
11	Keahole WT HMI Replacement	25

12	CT-4 Hot Section	845
13	CT-4 LP Turbine Replacement	(50)
14	CT-5 Hot Section	(1,405)
15	CT-5 LP Turbine Replacement	(50)
16	TOTAL	$ (557)

See HELCO-532.

Q. What is the basis for the Predictive Maintenance Program adjustment?

A. The $18,000 increase in the Predictive Maintenance Program is to correct the contract amount that was originally budgeted for. The final agreed upon price was $18,000 more than originally budgeted. The proposal was not received until early 2006, after the budgeting cycle as discussed above.

Q. What is the basis for the disbursed unit maintenance adjustment?

A. The decrease of $171,000 for maintenance of a disbursed generation unit is due to the Waikoloa disbursed generation unit not being installed in 2006, as originally budgeted for. This cost is for the maintenance of the unit.

Q. What is the basis for the abandoned capital projects adjustment?

A. The increase of $1,000 for abandoned capital projects is the average of the last six years (2000-2005) of actual abandoned project cost write-offs to the Production Department. Refer to the testimony of Paul Fujioka at HELCO T-9 for further discussion.

Q. What is the basis for the Outside Services – Temporary Help adjustment?

A. The increase of $62,000 for outside services-temporary help is the net amount of actual (January 2006) plus updated production labor and contracted temporary help over the original budgeted amounts. Production plans to spend the additional amount on overtime to man Shipman Plant as well as on temporary

help contracted to fill in for the vacant maintenance positions. (See HELCO-WP-510, page 5.)

Q. What is the basis for the Hill 6 Hydrogen Dryer and Controls, Hill 6 Boiler VFD Upgrades, CT-1 Low Smoke Fuel Nozzles, and Keahole Water Treatment MHI Replacement adjustments?

A. The cumulative increase of $543,000 is a result of these projects having a change in scope to deem them incorrectly categorized as capital, as they originally were. Being that the projects are not a capital unit, they are O&M in nature, and have been reclassified to the O&M budget.

The Hill 6 Hydrogen Dryer and Controls represents a new hydrogen analyzer and purge control cabinet that would be purchased to replace the existing obsolete analyzer. Also a new hydrogen dryer system would be installed to filter and dry the hydrogen gas in the machine.

The Hill 6 Boiler VFD upgrades project will install VFD Upgrades for Hill 6. VFD, or variable frequency drive, is a part of the boiler fan system.

The current CT-1 fuel nozzles are outdated and cause reliability and environmental problems. This problem will be eliminated with the installation of these new low smoke nozzles. Identical modification has proven successful at other utilities.

The Keahole Water Treatment MHI Replacement project will replace the existing water treatment man-machine interfaces with Citect based computers ("PC"). The original DOS based PCs are slow and in the event that a PC fails, it cannot be repaired due to its vintage. The new system would be networked throughout the plant to the main control room to allow for full remote control of the water treatment system.

Q. What is the basis for the Waiau Penstock Repairs, and Puueo Penstock Repairs adjustments?

A. The cumulative increase of $350,000 for Waiau and Puueo penstock repairs are due to the immediate need for inspection and maintenance of the entire penstock right-of-ways (excluding the intake structures and pipeline within the powerhouse). This would include cleaning, repair and treatment of wooden trestle, and repair of air release vault components as necessary, as well as repairs to concrete trestles and anchors, if necessary. There is also a need to clear overgrowth from penstock right-of-ways and conduct a G.I.S. survey to determine exact location for maintenance access purposes and maintaining that access. The identification and scope of this work was not received until early 2006, which is beyond the budgeting cycle as discussed above.

Q. What is the basis for the CT-2 Major Field Inspection adjustment?

A. The decrease of $700,000 for the CT-2 Major Field Inspection ("MFI") is a result of the reanalysis and later downgrading in scope of this major field inspection. MFIs are required every 80,000 operating hours or 2,000 startups. The MFI for CT-2 was originally scheduled in late 2004, but was deferred to 2005 due to system constraints. The MFI scheduled in 2005 was divided into 2 parts (2005 and 2006) because critical materials were unavailable in 2005. This work will perform the second part and complete the MFI.

Q. What is the basis for the CT-4 Hot Section, CT-4 LP Turbine replacement, CT-5 Hot Section, and CT-5 LP Turbine replacement adjustments?

A. The net decrease of $660,000 for the above projects is based on actual operating hours of the units. It was originally thought that hot section maintenance was needed on CT-4 and CT-5 in the near future, certainly before the end of 2006.

This was proposed in the original budget, but the CT-4 hot section was subsequently deferred to 2007 due to financial considerations. The work has been competitively bid and the need to perform the hot section on both units has been reassessed. The prudent thing is to perform a hot section on CT-4 in 2006, and to install the chromalloy components for extended life (25,000 hrs vs. 8,000 hrs), and the same for CT-5 in 2007. The rate case assumptions, production simulation runs, and normalized overhaul schedule are all based on HELCO converting from 8,000 hr to 25,000 hour components. The outside contractor bid received to perform the hot section is for $844,000. Moreover, this work would include detailed (inside the engine) assessments of the LPT blading on both engines. The prior type of hot sections incurred costs of the $1.4 million dollar range.

Normalization Adjustments

Q. What is the effect of the normalization adjustments on other production expense for HELCO's 2006 test year?

A. The net effect of the normalization adjustments is to increase the amount for other production O&M expense by $95,000 as shown in HELCO-533, Column C.

Q. What is the basis for the $95,000 net increase due to normalization?

A. The $95,000 net increase is the result of a $194,000 decrease in other production operation non-labor expense and a $289,000 increase in other production maintenance non-labor expense. (See HELCO-533.)

Q. What is the basis for the other production operation non-labor normalization?

A. The $194,000 decrease in other production operation non-labor expense is attributable to:

1	Emissions Fee	$	(61)
2	Hill Boiler Draw Engineering Docs		(67)
3	Shipman Boiler Draw Engineering Docs		(47)
4	Puna Boiler Draw Engineering Docs		(20)
5	TOTAL	$	(194)

Q. What is the basis for the emission fees normalization?

A. The normalized emissions fees amount is based on taking 80% of the 2006 forecast amount for emissions fees totaling $306,000.

Q. What was the basis for taking 80% of the forecast amount for emissions fees?

A. Within the last 10 years (1995-2005), HELCO was granted waivers for two of the 10 years. The granting of waivers is not predictable. Thus, for ratemaking purposes, the normalized amount was based on taking 80% of the 2006 forecast amount to derive the 2006 TY normalization cost of $245,000.

Q. How does HELCO estimate this fee to vary in the future?

A. The fee is expected to vary with the consumer price index, and this has not materially impacted the 2006 estimate in any way.

Q. What is the basis for the Shipman, Puna and Hill Draw Boiler Engineering Documents normalizations?

A. The normalized test year estimate represents one-third of the estimated third party and HELCO labor and non-labor costs that will be incurred.

Q. How was the test year estimate for Shipman, Puna and Hill Draw Boiler Engineering Documents determined?

A. The estimated costs for this rate case proceeding are based on cost estimates or input provided by consultants retained by HELCO. The estimate is also based on an amortization period of three years. The initial work is expected to be completed in 2006. This is for work to prepare the initial drawings, and to have

them computerized. Yearly maintenance to keep the electronic filed updated will be ongoing.

Q. How was the three-year amortization period determined?

A. A three year amortization period is proposed because it is anticipated that the electric rates established by the Commission in this docket will be in effect for approximately three years. The timing of HELCO's next case could be influenced by the completion of generating unit ST-7 at Keahole, possibly in the 2009-2010 timeframe.

Q. What is the basis for other production maintenance non-labor normalization?

A. The $289,000 increase in other production maintenance non-labor expense is attributable to:

1	Disbursed Generation Unit Overhaul	$	150
2	Hill 6 Boiler Inspection		230
3	Ship 3 Boiler Inspection		42
4	Ship 4 Boiler Inspection		42
5	Puna CT-3 LP Turbine Replacement		65
6	CT-2 Major Field Inspection		(700)
7	CT-4 LP Turbine Replacement		65
8	CT-5 LP Turbine Replacement		65
9	Diesel Engine Overhaul #1		350
10	Waimea Fuel Tank Repairs		(20)
11	TOTAL	$	289

Q. What is the basis for disbursed generation unit overhaul, Hill 6 Boiler Inspection, Shipman 3 Boiler Inspection, Shipman 4 Boiler Inspection, Puna CT-3 LP Turbine Replacement, CT-2 Major Field Inspection, CT-4 LP Turbine Replacement, CT-5 LP Turbine Replacement, and diesel engine overhaul normalizations?

A. The normalized overhaul costs are consistent with the assumptions used in the production simulation run in Ms. Lisa Giang's testimony (HELCO T-4). Overhaul normalizations are explained on HELCO-WP-510. For instance, one disbursed generation unit overhaul will be performed every four years. A steam turbine overhaul is performed once a year. Shipman 3 and 4 units will be utilized much more than in the past and require an increased scope of overhaul than what was done previously. CT-3, CT-4 and CT-5 LP Turbine replacements will be performed every 10 years at an average cost of $650,000 each. And finally, two diesel overhauls are shown to occur on the normalized overhaul schedule; this was proposed in the original budget, but both were subsequently deferred to 2007 due to financial considerations.

Q. What is the basis for the Waimea fuel tank repairs normalization?

A. The normalized Waimea fuel tank amount is based on cost estimates or input provided by HELCO engineers. The estimate is normalized based on an amortization period of three years.

Budget	Norm/Adj	TY Est
$30	$(20)	$10

Q. How was the three-year amortization period determined?

A. A three year amortization period is proposed for same reasons discussed above.

Other Production Operation Expense

Q. What is the 2006 test year estimate for other production operations expense?

A. As shown on HELCO-534, the 2006 test year estimate for other production operations expense is $9,587,000. Of this total, $6,054,000 is for labor expense and $3,533,000 is for non-labor expense. Discussion of the Technical Services Responsibility Area (of the Production Department) is being included in the

1 other production operations expense.

2 Q. What was the basis for the test year estimate for other production operations
3 expense?

4 A. The test year estimate is based on the O&M expense budget for 2006, with the
5 budget and normalization adjustments mentioned above.

6 Other Production Operations – Labor Expense

7 Q. What is included in the other production operations - labor expense?

8 A. The other production operations - labor expense includes salaries and wages for
9 operator and non-operator costs.

10 Q. What operator costs are included in the other production operations - labor
11 expense?

12 A. Operator wages make up the majority of the operator costs in the other
13 production operations - labor forecast. The forecast also includes the expense
14 for supervision, plant operation, and training.

15 Q. What non-operator costs are included in the production operations - labor
16 forecast?

17 A. Non-operator costs in the other production operations labor forecast include
18 wages and salaries for operational maintenance labor required to keep the plant
19 and associated facilities operating safely, compliantly, efficiently and reliably on
20 a day-to-day basis; environmental services to meet regulatory requirements; and
21 power purchase contract administration.

22 Q. How was the labor expense for operator costs forecasted?

23 A. The operator cost was developed by identifying manpower and supervision
24 requirements to support: Hill 5, Hill 6 and Puna power plants and associated
25 facilities baseload operation 24 hours per day, seven days per week; Keahole

1 Generating Station intermediate and peak operation 16 hours per day (2 shifts),
2 seven days per week; and Shipman Power Plant intermediate operation 16 hours
3 per day (2 shifts) seven days per week. The labor forecast derivation also
4 includes non-productive wages to account for vacation, holidays and sick leave.
5 Q. How is the labor expense for non-operator costs forecasted?
6 A. Labor expense for non-operator costs is forecasted by the respective HELCO
7 departments based on the support required. For example, the Technical Division
8 of the Distribution Department normally tests and maintains protective relays in
9 the generating plants. The labor cost to provide this service falls under the non-
10 operator costs in the other production operations - labor expense.
11 Q. How does the 2006 test year other production operations - labor expense of
12 $6,054,000 compare with 2005 recorded?
13 A. The 2006 other production operations - labor expense is $1,695,000 or 38.9%
14 higher than the recorded 2005 amount as shown on HELCO-534.
15 Q. What was the increase attributed to?
16 A. The increase between the 2005 actual and 2006 test year is mainly attributed to
17 high overtime due to existing vacancies created from intra-departmental
18 transfers, and an increase in the operations staffing level to support 14 eight-
19 hour shifts per week at the Shipman Power Plant. Vacancies do not result in
20 reduced costs because the work has to be done, either by other employees
21 working overtime (see HELCO-536, 537, 538, 539) or contractors (see
22 discussion below). HELCO-535 provides a staffing level breakdown of the
23 difference between 2005 actual and 2006 test year for the HELCO Production
24 Operations Division. It shows that the number of employees in the division will

increase from the actual count of 58 at year end 2005 to 67 at the end of the 2006 test year for a net increase of 9 employees.

Q. Please explain the need for employee staffing level increases in test year 2006.

A. The staffing level increases in operations are necessary at this time due to (1) expansion of the Keahole Power Plant to provide west-side generation, (2) increased reliance on HELCO's older generation units that were not anticipated in the 2000 rate case, (3) investment to improve reliability of HELCO's generating units, and (4) the significant increase in customer demand. These all contribute to driving the need to increase the availability and operation of all intermediate and peaking units, and thus the need for staffing level increases. HELCO-508 and HELCO-509 illustrate the significant increase in peaking and intermediate unit service hours (actual operating time). Further, it is economically justified to operate Puna three shifts (base-load) and Shipman two shifts (per day) and CT-4 and CT-5 two shifts for economics and grid stability. Despite the manning proposed in the previous rate case, HELCO has always operated Puna 24 hours per day and had it manned accordingly. Shipman was made unmanned due to it being thought unnecessary to operate, but with present fuel prices and loads, it is in fact justified to operate two shifts. Keahole CT-4 and CT-5 did not previously exist. Service hours would not have increased at steam plants except for Shipman. It is less expensive to operate this number of shifts on straight time rather than overtime.

This trend is having the greatest impact on the Hill and Puna units, as these units are currently staffed to support three shifts, seven days per week (i.e., 24x7), and at the Keahole units, as these units are currently staffed to support two shifts, seven days per week (i.e., 16x7). The need for Hill and Puna staff to

man the Shipman units is incurred at 100% overtime. The vacancies due to intra-departmental transfers at Keahole have made it necessary to run the plant on much overtime. The operations labor overtime trends as shown in HELCO-536 are high at the Keahole, Puna and Hill power plants. The additional operators will help to reduce the overtime to more manageable and healthy levels as well as increase the respective Shipman unit availabilities to 14 eight-hour shifts per week. Shipman time is assumed to be performed on 10 shifts of straight time and 4 shifts of overtime. This trend is expected to continue into the foreseeable future.

Q. Identify what specific positions will be added to Production Department Operations Division in 2006 which were not budgeted for in 2005.

A. The Production Department Operations Division will add the following positions in 2006, which were not budgeted for in 2005:

(3) Shipman Control Operators

(6) Shipman Boiler Operators

Q. Identify what specific positions will be added to Production Department Operations Division in 2006 that were also budgeted for in 2005.

A. Production Operations had 58 employees at the end of 2005, has 65 employees as of April 30, 2006, and has assumed 67 employees for 2006. The Production Department Operations Division filled all positions which were budgeted for in 2005.

Q. Identify what specific position will be added to the Production Department Technical Division in 2006 which was budgeted for in the latter part of 2005.

A. The Production Department Technical Division will add one Resource Planner position in 2006.

Q. What was HELCO's basis for increasing staffing in the Production Department Operations and Technical Divisions in 2006?

A. The Operations and Technical Divisions are two separate divisions, but for discussion purposes, they are being discussed together. The approach used to determine staffing requirements was based on the following:

1) Replacements of vacancies attributed to retirements, resignations, job transfers and terminations. What's different today versus in the past is that to the extent plans for separations are known in advance, positions being vacated are requested and approved as soon as possible to provide as much lead time and/or overlap for transition as possible.

2) Analysis of actual overtime for 2004 (HELCO-537) year-end and 2005 (HELCO-538) year-end identified where high overtime was required to operate Shipman 3 and 4. These exhibits show the following responsibility areas: HGA-Administration, HGC-Keahole Operations, HGH-Hill Operations, HGK-Keahole Maintenance, HGM-Steam/Hydro Maintenance, HGP-Puna Operations, HGT-Technical, and HGX-Combustion Turbine/Diesel Maintenance. HGW-Shipman Operations will appear on the 2006 overtime reports as positions are filled. With the plan to operate Shipman 3 and 4 more in 2006 (and beyond) than in recent years, the Company has decided to hire additional operators and assign them to Shipman Power Plant.

3) Increasing key resources to address critical requirements. As recommended in Phase 1 of the Asset Optimization Program, the Company will add an additional resource planner 2006 to support

maintenance planning and increased Predictive Maintenance ("PdM") activities.

Q. Please provide the justification for increasing the staffing in the Production Operations and Technical Services Divisions by 9 people (16 percent) relative to 2005 levels.

A. As shown on HELCO-535, the addition of 9 people is cost effective and has been justified as follows:

1) The additional resource planner is required to more effectively plan and execute planned outages, and to increase the levels of predictive maintenance, as recommended in the GAM Study.

2) The additional operators at Shipman Power Plant are based on the expectation that the plant will be operated approximately 200 days per year to meet system load demand requirements and for economic dispatch. For the past five years Shipman Power Plant has been operated exclusively by operators from Hill Power Plant and Puna Steam Plant that work overtime. As indicated earlier, the overtime costs have been high. The Hill and Puna plants have incurred overtime percentages of 27% and 34% in 2005 (HELCO-536). Moreover, in 2005, HELCO has not been able to fill shifts by operators working overtime on a voluntary basis, even though the plant operated fewer days in 2005 than that anticipated for 2006 and beyond.

3) Maximizing the availability of all generating units means increasing the staffing levels at Shipman Station from 100% overtime to 14 eight-hour shifts per week to increase the availability of the Shipman units. Currently, the differential in fuel prices between diesel oil and medium

sulfur oil make it economical to run Shipman. However, it has been very difficult to man the plant from the existing operations staff working solely overtime. Scheduled operations of the units were unfortunately cancelled for this reason in 2005. The Shipman units were operating in 2005, but only when operators volunteered to staff the plant on an overtime basis, and it was not always possible. Further, in an emergency, the Shipman plant would be staffed before-shift (which is very expensive) either by volunteer operators or management, if necessary.

Q. Based on this current trend, what are the primary drivers for the need for staffing level increases and increased expense levels?

A. The staffing level increases and increased expense levels in operations (HELCO-535) and maintenance (HELCO-542) are necessary at this time as opposed to any other time in the recent past due to:

1) Expansion of the Keahole Power Plant to provide West Hawaii generation. CT-4 and CT-5 began commercial operation in mid-2004. The facility is comprised of three combustion turbines and three diesel engines and has a capability of 64.8 MW. The facility is now manned to operate two shifts per day, seven days per week. The facility is being staffed with six Combustion Turbine Operators, two Diesel Mechanics, two Electricians, two Instrument Technicians, Maintenance Supervisor, two Power Plant Supervisors, and a Warehouse/Tool room Attendant (this latter position is budgeted for in the HELCO T&D Department, see testimony of Mr. Jay Ignacio, HELCO T-6).

2) Increased reliance on HELCO's older generation units to meet daily load demand and operate at higher regulating reserves that were not anticipated

in the 2000 rate case will result in Shipman 3 and 4 operating the majority of the year (as opposed to being on cold-standby). Correspondingly, Shipman 3 and 4 will be staffed to operate 10 shifts per week on straight time (as opposed to being operated by personnel from those assigned to Puna Steam or Hill Plant and having to work at Shipman exclusively on an overtime basis). This will result in eight new boiler operators beginning in 2006. Since Shipman 3 or 4 is required to operate 14 shifts per week to meet system load requirements and for economic dispatch reasons, there will be some utilization of operators working overtime.

3) Increased investments to improve reliability of HELCO's generating units in the Hilo area. The increased maintenance activities have resulted in four new maintenance personnel.

4) Increased load demand as compared to the forecast made in 2000.

Q. Explain and quantify the treatment of overtime hours and costs reflected in the test year, relative to historical overtime percentages in HELCO-536.

A. HELCO-536 compares overtime percentages for 2002 through 2005 for the Operations Division comprised of Administration (HGA), Keahole Plant Operations (HGC), Hill Plant Operations (HGH), and Puna Plant Operations (HGP). The attached HELCO-539 provides a breakdown, by Responsibility Areas ("RA") of actual overtime ("OT") hours compared to straight time hours for 2003, 2004 and includes the year-end 2005 result.

Q. Please explain the relationship between changes in staffing levels and the levels of overtime required both historically and in the test year for the Production Department Operations Division.

A. There is a relationship but it is complicated by a number of factors. The operations staffing levels estimated for the test year were based on the number of specific operations personnel required to keep up with anticipated increased workload requirements. Comparing the 2006 test year forecasted overtime percentages with actual historical trends indicates a slight decrease in OT % for the Keahole Operations RA. However, the remaining RA's show a pattern consistent with and in some cases slightly higher OT % over 2005. The actual overtime is not only a function of staffing levels but also a function of work requirements to keep available units operational and in compliance with environmental, safety, and permit requirements on a 24x7 basis. Also, supporting operator training, Shipman, Puna (CT-3 and Steam) and Hill plant overall and maintenance activities, plant startups/shutdowns, Keahole punch list resolution, overtime at Keahole for power plant supervisor days off, Keahole maintenance/operational work on the weekend, miscellaneous supervisory assignments, and attending mandatory training contribute to overtime trends as work is done on weekends, holidays after normal business hours, and on a call out basis. It is realistic to say that a fully manned plant at Shipman with trained operators will decrease overtime for other RAs that were previously providing labor to run the plant on an overtime basis. However, the overtime rate that is due to qualification training activities, replacement of retirees, mandatory training (e.g., DOT, OSHA and environmental), sick replacement will not decrease and will remain at historical levels. Further, as mentioned above, system demand is expected to continue to increase into the foreseeable future and will result in reduced generating reserve margins. This will tend to increase overtime as all available time and resources are utilized to keep the lights on.

1 This reality is one of the major differences between an intertwined system such
2 as those you find on the mainland and an island system that must be self
3 sufficient.
4 Q. What is the status of filling the vacancies to the test year levels shown in
5 HELCO-535?
6 A. The 2006 test year operations staffing level will be achieved by May 2006. The
7 Resource Planner has been recruited for, interviews are complete, and a job offer
8 has been made to an internal applicant. Approvals to fill all of vacant Shipman
9 Plant operator positions have been obtained, the 7 of the 9 positions are filled,
10 and one offer is pending.
11 Q. What other factors contribute to the difference between 2005 recorded and 2006
12 test year other production operations – labor expense?
13 A. Test year increases in wages and salaries for merit and bargaining unit
14 employees will increase other production operations – labor expense. The
15 Company anticipates a budget of 3.5% for merit salary increases effective May
16 1, 2006, and a 0.25% equity increase effective September 1, 2006, calculated as
17 a percentage of merit employee salaries as of April 30, 2006. The general wage
18 increase assumed for bargaining unit positions is 1.5% effective May 1, 2006,
19 and 3% effective November 1, 2006 calculated as a percentage of wages as of
20 November 1, 2002. The determination of the wage and salary increase estimates
21 is covered by Ms. Julie Price in HELCO T-10.
22 <u>Other Production Operations – Non-Labor Expense</u>
23 Q. What is included in other production operations - non-labor expense?
24 A. This cost category includes consumable items such as chemicals used for boiler,
25 waste and circulating water treatment, lubricants, gases, instrument chart paper,

1 city water and sewer charges, and office supplies. It also includes expenses for
2 technical training, transportation, waste removal, janitorial services, and weed
3 control services.
4 Q. Are non-operator non-labor costs forecasted in other production operations -
5 non-labor expense?
6 A. Yes. Non-operator non-labor costs include non-labor items for operational
7 maintenance, technical training, environmental services and fees, and purchase
8 power contract management.
9 Q. How does HELCO forecast other production operations - non-labor expense?
10 A. The Company forecasts other production operations - non-labor expense station
11 by station on the basis of projecting known recurring costs. Non-operator, non-
12 labor expense required to keep the plant operating efficiently and reliably and in
13 compliance with all applicable environmental and other government regulations
14 on a day-to-day basis is forecasted by the respective departments and divisions.
15 Q. How does the 2006 test year other production operations - non-labor expense
16 compare with the 2005 actual expenses?
17 A. As shown in HELCO-540 the 2006 test year other production operations - non-
18 labor expense of $3,533,000 is $108,000 or 3.2% higher than the 2005 actual
19 expense of $3,425,000.
20 Q. What was the increase in other production operations - non-labor expense
21 attributed to?
22 A. HELCO-540 itemizes and explains the differences between 2005 actual and the
23 2006 test year estimate for this expense by category.
24 Q. Is HELCO's estimate of the test year 2006 other production operations expense
25 reasonable?

A. Yes. The estimate is reasonable because it was derived from a review of the resources required to operate HELCO's generating units reliably and efficiently while complying with all environmental and other regulatory agencies. In addition, it supports increasing the staffing levels to allow 14 shifts per week of Shipman units to meet growing system demand while reducing high labor overtime to more manageable levels. All Operator and Shift Supervisor positions required to support operation of Shipman units are being filled by May 2006.

Other Production Maintenance Expense

Q. What is the test year 2006 estimate for other production maintenance expense?

A. The test year 2006 estimate for other production maintenance expense is $13,453,000 as shown on HELCO-541. Of this total, $3,228,000 is for labor expenses while $10,225,000 is for non-labor expenses.

Q. How was the 2006 O&M expense budget for other production maintenance expense determined?

A. The budget for other production maintenance expense is the summation of the labor and non-labor forecasts for work to be done by maintenance personnel at five generating stations and three non-firm generating stations.

Q. Explain the responsible areas of each maintenance division and describe the tasks of each?

A. Two generating stations—Kanoelehua and Keahole—have a permanently assigned maintenance staff. There are two separate groups at Kanoelehua, the steam and hydro ("ST&H") group, and east side combustion turbine and diesel ("CT&D") group. The maintenance group in Keahole is the west side combustion turbine and diesel ("CT&D") group. These three station

1 maintenance groups are responsible for operational maintenance performed on
2 their respective units on a day-to-day basis and for overhauls. They are also
3 available to support station maintenance work on any unit and/or emergencies if
4 called upon to do so.
5 Q. How are the labor expenses for the three maintenance groups forecasted?
6 A. Labor expenses for the three maintenance groups that perform operational
7 maintenance are forecasted based on staffing levels using standard labor rates,
8 less estimated labor for capital projects, plus an assumed percent of overtime.
9 Refer to the testimony of Mr. Paul Fujioka at HELCO T-9 for further discussion
10 of standard labor rates.
11 Other Production Maintenance – Labor Expense
12 Q. How does the 2006 test year estimate of other production maintenance - labor
13 expense of $3,228,000 compare with the 2005 recorded expense?
14 A. The 2006 TY other production maintenance - labor expense is higher than the
15 2005 recorded by $652,000, or 25.3%, as shown in HELCO-541.
16 Q. What is the difference attributed to?
17 A. The increase between the 2005 actual and test year 2006 is mainly attributed to a
18 vacancy due to a termination and an increase in maintenance staffing to support
19 maintenance crews at Kanoelehua and Keahole Power Plants to perform off-
20 peak maintenance, and higher volumes of work attributed to concurrent and
21 back-to-back scheduled and unscheduled outages. HELCO-542 summarizes the
22 maintenance body count impact for Kanoelehua and Keahole station
23 maintenance crews. By year-end 2006, Kanoelehua and Keahole station
24 maintenance will be fully staffed. Job vacancy requisitions ("JVRs") for the
25 four positions were approved in December 2005, and hiring commenced. As

1 stated above, the test year numbers assumed the vacancies are filled for the
2 entire year of 2006.
3 Q. Identify what specific positions will be added to Production Department
4 maintenance in 2006 that were not budgeted for in 2005.
5 A. Production Maintenance had 30 employees at the end of 2005, has 31 employees
6 as of April 30, 2006, and has assumed 34 employees for 2006. In 2006, the
7 Company added one CT/Diesel Mechanic position at Keahole. The Company
8 did not budget for this position in 2005.
9 Q. Identify what specific positions will be added to Production Department
10 maintenance in 2006 that were budgeted for in 2005 but not filled.
11 A. The Production Department will add the following maintenance positions in
12 2006, which were budgeted for in 2005 but not filled:
13 (1) Maintenance Supervisor (CT&D) – Keahole.
14 (1) Maintenance Supervisor (CT&D) – Kanoelehua.
15 (1) CT/Diesel Mechanic – Kanoelehua.
16 Q. What is the basis for these staff additions?
17 A. The staff additions are based on the actual amount of overtime required to
18 perform necessary maintenance in 2004 and 2005 (HELCO-537 and HELCO-
19 538). HELCO did not a conduct any formal study of the optimal staffing plan
20 for production maintenance personnel. The approach used to determine staffing
21 requirements was based on replacements of vacancies attributed to retirements,
22 resignations, job transfers and terminations. What is different today versus in
23 the past is that when separations are known in advance, recruitment to fill the
24 pending vacancies is requested and approved as soon as possible to provide as
25 much lead time and/or overlap as possible.

Q. Why did HELCO increase its maintenance employee levels by 4 people (13 percent) relative to 2005 levels?

A. HELCO increased its maintenance employee levels for the following reasons:

a. With the expansion of Keahole Power Plant, it was determined that one combustion turbine and diesel ("CT&D") Maintenance Supervisor was insufficient to oversee the maintenance activities in West and East Hawaii, thus a second CT&D Maintenance Supervisor was added. The second supervisor allows for more productive use of the supervisors' time because travel time (estimated round trip travel time is 5 to 6 hours) between Keahole and Hilo would no longer be necessary. Both the Hilo and Keahole CT&D supervisors oversee a crew of six (6) trades and craft personnel.

b. Due to high overtime rates experienced in 2004 and 2005, it was determined that the following additional positions were needed and would result in a more cost-effective way to perform the necessary maintenance work: (1) machinist/mechanic for steam and hydro ("S&HU") group; (2) diesel mechanic for CT&D (East) group; (3) Instrument technician for CT&D (East) group; and (4) Instrument technician for S&HU group.

Q. Explain and quantify the treatment of overtime hours and costs reflected in the test year, compared to the historical overtime percentages shown in HELCO-543.

A. HELCO-539 compares overtime percentages for the Maintenance Division comprised of CT&D Maintenance - Keahole (HGK), Steam and Hydro Maintenance (HGM) and CT&D Maintenance - Kanoelehua (HGX). It provides

1 a breakdown, by RA, of actual overtime hours compared to straight time hours
2 for 2003, 2004 and 2005. The total test year hours are approximately 5% higher
3 than the 2005 hours for reasons discussed below.
4 Q. Please explain the relationship between changes in staffing levels and the levels
5 of overtime required both historically and in the test year for the Production
6 Department Maintenance Division.
7 A. As is the case with Production Operations, a strong direct relationship does not
8 exist between staffing levels and overtime for the Maintenance Division. The
9 maintenance staffing levels forecasted were based on the numbers of specific
10 trades and craft personnel required to keep up with anticipated increased
11 workload requirements. Comparing the 2006 test year forecasted overtime
12 percentages with actual historical trends indicates a decrease in overtime % for
13 the Keahole Maintenance crew with the establishment of a supervisor and
14 additional mechanic. However, actual overtime is not only a function of
15 staffing levels, but also a function of work requirements to keep available units
16 operational and in compliance (environmental, safety, permit) on a 24x7 basis. .
17 Q. What is HELCO's expectation for the need of outside services for the test year?
18 A. The levels of outside services costs is expected to remain high and/or increase
19 due to the need to overlap unit outages to keep up with the maintenance of 24
20 firm generating units through the course of a year. As discussed above,
21 contractors are expected to continue to supplement the workforce as existing
22 HELCO labor forces are spread amongst multiple unit outages. While
23 maintenance staffing numbers are higher compared to previous years, as
24 discussed above, HELCO's additional staffing requirements forecasted in 2006
25 is the minimum staffing level required to keep up with multiple planned outages

(PO), maintenance outages (MO) and the occasional forced outage (FO). Further, there is one maintenance position in Kanoelehua CT&D that HELCO-542 shows as a filled position. Although filled, this individual is not physically present due to an extended medical leave. As a result, contractor service costs have been incurred to fill the void and get the work done.

Q. Please describe how HELCO's Production Department maintenance work requirements are compiled and the work is scheduled for implementation.

A. There are many factors that contribute to the work (maintenance) that is identified, categorized, prioritized, planned, and executed. Maintenance work packages are defined based on the need stemming from several mechanisms, including: (1) manufacturer's recommendations; (2) historical experience for preventative maintenance; (3) condition assessments based on PdM testing; (4) observed deterioration of equipment performance; and (5) malfunction or breakdown of equipment. The criticality of required maintenance package is initially assessed and a determination is made by the supervisory personnel in the HELCO Production Department as to whether the work can be performed while the unit is operating or an outage is required. If the latter, a determination is then made as to whether the work can be executed in the next planned outage (PO), a maintenance outage (MO) needs to be scheduled; or a forced outage (FO) is immediately needed. "Backlog" is a general term used to identify work that requires an outage and that is held in abeyance until it can be scheduled as part of an upcoming MO or PO. Examples may include repairs that require a unit shutdown, but not an immediate threat to safety, environmental compliance or unit reliability, repairs awaiting materials and/or parts, labor resource availability, infrastructure repairs not directly impacting unit availability and/or

1 system reliability. Hill 6 is having a major overhaul in 2006 which will include
2 extensive O&M and capital work. The process has begun now to plan this effort,
3 and due to the extended length out of the outage, many backlog items will be
4 addressed.
5 Q. What other factors contribute to the difference between 2005 recorded and test
6 year 2006 other production maintenance – labor expense?
7 A. Test year increases in wages and salaries for merit and bargaining unit
8 employees will increase other production maintenance – labor expense. The
9 Company anticipates a budget of 3.5% for merit salary increases effective May
10 1, 2006, and a .25% equity increase effective September 1, 2006, calculated as a
11 percentage of merit employee salaries as of April 30, 2006. The general wage
12 increase assumed for bargaining unit positions is 1.5% effective May 1, 2006,
13 and 3% effective November 1, 2006 calculated as a percentage of wages as of
14 November 1, 2002. The determination of the wage and salary increase estimates
15 is covered by Ms. Julie Price in HELCO T-10.
16 Q. Please summarize the status of filling the vacancies in maintenance described
17 above.
18 A. Interviews were held and offers were made to qualified applicants for both
19 maintenance supervisory positions (Keahole and Kanoelehua CT&D) in 2005.
20 The offers were rejected by the candidates, and HELCO is now in the recruiting
21 process for a second time. The JVR for the additional mechanic in Keahole has
22 been approved and interviews are pending.
23 Q. Please confirm that HELCO has assumed that each authorized position in the
24 Production Operations, Production Maintenance and Technical Services

1 divisions will be filled throughout the test year, and that no vacancies will exist
2 during 2006.
3 A. Yes, the 2006 test year forecast assumes that each authorized position is filled
4 throughout the entire year and no vacancies exist. The authorized positions are
5 in the process of being filled.
6 Q. Explain how HELCO's treatment of vacancies is thought to produce a
7 reasonable estimate of labor costs to be incurred in 2006, given the above
8 responses.
9 A. The labor estimates in the 2006 test year assume that all vacancies are filled for
10 the full 12 months. The estimates are reasonable for ratemaking purposes in
11 that the majority of the estimates are based on increasing the organization size
12 due to the need to establish 14 shifts per week operations at Shipman Plant, as
13 well as increasing the maintenance staffing level to address more work. Other
14 additions to the staff include an additional Resource Planner.
15 Q. Would a delay in the filling of these positions result in lower O&M labor costs
16 than what was included in the test year estimate?
17 A. No. During the time that those positions remain vacant, the Company would
18 incur unbudgeted overtime hours or contract outside labor to get the work done.
19 I have illustrated this in HELCO-WP-510, page 9. This schedule illustrates first,
20 total Production Department budgeted workers compensation, labor and outside
21 services-temporary help, second, recorded amounts through March 2006 as well
22 as an updated forecast for the remaining 2006 months, and third, the variance
23 between both. This variance shows that the hiring of outside temporary workers
24 would actually be more costly than having the associated vacancies filled with
25 permanent workers. However, the Company has only made an upward

1 adjustment of $62,000 based on the forecast after the January 2006 actuals were
2 recorded (see budget adjustments above).
3 Other Production Maintenance – Non-Labor Expense
4 Q. What is included in other production maintenance - non-labor expense?
5 A. The other production maintenance - non-labor expense includes direct costs for
6 materials, contract services, and transportation to maintain HELCO's five steam
7 units, five combustion turbines, 10 diesel generators, four distributed generators,
8 four hydro generators, one windfarm and associated infrastructure. It also
9 includes the budget and normalization adjustments covered earlier in my
10 testimony.
11 Q. How are the non-labor expenses for the three maintenance groups forecast?
12 A. The non-labor costs in the three Station Maintenance groups are forecast based
13 on identifying specific discretionary and nondiscretionary work, trended routine,
14 and a normal overhaul schedule where known requirements for the planned unit
15 outages ("PO") are identified and forecasted. Other factors are considered in the
16 development of the forecast, including trended cost for a particular item, for a
17 particular type of unit such as airpreheater baskets for intermediate units; level
18 of outside service support to supplement labor; special tests and inspections by
19 industry experts, and identification of long lead items.
20 Q. How does the 2006 test year other production maintenance - non-labor expense
21 estimate compare with the actual 2005 recorded amount?
22 A. As shown in HELCO-544, the 2006 test year forecast of other production
23 maintenance - non-labor expense of $10,225,000 is $2,476,000 or 32.0% higher
24 than the actual 2005 recorded amount of $7,749,000.
25 Q. What is the increase attributed to?

A. HELCO-544 shows the breakdown and explanation of the 2005 actual versus the test year 2006 variance of $2,476,000.

Q. What factors contribute to higher other production maintenance non-labor expenses?

A. Major factors contributing to higher other production maintenance non-labor expense include:

1) Aging plant and facilities. As shown in HELCO-502, the average age of HELCO steam units is 40.6 years, 14.8 years for combustion turbine units, 30.4 years for diesel generators, and 8.0 years for distributed generation units, respectively. As demand increases (and reserve margins decrease) all available units including Shipman 3 & 4, Kanoelehua CT-1, and Puna CT-3 will be dispatched more hours and at higher loads. The increase in operation will increase the wear and tear on the equipment and supporting infrastructure requiring a higher level of concurrent and back-to-back predictive, preventive and reactionary maintenance.

2) Aging IPPs. As shown in HELCO-502, the average age of the HEP and PGV units[2] is reaching a point where an increased level of maintenance will be required to maintain reliability. Forced outages, deratings, and maintenance outages are increasing as IPP units' age over time. With decreasing reserve margins, IPP forced outages and deratings will impact other Production O&M by placing more demands on HELCO units, including pressure to shorten outage durations. Consequently, these factors will increases HELCO labor overtime and applicable on-costs, the

[2] Despite HEP being only 6 years old, its maintenance requirements have increased significantly in 2005 and particularly in 2006.

need for additional contract service support, expedited transportation costs and higher material costs.

3) Maintenance of additional plant and facilities. The addition of plant and facilities at the Shipman, Puueo and Waiau Stations will cause other production maintenance - non-labor expense to increase accordingly. An example is the new hydroelectric generator at Puueo that was placed into service in July 2005 and increased maintenance on the facilities including the penstock is expected to be needed.

Q. Is HELCO's estimating of the test year 2006 other production maintenance expense reasonable?

A. Yes. The estimate is reasonable because it was derived from a review of the work required to maintain reliability and availability of HELCO's generating units and facilities. As explained above staffing increases are necessary at this time due to the significant increases in customer demand (load growth), which are causing existing and older units to run a lot harder than before. Even with forecasted staffing increases, additional outside services will be required to supplement the existing workforce and provide special skills and consulting.

<u>2005 Actual Versus 2006 TY Estimate Variances</u>

Q. Do you have any other items to cover regarding 2005 Actual versus 2006 TY comparisons?

A. Yes. Workpapers are provided summarizing Other Production O&M variances based on variances greater than $45,000 and plus or minus 10% of the difference between 2005 Actual and 2006 test year expenses by specific code block. Work paper HELCO-WP-501 is submitted to satisfy this. Variance explanations are also provided in the workpapers

Q. How do the workpaper results tie to the variance explanations provided earlier in your testimony?

A. The variance explanations provided earlier address the total variance as a net difference between 2005 actual and 2006 test year, and provide a better understanding of the dynamics involved in developing a normal forecast, and the real time challenges in managing the forecast as the operating year unfolds with all of the operations and maintenance challenges mentioned in my testimony. Many of the factors discussed earlier in my testimony such as reduced operating margins due to load growth, aging units running harder, safety and environmental compliance, all impact the actual year-end result. Priorities are constantly adjusted to maintain system reliability and every attempt is made to work with the approved budget. The various items in HELCO-WP-501 that met the 10% and $45,000 criteria are an indication of the dynamic nature of operating and maintaining five steam units, five combustion turbines, 10 diesel generators, four distributed generators, four hydro generators, one windfarm and associated infrastructure, where the mix of which specific units are actually shut down for maintenance differs from year to year while the nature of the work performed is similar. For example, overhaul expenditures will show a 100% variance because different generating units were overhauled in 2005 as compared to the 2006 test year.

PURCHASED POWER EXPENSES

Q. What is the 2006 test year purchase power expense?

A. The 2006 test year purchase power expense estimate is $117,318,000 as shown in HELCO-545.

This includes: $ 99,388,000 Purchased Energy expense

$ 17,930,000 Firm Capacity expense

$ 117,318,000 Total Purchased Power expense

Q. How are purchased energy expenses determined?

A. Purchased energy expenses are based on the projected amount of energy to be purchased by, or made available to, HELCO in the test year and the contract pricing terms for the various purchased power producers. These energy terms vary for different purchased power producers.

Q. How are firm capacity expenses determined?

A. Firm capacity expenses are based on the individual contract terms for delivery of firm capacity by the purchased power producers. The capacity terms are different for each contract.

Q. What purchased power contracts ("contracts" or "PPA's") are included in the test year's purchased power expense?

A. The test year purchased power expense includes purchased energy and capacity from the following firm power and as-available power producers.

Firm Power:

1) Puna Geothermal Venture (PGV)
2) Hamakua Energy Partners, L.P. (HEP)

As-available Power:

1) Wailuku River Hydroelectric Power Company, Inc. (WRH)
2) Hawi Renewable Development, LLC (HRD)
3) Apollo Energy Corporation (AEC) (also known as Kamaoa)
4) Various small hydro independent power producers i.e.; Hawi Agricultural and Energy Corporation, Palm Valley Farm (formerly known as Ho'owaiwai

1 Farms), Department of Water Supply, and Wenko Energy.

2 Q. Why does HELCO include its new contract with HRD in the test year?

3 A. HELCO will begin to purchase as available energy from HRD in 2006. Because
4 the 2006 operating forecast estimates that HRD will be fully installed in the
5 January-to-March 2006 period, the test year estimates have been normalized to
6 include HRD for a full year.

7 Q. What purchased power contracts will <u>not</u> be included in this 2006 Test Year?

8 A. The test year will not include the additional energy from Apollo Energy
9 Corporation. HELCO entered into a Restated and Amended Contract (RAC)
10 with Apollo Energy Corporation on October 13, 2004, which allows Apollo to
11 expand its generating facility from 7 megawatts to 20.5 megawatts, resulting in
12 an increase of 13.5 megawatts capacity. Although the RAC was approved by
13 the Public Utilities Commission in its Decision and Order No. 21693 on March
14 10, 2005, the installation of the larger facility will not occur in the 2006 test
15 year. The estimates provided in the test year for Apollo Energy Corporation are
16 based on its original contract for 7 megawatt capacity.

17 <u>Purchased Energy Expense</u>

18 Q. What is the 2006 test year purchased energy expense?

19 A. The purchase energy expense for 2006 test year is $99,388,000, as shown in
20 HELCO-545.

21 Q. How are purchased energy expenses determined?

22 A. Purchased energy expenses are based on the estimated amount of energy or
23 estimated gigawatthours (GWh) to be purchased by HELCO in the test year, and
24 calculated by the estimated contract rates as stated in each purchase power
25 contract.

Q. What is the estimated amount of energy to be purchased by HELCO in the test year?

A. In the 2006 test year, HELCO estimates that it will purchase approximately 710.1 GWh in energy. This represents approximately 57% of the total net energy produced of 1,251.2 GWh required in the test year 2006. A list of the estimated GWh of purchased energy is shown by Independent Power Producer (IPP) in HELCO-546.

Q. How was the test year estimate determined?

A. The test year estimate of energy purchases was derived from HELCO's 2006 Test Year production simulation run dated March 3, 2006.

Q. How were energy purchases for the test year estimated?

A. The production simulation model is updated with the latest key information on each firm power producer such as energy and hourly load capacity requirements, commitment and dispatch factors, efficiency characteristics, equivalent forced outage rates, scheduled outages, planned overhaul maintenance schedules, and minimum energy purchasing requirements. The production simulation run uses the following forecast methods to develop the 2006 test year energy purchase estimates.

1) Economic Dispatch - The production simulation run models all dispatchable units such as HEP and all HELCO owned units.
2) Power dispatch schedules and contract requirements.
3) Historical production average of actual production for as-available resources.

Q. What forecast method is used to determine the amount of energy that will be purchased from each IPP?

A. The forecast methods used in the production simulation run for each Independent Power Producer are as follows:

1) PGV energy estimate of 221.9 GWh in the test year is based on the production simulation run with PGV assumed to be at 30 MW during on-peak and 27 MW during off-peak periods in accordance with their contract as described by Ms. Lisa Giang in HELCO T-4. Prior to the start up of HRD, PGV was dispatched at 22 MW during off-peak periods. In accordance with the PGV contract, HELCO is obligated to take an additional 5 megawatts off-peak energy from PGV prior to taking off-peak as- available energy from the next as-available provider which is HRD. The test year 2006 production simulation run models PGV's equivalent forced outage rate (EFOR) at 7.10% on-peak, 0.63% off-peak and 4.4% total, based on a seven-month historical average from July 2005 to February 2006. Refer to HELCO-WP-404 page 100. It is during this period, after the completion of re-drill of KS-10 production well, PGV geothermal resource level returned and plant output was restored to contractual 30 mw level. The production simulation model dispatches PGV for energy levels up to of 25 MW and above 25 MW to 30 MW on peak and up to 22 MW and above 22 MW to 30 MW off-peak because of price differences for the original firm capacity and additional energy.

2) HEP energy estimate of 420.6 GWh in the test year is based on its model as a dispatchable unit in the production simulation. The model uses dispatch limits, efficiency characteristics and contract pricing formulas. The production simulation run uses the ABC or heat rate constants and minimum and maximum dispatch levels. Refer to HELCO-WP-404 page

97. The ABC constants are derived using the contract pricing formulas and base fuel price as shown in HELCO-WP-545, pages 18 to 20 and pages 22 to 25. The production simulation run accounts for Operations and Maintenance cost by dispatch type, EFOR at 2.22% based on 3-year historical average (2003 to 2005), and Maintenance Outage rates at 2.68% based on 3-year historical average (2003 to 2005), as shown in HELCO-WP-404 pages 98, 100, and 102, respectively. The model includes minimum down time of 3 hours and minimum up time of 10 hours.

3) Wailuku River Hydro energy estimate of 27.5 GWh in the test year is based on its historical monthly profile 5-year average (2001-2005).

4) Hawi Renewable Development energy estimate of 34.2 GWh in the test year uses flat profile of maximum capacity of 10.56 MW with 37% capacity factor installed for a full year.

5) Apollo Energy Corporation energy estimate of 4.8 GWh in the test year for its existing facility uses monthly profile for year 2005.

6) Other Small Hydro energy estimate of 1.0 GWh in the test year uses monthly profile 5-year average (2001-2005).

Refer to HELCO-WP-404 page 106 for Apollo and HRD energy estimates, and page 107 for Wailuku River Hydro and Other Small Hydro energy estimates.

Q. How does the test year estimate of energy purchases compare with the recorded level of energy purchased?

A. The primary difference between the recorded energy purchases and the test year estimate is the decrease in firm power energy due to the termination of the HCPC contract as of December 31, 2004, and the increase in as-available energy

1 due to a new contract with HRD which is expected to be fully installed in 2006.
2 Refer to HELCO-547 and HELCO-548.
3 Purchased Energy Rates
4 Q. How are the individual purchased energy rates determined?
5 A. The purchase energy price for each Independent Power Producer is based on
6 each of the purchase power contracts.
7 a. Puna Geothermal Venture Energy Rates
8 Q. Under what terms and conditions does HELCO purchase energy from PGV?
9 A. HELCO purchases energy from PGV under the PPA dated March 24, 1986, as
10 amended by the Firm Capacity Amendment dated July 28, 1989, Second
11 Amendment dated October 14, 1993, Third Amendment dated March 7, 1995,
12 and Fourth Amendment dated February 12, 1996 in Docket No. 96-0042.
13 Q. How do you determine PGV's purchased energy rates?
14 A. PGV's energy payment rates consist of two parts:
15 1) Original firm capacity - up to and including 25 MW on-peak and 22 MW off-
16 peak
17 2) Additional energy - Above 25 MW on-peak and 22 MW off-peak
18 Q. What is the test year PGV energy expense?
19 A. The estimated PGV test year energy expense is $34,393,207 which consists of
20 the following:
21 1) Firm Capacity Contract - $ 29,521,610
22 2) Additional Energy - $4,871,596
23 Refer to HELCO WP-545, page 2.
24 Q. How is PGV's original contract cost determined for the test year?
25 A. The energy rates for the original contract up to and including 25 MW on-peak

and 22 MW off-peak are based on the higher of HELCO's filed quarterly avoided energy cost rates, or contract floor rates of $0.0656 / net kWh on-peak and $0.0543 / net kWh off-peak. For the test year 2006, PGV rates are based on avoided energy rates of $0.1745 /net kWh on-peak and $0.1411 / net kWh off-peak.

Q. How is PGV's additional energy cost determined for the test year?

A. The rates for additional energy above 25 MW on peak and above 22 MW off-peak are based on a calculation including 1) fuel component and 2) variable O&M component. PGV rates cannot fall below their minimum purchase rate. For the test year 2006, PGV additional energy rates are calculated at $0.13032 /net kWh on-peak and $0.12032/ net kWh off-peak.

Q. How is PGV's fuel component determined for the test year?

A. The fuel component is computed using a fuel rate base charge of $0.038/kwh multiplied by a monthly fuel index.

Q. What is the PGV's monthly fuel index assumed for the 2006 test year?

A. The test year PGV fuel index is $ 1.8163, as shown in HELCO-WP-545, page 26.

Q. How was this PGV fuel index determined?

A. The PGV's fuel index is based on February 2006 average price as reported by Platts Los Angeles LS Diesel Pricing Report from December 21, 2005 to January 20, 2006.

Q. How is PGV's variable O&M component determined for the test year?

A. The variable O&M component is computed using a variable O&M base charge of $0.0029/kWh escalated annually based on changes in the Gross Domestic Product Implicit Price Deflator (GDPIPD.)

Q. What GDPIPD did HELCO use for test year 2006?

A. The GDPIPD used for test year 2006 for purposes of forecasting PGV variable O&M escalation is 112.527 current and 92.289 base which is the third quarter 2005 final GPDIPD numbers published on December 21, 2005 by the U. S. Department of Commerce, Bureau of Economic Analysis.

b. Hamakua Energy Partners

Q. Under what terms and conditions does HELCO purchase energy from HEP?

A. HELCO purchases energy from HEP under Power Purchase Agreement between Encogen Hawaii LP and Hawaii Electric Light Company, Inc. dated October 22, 1997, as approved by Decision an Order 17077 dated July 14, 1999 in Docket No. 98-0013.

Q. How do you determine HEP's purchased energy rates?

A. HEP's energy payment rate includes two components, 1) fuel component and 2) variable O&M component. The energy charges are reduced by a two percent discount for the energy component of avoided transmission losses.

Q. What is the test year HEP energy expense?

A. The estimated HEP test year energy expense is $54,246,064 which consists of the following:

1) Fuel component – $ 51,638,500

2) Variable O&M component - $2,607,564

The two percent discount applied to each component.

Refer to HELCO-WP-545, page 3.

Q. How is HEP's fuel component determined for the test year?

A. The fuel component is based on HEP's guaranteed heat rate efficiency curves at HELCO's Keahole fuel cost, and adjusted against fuel base price. The fuel

1 component is calculated using the base fuel which is the amount of kilowatts
2 calculated at various rates by type of dispatch, i.e. 2 combustion turbine
3 combined cycle (CTCC), 1 CTCC, 1 combustion turbine simple cycle (CTSC),
4 or 2 CTSC. The base fuel is multiplied by the Keahole monthly fuel price, and
5 divided by a fixed base factor of $4.35324 per one million British Thermal Unit.
6 The total fuel component is adjusted to 98% (reduced by 2%).
7 Q. What is the fuel price assumed for Keahole?
8 A. The test year composite fuel price for diesel at Keahole facility is $ 88.0456 per
9 barrel, as shown on HELCO-402, page 1.
10 Q. How was this price determined?
11 A. The fuel prices are covered by Ms. Lisa Giang in HELCO T-4.
12 Q. How is HEP's variable O&M component determined for the test year?
13 A. The variable O&M includes a variable component and an overhaul component.
14 The variable component is computed using the total kWh generated multiplied
15 by a variable factor of $.00092/kwh delivered (in 1995 dollars) which is
16 escalated annually based on changes in the Gross Domestic Product Implicit
17 Price Deflator (GDPIPD). The overhaul component is computed using
18 combustion turbine run hours and multiplied by an overhaul factor of
19 $103.43/hour (in 1995 dollars) which is escalated annually based on changes in
20 the GDPIPD. The total variable O&M is the sum of both the variable and
21 overhaul components, adjusted to 98% (reduced in total by 2%).
22 Q. What GDPIPD did HELCO use for test year 2006?
23 A. The GDPIPD used for test year 2006 for purposes of forecasting HEP O&M
24 escalation was 112.527 current and 90.530 base which was the Third Quarter
25 2005 Final GPDIPD numbers published on December 21, 2005 by the U. S.

1 Department of Commerce, Bureau of Economic Analysis.

2 c. As-Available Energy Rates

3 Q. How do you determine the energy rates for as-available power?

4 A. The energy rates for as-available power such as Wailuku River Hydro, HRD,
5 and Apollo Energy Corporation are established by each contract and generally
6 based on HELCO's filed quarterly avoided energy cost rates. Wailuku River
7 Hydro and HRD energy rates are based on 100% of the HELCO on-peak and
8 off-peak avoided energy cost. The Avoided Energy cost for the test year 2006
9 are 17.45 cents per net kWh for on-peak and 14.11 cents per net kWh for off-
10 peak. (Refer to avoided energy rates in HELCO-315, page 1).

11 The Apollo Energy Corporation energy rates are based on 85% of
12 HELCO's on-peak and off-peak avoided energy cost. For the test year, Apollo
13 Energy Corporation energy rates are 14.833 cents per net kWh for on-peak and
14 11.994 cents per net kWh for off-peak. Apollo's contract is structured on a
15 declining rates basis over the term of their contract. Apollo's energy rates were
16 at 100% of HELCO's avoided energy cost during the initial three years, 92.5%
17 during the fourth to ninth years, and 85% from the tenth to fifteenth year and
18 thereafter.

19 Other Small Hydro energy rates are based on HELCO's filed quarterly
20 avoided energy cost and quarterly Schedule Q rate. The Schedule Q rate for the
21 test year 2006 is 15.87 cents per net kWh. (Refer to avoided energy rates in
22 HELCO-315, page 1).

23 Purchased Firm Capacity

24 Q. What is the IPP firm capacity expense for the 2006 test year?

25 A. The IPP firm capacity expense for the 2006 test year is $17,930,000, as shown in

HELCO-545.

Q. How are the expenses for firm capacity determined?

A. Firm capacity payments are based on the individual contract terms for delivery of firm capacity by the purchased power producers. Below is a summary of the terms for the IPPs.

1) Puna Geothermal Venture capacity payments are based on a set amount of $4,000,000 per year for first 25 megawatts and $504,750 per year for additional 5 megawatts, for a total of $4,504,750 per year for 30 megawatts capacity. In accordance with their contract, PGV capacity payments are adjusted in proportion to the capacity amounts for periods when PGV's output falls below 30megawatts during on-peak hours. Since the productions simulation assumes PGV at 7.10% On-Peak Equivalent Forced Outage Rate, it is estimated that Capacity Sanctions and On-Peak Availability Factor Sanctions will apply to the test year. For the test year 2006, it is estimated that capacity sanctions in the amount of $232,738 will be applied as adjustments to the capacity payments. It is estimated that PGV will not meet the "On-Peak Availability" of 95% or better performance standards. It is estimated that PGV will perform at an approximate 93% availability factor, resulting in a $15,984 availability factor sanction. The adjusted Capacity Payment to PGV is estimated to be $4,256,028 in the test year 2006. (Refer to HELCO-WP-545, page 2 and 12).

2) Hamakua Energy Partners monthly capacity payments are based on a firm capacity amount of 58,000 kW (60,000 kW capacity adjusted by 2,000 kW for avoided transmission losses) and computed by a set capacity rate of

$15.43 per kW-month; and a firm O&M component of $196,754.16 per month, escalated annually based on changes in the GDPIPD. The Total Capacity Payment to HEP is estimated to be $13,674,018 in the test year 2006. (Refer to HELCO-WP-545, page 3 and 15.)

Purchased Power Administration Expense

Q. How does HELCO negotiate and administer PPAs?

A. When a developer contacts HELCO or HECO with a proposal for new generation or additional generation to the HELCO grid, they are required to submit a Non-Utility Generator (NUG) form which includes detailed information about their prospective generating facility. Negotiations of new purchase power agreements are managed by the HECO Purchase Power Division, and assisted by a team of HECO and HELCO professionals from various specialties, that is, personnel from HECO Generation Planning, HECO Legal, HELCO Production, and HELCO Engineering. The team is brought together to review the new proposals and to analyze if this new or expanded facility will meet the energy needs for HELCO's grid at a reasonable rate for its customers. An Interconnection Requirement Study (IRS) is performed by HECO/HELCO which determines the requirements needed for this facility to interconnect to the HELCO grid. If both parties agree to the terms and conditions of a purchase power agreement, the contracts are forwarded to the Commission for approval.

After Commission approval of the PPA, the contracts are transferred to HELCO Production for administration. The developer works in cooperation with HELCO Engineering and HELCO Production in the building or expansion of the facility. The HELCO Purchase Power Contracts Administrator manages

1 the invoicing to the IPP, works with HELCO Operations in the dispatch,
2 coordination, and scheduling of outages, and coordinates meetings to resolve
3 disputes with the IPP.
4 For clarification purposes, HELCO does not have a Purchased Power
5 Contracts division or department. The administration is handled by one person,
6 who is located in the administrative section of the Production Department.
7 Q. What does HELCO do to improve reliability of the IPPs?
8 A. HELCO monitors the reliability statistics for its firm power producers. If IPPs
9 experience problems in reliability, HELCO has requested for a third party
10 engineering review to assist in identifying the causes and suggested corrections
11 for poor performance. For example, in accordance with HEP's contract,
12 HELCO requested a third party engineering review for HEP when they
13 experienced excess unit trips. HELCO also enforces penalties and sanctions to
14 both HEP and PGV, in accordance with each contract. Under the HEP contract,
15 liquidated damages are applied when HEP is not be able to perform up to
16 standards in areas of Equivalent Availability Factor, Equivalent Forced Outage
17 Rate, Ramp Derating, and Excess Unit Trips. Under PGV's contract, sanctions
18 are applied when the PGV Availability Factor falls below acceptable levels and
19 adjustments are made to reduce capacity payments when they are not able to
20 provide 30MW during the on-peak period.
21 Summary
22 Q. Please summarize your 2006 test year purchased power expenses?
23 A. For 2006 test year, HELCO estimates purchasing 710.1 GWh from firm capacity
24 and as-available IPP's. As summarized in HELCO-545, the 2006 test year
25 purchased energy costs are $ 99,388,000, purchase capacity costs are

$17,930,000, and total purchase power expenses are $117,318,000, which HELCO is seeking to recover in this rate case.

PRODUCTION STORES INVENTORY

Q. What is the 2006 test year estimate for the production materials inventory?

A. The estimated test year 2006 production materials inventory is $1,062,000. (See HELCO-549.)

Q. How was the test year estimate determined?

A. The test year estimate was determined by using a 13-month averaging method (December 1, 2005-December 31, 2006). This methodology is consistent with the Commission's decision in Decision and Order No. 11893. Refer to HELCO-WP-504.

Q. What is included in the production material inventory?

A. The production material inventory includes material stock such as spare parts for turbines, boilers, internal combustion diesel engines, and generators.

Q. Why does HELCO keep a production materials inventory?

A. Most parts are purchased from mainland suppliers and take from one week to over a year for delivery. The spare parts are needed to maintain unit availability, reliability and operating efficiency.

Q. How does the inventory for the test year 2006 compare with past years?

A. The average 13-month inventory for the test year 2006 is estimated to increase 5.5% from actual 2005. A summary of HELCO Production Material Inventory is provided in HELCO-549.

Q. Why is the test year 2006 Production Materials Inventory reasonable for ratemaking purposes?

A. The Production Materials Inventory is reasonable because it was derived from historical trends and the need to maintain an inventory to support both new and original equipment/designs currently in service. Further, there is no departure in accounting for production material inventory from prior years.

SUMMARY

Q. Mr. Giovanni, please summarize your testimony.

A. HELCO's test year 2006 Other Production expense is estimated to be $23,040,000 after factoring in budget and normalization adjustments. The test year forecast is reasonable because it reflects a normal and adequate level of spend to operate and maintain the Company's generating plants. These expenses are higher than in recent years, in parts, due to the expansion of the Keahole Generating Station to provide west-side generation, investments to improve reliability of HELCO's generating units, hiring new operators and assigning them to the Shipman Power Plant for 14 shift operations per week. As mentioned throughout my testimony, all generating units on the island of Hawaii system including IPPs are getting older and running harder due to significant increases in customer demand, increased levels of regulating reserve to mitigate effects of wind energy, and for having to compensate for additional as-available energy (e.g., wind energy) coming onto the system that does not provide ancillary services (i.e., load regulation, frequency regulation, voltage regulation, and regulating reserve). HELCO has increased its efforts to improve the reliability of its generating units and the system as a whole, and reliability statistics for 2003 through 2005 verify that the improvement has been substantial. These efforts include increased HELCO maintenance personnel, increased maintenance during planned outages (PO), implementation of a

Generation Asset Management program, and implementation of an Asset Optimization program. Further, HELCO estimates purchasing 710.1 GWh from firm capacity and as-available IPP's, and amounts to total purchase power expenses in 2006 of $117,318,000, which HELCO is seeking rate recover. In addition, HELCO's 13-month average Production Materials Inventory is estimated to be $1,062,000. This level of inventory is necessary to store sufficient spare parts and materials to maintain unit availability, reliability and efficiency.

Q. Does this conclude your testimony?

A. Yes, it does.

HELCO - 500

HAWAIIAN ELECTRIC COMPANY, INC.

DAN V. GIOVANNI

EDUCATIONAL BACKGROUND AND EXPERIENCE

BUSINESS ADDRESS:	Hawaiian Electric Company, Inc. PO Box 2750, Honolulu, HI 96840
POSITION:	Manager, Power Supply O&M Department Hawaiian Electric Company, Inc. (March 2006 to present)
PRIOR POSITION	Manager, Production Department Hawaii Electric Light Company, Inc. (July 2001 to March 2006)
YEARS OF SERVICE:	5 Years
EDUCATION:	University of California, Berkeley, B.S. in Mechanical Engineering, 1970 University of California, Berkeley, M.S. in Mechanical Engineering, 1971
PREVIOUS POSITIONS:	President Electric Power Technologies, Inc. (California, New York, and Hawaii) (1982 to 2001) Program Manager Electric Power Research Institute (EPRI) (1978 to 1982) Research Section Manager Kaiser Aluminum and Chemical Company (1975 to 1978) Consulting Engineer KVB, Inc. (1971 to 1975)

HAWAII ELECTRIC LIGHT COMPANY, INC.

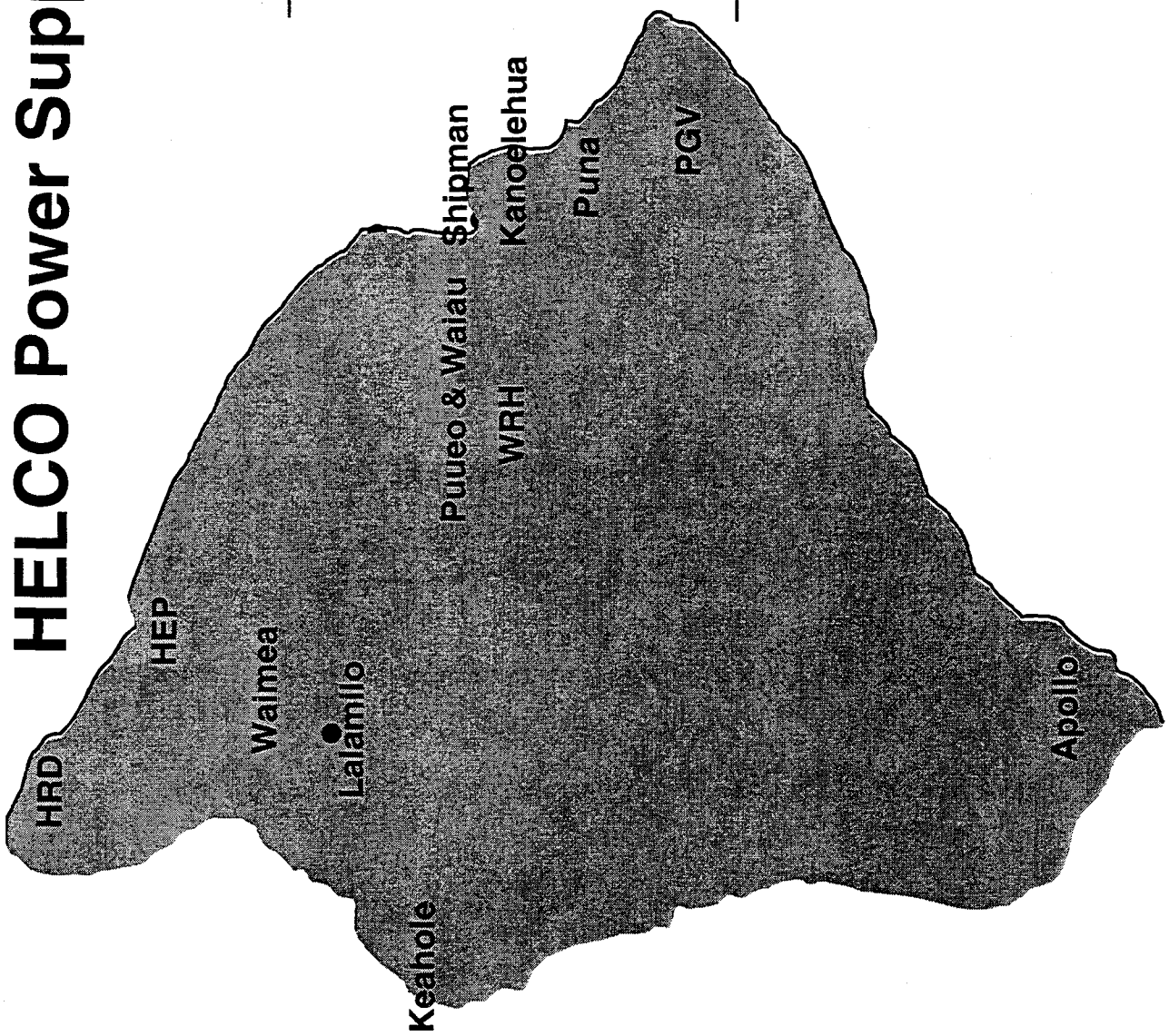
NORMAN VERBANIC, JR.

EDUCATIONAL BACKGROUND AND EXPERIENCE

BUSINESS ADDRESS:	Hawaii Electric Light Company, Inc. 54 Halekauila Street, Hilo, HI 96720
POSITION:	Manager, Production Department Hawaii Electric Light Company, Inc. (March 2006 to present)
PRIOR POSITION	Maintenance Superintendent, Production Department Hawaii Electric Light Company, Inc. (August 2004 to March 2006)
YEARS OF SERVICE:	17 Years
EDUCATION:	Attended Rochester Institute of Technology, no degree (1976 – 1978)
PREVIOUS POSITIONS:	Operations and Maintenance Superintendent Hamakua Energy Partners, L.P. Haina, Hawaii (March 2000 – August 2004) Electrical Maintenance Supervisor, Production Department Hawaii Electric Light Company, Inc. (1995 – 2000) Journeyman Electrician, Production Maintenance Hawaii Electric Light Company, Inc. (1991 – 1995) Power Plant Operator, Production Department Hawaii Electric Light Company, Inc. (1988 – 1991) Hawaiian Electric Company, Inc. (1984 – 1988)
MILITARY:	United States Navy, Honorable Discharge Nuclear Trained and Submarine Qualified Electrician (1978 – 1983)

Hawaii Electric Light Company, Inc.

HELCO Power Supply



- Firm Power
  - Shipman
  - Kanoelehua
  - Puna
  - Waimea
  - Keahole
  - PGV
  - HEP
- Non-Firm Power
  - Puueo Hydro
  - Waiau Hydro
  - WRH Hydro
  - Lalamilo Wind
  - Apollo Wind
  - HRD Wind

Hawaii Electric Light Company, Inc.

Age of Generating Units

(as of 2005)

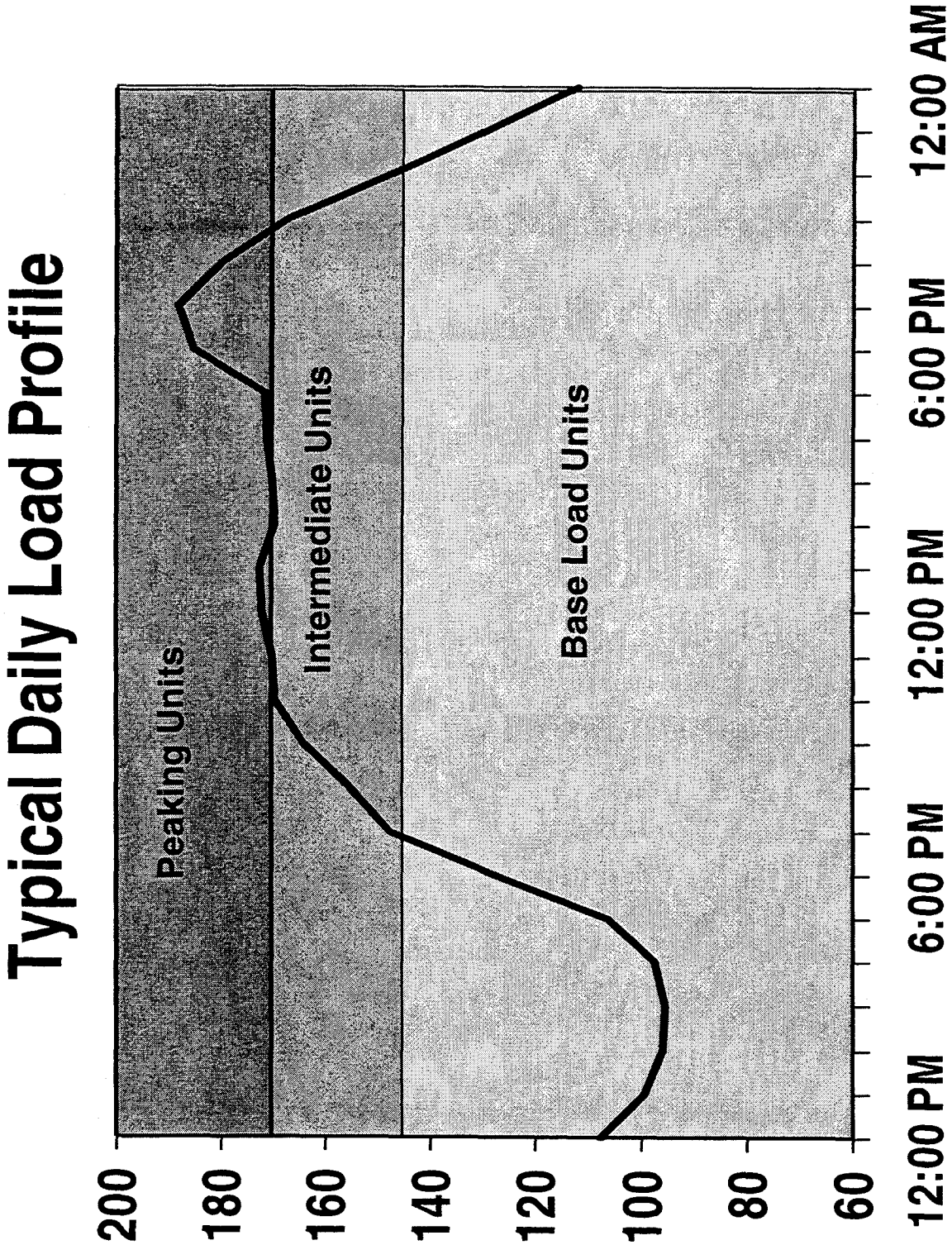
Unit	Capability (MW)	Type	Operating Mode	Service Date	Age
HELCO Generating Units					
Shipman 3	6.8	Steam, Non-Reheat	Intermediate	1955	50
Shipman 4	6.7	Steam, Non-Reheat	Intermediate	1958	47
Puna Steam	14.1	Steam, Non-Reheat	Base	1970	35
Puna CT-3	20.4	Combustion Turbine	Intermediate	1992	13
Hill 5	13.5	Steam, Non-Reheat	Base	1965	40
Hill 6	20.2	Steam, Non-Reheat	Base	1974	31
Kanoelehua D11	2.5	Diesel	Peaking	1962	43
Kanoelehua D15	2.5	Diesel	Peaking	1972	33
Kanoelehua D16	2.5	Diesel	Peaking	1972	33
Kanoelehua D17	2.5	Diesel	Peaking	1973	32
Kanoelehua CT-1	11.5	Combustion Turbine	Peaking	1962	43
Waimea D12	2.5	Diesel	Peaking	1970	35
Waimea D13	2.5	Diesel	Peaking	1972	33
Waimea D14	2.5	Diesel	Peaking	1972	33
Keahole D21	2.5	Diesel	Peaking	1983	22
Keahole D22	2.5	Diesel	Peaking	1983	22
Keahole D23	2.5	Diesel	Peaking	1987	18
Keahole CT-2	13.0	Combustion Turbine	Intermediate	1989	16
Keahole CT-4	22.1	Combustion Turbine	Intermediate	2004	1
Keahole CT-5	22.2	Combustion Turbine	Intermediate	2004	1
Panaewa	1.0	Distributed Generation	Peaking	1997	8
Ouli	1.0	Distributed Generation	Peaking	1997	8
Kapua	1.0	Distributed Generation	Peaking	1997	8
Punaluu	1.0	Distributed Generation	Peaking	1997	8
Major Independent Power Producers					
HEP	60.0	Combined Cycle	Intermediate	1999	6
PGV	30.0	Steam, Non-Reheat	Base	1986	19

Average age of HELCO Distributed Gen Units	8.0 Years
Average age of HELCO Diesel Units	30.4 Years
Average age of HELCO Combustion Turbine Units	14.8 Years
Average age of HELCO Non-Reheat Steam Units	40.6 Years
Average age of Independent Power Producers	12.5 Years

HELCO Generating Units - Non-Firm					
Hydro:					
Puueo No. 1	2,500.0	Hydro		2005	0
Puueo No. 2	750.0	Hydro		1918	87
Waiau No. 1	750.0	Hydro		1921	84
Waiau No. 2	350.0	Hydro		1928	77
Wind:					
Lalamilo Wind Farm	2,280.0	Wind		1986	19

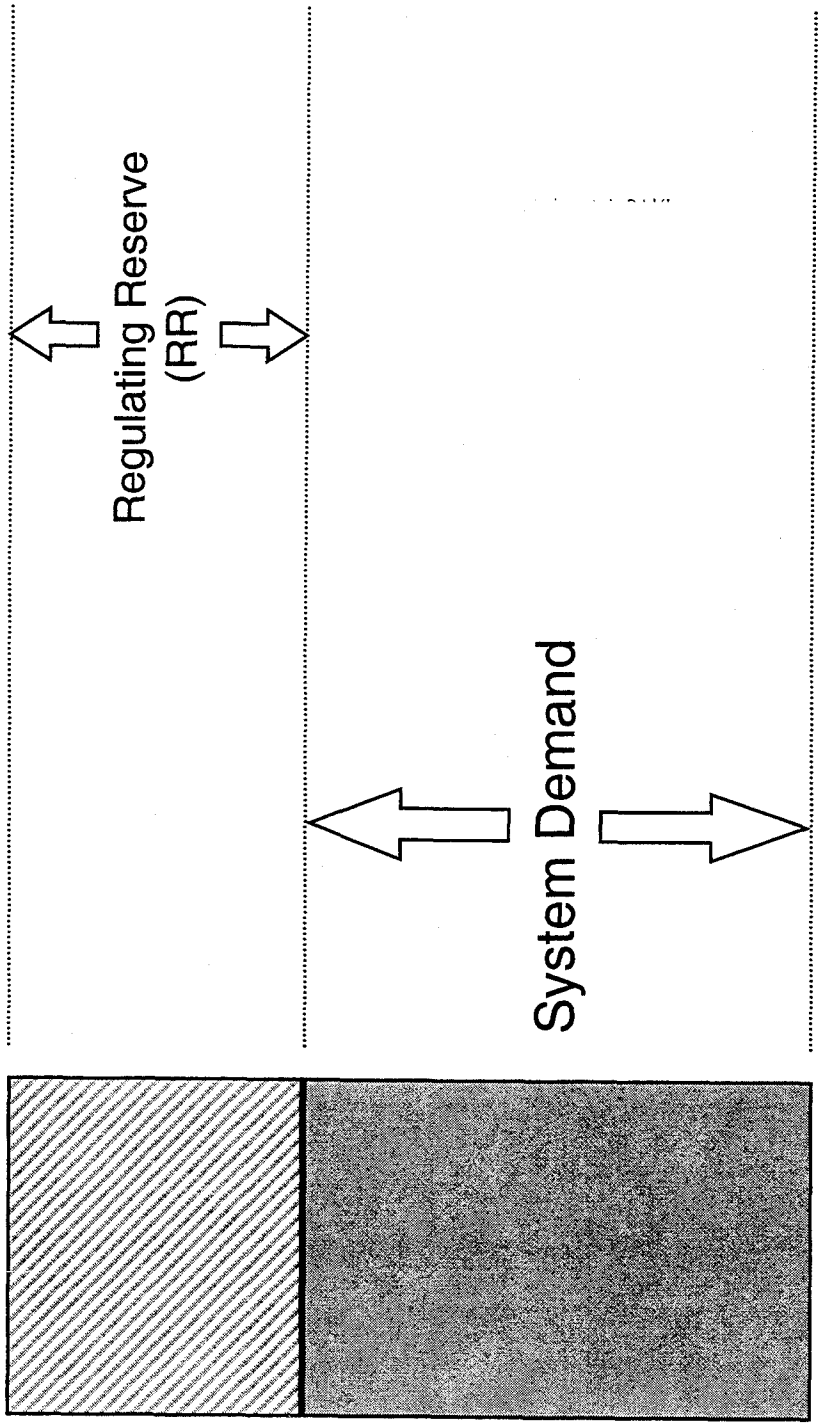
RECEIVED
AS
FOLLOWS

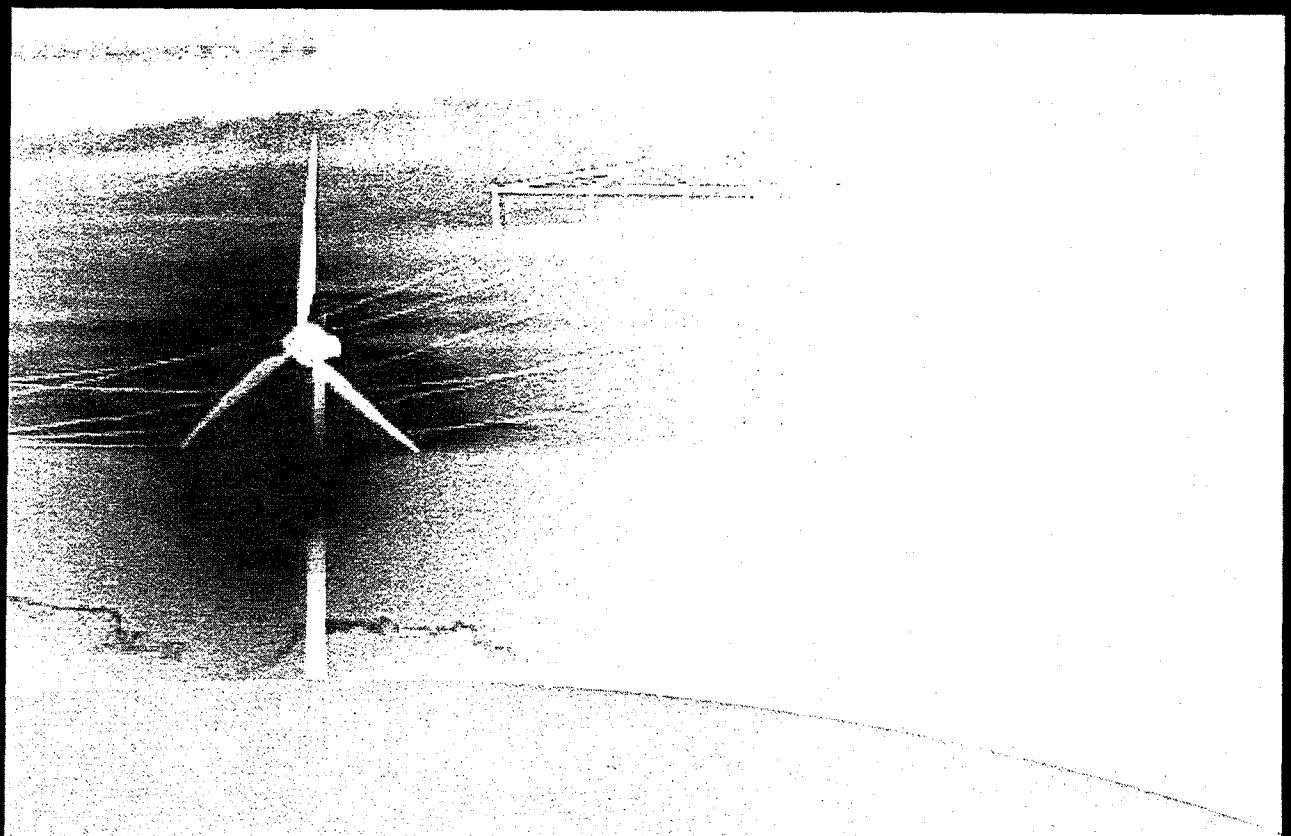
Hawaii Electric Light Company, Inc.



Hawaii Electric Light Company, Inc.

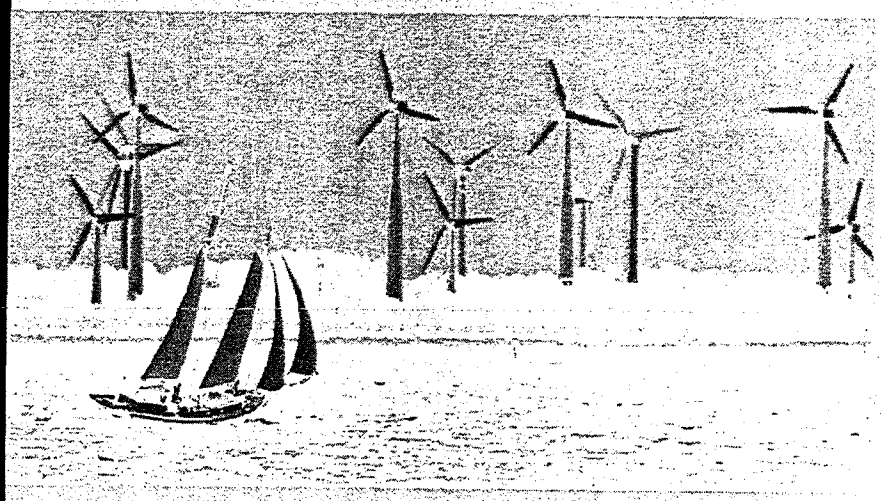
Relationship of Regulating Reserve to Demand





Wind Report 2004

e·on | Netz



Contents

3 Wind Year 2003 – an overview

4 Support allows a boom in new wind power construction – E.ON grid territory characterised by new construction

5 Electricity generation from wind fluctuates greatly

8 Only limited forecasting possible for wind power infeed – demand for wind-based reserve capacity increases with new wind power construction

10 Wind energy leads to regional price distortions – even load distribution overdue

11 Wind power needs a corresponding grid infrastructure – grid expansion necessary

12 Grid expansion needs planning and investment security

12 Grid expansion and new wind power construction must take place in parallel

13 Generation management – grid safety and renewable energy in harmony

14 Wind energy plants must in future also contribute towards stable grid operation

Wind Year 2003 – an overview

In 2003, Germany again led the world in wind energy use thanks to the Renewable Energy Act (EEG). At the end of 2003, wind power plants with a total installed capacity of around 14,350 Megawatts (MW) fed German electricity grids. Of this, the greatest proportion at around 6,250 MW was connected in the E.ON control area.

For technical reasons, the intensive use of wind power in Germany is associated with significant operational challenges:

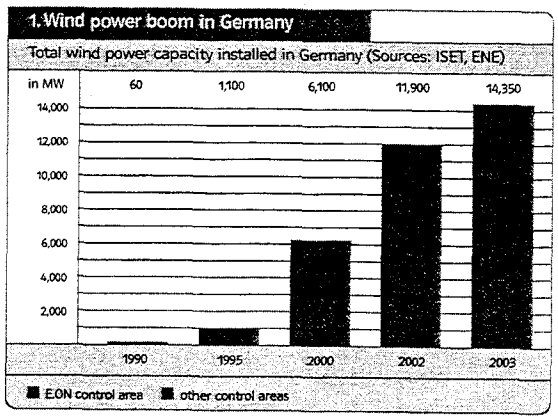
- *Only limited wind power is available. In order to* cover electricity demands, traditional power station capacities must be maintained as so-called "shadow power stations" at a total level of more than 80 % of the installed wind energy capacity, so that the electricity consumption is also covered during economically difficult periods.
- Only limited forecasting is possible for wind power infeed. If the wind power forecast differs from the actual infeed, the transmission system operator must cover the difference by utilising reserve capacity. This requires reserve capacities amounting to 50 – 60 % of the installed wind power capacity.
- Wind power requires a corresponding grid infrastructure. The windy coastal regions of Schleswig-Holstein and Lower Saxony are precisely the places where the grids have now reached their capacity limits through wind power. At present, just under 300 km of new high-voltage and extra-high voltage lines are being planned there in order to create the transmission capacities required for transporting the wind power.

Wind power 2003 – statistics

Installed wind power capacity in Germany on 31.12.2003 [1]	14,345 MW
– of which in the E.ON control area	6,250 MW
Average fed-in wind power capacity in the E.ON control area	969 MW
Wind power production in Germany [1]	18.6 TWh
– of which in the E.ON control area	8.5 TWh
EEG infeed remuneration for wind power (Germany) [2]	approx. 1,700 million €
– of which to be met by customers in the E.ON control area	approx. 510 million €

[1] Source: Institut für Solare Energieversorgungstechnik (ISET), [2] Source: Verband der Netzbetreiber (VDN)

Support allows a boom in new wind power construction – E.ON grid territory characterised by new construction



Germany

At the end of 2003, wind power plants with an installed capacity totalling some 14,350 MW were on line in Germany[3].

This was over 2,450 MW or just under 21 % more than in 2002. This means that since 2000, installed wind power capacity in Germany has increased by 137 %. FIGURE 1 shows the installed wind power capacity in Germany.

This means that Germany has become the world's Number One wind power country: In 2003, Germany accounted for approximately one third of the world's and half of Europe's installed wind power capacities. In Germany in 2003, some 18.6 Terawatt hours (TWh) of wind energy were fed in. This meant that arithmetically, it was able to cover just under 4% of Germany's demand for electricity. For this wind power, grid operators paid out 1.7 billion € in supply payments in accordance with the regulations of the Renewable Energy Act. This corresponds to an average payment of just over 9 € ct / kWh.

In Germany, wind power utilisation differs very much on a regional basis. In 2003 also, Lower Saxony and Schleswig-Holstein and therefore the E.ON control area accounted for most of Germany's wind power production.

E.ON Netz

In 2003, some 8.5 TWh or 46 % of the wind energy produced in Germany were fed in for E.ON Netz (ENE). Approximately 770 million € in infeed payments were paid out for this, with 510 million € of this figure being met by customers in the E.ON control area.

At the end of 2003, a total of 6,250 MW was on line in the E.ON control area – just under 44 % of Germany's entire wind power capacity. This means that in the E.ON control area alone, significantly more wind power generation capacity was installed than on the entire American continent.

For this reason, E.ON Netz GmbH is particularly affected by the technical and operational challenges that massive expansion of wind power brings with it.

[3] Source: Institut für Solare Energieversorgungstechnik (ISET)

Electricity generation from wind fluctuates greatly

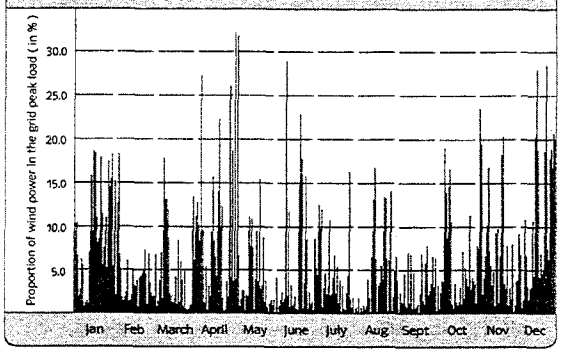
The level of wind power infeed fluctuates greatly depending on the prevailing wind strength. Due to these significant fluctuations, in 2003 the contribution made by wind power production to cover the respective peak load in the E.ON territory varied between zero in real terms and just under one third of the grid load (FIGURE 2).

Looked at over the course of the year, as the annual wind infeed curve shows (FIGURE 3), the availability of the installed wind power plants was relatively low:

- Simultaneous wind power infeed was maximum 4,980 MW, equivalent to just under 80 % of the installed capacity.
- The average fed-in capacity was less than one sixth of the wind power capacity installed in the yearly average.
- Over half the year, the wind power fed-in was less than 11% of the wind power capacity installed in the yearly average.

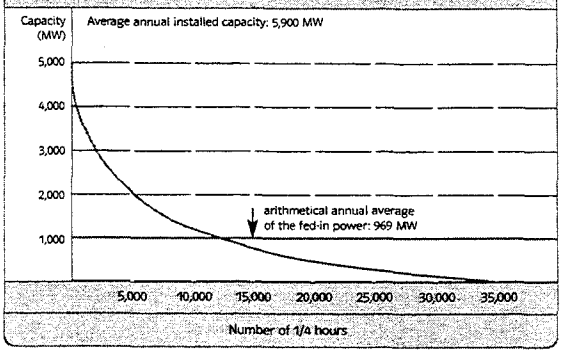
2. The contribution of wind power

to covering the daily grid peak load: 2003 between 0.1 and 32 %



3. Annual curve

Wind power infeed 2003 in the E.ON control area



Annual curve

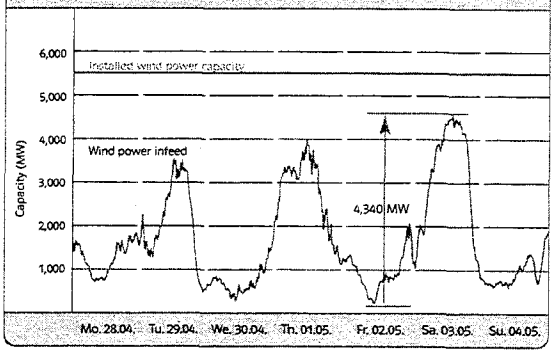
To depict the annual curve, the respective wind power is determined for each quarter-hour of a year and is then shown from left to right in a diagram - in descending order based on the wind power level. If we observe a point on the curve, the associated quarter-hour value (horizontal axis) states how many quarter-hours in the year the wind power plants fed in at least the power that can be read off on the vertical axis. For the remainder of the year, generation was below this power value.

The weather determines the wind level

Both cold wintry periods and periods of summer heat are attributable to stable high-pressure weather systems. Low wind levels are meteorologically symptomatic of such high-pressure weather systems. This means that in these periods, the contribution made by wind energy plants to covering electricity consumption is correspondingly low.

4. Strong fluctuations

in the wind power infeed (E.ON control area: 28.04. to 04.05.2003)



5. Brief decrease

possible in the wind power infeed (E.ON control area: 17.11. to 23.11.03)

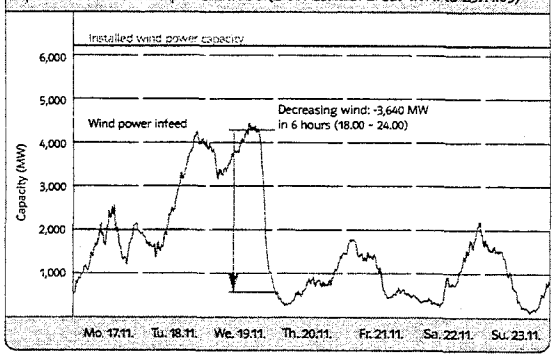


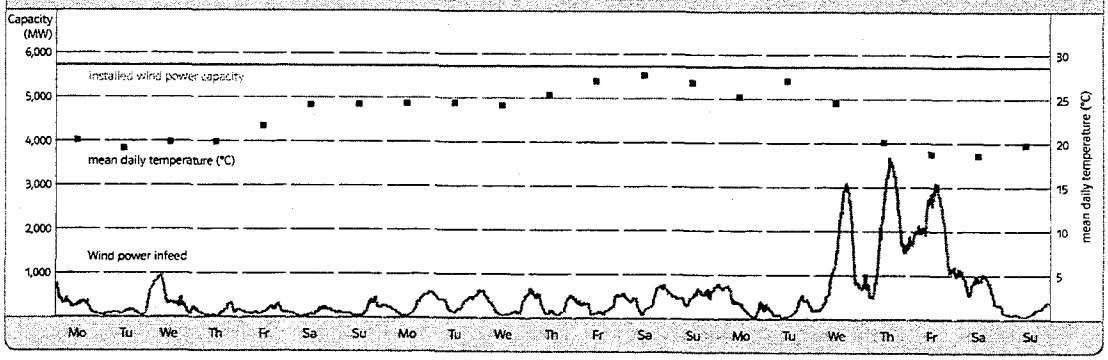
FIGURE 4 shows an example of the wind power infeed pattern in the E.ON territory during a week with strong winds. The difference between minimum and maximum infeed in this example was over 4,300 MW – equivalent to the capacity of six to eight large coal-fired power station blocks.

The wind power infeed changes can occur in a relatively short time. This can be seen in FIGURE 5, which shows the wind power infeed pattern in the E.ON control area in the week of 17th to 23rd November 2003. It is clear that on 19th November, the wind power infeed dropped very sharply – by 3,640 MW within six hours, with an average value of 10 MW per minute.

The experience of the past year has shown that whenever electricity consumption was comparatively high because of the weather, namely during cold wintry or hot summer periods, wind power plants could make only a minor contribution towards covering consumption.

6. Minor contribution of wind power during the 2003 heatwave

E.ON control area: 28.07. to 17.08.2003

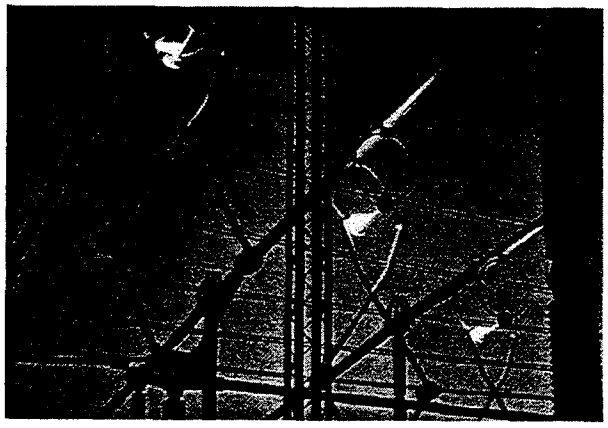


Midweek peak load
The midweek peak load is calculated on the basis of uniform international criteria. This day's load curve is used in energy management to characterise the electricity consumption of a grid territory, country etc.

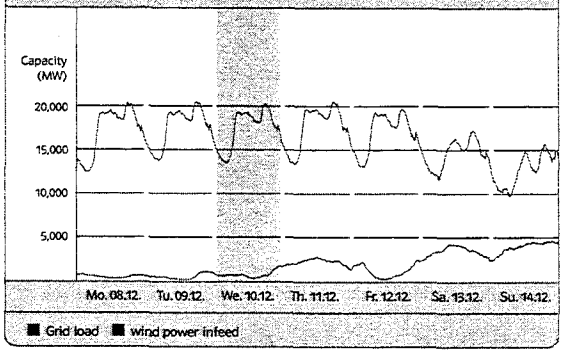
This relationship was again confirmed in Germany during the heatwave of July / August 2003 (FIGURE 6). The summer electricity consumption was at that time at an above-average high level due to the temperature. At the same time, traditional power stations had to partly reduce their capacity so as not to impermissibly heat up the rivers that serve as sources of cooling water. During this phase, wind power production was also very low due to the lack of wind and was not able to contribute towards relieving the strained supply situation.

FIGURE 7 shows that in the winter of 2003 also, the contribution of wind power towards covering load was low precisely in phases of particularly high electricity demand. The wind power infeed curve during the week of so-called "midweek peak load" in the E.ON grid in 2003 is shown.

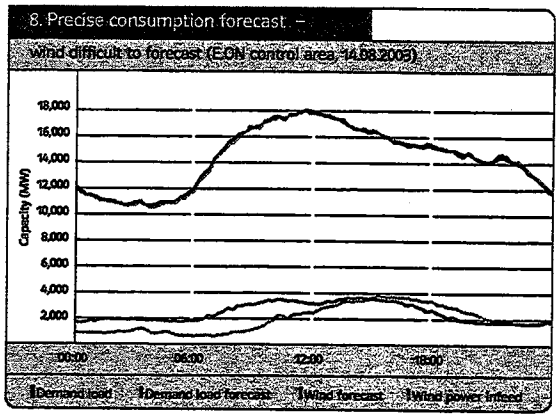
In order to also guarantee reliable electricity supplies when wind power plants produce little or no electricity - for example during periods of calm or storm-related shutdowns - traditional power station capacities must be available as a reserve. The characteristics of wind make it necessary for these "shadow power stations" to be available to an extent sufficient to cover over 80% of the installed wind energy capacity. This means that due to their limited availability, wind power plants cannot replace the usual power station capacities to a significant degree, but can basically only save on fuel.



7. The minor contribution of wind power
during midweek peak load (E.ON control area: 08.12. to 14.12.03)



Only limited forecasting possible for wind power infeed – demand for wind-based reserve capacity increases with new wind power construction



Power-frequency control

The purpose of power-frequency control is to create an equilibrium between generation and consumption in a defined grid territory (control area) at a stable grid frequency of 50 Hz. This is achieved by briefly activating additional generating capacity or by deactivating surplus generating capacity for seconds and minutes.

Large quantities of electrical energy cannot be directly stored. This means that every second, exactly the amount of energy must be fed into the grid that is taken out at the same time. If the amount fed in differs from the amount tapped, this can cause faults or even failure of the supply – as confirmed in 2003 by the wide-scale power failures in the USA, Italy, Sweden and Denmark.

The transmission system operators must therefore at all times ensure a balance in their control areas between generation and tapping (power-frequency control).

Generation in traditional power stations can be easily controlled in line with demand. As a result, in the past it was mainly only the time pattern of tapping from the grid that was relevant to power-frequency control. Thanks to constant consumption behaviour, this tapping can be forecast with a high degree of accuracy.

However, the increased use of wind power in Germany has resulted in uncontrollable fluctuations now also occurring on the generation side due to the stochastic character of wind power infeed, thereby increasing the demands placed on control and bringing about rising grid costs (FIGURE 8).

So that stable grid operation is possible despite the high volatility of wind power infeed, transmission system operators depend on the most accurate possible forecasts of the expected wind power infeed.

To forecast wind power, E.ON Netz uses a complex forecasting system developed by ISET and based on the forecasting data of the German Meteorological Service.

The quality of wind power forecasting is to a great extent limited by the quality of the wind forecasting. Like all weather forecasting, this is only partly reliable.

In 2003, the average negative forecasting error for the E.ON control area was -370 MW, and the average positive forecasting error was 477 MW.

However, during individual hours the deviations reached much higher levels of up to +/-2,900 MW. This was equivalent to just under half the installed wind power capacity. FIGURE 9 shows the frequency distribution of the forecast error.

The transmission system operator must balance out differences between the wind power forecast and the wind power actually fed in by using the controlling power range and reserve capacity.

Of crucial importance to the wind-related demand for reserve capacity is the expected maximum forecast deviation and not, for example, the mean forecast error. This is because even if the actual infeed deviates from the forecast level only on a few days in the year, the transmission system operator must also be prepared for this eventuality and have sufficient capacity available so that a reliable supply is still guaranteed. FIGURES 10 and 11 show examples of the deviation between the actual wind power infeed and the forecast.

The massive increase in the construction of new wind power plants in recent years has greatly increased the need for wind-related reserve capacity in Germany. In 2003, costs amounting to around 100 million € for this were incurred in the case of E.ON Netz alone.

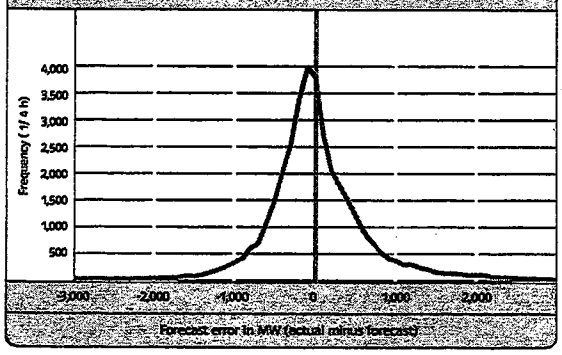
Operational experience over the past few years has shown that reserve capacities in the order of magnitude of up to 60 % of the installed wind power capacity must be kept for wind balancing in years when wind levels are normal. The need for reserve capacity and the resulting costs will therefore continue to rise in future parallel to the further expansion of wind power.

In 2003, wind levels and therefore also the absolute fluctuation range of the wind power infeed were at above-average high levels. This meant that in retrospect, only reserve capacity amounting to around 50 % of the installed wind power capacity actually had to be used.

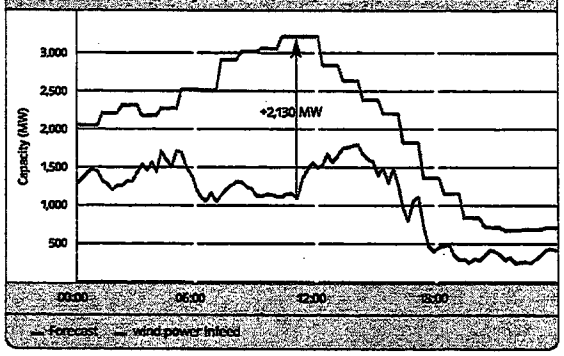
Forecasting error
The forecasting error is calculated from the actual wind infeed minus the forecast wind infeed. A forecasting error of -1,000 MW therefore means that the forecast was 1,000 MW too high.

Wind-related reserve capacity
This means power station capacities that can be brought onto or taken off load at short notice and which are reserved with the power station operators by the transmission system operators for a fee to be used for balancing out deviations between the actual and forecast wind power infeeds.

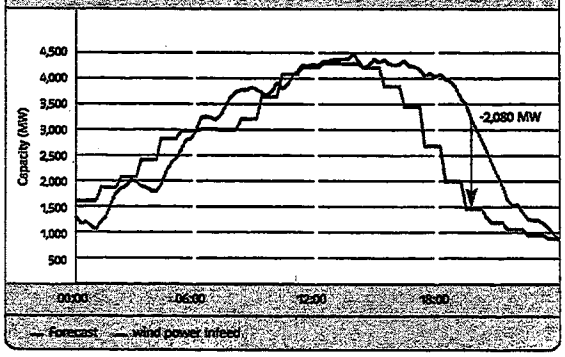
9. Frequency distribution of the forecast error
for wind power infeed 2003 in the E.ON control area 2003



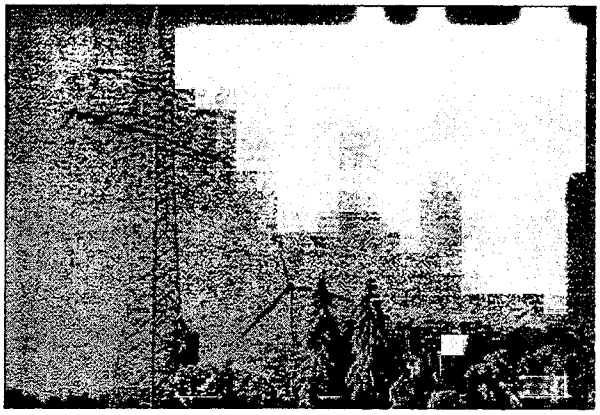
10. Less wind than forecast
Positive reserve capacity required (Example: E.ON control area 01.07.03)

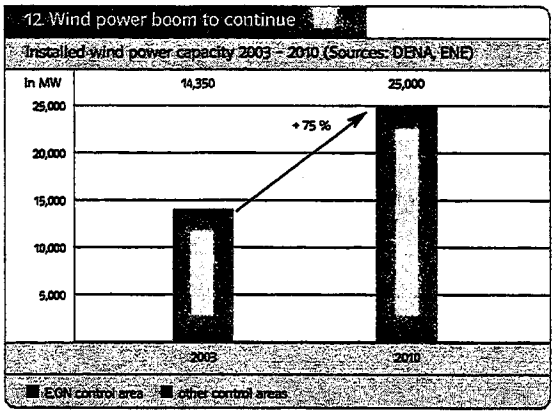


11. Wind blows longer than forecast
Negative reserve capacity required (Example: E.ON control area 03.05.03)



Wind energy leads to regional price distortions – even load distribution overdue





In 2003, the expense required for balancing out the wind power fluctuations differed greatly in the four German control areas, depending on the wind power capacities installed there. Approximately half the wind balance was done by E.ON Netz GmbH, even though its share of the ultimate consumer sales in Germany was only 30 %. The Renewable Energy Act provides for national distribution of the EEG infeed remuneration and energy quantities (work equalisation). However, so far there is no law covering a national allocation of the costs incurred for balancing out the fluctuating wind power infeed (capacity equalisation). The result of this is a higher grid utilization cost burden in the "windy" control areas.

In the E.ON Netz territory alone, almost 10,000 MW of on-shore wind power capacity and some 2,500 MW of offshore wind power capacity are expected by 2010. In total, according to forecasts of the German Energy Agency (DENA), the wind power capacity installed in Germany should increase by 75 % to 25,000 MW by 2010 (FIGURE 12).

Demand for wind-based reserve capacity will continue to increase accordingly. If the framework conditions were to remain unchanged, this would lead to a further intensification of the existing imbalance between the transmission system operators.

In addition to the already existing allocation mechanisms in the EEG, it is therefore necessary to also establish a simultaneous proportional involvement of all transmission system operators in the wind equalization program. Technical implementation of such a legal ruling is possible within a few months. It would eliminate existing wind-related grid price distortions and also reduce the total wind-related reserve requirement in Germany, because wind patterns are not the same in all regions of Germany and the wind power fluctuations would therefore partly balance each other out.

Wind power needs a corresponding grid infrastructure – grid expansion necessary

One decisive factor for the further expansion of wind energy use will be the capacities of the electricity grids. Today, the grids in some regions of Germany, for example in Schleswig-Holstein and Lower Saxony, are already approaching their capacity limits. When the wind is strong, they are unable to take any additional wind power.

The reason: Up to now, electricity supplies in Germany have largely been decentralized, with power stations having been built across the country as close to the points of consumption as possible. This has made it possible to avoid transporting electricity across long distances.

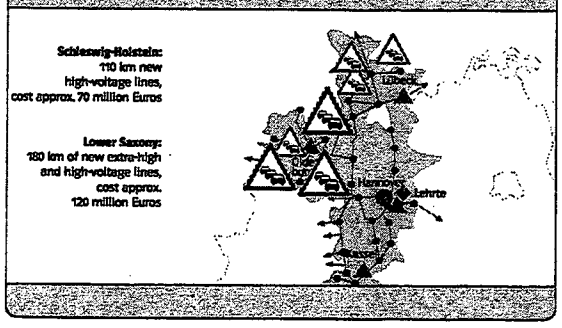
The power grids were built to bring the energy from these power stations to the consumers, which has meant that, expressed in simple terms, energy has always flown in one direction and only across relatively short distances. This has changed with the boom in wind energy. An increasing number of wind parks have been and are being built primarily in coastal and relatively sparsely populated areas of low consumption, which in periods of strong wind generate more energy than the area in question consumes at the same time. Consequently, this surplus energy must be transported over long distances. The line grids in the coastal regions can no longer do this in their current state without limits.

The Renewable Energy Act obligates grid operators to remedy wind-related grid congestion at their own expense. As a transmission system operator in the north German coastal states of Schleswig-Holstein and Lower Saxony, E.ON Netz GmbH is particularly affected by this obligation.

To remedy wind-related congestions, E.ON Netz is planning around 110 km of new 110 kV high-voltage lines in Schleswig-Holstein, the cost of which is estimated at 70 million €.

Approximately 180 km of high-voltage and extra-high voltage lines are being planned in Lower Saxony, including for the first time a new wind-related extra-high voltage route in the Oldenburg Münsterland. The estimated cost for the line construction in Lower Saxony is around 120 million € (FIGURE 13).

13. Wind-related grid congestions in the E.ON control area necessitate grid expansion in Schleswig-Holstein and Lower Saxony

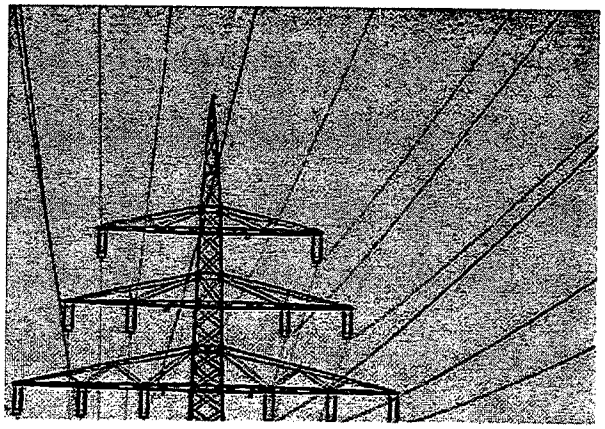


In both cases, the plans are based on pure onshore expansion scenarios. If offshore wind parks will also be built on a greater scale in the future, additional grid expansion measures would also be necessary in the extra-high voltage grid.

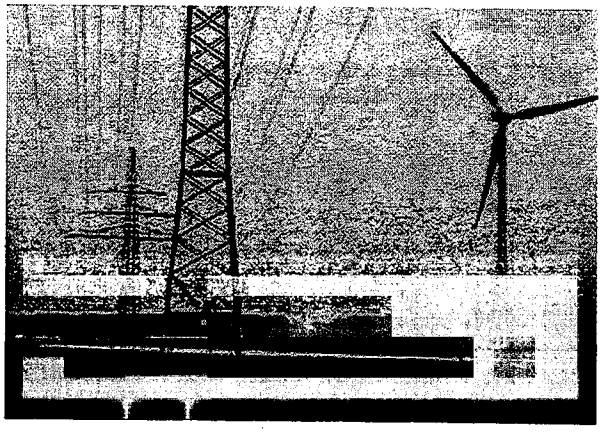
Wind power does not only cause regional grid congestion in the north German Federal States. In Schleswig-Holstein and Lower Saxony, far more wind power is generated under conditions of high wind and low load than is consumed in these states. Since in the coming years the expansion of wind power is set to progress on the basis of political will, by the end of the decade at the latest, Schleswig-Holstein and Lower Saxony will be wind power export states across long distances. The same will probably also then apply to Mecklenburg-Vorpommern if the current offshore plans become reality. This will drastically change the current principle of decentralized electricity generation close to the point of consumption. Cross-border electricity trading will also be significantly hindered by increased grid congestion. New transport lines will be necessary on a large scale in order to bring wind power generated on the coast and at sea to the consumer centres in the Ruhr or Rhine-Main region. In its expert assessment relating to this, the Institute for Electrical Plant and Energy Management of the RWTH Aachen assumes that by 2016, up to 1,500 km of new high-voltage and extra-high voltage power lines will be required for this in Germany[4].

[4] Energiewirtschaftliche Tagesfragen 9/2003, Page 566

Grid expansion needs planning and investment security



The grid operators require planning and investment security for expanding the wind power grid. Politicians, wind park planners and grid operators must therefore develop realistic scenarios for the further expansion of wind power – including offshore – that can serve the grid operators as a planning basis for the additional capacity requirement. As part of the so-called DENA study, a national reference scenario is being worked on for the first time by the German Energy Agency in collaboration with plant operators, wind park planners and politicians, with the support of E.ON Netz GmbH.



Grid expansion and new wind power construction must take place in parallel

Due to the often lengthy approvals procedures that are involved, comparatively long realization times must be expected in Germany for the construction of new high-voltage and extra-high voltage power lines, as is currently becoming clear in the case of the power line construction plans in Schleswig-Holstein.

It is therefore necessary to speed up the approvals procedures for the construction of required new lines for wind power and to in future link the approvals procedures for new wind parks to the approvals procedures for the required grid expansion. There is a risk of bad investments being made if this is not successful: Wind parks without a sufficient grid connection, or lines set up for wind power but for which there is no supply.

Generation management – grid safety and renewable energy in harmony

In Schleswig-Holstein, due to the many wind power plants installed there, the grid capacities are now exhausted when there is strong wind. Although the approvals procedures for the required grid expansion measures have already been initiated, it can be assumed that it will be several years before the planned power lines are realized. So that additional wind parks can still be brought on line until completion of the grid expansion, in 2003 E.ON Netz GmbH introduced what is referred to as "generation management" in Schleswig-Holstein.

This refers to a temporary reduction in the power fed in by wind energy plants when there is strong wind in order to protect grid infrastructure such as overhead lines or transformers against supply-related overloads and to avoid supply failures.

The aim is to guarantee a reliable electricity supply and still make optimum use of the grids for the receiving electricity generated from wind power.

At present in Schleswig-Holstein, wind power plants with an installed capacity of 600 MW – just under one third of the total wind power capacities in Schleswig-Holstein – are involved in the generation management.

Until the grid expansion is completed, new wind parks in Schleswig-Holstein can be granted only conditional grid connection approval. A condition is agreement to participate in the generation management.

Without generation management, further expansion of wind power in Schleswig-Holstein is for the time being not possible.

In view of the wind power-related grid congestions in Lower Saxony, E.ON Netz is also introducing generation management there.

How generation management functions in Schleswig-Holstein

Based on grid calculations, the E.ON grid has been divided up into ten regions in Schleswig-Holstein.
Every impermissible load on equipment is automatically forwarded to the grid management centre of E.ON Netz GmbH in Lübeck. Following identification of the affected region, a signal is sent to the wind parks feeding in electricity in this region. The signal defines the maximum active power at which the region's wind energy plants can feed electricity into the grid in view of the current grid situation.
The wind park operators are responsible for the demanded reduction in the infeed power. They therefore make an essential contribution towards maintaining a safe supply. Direct power control of the plants by E.ON Netz is not possible for technical reasons.
When sufficient grid capacities are available again, the power restrictions are immediately lifted again – also via a signal sent to the respective wind park management system.

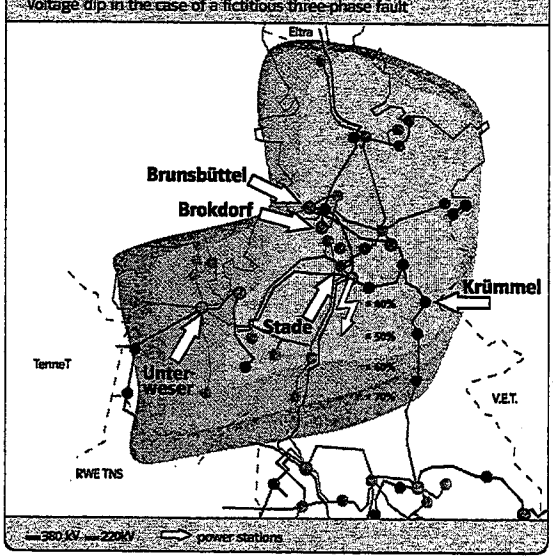
Wind energy plants must in future also contribute towards stable grid operation

The foreseeable further expansion of wind energy in Germany and Europe means that in future, it will be necessary to pay more attention than before to supply reliability when designing new wind energy plants.

The operational behaviour of wind power plants has so far differed greatly from that of traditional large power stations. Due to the massive and ongoing new expansion of wind power, it has therefore become increasingly difficult to guarantee the stability of the electricity supply - particularly in the event of a power failure.

14. Potential gradient area

Voltage dip in the case of a fictitious three-phase fault



Potential gradient area
As an example, FIGURE 14 shows the voltage dip as a percentage of the grid nominal voltage in the case of a fictitious three-phase fault close to the Dollern substation.
In this case, the grid voltage would briefly fall to below 80 % everywhere. This would result in the sudden failure of almost the entire wind power supply in this area.

This means that wind power plants do not contribute to the same extent towards stabilising the grid frequency and to voltage stabilising as is the case with traditional power stations, which are actively involved in grid control.

But even more serious is the fact that wind power plants of the usual type have so far disconnected themselves from the grid even in the event of minor, brief voltage dips, whereas large thermal power stations are disconnected only following serious grid failures.

Faults in the extra-high voltage grid can therefore result in all wind power plants in the affected region failing suddenly. This means that within a very short time, the wind power supply of up to 3,000 MW can fail, thereby putting the grid stability at risk.

New grid connection regulations for wind power plants

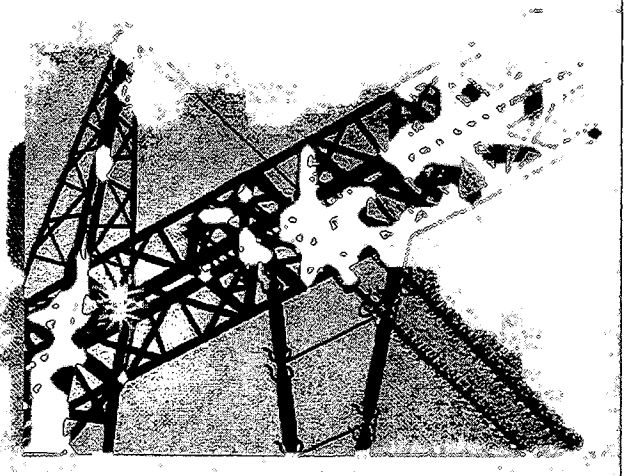
Even today, the failure of wind power generation in the event of grid problems is barely possible to master via system technology. With regard to the further expansion of wind power, E.ON Netz therefore published new grid connection regulations in August 2003[5]. The minimum technical requirements for wind power plants defined therein are essential in the interests of grid stability and supply reliability.

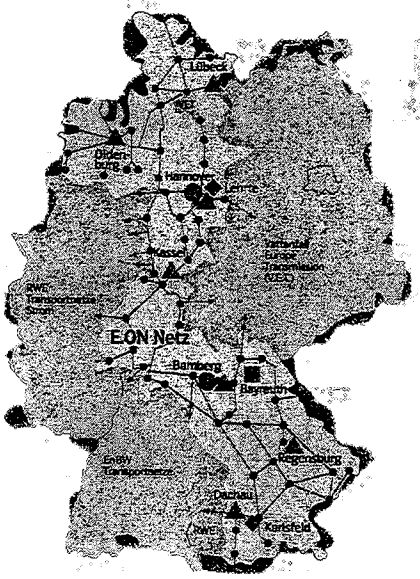
In future, wind power plants may no longer be disconnected from the grid following a grid failure. They must operate without reaction and must be able to act so as to provide voltage back-up on the grid when there is an operational fault. Like conventional power stations, wind power plants must in future also feed active power into the transmission system to support the grid frequency immediately after the grid failure has been remedied.

[5] Download the grid connection regulations under www.eon-netz.com

A profile of E.ON Netz GmbH

E.ON Netz GmbH is responsible for the electricity transport grid of the E.ON Group. With over 32,500 kilometres of high-voltage and extra-high voltage lines from Flensburg to Garmisch-Partenkirchen, the company is one of the main electricity grid operators in Europe. The control area of E.ON Netz GmbH covers one third of Germany. More than 20 million people profit from a reliable system operation. With a total of over 6,000 MW of installed wind power capacity in its control area, E.ON Netz makes a leading contribution on both a national and a European scale towards integrating wind energy into the electricity grid.





Imprint

Layout, realisation:
agentur marks, Fürth

Photos:
E.ON Hanse (Pages 2, 4)
E.ON Netz (title archive, Page 7 - Archive, 11 - Georg Birkner, 13 - Jens Voltmer, 15 - Archive)

E.ON Netz GmbH
Corporate Headquarter
Bernecker Straße 70
95448 Bayreuth
Germany

Editors:
Dr. Hanns Bouillon, Peter Fösel, Dr. Jürgen Neubarth, Dr. Wilhelm Winter

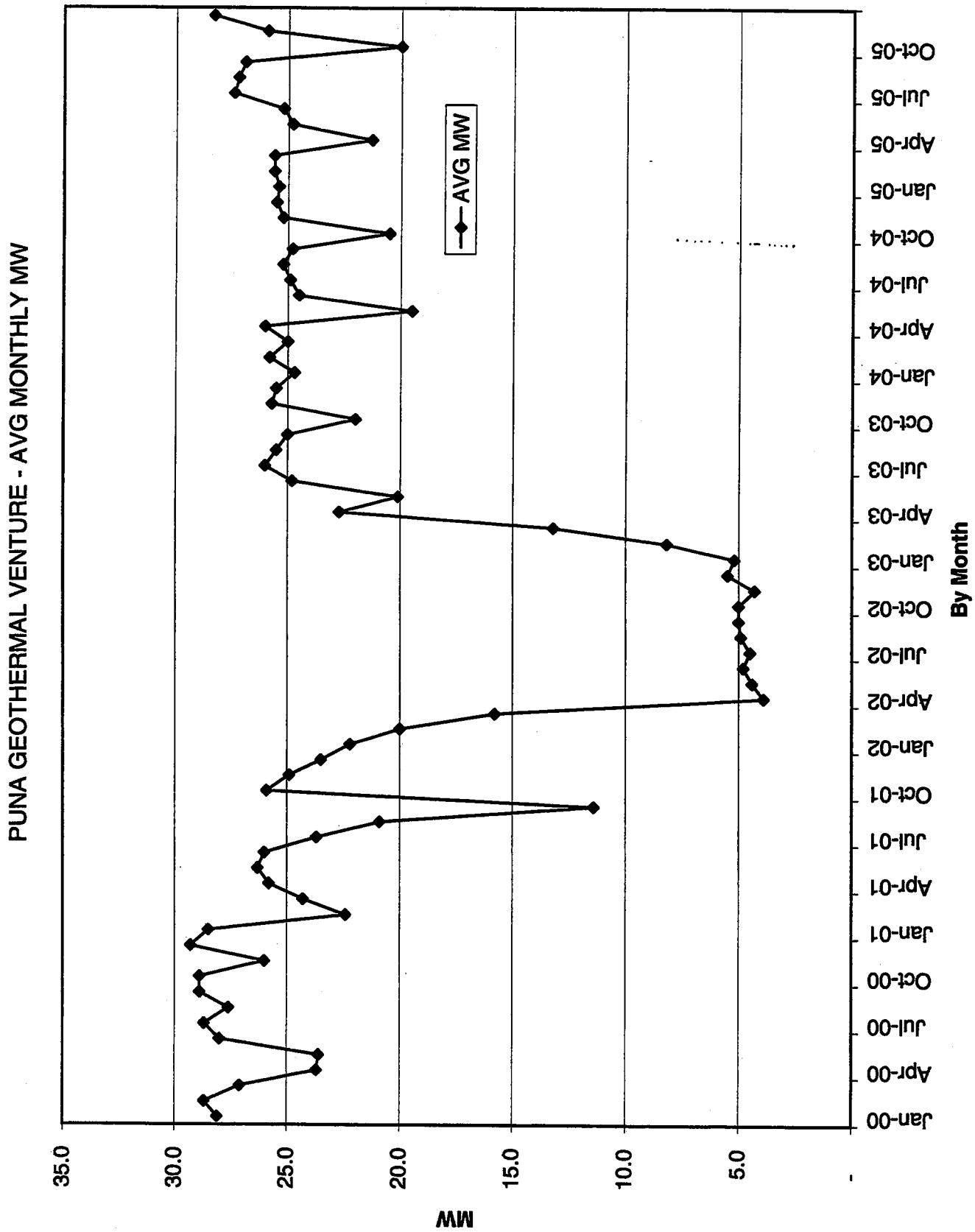
Contact:
Corporate Communications

T +49(0)921-915-2081
F +49(0)921-915-2089

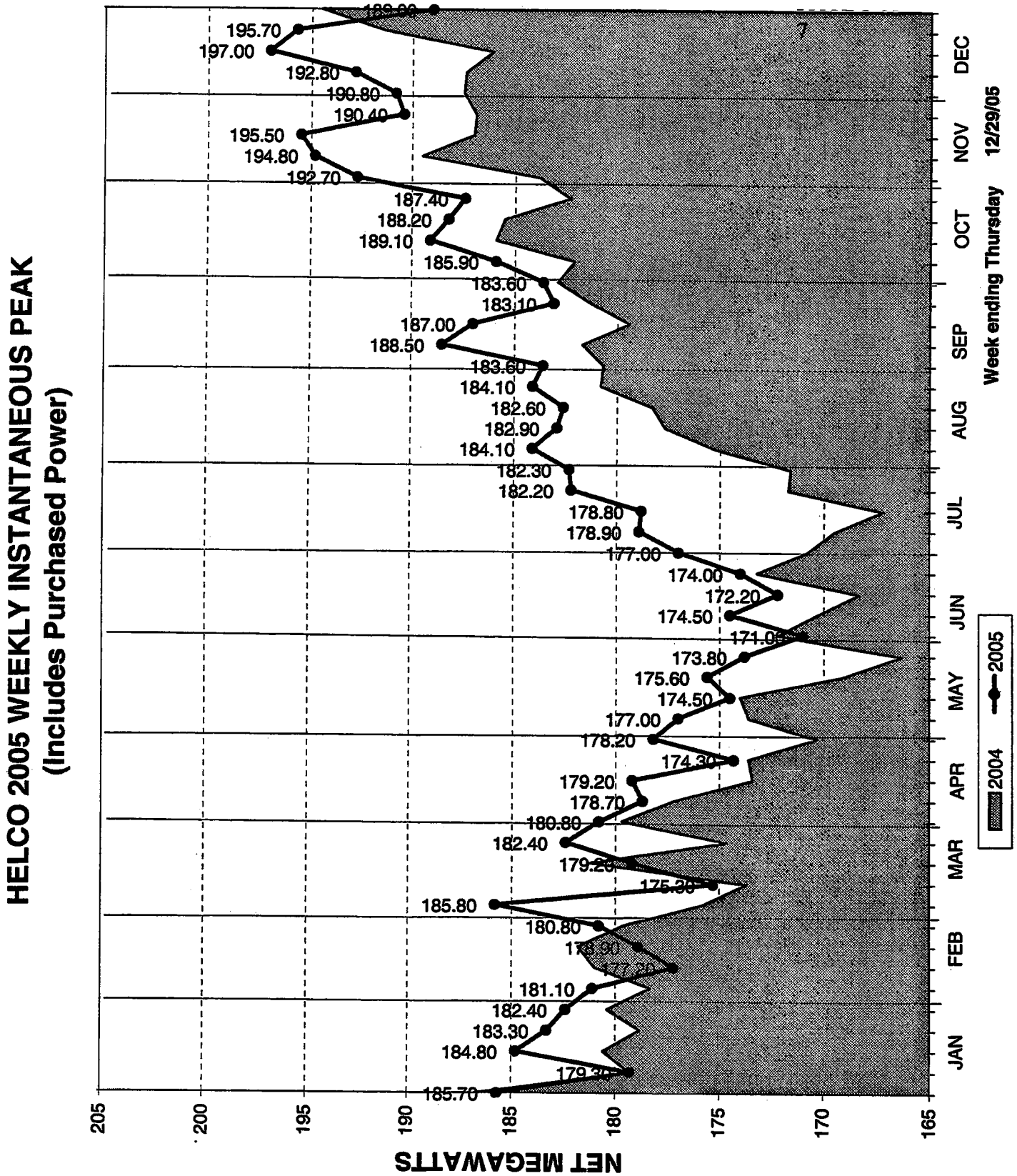
info@eon-netz.com

ENE 05/2004

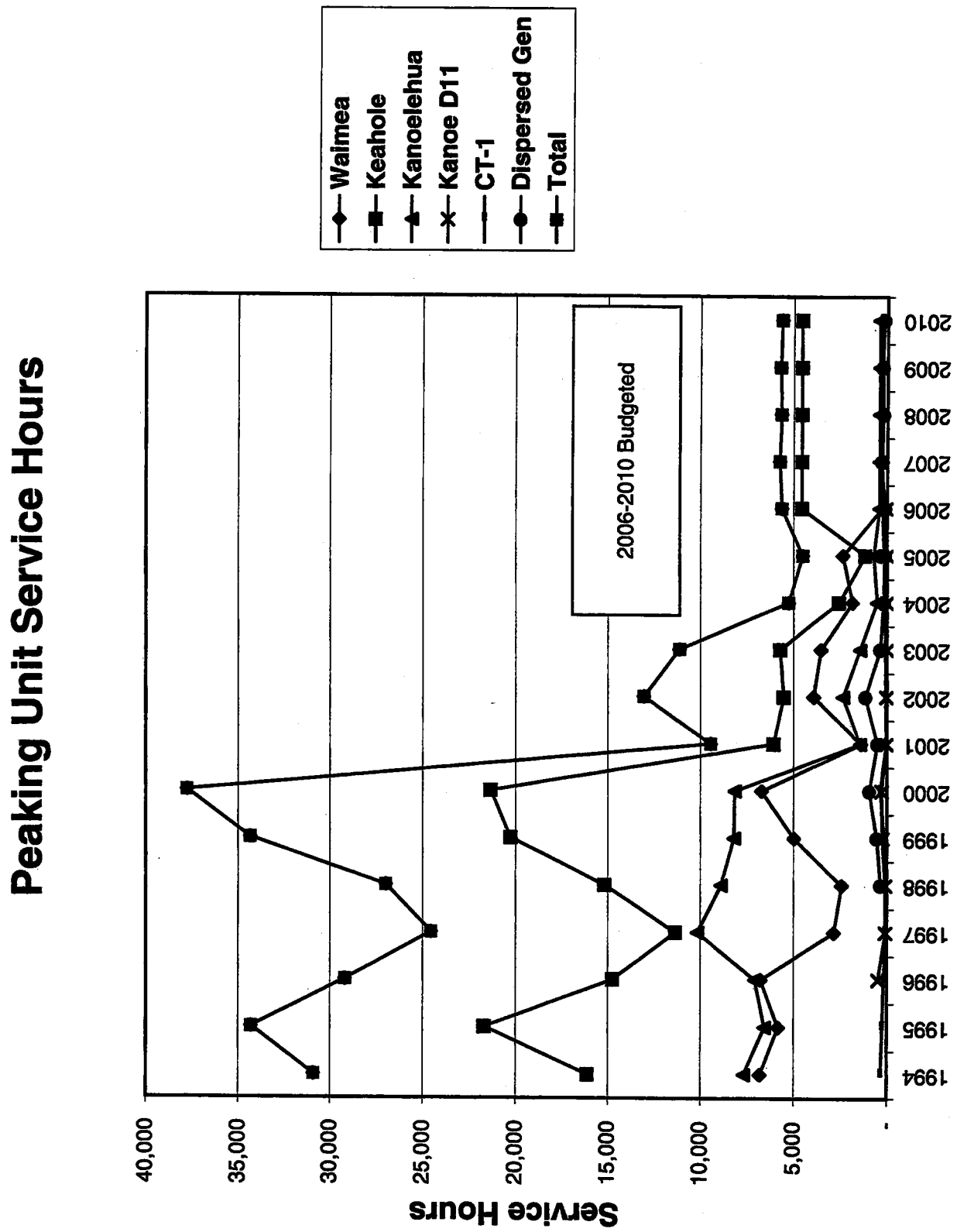
Hawaii Electric Light Company, Inc.



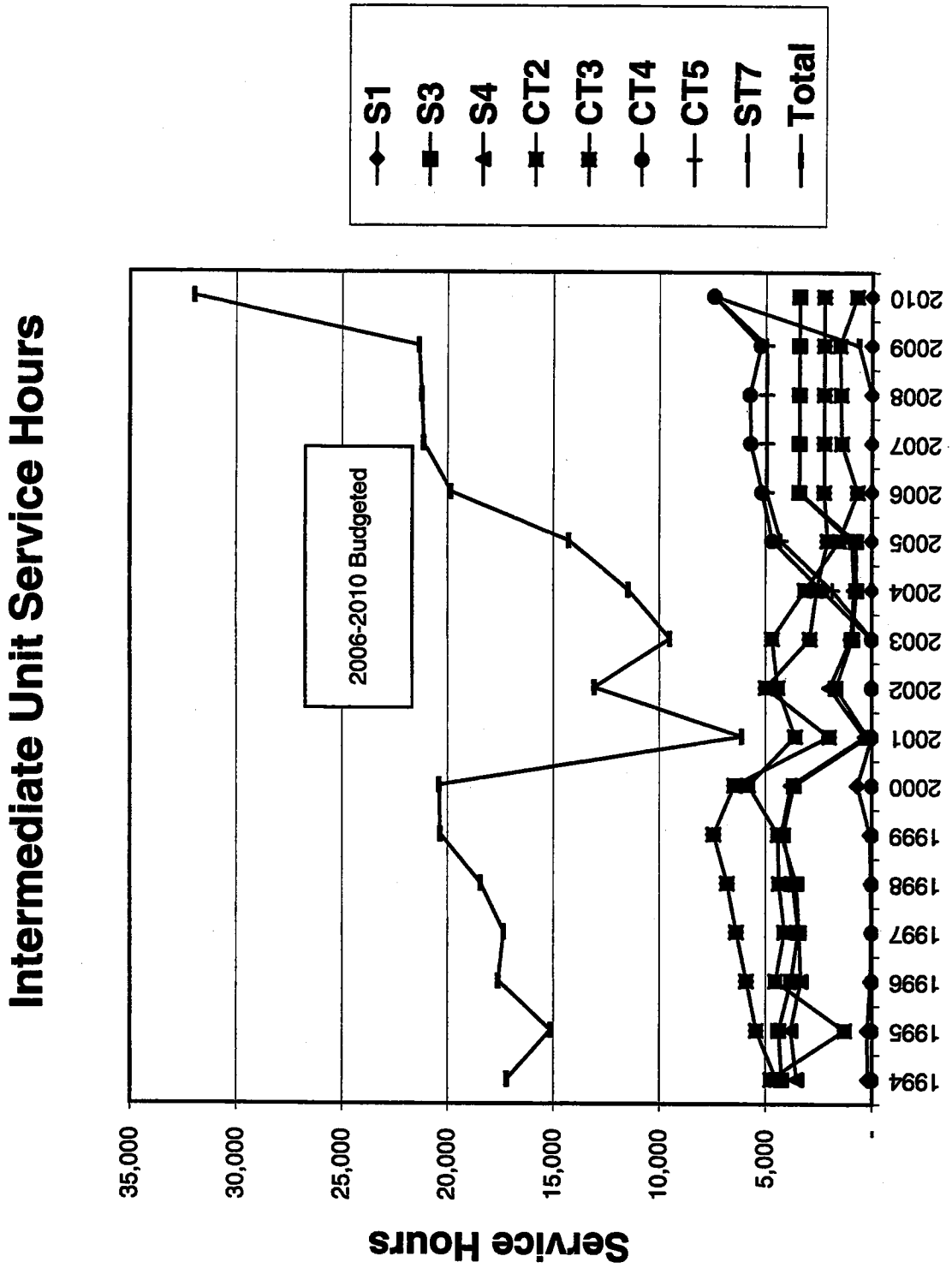
Hawaii Electric Light Company, Inc.



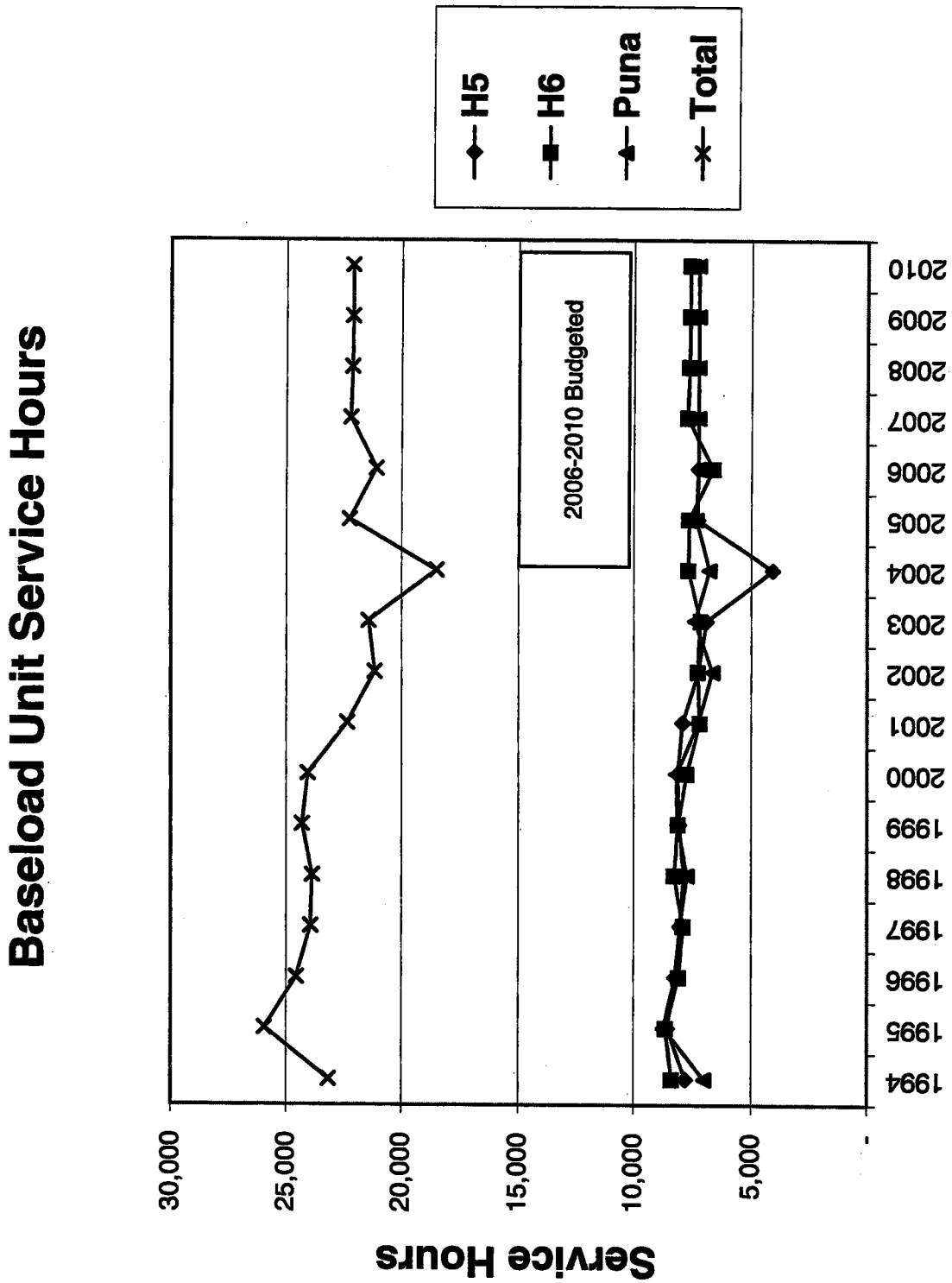
Hawaii Electric Light Company, Inc.



Hawaii Electric Light Company, Inc.



Hawaii Electric Light Company, Inc.

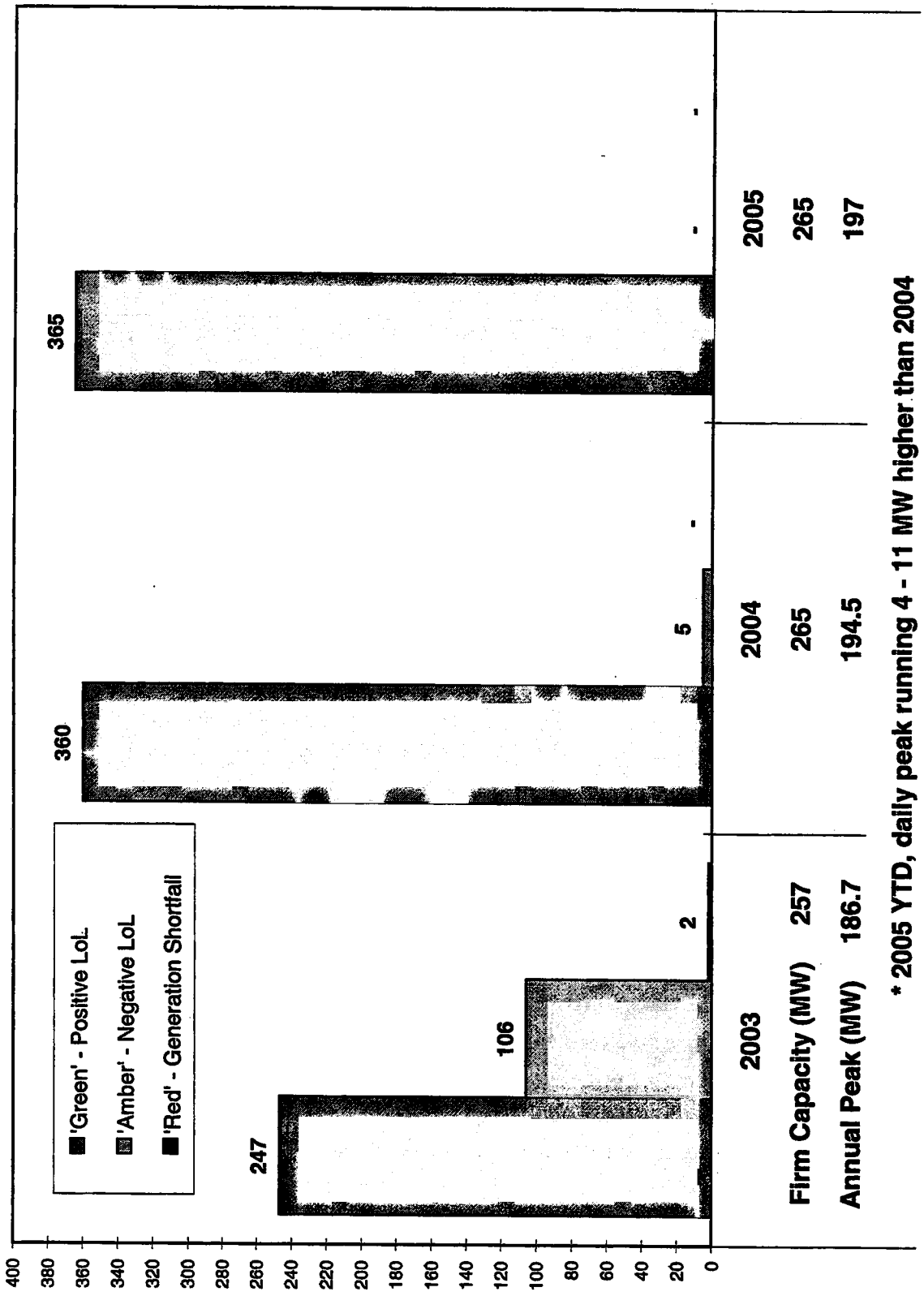


INTENTIONALLY LEFT BLANK

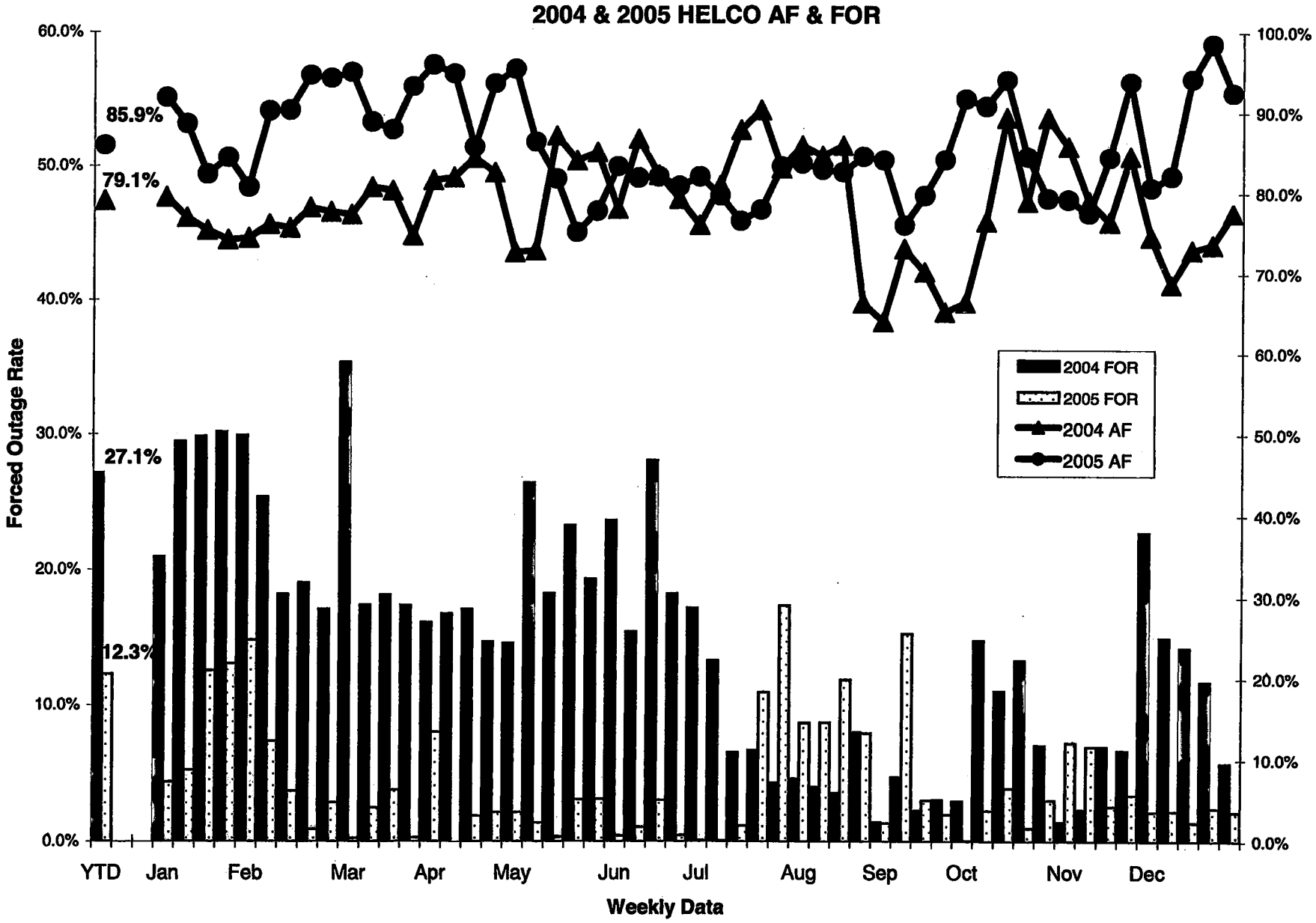
INTENTIONALLY LEFT BLANK

Hawaii Electric Light Company, Inc.

System Margins



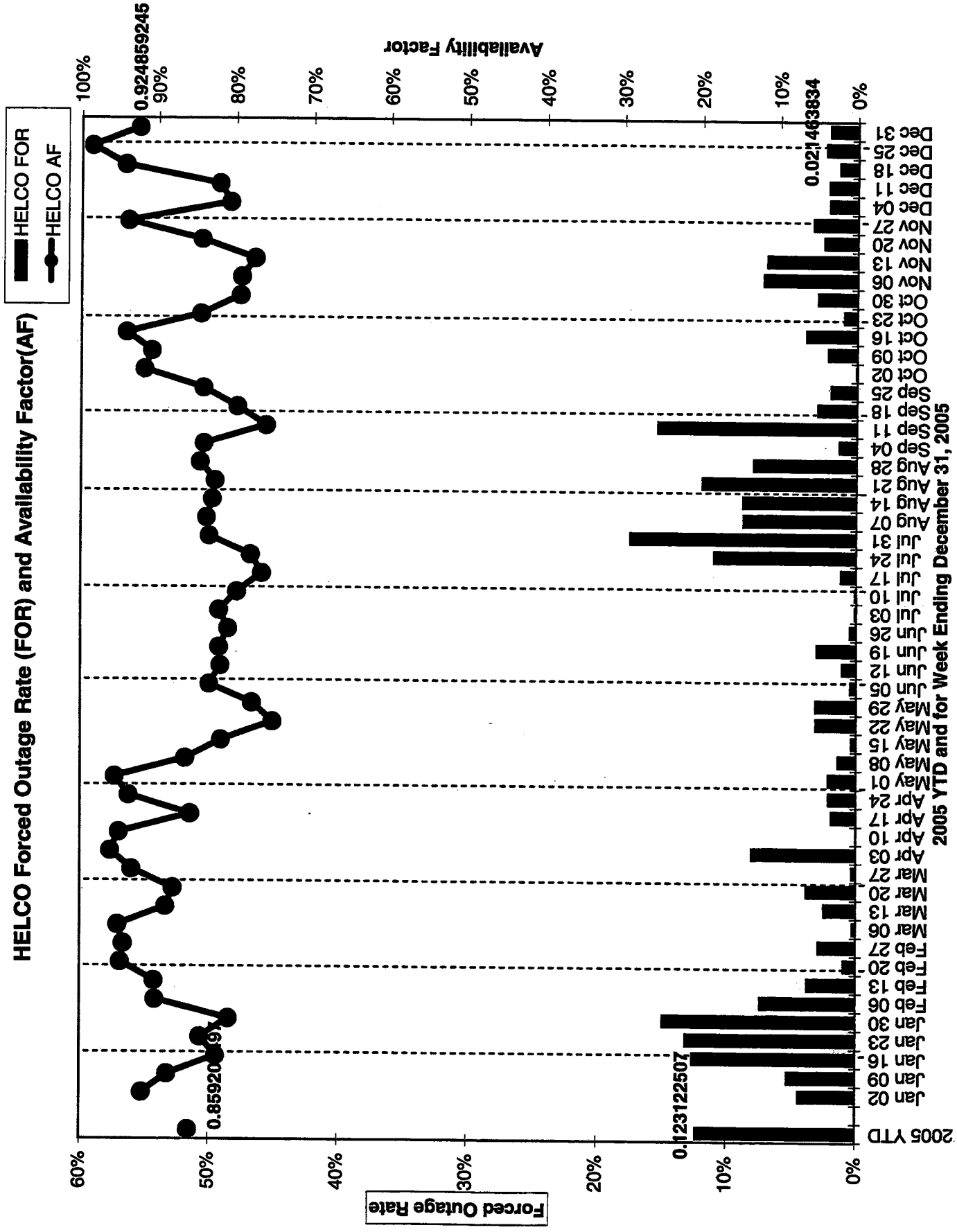
Relationship of AF and FOR



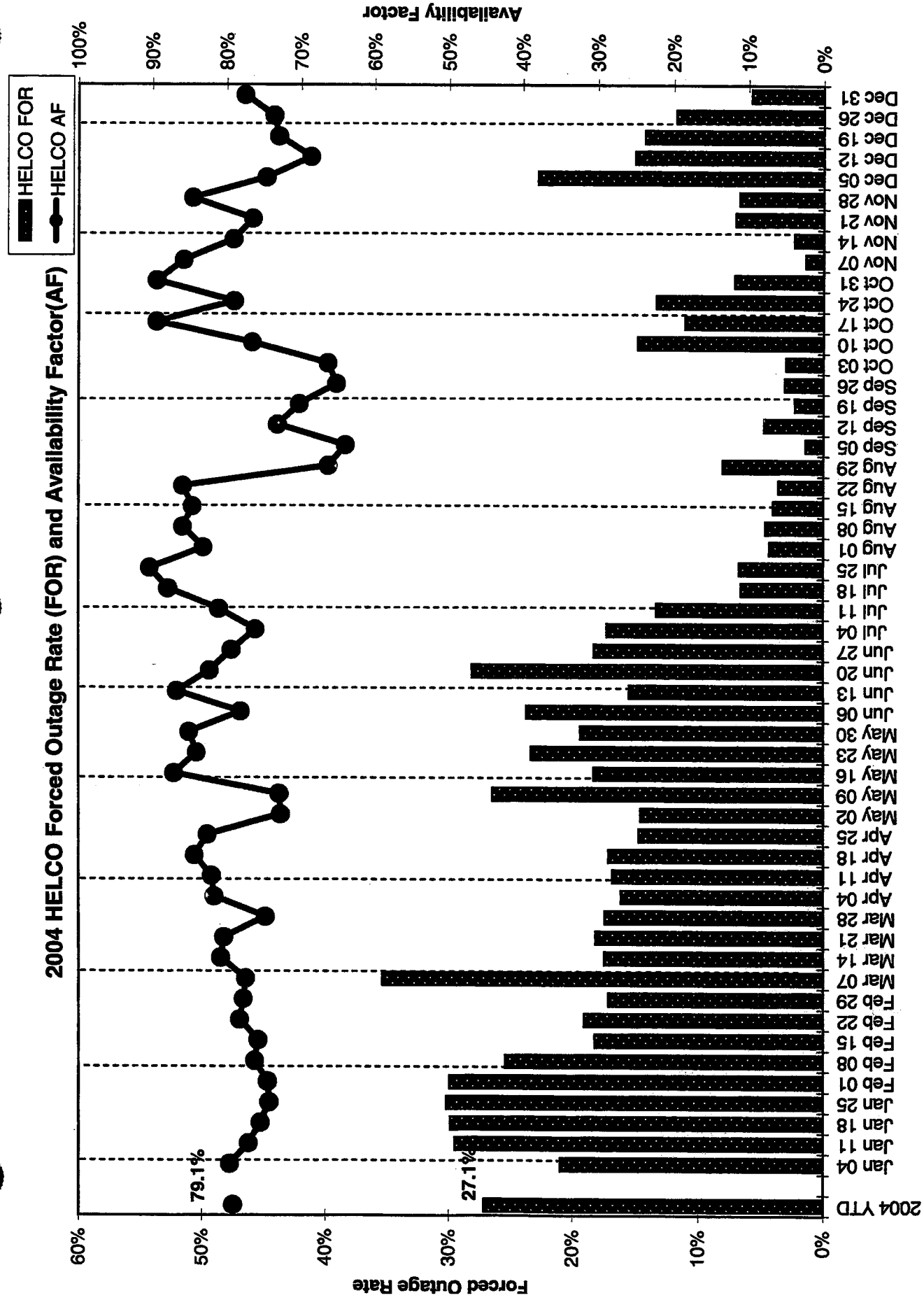
Hawaii Electric Light Company, Inc.

HELCO-514
DOCKET NO. 05-0315
PAGE 1 OF 1

Hawaii Electric Light Company, Inc.

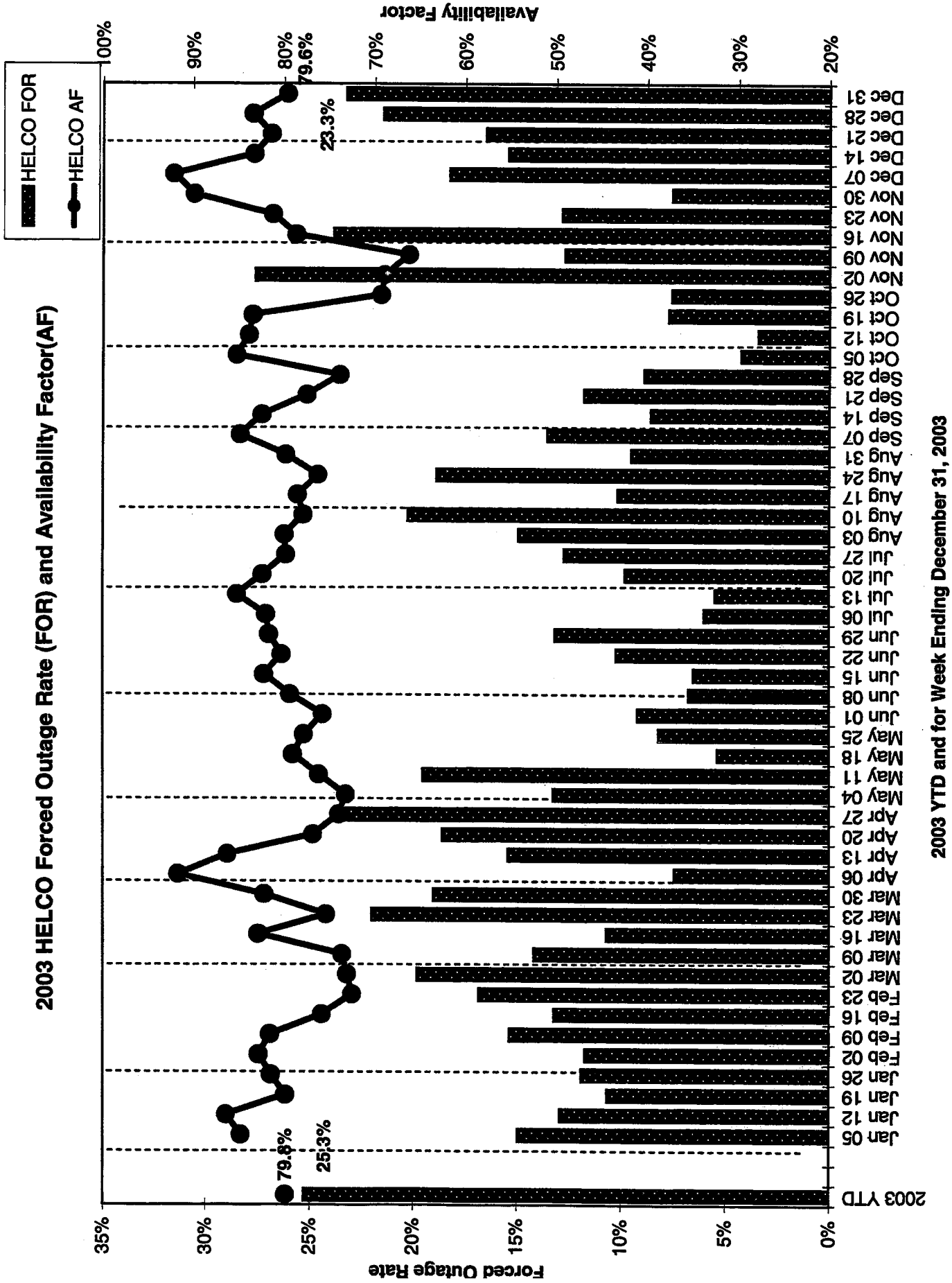


Hawaii Electric Light Company, Inc.

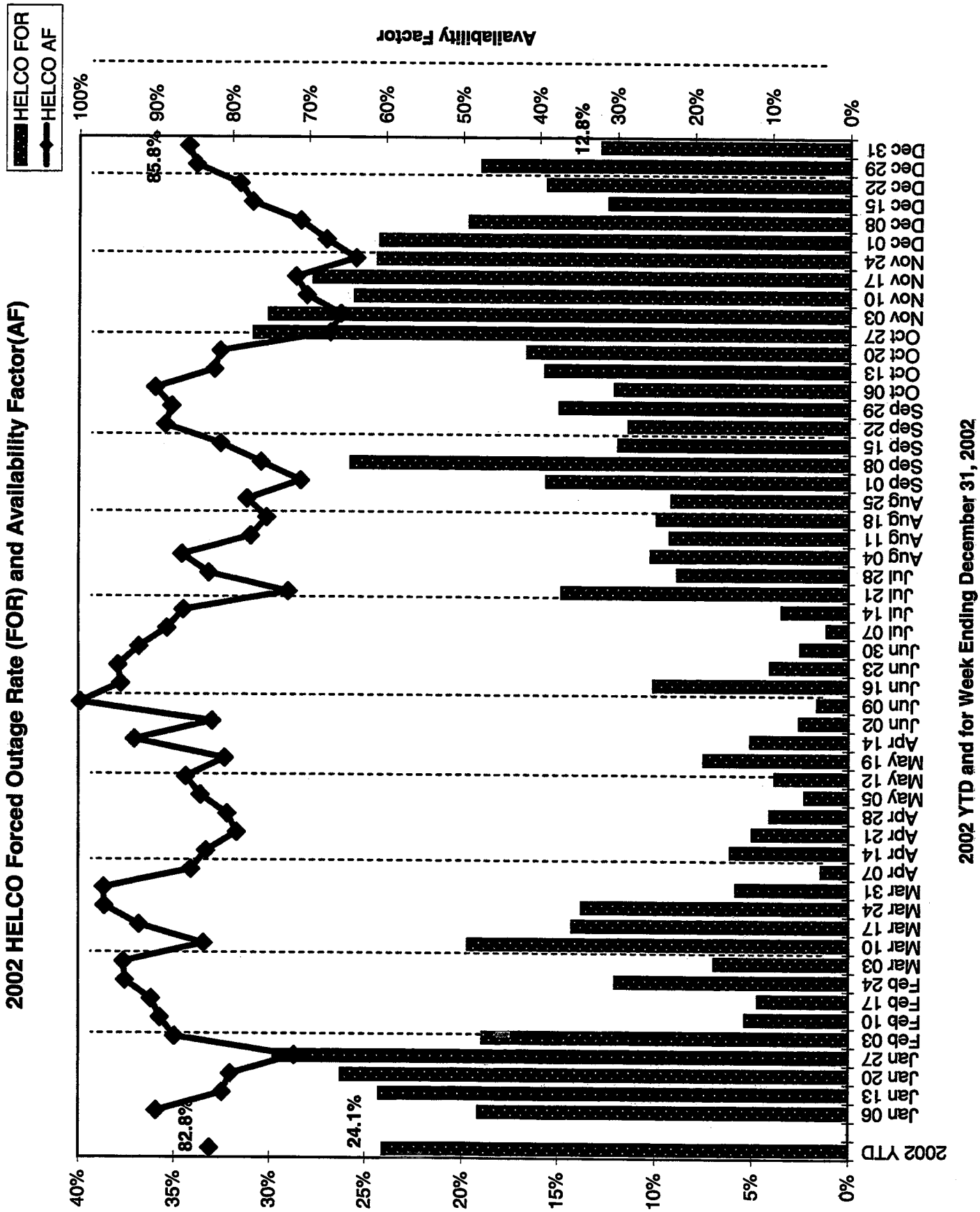


2004 YTD and for Week Ending December 31, 2004

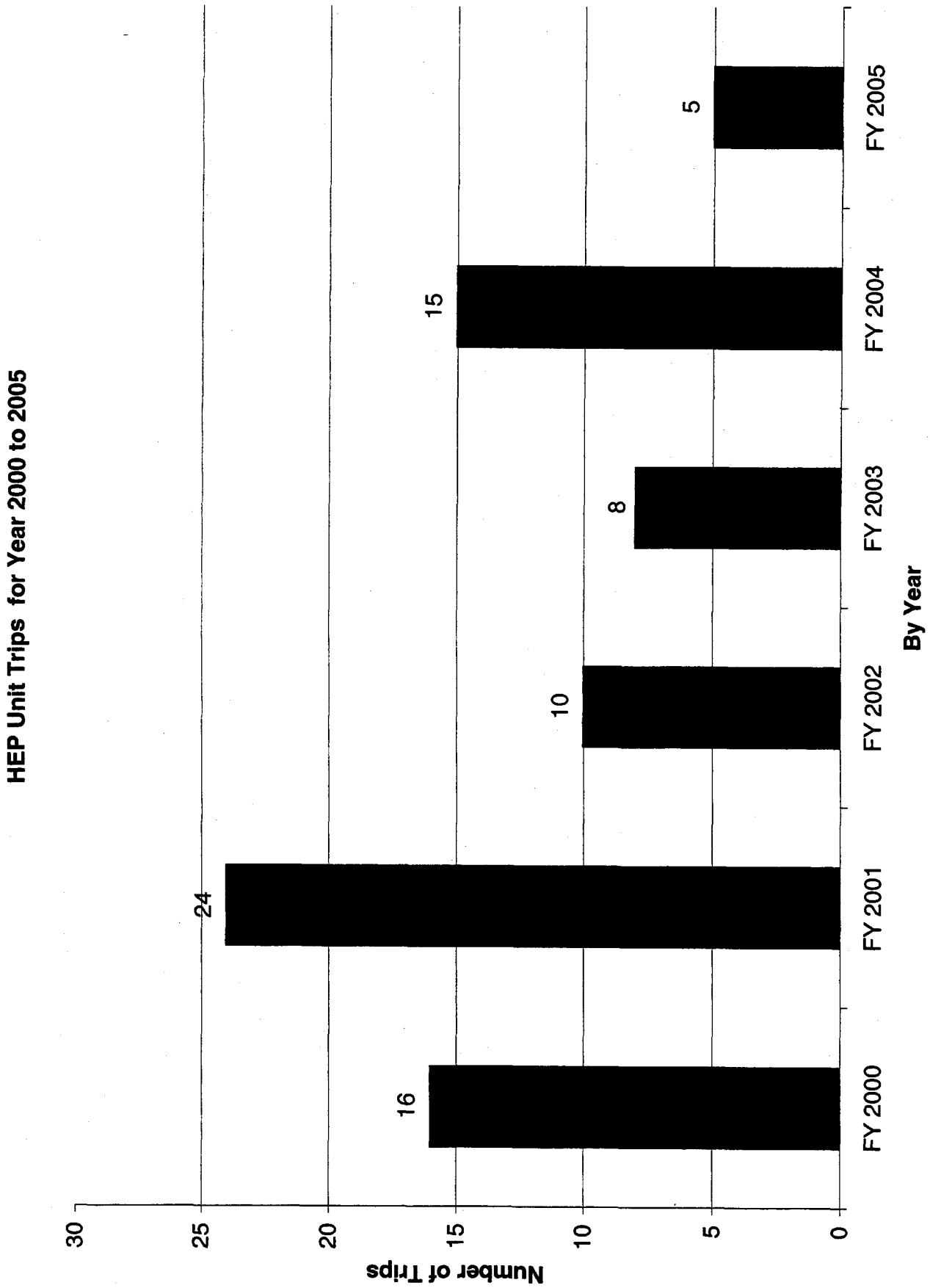
Hawaii Electric Light Company, Inc.



Hawaii Electric Light Company, Inc.

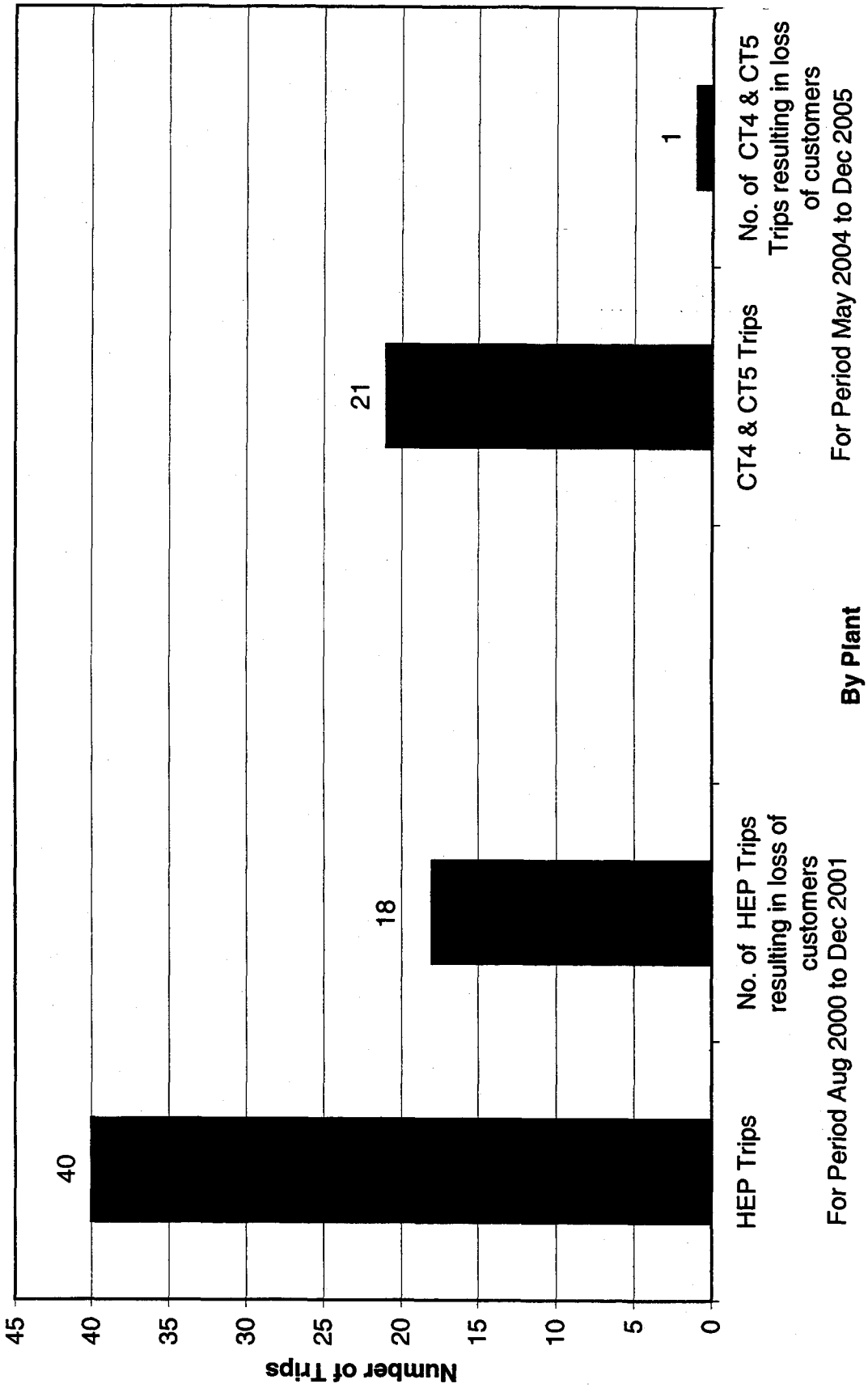


Hawaii Electric Light Company, Inc.



Note: FY 2000 (for period August to December 2000)

Hawaii Electric Light Company, Inc.



Hawaii Electric Light Company Inc.

2006 TEST YEAR
2000 - 2005 Change in Other Production Training O&M Labor Cost
(In the Thousands)

NARUC	Recorded 2000	2001	2002	2003	2004	2005	Estimate 2006 TY
500220	$ 18	$ 23	$ 14	$ 20	$ 19	$ 22	$ 41
506210	53	69	40	58	57	65	122
506220	42	53	31	45	44	51	95
506230	51	66	38	56	55	63	117
510220	1	2	1	2	2	2	3
546280	3	4	2	3	3	4	7
549260	6	7	4	6	6	7	13
549280	9	11	6	9	9	11	20
925	35	45	26	38	37	43	80
Total	$ 218	$ 280	$ 163	$ 237	$ 232	$ 267	$ 498
Change Between Yrs		$ 62	$ (117)	$ 74	$ (5)	$ 35	$ 231

EMERSON
Process Management

Asset Optimization
Final Project Report

for

Production Department
Hawaii Electric Light Company, Inc.
(HELCO)

Hilo, HI

Respectfully Submitted By:
Jim Easton
Jim Luchs
September 30, 2005

TABLE OF CONTENTS

TABLE OF CONTENTS i
DEFINITIONS 1
EXECUTIVE SUMMARY 2
Introduction 2
Study Methodologies 2
Maintenance Practice Review with GAP Analysis 2
Asset Identification and Prioritization. 3
Defining of Preventive and Predictive Maintenance for Assets 3
General Findings. 4
General Recommendations. 4
1. Work Flow Process 4
2. Condition-Based Monitoring (PdM) Program 4
3. Configuration Control Process 5
Summary of Key Element Recommendations 6
INTRODUCTION 8
Study Methodologies 9
Maintenance Practice Review with GAP Analysis 9
Asset Identification and Prioritization. 10
Defining of Preventive and Predictive Maintenance for Assets 11
Predictive Maintenance Evaluation of Critical Assets 12
MAINTENANCE PRACTICE REVIEW 13
GAP Analysis - Overview 13
General Findings. 15
General Recommendations. 15
1. Work Flow Process 15
2. Condition-Based Monitoring (PdM) Program 15
3. Configuration Control Process 16
Work Processes 17
1. Work Identification 18
2. Work Planning 21
3. Spare Parts 24
4. Work Scheduling 26
5. Work Execution 27
6. Work Order Close-Out 29
Technologies 31
7. Work Management Systems 31
8. Maintenance and Diagnostics Technologies 33
9. Information Integration Systems 35
Work Culture & Management 36
10. Continuous Improvement 37
11. Accountability 38
12. Organization 39
13. Leadership 40

© Emerson Process Management, 2005

14. Global Metrics and Reporting 42
15. Plant-Wide Communications 43
16. Goal Setting 44
17. Benchmarking 44
People Skills 46
18. Training 46
19. Utilization 47
20. Qualifications/Job Descriptions 48
Summary of Key Element Recommendations 49
ASSET IDENTIFICATION and PRIORITIZATION 51
Introduction 51
Asset Identification and Equipment Hierarchy 51
Asset Prioritization 56
PREVENTIVE MAINTENANCE TASK OPTIMIZATION 58
Introduction 58
Streamlined RCM Process 58
Streamlined RCM Results 60
PdM Plan 60
CRITICAL ASSET CONDITION ASSESSMENT 61
Introduction 61
Valve and Instrument Survey 62
Controls Survey 64
Shipman 3 and 4 64
PUNA 65
Hill 5 And 6 65
CONCLUSIONS 67
Formal Work Process 67
Configurational Control System 67
Predictive Maintenance (PdM) 68
Effective Utilization of ELLIPSE for Work Process Management 68
Repair or Replacement of Critical Assets 68
Expanding AO Analysis to CT&D Units 69
Path to a World Class Maintenance Program 70
APPENDIX A EQUIPMENT HIERARCHY ..... A
APPENDIX B ASSET RANKING ..... B
APPENDIX C PM and PDM TASKS C
APPENDIX D ROTATING EQUIPMENT SURVEY ..... D
APPENDIX E VALVE and INSTRUMENT SURVEY ..... E
APPENDIX F CONTROLS SURVEY ..... F

© Emerson Process Management, 2005

DEFINITIONS

AO	Asset Optimization. Combination of SRCM, SERP, and Work Process improvements to increase equipment reliability and availability.
CM	Corrective Maintenance consisting of repairs to equipment. Can be scheduled or unscheduled.
E&T Matrix	Engineering and Technology Matrix. Displays PM and PdM periodicities for each asset.
Overhaul	Complex Unit shutdown lasting 10 days or more
PdM	Predictive Maintenance consisting of Inspections, Tests, or Monitoring with Technology.
PM	Preventive Maintenance consisting of Life Renewal Tasks.
RCFA	Root Cause Failure Analysis Process to establish the reasons for consistent functional failure with an asset.
SERP	System Equipment Reliability Prioritization. Process to establish criticality and quantify Risk to production for each asset in the plant.
Shutdown	Unit shutdown lasting 6 days or less.
SRCM	Streamlined Reliability Centered Maintenance. Process to validate existing periodic maintenance tasks.
Validation	Review of Maintenance Tasks to ensure that they are worth doing.

© Emerson Process Management, 2005

EXECUTIVE SUMMARY

Introduction

The Asset Optimization (AO) Division of Emerson Process Management (Emerson) was contracted by the Production Department within Hawaii Electric and Light Company, Inc (HELCO) to conduct a five part project within the steam units in the Hilo area. The project consisted of Identifying and Prioritizing the equipment in the four steam units, Optimizing the Preventive Maintenance Tasks for the most critical equipment (critical to be defined later), Assessing the current health of the critical equipment, Assessing the Maintenance Programs within the Production Department, and installing Emerson's Equipment Integration Software, Asset Portal. The original contract scope was to rank up to 2000 assets and optimize the tasks on the 600 most critical. Because there was no centralized list of equipment and no standard hierarchy of the equipment, the number of assets was reduced and the development of an Equipment Hierarchy, Identification of individual assets, and the loading of them into HELCO's Computerized Maintenance Management System (CMMS), Ellipse, was added to the project in lieu of ranking 1200 assets and optimizing tasks on 300 of the most critical in the original contract. In the end 862 assets were identified and prioritized and over 600 assets were part of the PM Task optimization task.

The project spanned over 6 months with a total of 101 days onsite assessing and working closely with Production Personnel in identifying equipment and work process improvements within the Steam Generation Group. In addition two trips were made to Keahole Generating Units to understand their unique requirements for assisting them to develop work processes in future efforts.

Study Methodologies

Maintenance Practice Review with GAP Analysis. While on site, the AO Team interviewed a variety of individuals including the Production Manager, Operations Manager, Maintenance Superintendent, Operations supervisory staff and operators, maintenance supervisors and working foreman, and support personnel to understand how work is accomplished at the various facilities. In addition to the interviews, the AO Team had the opportunity to tour HELCO's steam plants, maintenance facilities, warehouses, and offices in Hilo, review work process information, view CMMS operation and available reports, read typical condition reports, view metrics, and review other miscellaneous documentation. The AO Team compiled the information gained from this process relative to that for a "world class organization" and presents it below in graphical form. This Gap Analysis identifies strengths and opportunities for improvements. The results are divided into four major categories: 1) Work Processes, 2) Technologies, 3) Management & Work Culture and 4) People Skills. Within each category, specific rankings are provided relative to world class "best practice" standards. The results of this GAP Analysis will form the basis for areas of more detailed study, and for the recommendations to improve HELCO's maintenance practices.

© Emerson Process Management, 2005

Asset Identification and Prioritization. During the interview process, the Emerson Process Management AO Team worked with Production Department personnel to identify the assets within the five steam units. Because of the lack of up to date drawings and any entries in the Ellipse Equipment Register, the team relied on sketches, plant walk-throughs, and interviews to locate all of the assets and assign them to the applicable system within the individual units. The systems were determined from those that were already entered in Ellipse Equipment Register and are displayed in Figure 3 on Page 52. The assets were displayed by Unit and System using Microsoft Visio and are all displayed in Appendix A.
Next a team was created from within the Production Department to prioritize and rank the systems using Emerson Process Management's System Equipment Ranking and Prioritization (SERP) Process. The AO Team from Emerson Process Management trained the team and facilitated the process. Details of the SERP Process are found on Page 56. The team developed a set of criteria for each of the three rankings which can be used on every unit, every system, and every asset within the department. The power of this concept is that now an asset anywhere can be objectively prioritized against another for allocation of valuable resources without the usual emotions and personal bias that can accompany such decisions. All 843 assets in the five steam units were ranked and prioritized. The results are detailed in Appendix B. The team next established a group of critical assets that would be part of the task optimization portion of the project. The criteria they selected resulted in 208 assets being classified as critical or creating the most risk for the business.

Defining of Preventive and Predictive Maintenance for Assets. A review of the Preventive Maintenance (PM) Tasks for the 208 assets previously classified as critical was accomplished by a team of Production personnel from Maintenance and Operations composed of watch supervisors, working foreman, and trades people using Emerson Process Management's Streamlined Reliability Centered Maintenance (RCM) process. This process reviews the existing maintenance tasks using a number of criteria. Details on the process are on Page 58 in the body of the report. Essentially Streamlined RCM ensures that the work is productive and makes sense using a repeatable process. Management can be assured that all man-hours utilized for preventive maintenance are justified.

Because there was no PM program in place for the steam units and thus no documented PM tasks, existing maintenance was gleaned from previous scheduled outage work lists, assessment interviews, and industry standard tasks for like equipment. Similar tasks were packaged into templates and the templates assigned to appropriate equipment. The templates were then analyzed against the assigned equipment and modified as required. For any of the critical assets that did not have any tasks, maintenance strategies as appropriate were developed using the guidelines within the Streamlined RCM Process. In addition because of the efficiency inherent in using Templates Preventive Maintenance tasks for a total of 738 pieces of equipment were able to be created in the time frame available. A complete listing of the results can be found in Appendix C.

© Emerson Process Management, 2005

General Findings.

Emerson Process Management is very impressed with the overall professionalism and spirit of all Production Department employees, an environment not often seen during our assessments. Despite the reactive maintenance culture currently in place, the work gets done and the lights stay on. The greatest weaknesses found were a lack of effective work planning and resource scheduling, very little documented Predictive and Preventive Maintenance, and lack of configuration or document control. The Production Department's greatest strengths are in the Leadership and Goal Setting areas. It is apparent that management within the department has a definite set of goals for improving its operations with a vision to match. The 20 categories assessed are presented in detail beginning on Page 15.

General Recommendations.

The majority of the specific recommendations can be consolidated into 3 major areas. These are listed below.

1. **Work Flow Process**

   The number one recommendation is to institute a formal work flow process that defines how work is identified, planned, scheduled, monitored, executed and improved for all of the generating units and their systems within the department. This is critical because any other improvements to increase operating efficiency, identify pending equipment failures, etc. will fail without a work process to take advantage of the improvements.

   A properly designed and implemented work flow provides the ability to identify and plan for the proper level of resources required to perform maintenance work. Accurate prediction for HELCO's Production Department's manning and budget requirements is dependent on its ability to accurately predict future maintenance requirements using data from previous years and future maintenance requirements.

   Many of the specific recommendations (13) will also be accomplished with the creation of the work flow process. Carrying out this initiative will require between 3 and 5 years of dedicated management attention and outside help in order to get it into a self sustaining mode. However, increased availability (measurable) and less stress (not measurable) will be apparent within 18 months. The outside help is required to facilitate the creation of the Work Flow Process and provide management with guidance in implementing and sustaining the effort.

2. **Condition-Based Monitoring (PdM) Program**

   The corrective work accomplished is almost entirely reactive in nature and difficult to turn around. While creating the work flow process, converting maintenance from reactionary to predictive is required. The work flow process will be able to take

© Emerson Process Management, 2005

advantage of the data that results from condition monitoring and plan any resulting work in an efficient and orderly manner.

The first step is using the PdM tasks created during Phase I of the project. This requires uploading the tasks into Ellipse, scheduling the tasks, and monitoring schedule adherence. Scheduling the tasks and ensuring that they are completed will help to prevent any return to reactionary maintenance within the department.

3. Configuration Control Process

There is no document control process in place. Except for the LM2500 Manuals, none of the technical manuals we saw had been updated. The P&ID drawings were so far out of date, that personnel were relying on sketches that lacked any detail to troubleshoot and train on. Updating spare parts inventories when new assets are installed, original assets upgraded, or original assets are removed is not accomplished on a regular basis. There is a current initiative to update the drawings which when finished should then be moved to inventorying and updating technical manuals. For the long term, procedures should be put in place as part of the work processes to update all software (i.e. drawings, training, spare inventories) when changes are made to any of the plants.

© Emerson Process Management, 2005

Summary of Key Element Recommendations

Table 1 lists all of the recommendations with priorities, link to the appropriate page, and the recommendation that it is associated with. Priorities are listed as VH (Very High), H (High), M (Medium), and L (Low). Associated recommendations are those that should be accomplished at the same time as the original and thus will inherit the original priority.

Number	Recommendation	Page	Priority	Associated Recommendation
1	**Institute a Formal Work Process**	19	VH	
2	**ELLIPSE Configured to Asset Level**	19	H	
3	**Definition of PM and PdM Requirements**	19	H	
4	**Single Method to Work Identification**	20	VH	1
5	**Maintenance Work Orders Written to Asset Level**	20	VH	1
6	**Root Cause Failure Analysis Requirements**	20	M	
7	**Planning and Scheduling Non-Outage Maintenance**	22	VH	1
8	**Planning Outage Work**	22	VH	1
9	**Monitoring the Planning Process**	23	VH	1
10	**Repair Testing**	23	VH	1
11	**Department Documentation**	24	H	
12	**Project Drawings**	24	H	11
13	**Increase Lead time for Ordering Spare Parts**	25	H	
14	**Review Current Stocking Levels**	25	M	
15	**Update Spare Requirements**	25	M	
16	**Prioritize Work Assignments**	27	VH	1
17	**Monitor Schedule Adherence**	27	VH	1
18	**Overhaul Scheduling**	27	VH	1
19	**Functions and Responsibilities in Outages**	28	VH	1
20	**Institute Quality Assurance Program for Repairs**	28	M	
21	**Upload Preventive/Predictive Maintenance Tasks**	29	H	
22	**Standard Repair Procedures**	29	L	
23	**Work Order Close-Out Process**	30	VH	1
24	**Maintaining ELLIPSE Equipment Registry**	32	H	11
25	**Standardize ELLIPSE Hierarchy**	33	VH	1
26	**Predictive Maintenance**	34	H	3

© Emerson Process Management, 2005

27	Servers for Online Databases	34	M	
28	Online Monitoring Training	34	M	
29	Workforce Involvement in Policy Decisions	37	M	
30	Recording PdM Data	38	M	
31	Electronic Operator Data Recording	40	L	
32	Workforce Mentoring	40	H	
33	Dedicate PdM Personnel	40	H	3
34	Create Asset Management Organization	40	M	
35	Monitor Resource Requirements	41	VH	1
36	Communicate Performance and Reliability Metrics	41	M	
37	Workforce Involvement with Work Flow Improvements	42	H	
38	Maintenance Supervisor Involvement	42	H	
39	Communication of Results Within the Work Force	43	M	
40	Communicate Goals and Vision to Employees	43	M	
41	Benchmarking	45	L	
42	Training for Skill Development	46	L	
43	Training for New Equipment and Processes	47	H	11
44	Cross Training of Crafts	47	L	
45	Requalification	48	L	

Table 1
List of Recommendations

© Emerson Process Management, 2005

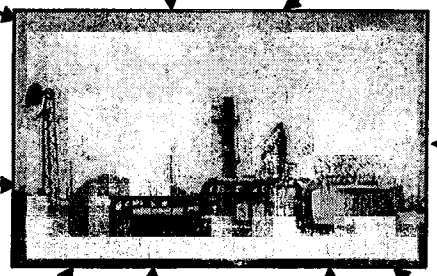
Hawaii Electric Light Company, Inc.

Regulations Affecting Production and T&D

Clean Air Act
- NSR
- PSD
- CSP

Noise

Clean Water Act
- NPDES
- WETT
- Stormwater
- 316(b)
- ZOM



CERCLA (Superfund)
- State Contingency Plan
- Due Diligence/ESAs

Oil Pollution Act & SPCC (OPA 90)
- Spill Prevention Plans
- Spill Response Plans
- Oil Spill Drills

EPCRA
- Emergency Planning
- Community Right to Know
- TRI

PCB

SDWA/UIC
- Injection Wells
- Cesspools
- Drywells

RCRA
- Solid/Hazardous Waste
- Used Oil
- Universal Wastes
- USTs
- Asbestos

Regulations Affecting Production and T&D (Glossary of Terms)

Clean Air Act

NSR – New Source Review

PSD – Potential Source Deterioration

CSP – Covered Source Permit

Clean Water Act

NPDES – National Pollutant Discharge

WETT – Whole Effluent Toxicity Test

ZOM – Zone of Mixing

CERCLA (Superfund) – Comprehensive Environmental Response Compensation and Liability Act

Due Diligence/ESAs – Environmental Site Assessment

Oil Pollution Act & SPCC (OPA 90) - Spill Prevention Control And Counter Measure

EPCRA - Emergency Planning

Community Right-to-Know Act

TRI – Toxic Release Inventory

PCB – Polychlorinated Biphenyls

SDWA – Safe Drinking Water Act

UIC - Underground Injection Control

RCRA – Resource Conservation and Recovery Act

USTs – Underground Storage Tank

Hawaii Electric Light Company Inc.

2006 TEST YEAR
2000 - 2005 Change in Other Production O&M Cost
(In the Thousands)

Acct Group	Recorded 2000	2001	2002	2003	2004	2005	Estimate 2006 TY
Operation	7,382	5,714	6,344	9,484	7,612	7,784	9,587
Maintenance	5,753	6,099	8,955	9,190	9,858	10,325	13,453
Total	13,135	11,813	15,299	18,674	17,470	18,109	23,040
Change Between Yrs		(1,322)	3,486	3,375	(1,204)	639	4,931

HELCO
2004 OVERHAUL SCHEDULE
(REV. 0)

UNIT	DATE	WEEKS	DESCRIPTION
Hill Unit No. 5	Dec 29 - Jun 27	24	Generator Rewind / Boiler Inspection
HEP	Jan 10 - 11	0	CT2 Borescope (Off-Peak Outage)
Kanoelehua D-15	Mar 16 - 17	2 days	Vacuum Breaker Installation
HEP	Mar 18 - 20	3 days	ST Annual Inspection
HEP	Apr 12 - 25	2	CT1 & CT2 Annual Inspection
PGV	May 10 - 23	2	Annual Overhaul
Hill Unit No. 6	May 24 - Jun 13	3	Boiler Inspection
Kanoelehua CT-1	Jun 14 - Jul 4	3	General Inspection
HEP	Jul 10 - 11	0	CT2 Borescope (Off-Peak Outage)
HCPC	Jul 12 - Aug 8	4	Annual Overhaul
Kanoelehua D15-D17	Jul 18 - 24	1	Vacuum Breaker Installation
Waimea D12-D14	Jul 25 - 31	1	Vacuum Breaker Installation
Puna Steam	Aug 9 - Sep 5	4	Boiler Retube
Keahole CT-2	Aug 30 - Oct 10	6	Major Field Inspection
Shipman Unit No. 3	Sep 13 - Oct 24	6	Boiler Retube / GAM / Turbine Work
HEP	Oct 25 - 31	4 days	CT1 & CT2 Semi-Annual Inspection
Shipman Unit No. 4	Oct 25 - Dec 5	6	Boiler Retube / GAM
Waimea D14	Nov 1 - Dec 14	6	Overhaul
HEP	Nov 6 - 7	0	CT1 Borescope (Off-Peak Outage)
Puna CT-3	Nov 8 - 21	2	General Inspection

(DYM 3/15/04)

HELCO
2004 OVERHAUL SCHEDULE
(REV. 3)

UNIT	DATE	WEEKS	DESCRIPTION
Hill Unit No. 5	Dec 29 - Jul 25	30	Generator Rewind / Boiler Inspection
HEP	Jan 10 - 11	0	CT2 Borescope (Off-Peak Outage)
Kanoelehua D-15	Mar 16 - 17	2 days	Vacuum Breaker Installation
HEP	Mar 18 - 20	3 days	ST Annual Inspection
HEP	Apr 12 - 25	2	CT1 & CT2 Annual Inspection
Keahole CT-2	May 10 - 16	1	Maintenance
PGV	May 16 - Jun 13	4	Annual Overhaul / KS-11 Repair
Kanoelehua CT-1	Jun 21 - Jul 11	3	General Inspection
HEP	Jul 12 - 13, 20 - 21	0	Off-Peak Maintenance Outages
Kanoelehua D15 - D17, CT-1, D11	Jul 18 - 24	1	Vacuum Breaker Installation
Waimea D12 - D14	Jul 25 - 31	1	Vacuum Breaker Installation
Hill Unit No. 6	July 26 - Aug 24	4	Boiler Inspection
Keahole CT-4	Aug 9 - Oct 10	9	Noise Abatement / Transformer Barrier
Keahole CT-5	Aug 23 - Sep 5	2	Transformer Barrier Work
Puna Steam	Aug 23 - Oct 5	6	Boiler Retube
Shipman Unit No. 3	Sep 13 - Dec 12	13	Boiler Retube / GAM / Turbine Work
Keahole CT-2	Sep 20 - Oct 5	2	Annual Inspection
HEP	Oct 11 - 18	1	CT1 & CT2 Semi-Annual Inspection & CT1 Boroscope
Puna CT-3	Oct 19 - 25	2	General Inspection
PGV	Oct 24 - 29	1	Upgrade & Repairs
Waimea D14	Nov 1 - 26	4	Overhaul
Keahole CT-4	Nov 8 - 14	2	Misc Noise Abatement
Keahole CT-5	Dec 6 - 30	3	Noise Abatement

Joan Gouveia 12-8-04

Emailed 12/10/04 (3:30pm)
Mailed 12/13/04 to IPP

(DYM, 12/8/04)

HELCO
2005 OVERHAUL SCHEDULE
(REV. 0)

UNIT	DATE	WEEKS	DESCRIPTION
Keahole D23	Nov 04 - Mar 6	15	Overhaul (w/ swing engine swap out)
Shipman 4	Jan 5 - Mar 27	12	Re-tube / GAM
Keahole D-21	Mar 7 - Apr 17	6	Overhaul (w/ swing engine swap out)
Waimea D12	Mar 14 - 27	2	Noise Abatement
Waimea D13	Mar 28 - Apr 10	2	Noise Abatement
HEP ST, CT1, & CT2	Mar 28 - Apr 10	2	ST & CT1 Annual, CT2 Semi-Annual Insp.
Waimea D14	Apr 11 - 24	2	Noise Abatement
PGV	Apr 18 - May 1	2	Maintenance
Hill Unit No. 5	May 2 - 29	4	Boiler Inspection
Keahole CT-2	May 2 - Jun 26	8	Noise Abatement
Kanoelehua CT-1	May 9 - 29	3	General Inspection
Puna CT-3	Jun 13 - Jul 3	3	General Inspection / Governor Control
Hill Unit No. 6	Jun 27 - Jul 24	4	Boiler Inspection
Keahole CT-4	Jul 4 - 24	3	General Inspection / Governor Control
Keahole CT-5	Jul 25 - Aug 14	3	General Inspection / Governor Control
Puna Steam	Aug 1 - Sep 4	5	Boiler Inspection / Controls / Governor
Keahole CT-2	Sep 5 - Oct 30	8	Major Field Inspection
HEP CT1 & CT2	Sep 12 - 25	2	CT1 Semi-Annual, CT2 Annual Insp.
Shipman 3	Sep 26 - Oct 23	4	Boiler Inspection
Kanoelehua D-15	Oct 31 - Dec 11	6	Overhaul (w/ swing engine swap out)
PGV	Oct 31 - Nov 13	2	Maintenance
Shipman 4	Nov 7 - Dec 4	4	Boiler Inspection

1/21/05

(DYM, 1/12/05)

HAWAII ELECTRIC LIGHT COMPANY INC.
2005 ACTUAL OVERHAUL SCHEDULE
(REV. 6)

UNIT	DATE	WEEKS	DESCRIPTION
Keahole D23	Nov 04 - Mar 6	15	Overhaul (w/ swing engine swap out)
Shipman 4	Jan 5 - Jul 17	28	ACM / Re-tube / GAM
HEP ST & CT1	Feb 15 - 20	5 days	ST & CT1 Annual Insp.
Keahole D21, D22, D23	Mar 9 - 11	3 days	Transformer Retro-Fill
Waimea D-12	Mar 14 - Aug 12	24	Overhaul (w/ swing engine swap out)
HEP CT2	Apr 8 - 9	2 days	CT2 Semi-Annual Insp.
PGV	Apr 24 - 29	6 days	Maintenance
Keahole CT-2	May 2 - Jul 16	11	Noise Abatement
Hill Unit No. 6	May 13 - 29	2	Boiler Inspection
Kanoelehua CT-1	May 30 - Jun 26	4	General Inspection
Keahole CT-4	Jul 14 - 28	2	Generator Bearing Work
Puna Steam	Jul 3 - 24	3	Boiler Inspection
Hill Unit No. 5	Aug 6 - Sep 4	4	Boiler Inspection
Keahole CT-2	Aug 22 - Sep 25	5	Minor Field Inspection
HEP CT1 & CT2	Sep 26 - Oct 5	2	CT1 Semi-Annual, CT2 Annual Insp.
Shipman 3	Oct 3 - 30	4	Boiler Inspection / Exciter / Controls
PGV	Oct 6 - 16	2	Maintenance
Puna CT-3	Oct 17 - Nov 6	3	General Inspection / Governor Control
Keahole CT-4	Nov 7 - 27	3	General Inspection / Governor Control
Keahole CT-5	Nov 28 - Dec 18	3	General Inspection / Governor Control

(DYM, 8/23/05)

HELCO
2006 OVERHAUL SCHEDULE
Test Year - Normalized
(DRAFT - 11/18/05)

UNIT	DATE	WEEKS	DESCRIPTION
Keahole CT-2	Feb 20 - Mar 19	4	Governor Control, MFI, Carbo Blast Mods
HEP ST, CT1, & CT2	Apr 9 - 22	2	ST & CT1 Annual, CT2 Semi-Annual
Keahole D-21	Apr 17 - 30	2	Overhaul (Swing Engine Install)
PGV	Apr 24 - May 7	2	Maintenance
Hill Unit No. 6	May 8 - Jul 2	8	Boiler Insp, Tube Repl, Condenser Retube
Kanoelehua CT-1	Jun 5 - 18	2	Gen. Insp., Low Smoke Nozzles & Ignitors
Shipman 4	Jun 26 - Jul 23	4	Boiler Insp., BFW Pumps, Control System
Keahole CT-4	Jun 26 - Jul 9	2	LP Turbine, General Inspection
Keahole CT-5	Jul 17 - Aug 6	3	LP Turbine, Hot Section
Puna Steam	Jul 31 - Aug 27	4	Boiler Inspection, Control System, Turb. Gov.
Puna CT-3	Aug 28 - Sep 10	2	General Inspection
Hill Unit No. 5	Sep 4 - Oct 1	4	Boiler Inspection, Water Purifier
Keahole D-21	Sep 4 - 10	1	Overhaul (Swing Engine Removal)
HEP CT1, CT2	Oct 2 - 15	2	CT1 Semi-Annual, CT2 Annual
PGV	Oct 16 - 29	2	Maintenance
Shipman 3	Oct 30 - Nov 26	4	Boiler Insp., BFW Pumps, Control System

Notes:
1. Removed HEP CT1 Maintenance from Jan06...atypical, rescheduled from Dec05.
2. Keahole CT2 reduced from 6 wks (MFI) to 4 wks...3 wks + 1 wk turbine ovhl (MFI every 5 yrs).
3. 6 wks for HEP ST major every 6 yrs...+ 1 additional wk per yr.
4. Hill 6 increased to 8 wks...+ 2 additional wks for ST major.

HELCO
2006 OVERHAUL SCHEDULE
(DRAFT - 11/18/05)

UNIT	DATE	WEEKS	DESCRIPTION
HEP CT1	Jan 16 - 22	1	CT1 Annual & Maintenance
Keahole CT-2	Feb 20 - Apr 2	6	Governor Control, MFI, Carbo Blast Mods
HEP ST & CT2	Apr 9 - 16	1	ST Annual, CT2 Semi-Annual
PGV	Apr 24 - May 7	2	Maintenance
Hill Unit No. 6	May 8 - Jun 18	6	Boiler Insp, Tube Repl, Condenser Retube
Kanoelehua CT-1	Jun 5 - 18	2	Gen. Insp., Low Smoke Nozzles & Ignitors
Shipman 4	Jun 26 - Jul 23	4	Boiler Insp., BFW Pumps, Control System
Keahole CT-4	Jun 26 - Jul 9	2	LP Turbine, General Inspection
Keahole CT-5	Jul 17 - Aug 6	3	LP Turbine, Hot Section
Puna Steam	Jul 31 - Aug 27	4	Boiler Inspection, Control System, Turb. Gov.
Puna CT-3	Aug 28 - Sep 10	2	General Inspection
Hill Unit No. 5	Sep 4 - Oct 1	4	Boiler Inspection, Water Purifier
Keahole D-21	Sep 4 - 10	1	Overhaul (Swing Engine Removal)
HEP CT1, CT2	Oct 2 - 15	2	CT1 Semi-Annual, CT2 Annual
PGV	Oct 16 - 29	2	Maintenance
Shipman 3	Oct 30 - Nov 26	4	Boiler Insp., BFW Pumps, Control System

EMERSON
Process Management

Asset Optimization PlantWeb® Services Predictive Maintenance Program

for

HAWAII ELECTRIC LIGHT CO. INC. (HELCO)

HILO, HI

by

Emerson Process Management

Document No. PW-HOP-07-19-2005-55249
August 18, 2005

TABLE OF CONTENTS

1 EXECUTIVE SUMMARY 1
2 SCOPE OF WORK 1
TASK 1: VIBRATION ANALYSIS/ROUTE VIBRATION READING .. 1
TASK 2: THERMOGRAPHY 4
TASK 3: OIL COLLECTION AND ANALYSIS 5
TASK 4: REMOTE VIBRATION ANALYSIS 6
3 PROJECT MANAGEMENT, DESIGN AND IMPLEMENTATION 7
4 ASSUMPTIONS AND CLARIFICATIONS 7
5 DELIVERABLES 8
6 FINANCIAL SUMMARY 9
7 ADDITIONAL SERVICES 9
8 PURCHASE ORDER POLICY 9
9 CANCELLATION TERMS 9
10 TERMS AND CONDITIONS 10

© Emerson Process Management, 2005

1 EXECUTIVE SUMMARY

Emerson Process Management welcomes the opportunity to provide this technical proposal to Hawaii Electric and Light Co. Inc. (HELCO). Based on our meeting of May 26, 2005 at your Hilo facilities, we will build on our previous work to provide a Predictive Maintenance (PdM) Program using the PdM Plan developed in the Preventative Maintenance Task Optimization Process conducted in November and December of 2004. Details are contained in Phase I project report dated April 28, 2005.

The objective of this proposal is to provide the Production Department with a robust and comprehensive vibration monitoring, oil analysis, and thermography on the assets and periodicity specified in the PdM Plan. This will provide the department with a firm foundation in its attempt to reduce the current reactive maintenance practices and begin scheduling maintenance without affecting the customers of Hawaii.

The monthly vibration readings and periodic oil samples will be taken by personnel located within the State of Hawaii. Twice a year thermographic analysis will be conducted by a certified individual from Emerson Process Management on the mainland. Analysis of the route vibration data, online vibration data, and oil samples will be done by the Emerson Process Management Remote Analysis Group in Knoxville, TN.

This Project will be managed by a single Project Manager assigned for all Emerson Process Management projects contracted by the Production Department HELCO.

This proposal will involve four tasks: Route Vibration Readings, Oil Sampling, Thermography, and Remote Vibration Analysis conducted over a period of 12 Months.

2 SCOPE OF WORK

Emerson Process Management will provide a service with qualified, experienced and fully trained personnel equipped with the required tools, transportation, equipment, instrumentation, and supplies to provide Vibration Analysis, IR Thermography and Oil Analysis services at your Steam Generating Units in Hilo HI for 12 Months.

TASK 1: VIBRATION COLLECTION AND ANALYSIS/ROUTE VIBRATION READING

The collection and reduction of vibration data allows you to perform three important analysis techniques:

1. Certification
2. Potential fault analysis
3. Diagnostic analysis

Certification – Vibration data are taken on new and/or rebuilt machinery to ensure that the machinery is operating within acceptable vibration tolerance. If excessive vibration is discovered, the cause can be remedied before the equipment is put in service.

© Emerson Process Management, 2005

Potential Fault Analysis – Potential fault analysis allows you to determine the health of equipment components. A good assessment of machine health allows you to predict what component is most likely to fail first and approximately how long that component will continue to operate before fault conditions begin to occur. This information allows you to anticipate and schedule machine overhauls, thereby minimizing the impact of process shutdown and avoiding damage that results from running a machine until catastrophic failure occurs.

Diagnostic Analysis – Whereas potential fault analysis is more proactive, diagnostic analysis is performed once a problem has occurred. Once the vibration data are collected, a comparison is made between the calculated fault frequencies and their harmonics and the actual frequencies that dominate the vibration signature. The cause of each fault frequency is determined and corrective measures are taken to correct the problem. Follow-up readings are taken to ensure that the problem was solved and that the machine is operating within tolerance.

The vibration data collected in the monitoring program will allow the detection of faults such as imbalance or misalignment and the more challenging detection and diagnosis of developing bearing or gear faults. Detection of fatigue, cracked gear teeth, abrasive wear, or scuffing and impacting in their earliest stages gives warning of impending failure along with an objective trendable measure of the fault severity. This is especially critical with slow speed machinery and complex gear boxes.

Early accurate detection results in better planning for repairs and replacements, enabling lower costs, decreased downtime, and reduced spare parts inventories.

VIBRATION ACTIVITIES

The following activities will be performed in association with the Machinery Health Management program at your facility:

Regular Monitoring and Analysis

- Regular monitoring and analysis of the operating condition of critical equipment is an absolute requirement of the Machinery Health Management program. The initial interval for all equipment in the program should be thirty (30) days. Based on failure history for equipment, monitoring intervals greater than thirty (30) days may be acceptable as the program matures.

Data Management

- *Data for all technologies will be managed by Emerson's AMS™ Suite: Machinery Health Manager Software package.* AMS Machinery Manager uses a relational database, which provides the most efficient method for accessing, correlating, and managing all the data for all the technologies that are being applied.
- All major vibration, oil analysis, infrared thermography, motor current, balance and alignment hardware and software is manufactured by Emerson at our headquarters in Knoxville. This may include but is not limited to: *Model 2130 Machinery Analyzer, OilView, Oil Analyzer, Emerson's Infrared Thermography System, AMS Machinery Manager software including Nspectr II, MotorView, and OilTrend packages.*

© Emerson Process Management, 2005

Problem Identification and Reporting

- A report will be prepared each visit that defines specific maintenance tasks that are required to correct incipient problems identified by the data acquisition and analysis program. The format of the report should be designed to reduce the amount of paperwork necessary to properly maintain accurate communication between the predictive maintenance group and the production divisions. Each report will provide a prioritized list of specific maintenance or inspection tasks that are required to verify or correct developing problems.

Preparation and Distribution of Reports

- The predictive maintenance coordinator or designee will notify responsible operations and maintenance personnel immediately when any deficiency is noted that could jeopardize equipment operation or personnel safety.
- Written reports will address all monitoring points, but will place a priority on exception reports describing problems that have been identified including a detailed evaluation of machinery status and recommended maintenance actions.

Corrective Action and follow-up

- Corrective action should be scheduled and performed, by customer, on any equipment found to have exceeded established alarm limits.
- Following notification of corrective action, vibration readings should be taken to establish new baselines and to verify corrective action.

TASK 2: THERMOGRAPHY

Emerson Process Management will provide a service to administer semi-annual Infrared Thermographic Imaging (performed during a monthly vibration visit) at your Steam Generating Units in Hilo HI. Performance of these services will exceed those industry standards currently in place and also comply fully with Emerson quality of service guidelines and mission statement.

Thermographer Responsibilities

Thermographers will perform infrared inspections of plant equipment and/or structures confirming the following responsibilities are met:

1. Infrared imaging and measurement systems with the proper accessories and calibrations necessary to meet the inspection requirements will be used. Additionally, the instruments are to be periodically checked to assure that they meet the manufacturers' specifications for accuracy.
2. Infrared inspections will be carried out when environmental and physical conditions such as solar gain, wind, surface condition, moisture content and heat transfer are favorable to gathering accurate data.
3. The Thermographer will have sufficient electrical, mechanical and construction knowledge to understand measure and document the observed patterns of infrared radiation.
4. All plant and standard Emerson safety rules, standards and practices will be strictly adhered to.
5. The Thermographer will be accompanied by one or more qualified assistants who are employed by the plant and are knowledgeable of the equipment being inspected. Thermographers **will not** perform any of the tasks that are assigned to this personnel

 © Emerson Process Management, 2005

unless duly authorized, in writing, by plant management and agreed to by Emerson.
6. Recommend re-inspection of potential problems, after repairs have been completed.

Thermographers **will not**: touch, remove/replace covers or open/close doors of electrical or mechanical equipment, measure electrical loads or voltage, or encroach on the safe clearances specified for the equipment under test.

Plant Management Responsibilities
Qualified assistants should be knowledgeable of the operation and maintenance history of the equipment to be inspected. Qualified assistants will be qualified and authorized by Plant Management to:

1. Provide or help compile a list of equipment to be inspected. This list should be as complete and accurate as possible to facilitate the preparation of the database.

2. Assume all responsibility for the consequences resulting from actions, either taken or not taken, as a result of information provided by the inspection.

3. Assign and authorize qualified individuals to assist the Thermographer. These individuals will help the inspection team and will be referred to as qualified assistants.

TASK 3: OIL COLLECTION AND ANALYSIS
Emerson Process Management will provide qualified, experienced and fully trained personnel equipped with the required tools, transportation, equipment, and instrumentation to perform oil sample collection (performed in conjunction with the vibration analysis visits) and analysis at the CSI Oil Lab of *40 oil samples per quarter*. Emerson will provide all bottles and necessary sampling accessories.

Objective
CSI Oil Lab is an analytical chemistry/testing laboratory which provides testing services on lubricants and hydraulic fluids to Emerson Process Management clients.

The product provided by CSI Oil Lab has two distinct components: a laboratory component (testing and analysis) and a consulting component (data interpretation and recommendations). Therefore, CSI Lab has two distinct missions. The first is to provide the highest quality testing and analytical results while maintaining an acceptable sample turnaround time. The second is to interpret the laboratory results and advise clients as to appropriate action based on the results.

© Emerson Process Management, 2005

To accomplish the first mission, CSI Oil Lab is equipped with modern high quality laboratory instruments, and staffed with dedicated, qualified chemists and technicians. To accomplish the second mission, the lab is staffed with qualified data analysts who draw upon the vast experience of CSI employees, customers, and industry experts to solve Tribology related problems to help clients improve plant operations.

Turnaround time in the lab averages less than three working days. Results will be available in electronic or paper form depending on what is required. Emerson Process Management will alert the customer by telephone or by fax for critical samples.

Industrial/Clean Profile Testing
Part Number: **Services-OIL** or **Services-TLAB**

The following tests will be performed on your oil samples by the Trivector Laboratory:
1. Emission Spectroscopy
2. Fourier Transform Infrared Absorption Spectroscopy (FTIR)
3. 40C & 100C Viscosity and Viscosity Index
4. Water Determination by Karl Fischer Water.
5. Ferrous Index
6. Total Acid Number (TAN) or Total Base Number (TBN)
7. Wear Debris Analysis (WDA) (when indicated by an increase in Particle Count or Ferrous Wear Index).

TASK 4: REMOTE VIBRATION ANALYSIS

Program Startup
The Vibration Analysis program will continue the work accomplished during the current contract under Proposal HIL-04-07-2004-47104-R1 and started under Proposal HELCO-HOP-04-15-2004-45070R1. The route data will be taken by Process Controls individual visiting the Steam Generation Units twice a month. Analysis of both route data and online data will be accomplished by CSI personnel in Knoxville, TN with the data bases remaining in HECO's Machinery Health Management LAN for access by Asset Portal and HECO Technicians.

Adjustments to the databases
The Machinery Health Analysts in Knoxville will review the database, editing routes and adjusting alarm levels as necessary.

Program Review
Emerson will present its findings of the overall machinery health along with a review of the major diagnostic case histories. Successes and challenges regarding the program will be identified and any corrective actions will be planned and implemented. A full review of customer value will be conducted to make sure the customer's expectations are being met.

 © Emerson Process Management, 2005

TASK SUMMARY

TASK 1: VIBRATION ANALYSIS AND ROUTE VIBRATION READINGS. An individual, trained and mentored by Emerson Process Management will take the readings during a two day period each month. The database will be sent to the Remote Analysis Center in Knoxville, TN for analysis.

TASK 2: THERMOGRAPHY. A Certified individual from Emerson Process Management will conduct Thermographic Analysis of identified Equipment once a year as required in the PdM Plan.

TASK 3: OIL COLLECTION AND ANALYSIS. An individual, trained and mentored by Emerson Process Management will take oil samples for identified equipment and send the samples to the CSI Oil Lab in Knoxville, TN for analysis. This task will be accomplished in conjuncture with Task 1. Samples on the Turbines will be taken on a monthly basis for the first 6 months to obtain a baseline. Periodicity will be reviewed after that period.

TASK 4: REMOTE VIBRATION ANALYSIS (177 ASSETS). The Remote Analysis Group, located in Knoxville, TN will provide monthly analysis for all route based and online monitored equipment. The databases will be updated for Asset Portal. Reports for equipment requiring scheduled maintenance or additional attention will be provided.

This work will be sequenced in with the current PdM Project at HELCO, under Emerson Process Management Proposal HIL-07-14-2004-47104-R1 and HELCO PO H28760.

3 PROJECT MANAGEMENT, DESIGN AND IMPLEMENTATION

Among our strengths is our ability to provide strong project management for the work undertaken by the team. Project management begins with a disciplined approach to project authorization that allows adequate time for developing the scope of professional services and the associated schedule and budget. Much of the detailed planning is performed before project authorization as part of developing the estimate for the work. Following client review and authorization, we prepare a Project Schedule that serves as the roadmap for our work. During project implementation, we monitor and evaluate the technical quality of the work, schedule and the budget. Because this is a team effort between Emerson Process Management, Caltrol/Process Controls and HELCO to customize the specifications to HELCO requirements, the Project Manager will be in frequent contact with the Production Manager and Maintenance Supervisor at HELCO for the duration of the project.

4 ASSUMPTIONS AND CLARIFICATIONS

With any Services offering, some assumptions are needed to simplify the process. The basic assumptions for this project are based on our experience designing, developing and implementing this type of program at over 100 varied industry sites.

- HELCO personnel must be available to start and stop machinery, perform any necessary lockouts, and for opening up electrical cabinets, etc.

© Emerson Process Management, 2005

- Emerson Process Management and Process Controls Personnel will have full access to Machinery Health Management Software to upload route data as well as transfer databases for remote analysis
- Emerson Process Management assumes there will be full access to all equipment, drawings, documentation, manuals, and procedures, upon request.
- Emerson Process Management reserves the right to interchange personnel from this project. Emerson shall work to minimize such changes. Personnel change-out for projects such as this is not standard procedure.
- HELCO will provide opportunity for work to be done in a safe manner.
- Emerson will interface with HELCO safety to ensure plant safety regulations are being met and proper safety equipment is being worn.
- End-user site supervisor and Emerson lead project personnel will work off of an Emerson-supplied schedule to determine work to be performed each day so to minimize the impact of plant maintenance activities.
- Any change in scope, scheduling, or assumptions may result in a change in the final billing.
- Any changes requested by the customer to this scope of work will result in the generation of a change order request by our Project Manager. Upon approval by HELCO of the change order request, Emerson Process Management will perform the requested work.
- Follow-on and subsequent plans will be provided upon completion of this scope of work.

5 DELIVERABLES

TASK 1: VIBRATION ANALYSIS/ROUTE VIBRATION READING

- Detailed Report on areas of concern and actions required by HELCO Production Department Personnel on Rotating Equipment.

TASK 2: THERMOGRAPHY

- Detailed Report on areas of concern and actions required by HELCO Production Department Personnel on Electrical Equipment

TASK 3: OIL COLLECTION AND ANALYSIS

- Detailed report on areas of concern and actions required by HELCO Production Department Personnel.

TASK 4: REMOTE VIBRATION ANALYSIS (177 ASSETS)

- Development of a comprehensive database for critical equipment.
- Determine the initial operating condition of selected critical equipment
- Obtain diagnostics signatures on critical equipment
- Analyze data to determine condition of equipment.
- Transition of Data Collection to HELCO Maintenance personnel.

 © Emerson Process Management, 2005

6 FINANCIAL SUMMARY

Project: AO PlantWeb Services Program

• **Task 1: Vibration Analysis and Route Vibration Readings (167 Assets) @ $3,454/Month**	**$41,448**
• **Task 2: Thermography (25 Assets)**	**$4,701**
• **Task 3: Oil Collection and Analysis (70 Samples per year)**	**$2,520**
• **Task 4: Remote Vibration Analysis (177 Assets)**	**$29,850**
• **Project Management (16 Hours @ 150.00 per hour)**	**$2,400**
TOTAL PROJECT	**$80,919**

Emerson Process Management's AO Services will offer a Firm Fixed Price Project cost of **$80,919** for the Services as outlined above, including all necessary travel and living expenses. Invoicing will occur in 12 equal monthly installments of **$6,743.25**.

Emerson Process Management's standard payment terms are net 30 days from date of invoice with approved credit. Please reference Quote # **HOP-07-19-2005-55249** when placing the purchase order.

7 ADDITIONAL SERVICES

Any additional services for HELCO will be quoted separately. Prices listed are effective for (30) thirty days from the date of this proposal. Services must be scheduled within (90) ninety days of purchase order submittal for price to remain valid without incurring additional administration fees.

8 PURCHASE ORDER POLICY

Emerson Process Management requires a copy of all purchase orders prior to processing your order. ***All purchase orders must be made out to Computational Systems, Inc., c/o Process Controls, Attn: Troy Johnson, 99-1295 Waiua Place, Aiea, HI 96701, Fax 808-488-3343. NOTE: Payments must be made to Computational Systems, Inc., P.O. Box 73121, Chicago, IL 60673-7121.***

9 CANCELLATION TERMS

Cancellation after Purchase Order at Buyer's Request: Buyer may cancel orders only upon advanced written notice to Emerson. A cancellation charge of 15% of the order value or a minimum of $500.00, whichever is greater along with all costs and expenses incurred by Emerson in the course of performance under an order or agreement. To initiate cancellation, please submit a written notice with purchase order number(s), Emerson sales order number(s), Emerson's product number(s), duration of Service, and the reason for cancellation, to the attention of the Scheduling Coordinator, fax: 865-218-1742 or email to beth.travis@emersonprocess.com.

© Emerson Process Management, 2005

Cancellation after Purchase Order at Emerson's Request: Emerson may cancel orders after (90) ninety days from receipt of purchase order and after (3) three documented attempts to contact customer and request scheduling of service. The Scheduling Coordinator initiates termination of services by sending a copy of the purchase order, cancellation policy and written documented attempts to contact customer to accounting to be included with the invoice. A cancellation charge of 20% of the order value or a minimum of $750.00, whichever is greater, will be charged along with all costs and expenses incurred by Emerson in the course of performance under an order or agreement.

10 TERMS AND CONDITIONS

This contract will be executed under the Terms and Conditions of a General Services Master Agreement, between Emerson and Hawaii Electric Light Company, Inc.

© Emerson Process Management, 2005

Hawaii Electric Light Company, Inc.
2006 TEST YEAR

OTHER PRODUCTION
OPERATIONS & MAINTENANCE EXPENSE
($ Thousands)

	2006 TEST YEAR
TOTAL OTHER PRODUCTION O&M EXPENSE	$ 23,040

Source:
HELCO-531

Hawaii Electric Light Company, Inc.
2006 TEST YEAR

OTHER PRODUCTION O&M EXPENSE
($ Thousands)

		2006 TEST YEAR ESTIMATE
1	Operations Expense	$ 9,587
2	Maintenance Expense	$ 13,453
3	TOTAL OTHER PRODUCTION O&M EXPENSE	$ 23,040

Source:
HELCO-531

Hawaii Electric Light Company, Inc.
2006 TEST YEAR

OTHER PRODUCTION
OPERATIONS & MAINTENANCE EXPENSE
($ Thousands)

	(A) OPERATING BUDGET	(B) BUDGET ADJ	(C) NORMAL-IZATION	(D) 2006 TEST YEAR
OTHER PROD OPERATIONS EXPENSE				
1 Labor	$ 6,054	$ -	$ -	$ 6,054
2 Non-Labor	$ 3,527	$ 200	$ (194)	$ 3,533
3 TOTAL	$ 9,581	$ 200	$ (194)	$ 9,587
OTHER PROD MAINTENANCE EXPENSE				
4 Labor	$ 3,228	$ -	$ -	$ 3,228
5 Non-Labor	$ 10,493	$ (557)	$ 289	$ 10,225
6 TOTAL	$ 13,721	$ (557)	$ 289	$ 13,453
7 TOTAL PRODUCTION O&M EXPENSE	$ 23,302	$ (357)	$ 95	$ 23,040

Source:
HELCO-WP-101(A), page 2, for Column A.
HELCO-532 for Column B.
HELCO-533 for Column C.

Hawaii Electric Light Company, Inc.
2006 TEST YEAR

OTHER PRODUCTION O&M EXPENSE ADJUSTMENTS
($ Thousands)

Line	Adjustments	(A) Operations Non-Labor	(B) Maintenance Non-labor	(C) Total
1	Predictive Maintenance Program		18	18
2	Maintenance of DG Unit		(171)	(171)
3	Abandoned Capital Projects		1	1
4	Outside Services - General	(100)		(100)
5	Outside Services - Temp Help		62	62
6	Hill Boiler Draw Engineering Docs	150		150
7	Hill 6 Hydrogen Dryer & Controls		100	100
8	Hill 6 Boiler VFD Upgrades		150	150
9	CT-1 Low Smoke Fuel Nozzles		268	268
10	Shipman Blr Draw Engineering Docs	100		100
11	Puna Blr Draw Engineering Docs	50		50
12	Waiau Penstock Repairs		150	150
13	Puueo Penstock Repairs		200	200
14	CT-2 Major Field Insp 2006		(700)	(700)
15	Keahole WT HMI Repl		25	25
16	CT-4 Hot Section		845	845
17	CT-4 LP Turbine Upgrade		(50)	(50)
18	CT-5 Hot Section		(1,405)	(1,405)
19	CT-5 LP Turbine Upgrade		(50)	(50)
20	TOTAL	200	(557)	(357)

Hawaii Electric Light Company, Inc.
2006 TEST YEAR

OTHER PRODUCTION O&M EXPENSE NORMALIZATIONS
($ Thousands)

Line	Normalization	(A) Operations Non-Labor	(B) Maintenance Non-labor	(C) Total
1	Disbursed Gen Unit Overhaul		150	150
2	Emissions Fee	(61)		(61)
3	Hill Boiler Draw Engineer	(67)		(67)
4	Hill 6 Blr Insp 2006		230	230
5	Shipman Blr Draw Engine	(47)		(47)
6	Ship 3 Blr Insp 2006		42	42
7	Ship 4 Blr Insp 2006		42	42
8	Puna CT3 LP Turbine Upgrade		65	65
9	Puna Blr Draw Engineerin	(20)		(20)
10	CT2 Major Field Inspection		(700)	(700)
11	CT4 LP Turbine Upgrade		65	65
12	CT5 LP Turbine Upgrade		65	65
13	Diesel Engine Overhaul #1		350	350
14	Waimea Fuel Tank Repairs		(20)	(20)
15	TOTAL	(194)	289	95

Hawaii Electric Light Company, Inc.
2006 Test Year

OTHER PRODUCTION OPERATIONS EXPENSE
($ Thousands)

Line		RECORDED						2006 TEST YEAR	2005 vs 2006	
		(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H=G-F)	(I=H/F)
		2000	2001	2002	2003	2004	2005	2006	$	%
1	Labor	$4,138	$3,391	$3,886	$3,861	$4,359	$4,359	$6,054	$1,695	38.9
2	Non-Labor	$3,244	$2,323	$2,458	$5,623	$3,253	$3,425	$3,533	$108	3.1
3	TOTAL	$7,382	$5,714	$6,344	$9,484	$7,612	$7,784	$9,587	$1,803	23.2
	% Change		-23%	11%	49%	-20%	2%	23%		

Source:
HELCO-WP-101(A), page 2 for Columns A to F.
HELCO-531 for Column G.
Note:
Figures may not total exactly due to rounding.

Hawaii Electric Light Company, Inc.
2006 TEST YEAR

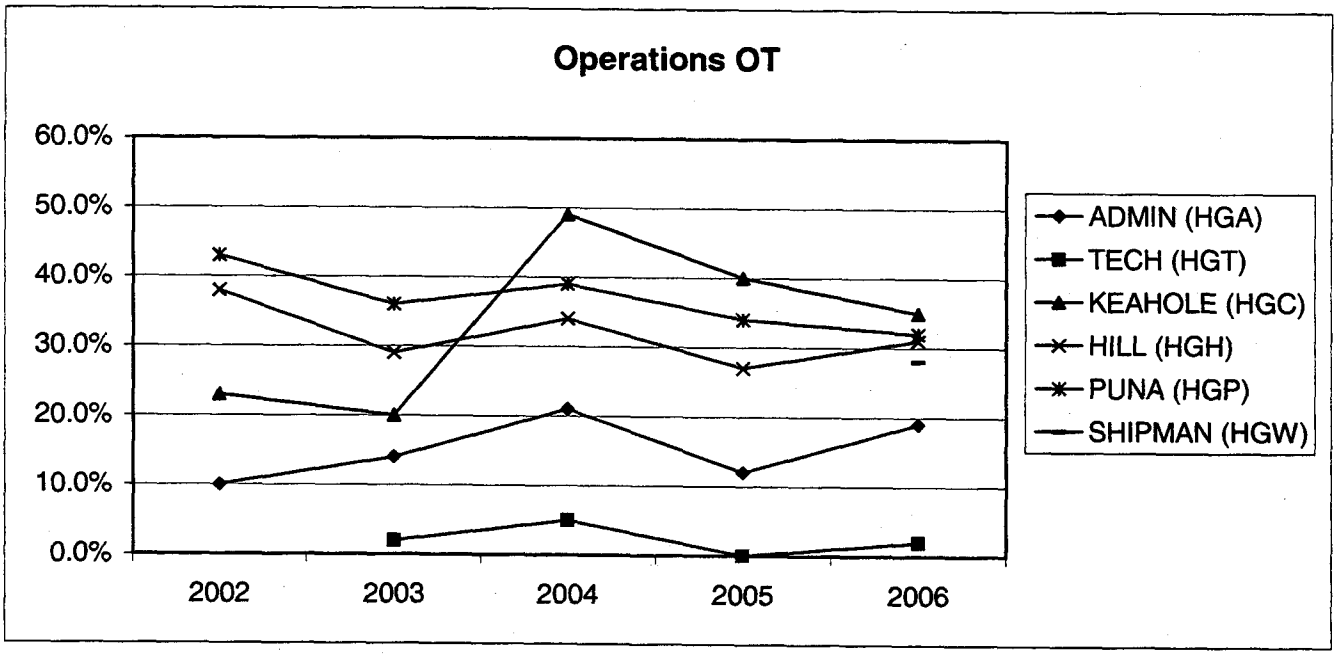
OTHER PRODUCTION
OPERATIONS - EMPLOYEE COUNT

Site/Position	YE 2005 Actual	30-Apr-06 Year-to-Date	YE 2006 Test Year	'05 vs '06 Change
Operations				
Manager	1	1	1	0
Maint Supt	1	1	1	0
Oper Supt	1	1	1	0
Oper Asst Supt	2	2	2	0
Shift Superv	5	5	5	0
Purch Pwr Admin	1	1	1	0
Prod Dept Admin	1	1	1	0
Stat Clerk	1	1	1	0
	13	13	13	0
Technical Services				
Tech Supt	1	0	0	-1
Staff Engineer	1	1	1	0
Environ Coor	1	1	1	0
Res Plann	1	1	2	1
	4	3	4	0
Keahole				
Pwr Plant Supv	2	2	2	0
Operators	6	6	6	0
	8	8	8	0
Hill				
System Oper	5	5	5	0
Control Oper	5	5	5	0
Sr Blr Oper	5	5	5	0
Blr Oper	4	3	6	2
CT3 Oper	2	2	2	0
	21	20	23	2
Puna				
Control Oper	5	5	5	0
Blr Oper	4	4	4	0
Oper Trainee	3	5	1	-2
	12	14	10	-2
Shipman				
Control Oper	0	3	3	3
Blr Oper	0	4	6	6
	0	7	9	9
Total	58	65	67	9

Hawaii Electric Light Company, Inc.
2006 TEST YEAR

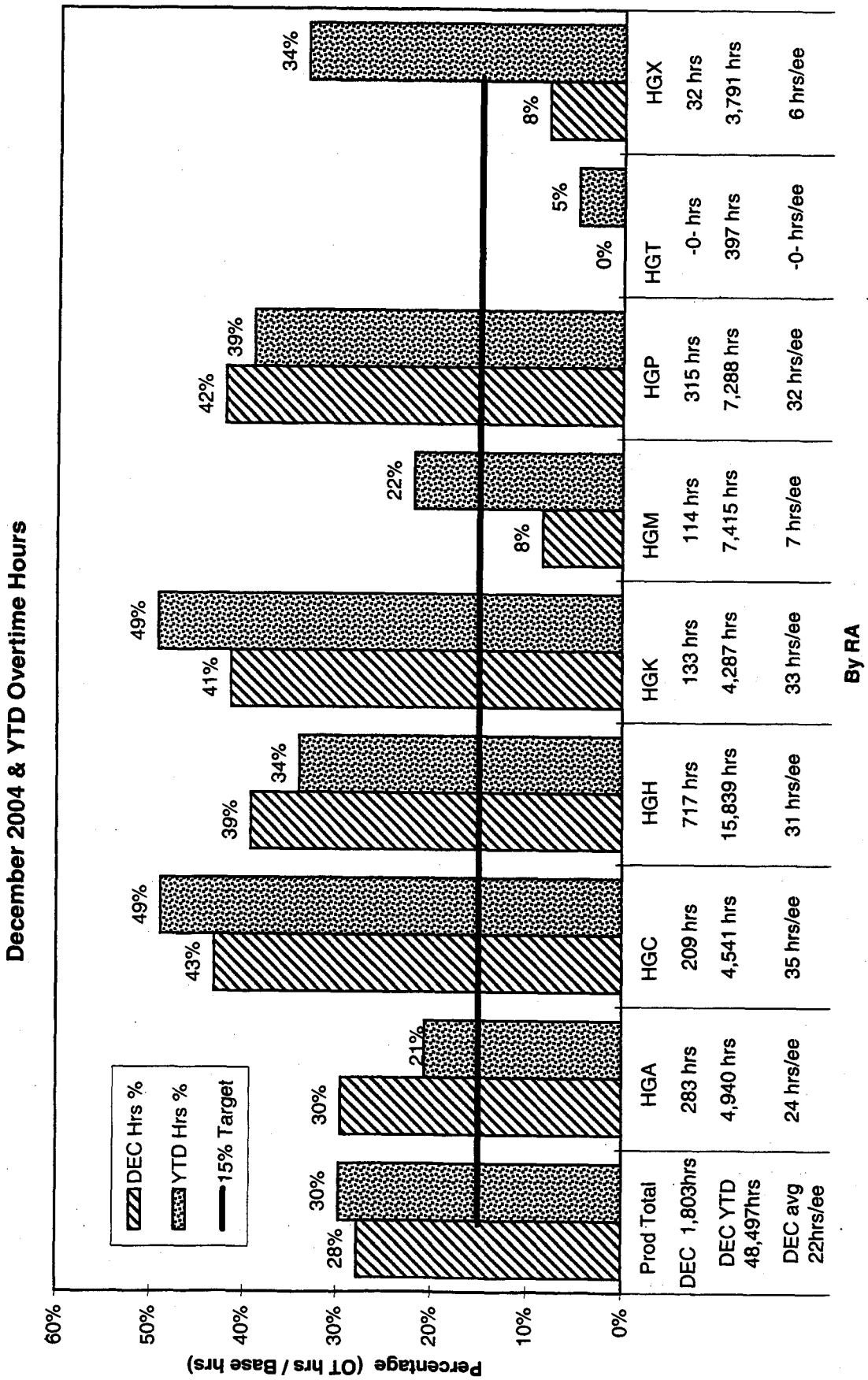
OTHER PRODUCTION
OPERATIONS - LABOR OVERTIME COMPARISION

	2002	2003	2004	2005	2006
ADMIN (HGA)	10.0%	14.0%	21.0%	12.0%	19.0%
TECH (HGT)		2.0%	5.0%	0.0%	2.0%
KEAHOLE (HGC)	23.0%	20.0%	49.0%	40.0%	35.0%
HILL (HGH)	38.0%	29.0%	34.0%	27.0%	31.0%
PUNA (HGP)	43.0%	36.0%	39.0%	34.0%	32.0%
SHIPMAN (HGW)					28.0%

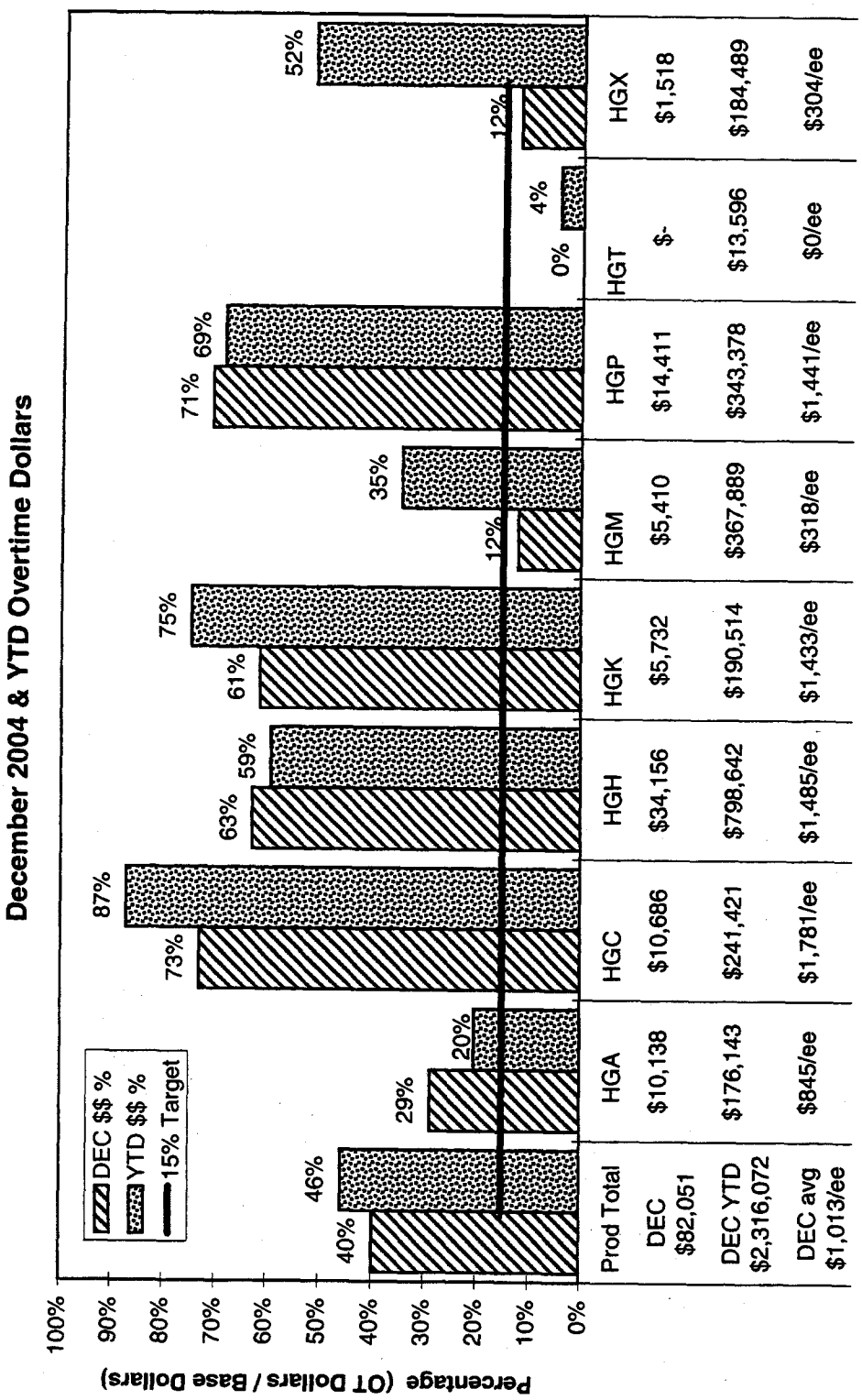


Source:
HELCO-539

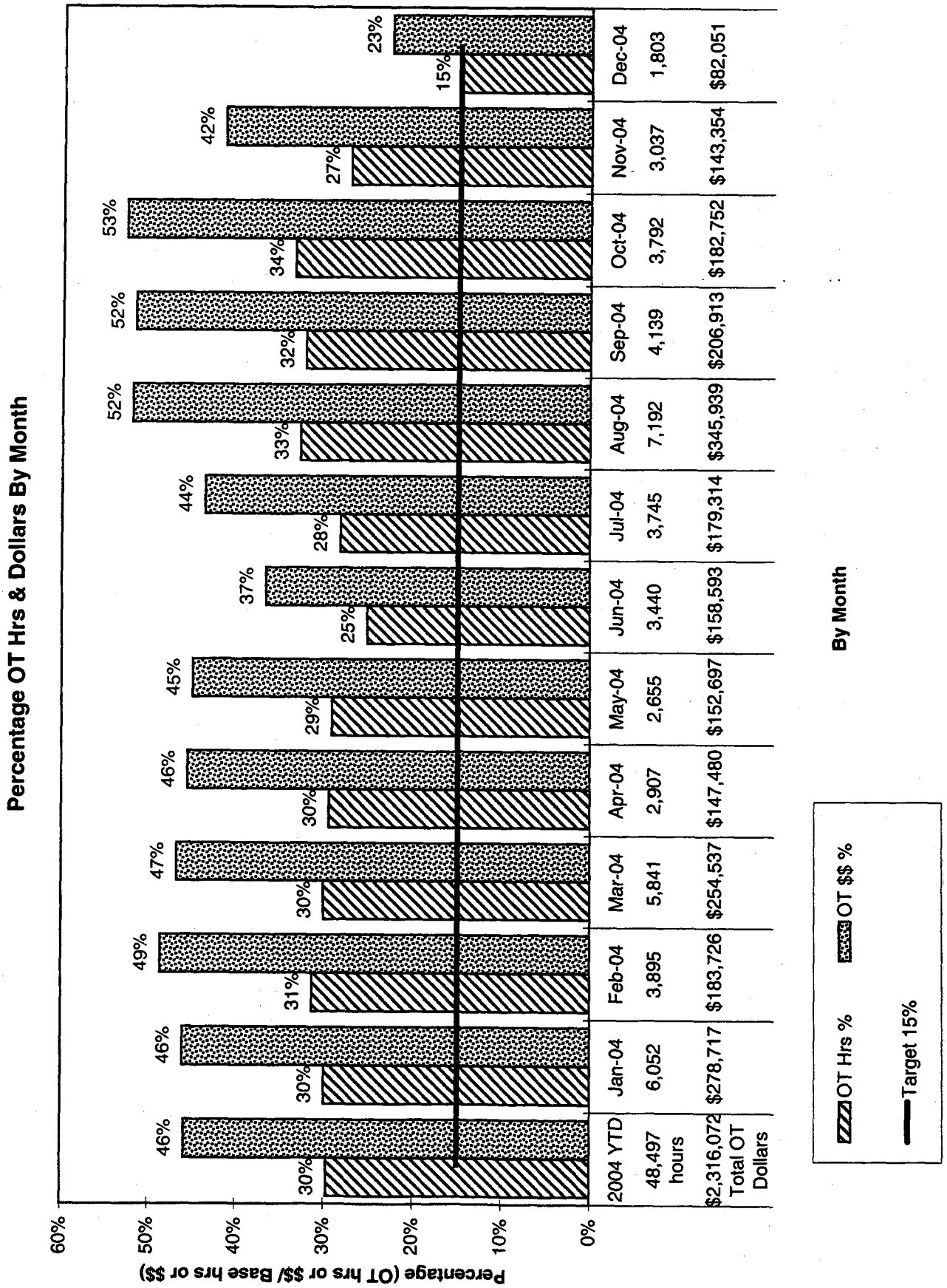
Hawaii Electric Light Company, Inc.



Hawaii Electric Light Company, Inc.

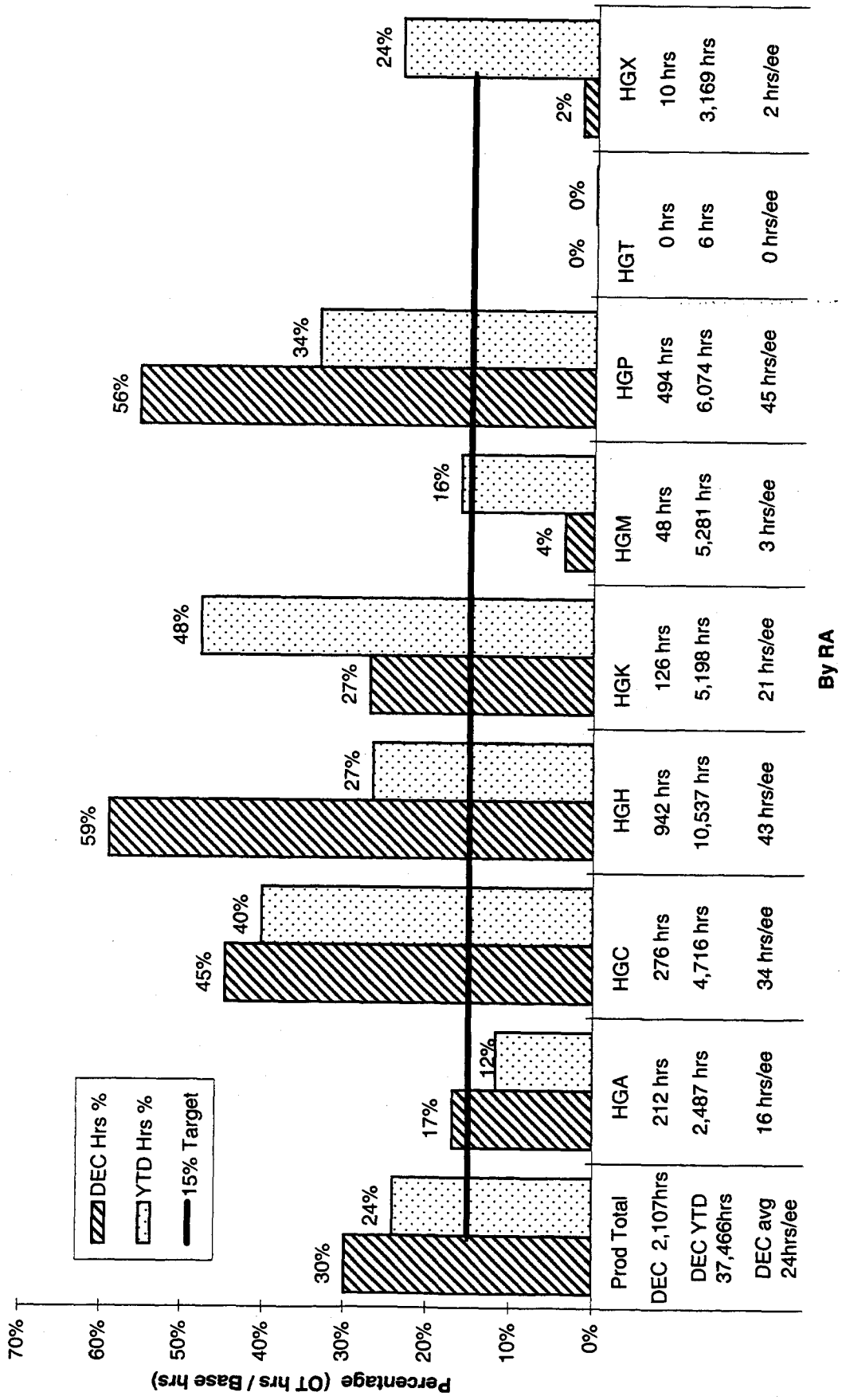


Hawaii Electric Light Company, Inc.

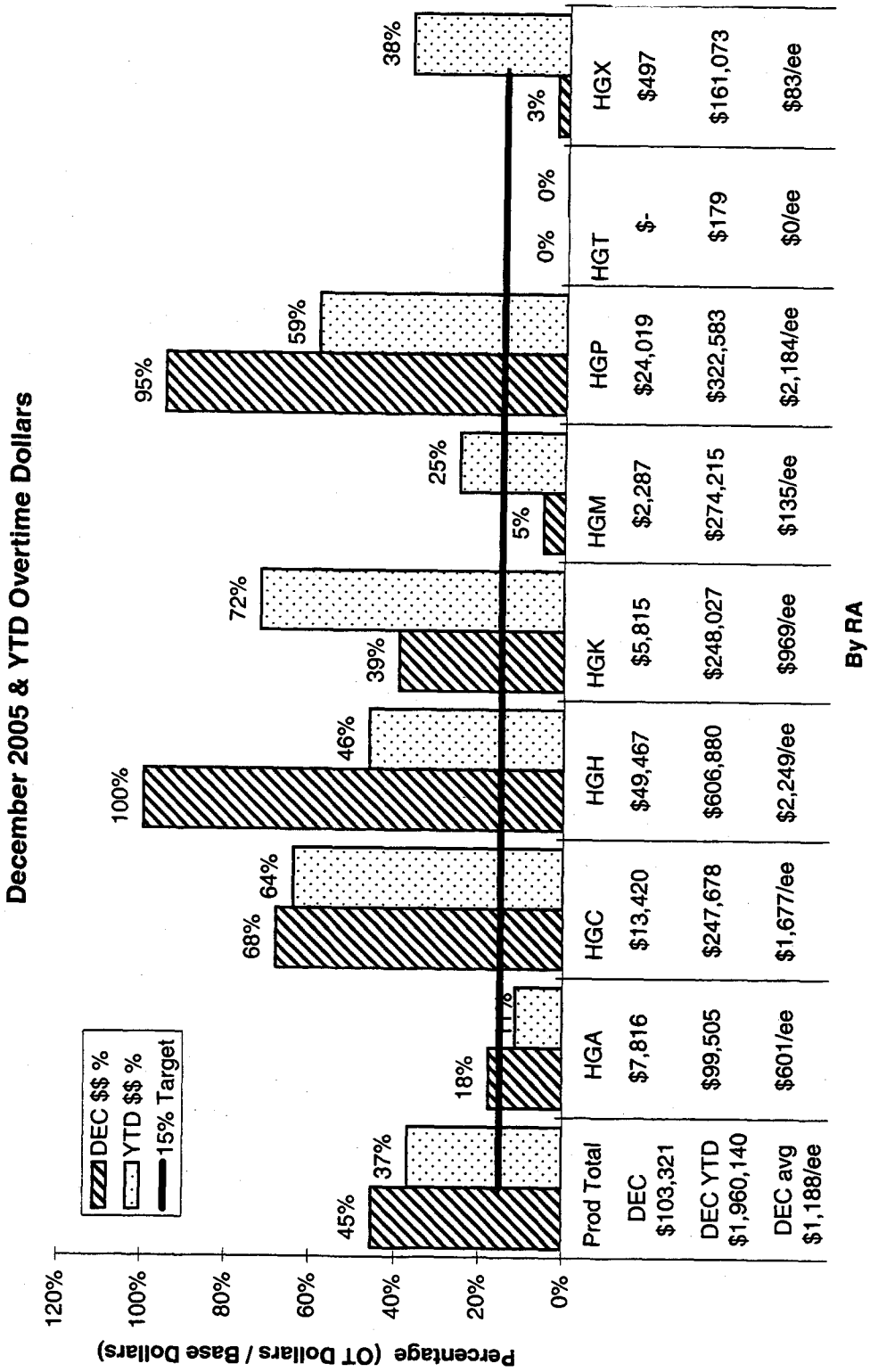


Hawaii Electric Light Company, Inc.

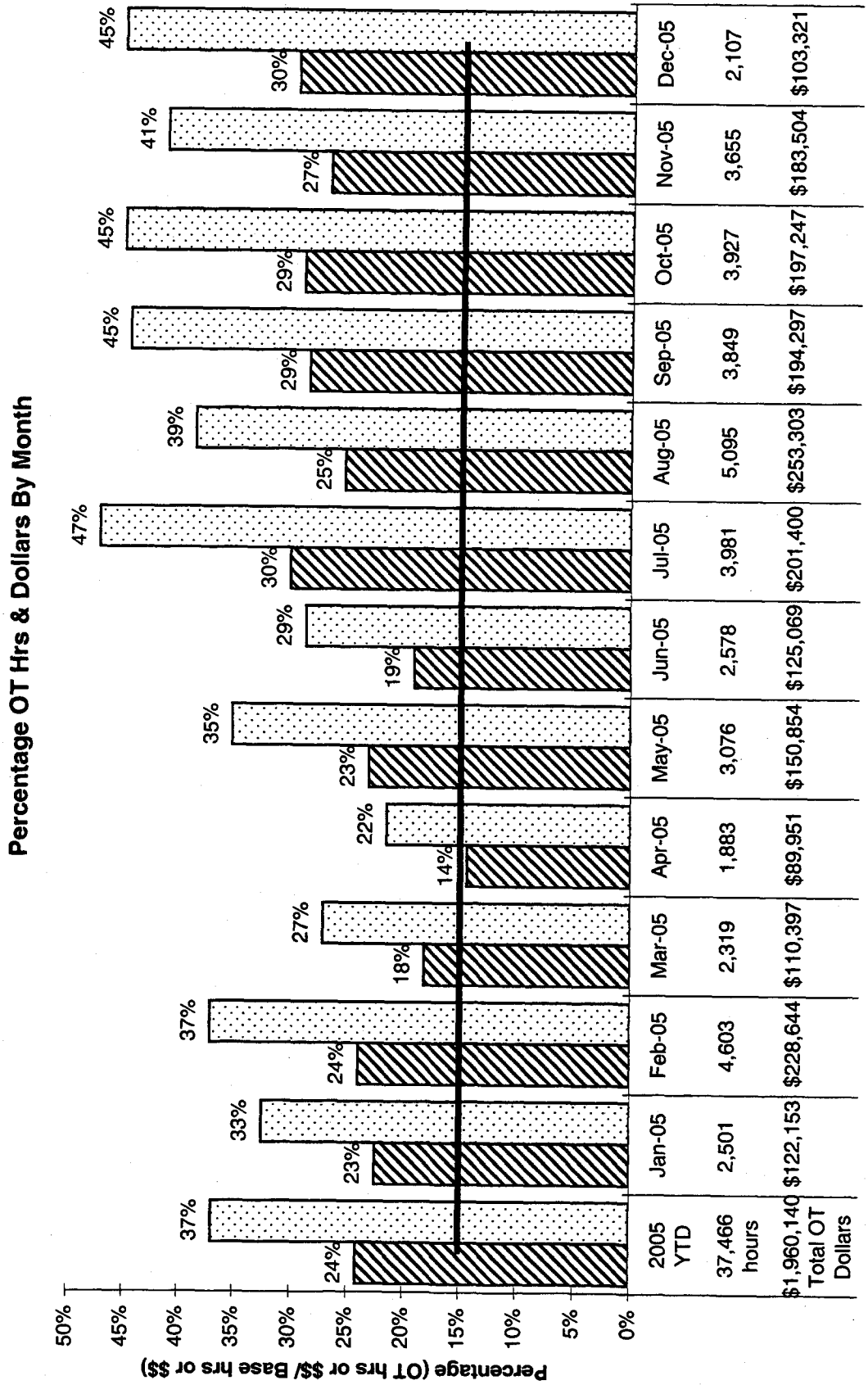
December 2005 & YTD Overtime Hours



Hawaii Electric Light Company, Inc.



Hawaii Electric Light Company, Inc.



By Month

Hawaii Electric Light Company Inc.
Rate Case - Test Year 2006
Labor Overtime

RA	RA Desc	Overtime Hours	Straight Time Hours	Proportion OT/ST Hrs %
2003 Actual				
HGA	Admin-Prod O&M	3,073	21,300	14%
HGT	Technical	129	7,640	2%
HGC	Keahole Stn Oper	801	4,028	20%
HGH	Hill Stn Oper	12,915	44,516	29%
HGP	Puna Stn Oper	8,655	23,952	36%
HGW	Shipman Stn Oper			0%
HGK	Keahole Stn Maint	2,467	6,832	36%
HGM	St/Hy Maint	11,519	37,547	31%
HGX	CT&D Hilo Maint	2,904	6,720	43%
TOTAL		42,463	152,535	28%
2004 Actual				
HGA	Admin-Prod O&M	4,940	23,523	21%
HGT	Technical	397	7,947	5%
HGC	Keahole Stn Oper	4,541	9,267	49%
HGH	Hill Stn Oper	15,839	46,587	34%
HGP	Puna Stn Oper	7,288	18,687	39%
HGW	Shipman Stn Oper			0%
HGK	Keahole Stn Maint	4,287	8,749	49%
HGM	St/Hy Maint	7,415	33,702	22%
HGX	CT&D Hilo Maint	3,791	11,149	34%
TOTAL		48,497	159,609	30%
2005 Actual				
HGA	Admin-Prod O&M	2,982	25,539	12%
HGT	Technical	6	8,403	0%
HGC	Keahole Stn Oper	5,200	12,909	40%
HGH	Hill Stn Oper	12,197	45,617	27%
HGP	Puna Stn Oper	6,882	20,474	34%
HGW	Shipman Stn Oper			0%
HGK	Keahole Stn Maint	5,456	11,399	48%
HGM	St/Hy Maint	5,443	33,635	16%
HGX	CT&D Hilo Maint	3,210	13,513	24%
TOTAL		41,376	171,489	24%

Hawaii Electric Light Company Inc.
Rate Case - Test Year 2006
Labor Overtime

RA	RA Desc	Overtime Hours	Straight Time Hours	Proportion OT/ST Hrs %
2006 Budget				
HGA	Admin-Prod O&M	5,470	29,120	19%
HGT	Technical	161	8,320	2%
HGC	Keahole Stn Oper	5,840	16,640	35%
HGH	Hill Stn Oper	15,580	49,920	31%
HGP	Puna Stn Oper	6,680	20,800	32%
HGW	Shipman Stn Oper	4,704	16,640	28%
HGK	Keahole Stn Maint	6,200	16,640	37%
HGM	St/Hy Maint	9,940	37,440	27%
HGX	CT&D Hilo Maint	7,760	16,640	47%
TOTAL		62,335	212,160	29%

2006 Budget - Breakdown of Straight Time Hours

		O&M Hrs	All Oth Hrs	Total
HGA	Admin-Prod O&M	28,240	880	29,120
HGT	Technical	8,300	20	8,320
HGC	Keahole Stn Oper	16,640		16,640
HGH	Hill Stn Oper	49,920		49,920
HGP	Puna Stn Oper	20,800		20,800
HGW	Shipman Stn Oper	16,640		16,640
HGK	Keahole Stn Maint	13,760	2,880	16,640
HGM	St/Hy Maint	25,664	11,776	37,440
HGX	CT&D Hilo Maint	13,328	3,312	16,640
TOTAL		193,292	18,868	212,160

Hawaii Electric Light Company, Inc.
2006 TEST YEAR

OTHER PRODUCTION OPERATION NON-LABOR EXPENSE
2005 ACTUAL VS. 2006 TEST YEAR
($ Thousands)

	EXPENSE	(A) 2005 ACTUAL	(B) 2006 TEST YEAR	(C) CHANGE	(D) %	Reason
1	Material	$ 681	$ 1,010	$ 329	48.3	Increase is mainly attributed to the net impacts of the Keahole expansion and full operation for the year.
2	Outside Srvcs	$ 1,839	$ 1,680	$ (159)	(8.7)	Decrease is due to large GAM projects which occurred in 2005, and will not be reoccurring in 2006.
3	Intercompany Charges	$ 542	$ 718	$ 176	32.5	Increase is mainly attributed to the net impacts of environmental compliance services to be provided by HECO. It is projected that HECO will be charging over $130,000 more than they did in 2005 for environmental services regarding increased air, wastewater and noise permitting issues for Keahole and Hill plants.
4	Labor Related On-Cost	$ 1,286	$ 2,534	$ 1,248	97.1	Non-labor on-cost is comprised of energy delivery on-cost, production on-cost, corporate administration on-cost, employee benefit on-cost, and payroll taxes on-cost. The $1,248,000 increase in non-labor on-cost expenses is primarily due to the increase in staffing levels in Production Operations. Refer to Mr. Paul Fujioka at HELCO T-9 for further discussion.
5	Reclassification of On-Cost	$ (1,055)	$ (2,552)	$ (1,497)	141.9	Refer to Mr. Paul Fujioka at HELCO T-9 for further discussion.
6	Other	$ 132	$ 137	$ 5	3.8	Negligible for discussion purposes.
7	Adj & Normalizations	$ -	$ 6	$ 6	0.0	Adjustments and normalizations were covered earlier in my testimony. (See HELCO-532 and HELCO-533.)
8	TOTAL	$ 3,425	$ 3,533	$ 108	3.2	

Hawaii Electric Light Company, Inc.
2006 Test Year

OTHER PRODUCTION MAINTENANCE EXPENSE
($ Thousands)

Line		RECORDED						2006 TEST YEAR	2005 vs 2006	
		(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H=G-F)	(I=H/F)
		2000	2001	2002	2003	2004	2005	2006	$	%
1	Labor	$1,939	$1,819	$2,109	$3,282	$2,328	$2,576	$3,228	$652	25.3
2	Non-Labor	$3,814	$4,279	$6,846	$6,808	$7,530	$7,749	$10,225	$2,476	32.0
3	TOTAL	$5,753	$6,098	$8,955	$10,090	$9,858	$10,325	$13,453	$3,128	30.3
	Percentage Change		6%	47%	13%	-2%	5%	30%		

Source:
HELCO-WP-101(A), page 2 for Columns A to F.
HELCO-531 for Column G.
Note:
Figures may not total exactly due to rounding.

Hawaii Electric Light Company, Inc.
2006 TEST YEAR

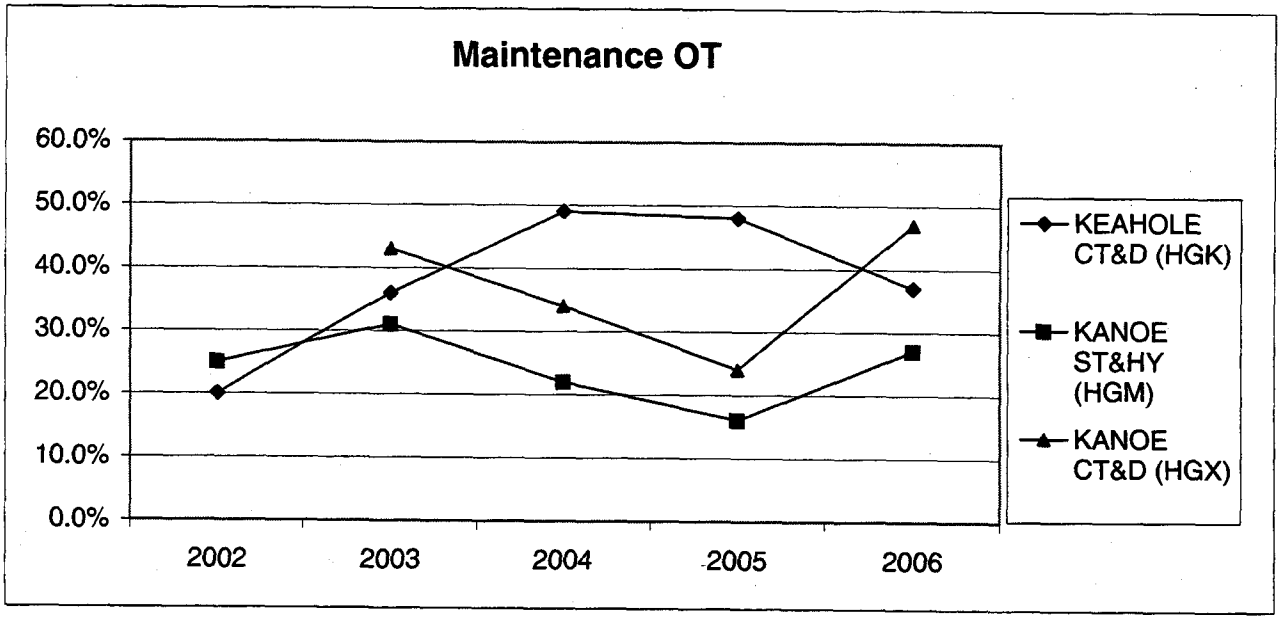
OTHER PRODUCTION
MAINTENANCE - EMPLOYEE COUNT

Site/Position	YE 2005 Actual	30-Apr-06 Year-to-Date	YE 2006 Test Year	'05 vs '06 Change	
Keahole CT&D					
Maint Superv	0	0	1	1	
Crew	6	6	7	1	
	6	6	8	2	
Kanoelehua CT&D					
Maint Superv	0	0	1	1	
Crew	7	7	7	0	
	7	7	8	1	
Kanoelehua ST&Hy					
Maint Superv	1	1	1	0	
Crew	16	17	17	1	
	17	18	18	1	
Total	30	31	34	4	
Production Operations	58	65	67	9	HELCO-535
Grand Total Production	88	96	101	13	

Hawaii Electric Light Company, Inc.
2006 TEST YEAR

OTHER PRODUCTION
MAINTENANCE - LABOR OVERTIME COMPARISION

	2002	2003	2004	2005	2006
KEAHOLE CT&D (HGK)	20.0%	36.0%	49.0%	48.0%	37.0%
KANOE ST&HY (HGM)	25.0%	31.0%	22.0%	16.0%	27.0%
KANOE CT&D (HGX)		43.0%	34.0%	24.0%	47.0%



Source:
HELCO-539

Hawaii Electric Light Company, Inc.
2006 TEST YEAR

OTHER PRODUCTION MAINTENANCE NON-LABOR EXPENSE
2005 ACTUAL VS. 2006 TEST YEAR
($ Thousands)

	EXPENSE	(A) 2005 ACTUAL	(B) 2006 TEST YEAR	(C) CHANGE	(D) %	Reason
1	Material	$ 2,116	$ 4,984	$ 2,868	135.5	Increase in non-labor material expenditure is mainly attributed to the differences between the scope of normal and recurring work forecasted in the 2006 test year vs. 2005 actual material expenditures, which reflects all material purchases including unforecasted material purchases resulting from unanticipated repairs and/or unscheduled outages. When units are shut down for maintenance and unforecasted repairs are required, resources are redirected to support the repairs to ensure reliable and efficient operation. HELCO-526 and HELCO-527 illustrate the differences between 2005 actual and 2006 test year from a unit outage perspective.
2	Outside Srvcs	$ 5,746	$ 5,208	$ (538)	(9.4)	Decrease in non-labor outside services expenditure is mainly due to the expectation that all vacant positions would be filled and there would be less of a need for outside services on both projects (i.e., overhauls) and non-projects (i.e., temporary hire).
3	Transportation	$ 177	$ 222	$ 45	25.4	Increase is mainly attributed to the higher 2006 budgeted cost for transporting and/or expediting shipment of materials and equipment to support higher levels of maintenance and repairs. This is mainly due to the 14 shift operation of Shipman Plant.
5	Intercompany Charges	$ 97	$ 126	$ 29	29.9	Increase is mainly due to the higher costs of HECO labor needed to perform boiler tube inspections on Hill and Puna steam units.
4	Labor Related On-Cost	$ 815	$ 1,352	$ 537	65.9	Labor-related on-cost – Non-labor on-cost is comprised of Energy Delivery on-cost, Power Supply on-cost, Corporate Administration on-cost, Employee Benefit on-cost, and Payroll Taxes on-cost. The $537,000 increase in non-labor on-cost expenses is primarily due to the increase in staffing levels in maintenance. For further discussion regarding on-cost, see Mr. Paul Fujioka at HELCO T-9.
5	Reclassification of On-	$ (1,566)	$ (1,444)	$ 122	(7.8)	Refer to Mr. Paul Fujioka at HELCO T-9 for further discussion.
6	Other	$ 364	$ 45	$ (319)	(87.6)	Decrease is due to a 2004 completed capital project that was reclassified to O&M based on a change in final scope. The journal entry to correct the cost occurred in early 2005.
7	Adj & Normalizations	$ -	$ (268)	$ (268)		Adjustments and normalizations were covered earlier in my testimony. (See HELCO-532 and HELCO-533.)
8	TOTAL	$ 7,749	$ 10,225	$ 2,476	32.0	

Hawaii Electric Light Company, Inc.

TEST YEAR 2006 PURCHASED POWER EXPENSE TOTAL
Direct Testimony

Line	Purchased Power ($000)	(A) Energy Payments ($000)	(B) Capacity Payments ($000)	(C) Total Payments ($000)
	Firm Power:			
1	Puna Geothermal Venture (PGV)	$ 34,393	$ 4,256	$ 38,649
2	Hamakua Energy Partners (HEP)	$ 54,246	$ 13,674	$ 67,920
	As Available Power:			
3	Wailuku River Hydro (WRH)	$ 4,412		$ 4,412
4	Hawi Renewable Development (HRD)	$ 5,496		$ 5,496
5	Apollo Energy Corp (Kamaoa)	$ 677		$ 677
6	Other Small Hydro	$ 164		$ 164
7	Total	$ 99,388	$ 17,930	$ 117,318

Source:
Column A = HELCO-WP-545, page 1
Column B = HELCO-WP-545, page 2 & 3
Column C = Column A + Column B

Note: Totals may not add exactly due to rounding.

Hawaii Electric Light Company, Inc.

TEST YEAR 2006 NET PURCHASED ENERGY (GWH)
Direct Testimony

Purchased Power	2006 Test Year (GWH)
Firm Power:	
1. Puna Geothermal Venture (PGV)	221.9
2. Hamakua Energy Partners (HEP)	420.6
Subtotal Firm Power	642.5
As Available Power:	
3. Wailuku River Hydro	27.5
4. Hawi Renewable Development	34.2
5. Apollo Energy Corp (Kamaoa Wind Farm)	4.8
6. Other Small Hydro	1.0
Subtotal As-Available Power	67.6
Total Purchased Power (GWH)	710.1

Source:
HELCO-WP-545, page 1

Note: Totals may not add exactly due to rounding.

Hawaii Electric Light Company, Inc.

HISTORICAL PURCHASED ENERGY (ANNUAL GWH)
Direct Testimony

Purchased Power (GWH)	FY 2001	FY 2002	FY 2003	FY 2004	FY 2005	**Test Year 2006**
Firm Power:						
1. Puna Geothermal Venture (PGV)	207	74	176	211	221	**222**
2. Hamakua Energy Partners (HEP)	322	421	439	442	431	**421**
3. Hilo Coast Power Company (HCPC)	69	89	82	79	-	**-**
Subtotal Firm Power	598	584	697	731	652	**643**
As Available Power:						
4. Wailuku River Hydro	33	27	24	26	30	**27**
5. Hawi Renewable Development	-	-	-	-	-	**34**
6. Apollo Energy Corp (Kamaoa Wind Farm)	15	10	10	6	5	**5**
7. Other Small Wind and Hydro	1	1	1	1	1	**1**
Subtotal As-Available Power	49	38	35	33	35	**68**
Total HELCO Purchased Power	648	622	732	764	688	**710**

Note: Totals may not add exactly due to rounding.

Hawaii Electric Light Company, Inc.

HISTORICAL PURCHASED POWER EXPENSES
Direct Testimony

Purchased Power Expense	2004 Recorded ($000)	2005 Recorded ($000)	2006 Test Year Estimate ($000)
1. Puna Geothermal Venture (PGV)	$ 21,067	$ 30,746	$ 34,393
2. Hamakua Energy Partners (HEP)	$ 37,489	$ 49,380	$ 54,246
3. Hilo Coast Power Company (HCPC)	$ 7,040	$ -	$ -
4. Wailuku River Hydro (WRH)	$ 2,555	$ 4,394	$ 4,412
5. Hawi Renewable Development (HRD)	$ -	$ -	$ 5,496
6. Apollo Energy Corporation (AEC)	$ 535	$ 573	$ 677
7. Other Small Wind & Hydro	$ 62	$ 129	$ 164
Total Energy Payments	$ 68,748	$ 85,222	$ 99,388
1. Puna Geothermal Venture (PGV)	$ 3,950	$ 4,104	$ 4,256
2. Hamakua Energy Partners (HEP)	$ 13,500	$ 13,569	$ 13,674
3. Hilo Coast Power Company (HCPC)	$ 4,930	$ -	$ -
Total Capacity Payments	$ 22,380	$ 17,672	$ 17,930
Total HELCO Purchased Power Expense	$ 91,128	$ 102,894	$ 117,318

Note: Totals may not add exactly due to rounding.

Hawaii Electric Light Company, Inc.
2006 TEST YEAR

PRODUCTION MATERIAL INVENTORY
13-MONTH AVERAGE
(DECEMBER 1 - DECEMBER 31)

					2006 TEST YEAR	2005 vs 2006	
	(A) 2002	(B) 2003	(C) 2004	(D) 2005	(E) 2006	(F=E-D) $	(F/D) %
1 Year-End Value	862,838	879,834	1,004,029	1,006,978	1,061,943	54,965	5.5
2 Difference		16,996	124,195	2,949	54,965		

Source:
HELCO-WP-509, page 1, for Line 1.

T-6 J. M. IGNACIO

HELCO T-6
DOCKET NO. 05-0315

TESTIMONY OF
JAY M. IGNACIO

MANAGER
DISTRIBUTION
HAWAII ELECTRIC LIGHT COMPANY, INC.

Subject: Transmission and Distribution ("T&D") System
T&D Operation and Maintenance ("O&M") Expense
T&D Materials Inventory

INTRODUCTION

Q. Please state your name and business address.

A. My name is Jay Ignacio and my business address is 54 Halekauila Street, Hilo, Hawaii.

Q. By whom are you employed and in what capacity?

A. I am the Manager of the Distribution Department at the Hawaii Electric Light Company, Inc. ("HELCO" or "Company"). I have been employed for 15 years at HELCO in positions involving the design and construction of the Company's transmission and distribution ("T&D") facilities. HELCO-600 provides my educational background and work experience in greater detail.

Q. Please specify the areas that your testimony will address.

A. My testimony will cover the following:

- Summary of T&D O&M Expense
- Description of the HELCO T&D system
- Customer Growth and Demand
- HELCO Service Reliability
- Generation Service Reliability
- Transmission and Distribution Service Reliability
- Capital Projects to Improve T&D Reliability
- HELCO Distribution Department
- Staffing for T&D Work
- Trouble inspectors
- Reasonableness of the 2006 test year estimate
- T&D materials inventory

1 SUMMARY OF T&D O&M EXPENSE

2 Q. Please summarize the 2006 test year estimate addressed by your testimony.

3 A. HELCO's normalized estimate for T&D O&M expense for the 2006 test year is
4 $8,999,000 as shown on HELCO-601. Of this amount, $2,401,000 is for
5 transmission O&M expense and $6,598,000 is for distribution O&M expense, as
6 shown on HELCO-601.

7 Q. How was the 2006 test year estimate of T&D O&M expenses derived?

8 A. The 2006 test year estimate of T&D O&M expenses was based on HELCO's
9 O&M expense budget for the year.

10 Q How is the T&D O&M expense budget prepared?

11 A. Each responsibility area ("RA") from the various departments determines the
12 level of O&M work required to provide reliable electric service to HELCO's
13 customers. This level of work is based on reviewing historical trends, making
14 adjustments for changes in operations and making adjustments for other
15 improvements. Staff with extensive knowledge of the operating and
16 maintenance requirements of HELCO's facilities and systems are involved in the
17 budget preparation process. Estimates for each RA's labor and non-labor costs
18 are allocated to activities, each of which is linked to National Association of
19 Regulatory Utility Commissioners (NARUC) account numbers.

20 Q. What items are included in HELCO's T&D O&M expense?

21 A. T&D O&M expense includes the labor and non-labor expenses incurred in the
22 operation and maintenance of HELCO's T&D system. These expenses are
23 captured in the following NARUC series of accounts:

24 560-567 - Transmission Operation Expenses

25 568-573 - Transmission Maintenance Expenses

580-589 - Distribution Operation Expenses

590-598 - Distribution Maintenance Expenses

HELCO-WP-602, HELCO-WP-603, HELCO-WP-604 and HELCO-WP-605 provide the NARUC descriptions of the expenses that are included in these accounts.

Q. How are direct labor costs for O&M activity budgeted?

A. The standard labor unit in the T&D O&M forecasts is a man-hour. HELCO labor requirements are estimated in man-hours. The amount of man-hours required for O&M activity is estimated based upon the historical trends and anticipated changes to meet customer growth and improve operations. The man-hours are converted to direct labor dollars by multiplying man-hours by appropriate labor rates. HELCO utilizes Standard Labor Rates, which are based on existing union wage agreements and salary estimates for merit employees as discussed by Ms. Julie Price in HELCO T-10.

Q. How are direct non-labor costs budgeted?

A. Direct non-labor costs are budgeted using estimates for materials, information system services and contracts/services necessary to support and supplement the work performed by the HELCO work force. These costs are budgeted in dollars.

Q. Does the T&D expense estimate include only the direct labor and direct non-labor costs?

A. No. Overhead costs (i.e., on-costs) are applied to direct T&D labor and non-labor expenses. These overhead costs include related indirect expenses such as T&D supervision and administrative costs as well as non-productive labor costs.

Q. How was the 2006 test year Estimate derived from the O&M Budget?

A. To derive the 2006 test year estimate for T&D O&M expense we made certain

budget adjustments to account for known or expected changes in the test year which were not reflected in the T&D O&M budget or to correct errors that we discovered after the budget was finalized.

Q. What was the net impact of these budget adjustments?

A. The net total of these budget adjustments was $165,000. HELCO-602 provides a description of the adjustments that were made for rate case purposes.

Q. Does the T&D O&M test year estimate include any normalization adjustments?

A. No. It was not necessary for us to make any normalization adjustments to derive the T&D O&M 2006 test year estimate.

Q. What is the break down of the 2006 T&D O&M expense by labor and non-labor costs?

A. HELCO-603 provides a chart of HELCO T&D labor and non-labor costs for 2000 to 2006. The 2006 test year T&D, labor and non-labor costs are as follows:

Transmission Operation Labor	$ 467,254
Transmission Operation non-labor	491,516
Transmission Maintenance labor	462,115
Transmission Maintenance non-labor	980,415
Distribution Operation labor	1,142,470
Distribution Operation non-labor	1,344,301
Distribution Maintenance labor	1,324,143
Distribution Maintenance non-labor	2,787,110
Total T&D O&M Expense	$8,999,324

Q. How do the 2006 test year T&D O&M labor and non-labor estimates compare with the actual 2005 amounts?

A. The 2006 T&D O&M test year estimate has total labor costs of $3,395,982 as

compared to 2005 actual labor costs of 3,150,779. The higher labor costs of $245,203 are due to additional staffing and operational changes that will be discussed in more detail in my testimony. The 2006 O&M test year estimate has total non-labor costs of $5,603,342 as compared to 2005 actual non-labor costs of $5,862,427. The lower non-labor costs of $259,087 are due to certain expenses that occurred in 2005 that will not be done in 2006 and other operational changes that will be discussed in more detail in my testimony. (See HELCO-603, page 2.)

Q. What is the 2006 test year estimate for the T&D materials inventory?

A. The 2006 test year estimate for the T&D materials inventory is estimated to be $2,512,000 and is further detailed in HELCO-604.

DESCRIPTION OF THE HELCO T&D SYSTEM

Q. Please provide a high-level description of HELCO's T&D system?

A. HELCO's transmission system is a network of 69 kilovolt ("kv"), 34.5kv and 13.8kv transmission lines and transmission switching stations used to transport power from power plants to customer load centers. The power generated at power plants enters the transmission network through generator step-up transformers that are located at transmission switching stations. At the customer load centers, distribution substations are installed to allow power to be extracted from the transmission network through distribution substation transformers. From the distribution substations overhead and underground distribution power lines energized at 13.8kv, 12.47kv, 4.16kv or 2.4kv deliver electric service to customer locations.

Most of HELCO's transmission network is constructed and energized at 69,000 volts, although there are 34,500 volt transmission lines used to transmit power to distribution substations along the Hamakua coast, North Kohala and in

the Puna district. There are also three 13.8kv transmission ties between the Shipman Power Plant and Kanoelehua Power Plant. Most of HELCO's transmission lines are supported by wood poles, with steel poles being used in the more recent transmission line additions. There are approximately 641 miles of transmission lines on the HELCO system and a total of 22 transmission switching stations.

HELCO's distribution network utilizes voltages of 13.8kv, 12.47kv, 4.16kv and 2.4kv. The majority of the distribution facilities are at HELCO's standard distribution voltage of 12.47kv and nearly all new distribution facilities are constructed at 12.47kv. HELCO confines the use of 13.8kv distribution voltage to the Hilo area near the Kanoelehua and Puueo switching stations since adopting 12.47kv as the new standard distribution voltage. The 4.16kv and 2.4kv installations are located in rural areas with older distribution systems such as Hawi in North Kohala and smaller communities along the Hamakua Coast. There are approximately 2,500 miles of overhead distribution lines and 550 miles of underground distribution lines on the HELCO system. A total of 68 distribution substations are installed on the HELCO system.

Q. What power generation sites are interconnected by HELCO's transmission system?

A. HELCO's transmission system interconnects HELCO's major generation sites at Keahole (64.8 megawatts or "mw"), Kanoelehua (55.2 mw), Puna (34.5 mw), Shipman (13.5 mw) and Waimea (7.5 mw), and major independent power producers at Hamakua Energy Partners L.P. ("HEP)(60 mw) and Puna Geothermal Venture ("PGV") (30.0 mw). Other as-available generation sites at Puueo Hydro (3.25 mw), Wailuku River Hydro (12.1 mw), Apollo Energy

Corporation Windfarm (7.0 mw), Lalamilo Windfarm (2.3 mw) and Hawi Renewable Development Inc. (10.56 mw) are also interconnected to HELCO's transmission system. There are also 4 dispersed diesel units (1 mw each) interconnected to the distribution system at Panaewa substation, Kapua substation, Ouli substation and Punaluu substation.

Q. Please compare the location of customer load with the location of the power plants on the island of Hawaii ("Island").

A. HELCO-605 shows the east-west distribution of firm capacity on the HELCO system. The majority of the firm capacity power plants on HELCO's system are located on the eastern half of the Island while approximately half of the customer loads are on the western half of the Island. HELCO firm capacity power plants at Kanoelehua (55.2 mw), Puna (34.5 mw), and Shipman (13.5 mw), and firm capacity independent power producer plants at PGV (30 mw) and HEP (60 mw) are located on the eastern half of the Island. HELCO firm capacity power plants at Keahole (64.8 mw) and Waimea (7.5 mw) are located on the western half of the Island. Net power generally flows from the power plants in the east to the load centers near Kailua Kona on the west side.

Q. What are the main transmission routes that deliver power from the power plants in the east to the locations of customer load in the west?

A. There are four basic transmission routes for this cross-Island power flow. Two transmission routes traverse between Mauna Kea and Mauna Loa closely following the path of the Saddle road, then through the South Kohala area on to Kailua Kona. Another route traverses from Hilo through the northeast part of the Island along the Hamakua Coast, through Waimea town and then through the South Kohala area into Kailua Kona. The fourth route traverses from Hilo,

through the volcano area, through the Southpoint area, continuing through South Kona and into Kailua Kona. See HELCO-606 for a drawing of the HELCO Transmission System.

Q. Please explain how the design of this transmission network enhances system reliability.

A. The HELCO transmission network allows for redundancy in the event of an outage to a line or system component. HELCO uses single contingency criteria for the planning of its transmission system, which means the system is designed to maintain normal voltages and line loadings if a single transmission line is out of service. However, the HELCO transmission system is not designed to maintain normal voltages and line loadings if simultaneous outages occur to two or more transmission lines. Because such outages can result in large and serious system disturbances, the proper operation and maintenance of HELCO's transmission system are vital to providing reliable service.

CUSTOMER GROWTH AND DEMAND

Q. Please describe the customer and load growth trends that HELCO has experienced since 2000?

A. The average number of HELCO's customers has increased from 63,208 in 2000 to 72,521 in 2005, or 14.7% over this time period as shown in HELCO-607. The system peak load has increased 15% from 171 MW in 2000 to 197 MW in 2005.

Q. How has this growth impacted the construction of T&D facilities?

A. This growth has required the construction of new overhead and underground facilities. Since 2000, HELCO has installed over 9,000 new customer services, one new switching station, two substations and two substation transformer additions. All of these additional facilities now require inspection and

1 maintenance contributing to increased operations and maintenance costs.
2 Q. Has this growth accelerated in the past year?
3 A. Yes. In 2005 the Big Island experienced a large increase in the construction of
4 new subdivisions, businesses and residences. The growth has occurred in all parts
5 of the Island. The average number of customers increased from 70,124 in 2004 to
6 72,521 in 2005 as shown in HELCO-607. This is an increase of 2,397 or 3.4%.
7 The growth placed a serious burden on HELCO's construction and maintenance
8 crews. To meet the new customer demand in 2005, HELCO construction and
9 maintenance employees worked at 35%, 35% and 29% overtime levels in Hilo,
10 Kona and Waimea respectively and still could not keep up with the demand. The
11 Company contracted crews from the mainland to mitigate the work load. As
12 shown in HELCO-608, this level of overtime has continued into 2006.
13 Q. What is HELCO's forecast of customers and load in the 2006 test year?
14 A. The total average number of customers forecasted for the 2006 test year is 74,174,
15 as shown by rate schedule in HELCO-207.
16 Q. How has the increase in customer load impacted operations of the HELCO
17 transmission system?
18 A. As I explained earlier, the net power flow in HELCO's system is from east to west
19 Hawaii. It is critical to have adequate generation on the west side of the Island to
20 sustain adequate voltages and to maintain the single contingency criteria in the
21 Company's transmission facilities. The loads during the normal business day
22 periods have increased to the point that it is difficult to take the heavier loaded
23 transmission lines out of service for maintenance without imposing serious risks
24 to the HELCO system. The Company is more frequently conducting maintenance
25 of transmission lines during weekends and nights when the loads on the system

are lower. This reduces risks to the system but increases O&M costs.

TRANSMISSION AND DISTRIBUTION RELIABILITY

Q. Does HELCO prepare service reliability reports?

A. Yes. HELCO files an Annual Service Reliability Report with the Commission. The Annual Service Reliability Report provides service reliability data for the reported year and for the previous five years.

Q. Was an Annual Service Reliability Report filed for year 2005?

A. Yes. The HELCO Annual Service Reliability Report was filed with the Commission on April 21, 2006. A copy of the report is provided in HELCO-WP-617.

Q. Please describe data collected by HELCO to measure service reliability.

A. To measure the quality of service to customers HELCO tracks the number of customer interruptions experienced in the year, the hours of customer interruptions experienced during a year and the causes of those interruptions. HELCO also tracks the location of interruptions by transmission and distribution circuits.

Q. Does HELCO use reliability indices to measure reliability?

A. Yes. HELCO uses the Average Service Availability Index ("ASA"), the System Average Interruption Frequency Index ("SAIF") and the Customer Average Interruption Duration Index ("CAID") to measure service reliability. These indices are described in Appendix B of the "Annual Service Reliability Report 2005":

Average Service Availability Index ("ASA") represents total customer hours actually served as a percentage of total customer hours possible during the year. This indicates the extent to which electrical service was available to all

1 customers.

2 System Average Interruption Frequency Index ("SAIF") represents the
3 number of customer interruptions per customer served during the year. This
4 index indicates the average number of interruptions experienced by all customers
5 serviced on the system.

6 Customer Average Interruption Duration Index ("CAID") represents the
7 interruption duration per customer interrupted during the year. This index
8 indicates the average duration of an interruption for those customers affected by
9 a sustained interruption.

10 Q. Does HELCO normalize its service reliability data?

11 A. Yes. HELCO normalizes service reliability data according to a December 1990
12 report, "Methodology for Determining Reliability Indices for HECO Utilities".
13 Although HELCO utilizes normalization, data that has not been normalized is
14 also retained and provided in the annual service reliability report.

15 Q. What does it mean to normalize service reliability data?

16 A. When service reliability data is normalized, "abnormal" situations such as
17 hurricanes, tsunamis, earthquakes, floods, catastrophic equipment failures, and
18 single equipment outages that cascade into a loss of load that is greater than 10%
19 of system peak load are excluded from the data.

20 Q. Why is normalization useful?

21 A. "Abnormal" events can skew the service reliability data. Normalized data
22 provide a clearer picture of how the Company's systems are performing under
23 typical conditions and enable more dependable identification of system problems
24 and strengths.

25 Q. What are some of the common causes of power interruptions related to

1 Transmission and Distribution on the HELCO system?

2 A. Some of the problems that occur more frequently on the T&D system are trees
3 and branches contacting power lines, lightning striking on or near power lines,
4 automobile accidents, underground cable faults, deterioration of equipment and
5 structures, and failure of equipment. A summary of the T&D System reliability
6 data for years 2000 to 2005 is provided in HELCO-609. Details regarding these
7 causes are provided later in this testimony.

8 Q. What is the Distribution Department's strategy to improve the ASA index?

9 A. Because the ASA index is related to the number of customer hours of
10 interruption, strategies to prevent interruptions and improve SAIF and strategies
11 to reduce interruption times and improve CAID will also improve the ASA
12 index.

13 Q. What are the Distributions Department's general strategies to improve the SAIF
14 index?

15 A. Because the SAIF index is related to the number of interruptions that occur,
16 strategies and actions that prevent interruptions from occurring will result in
17 improvements to the SAIF index. Strategies such as inspecting and maintaining
18 or replacing equipment before failure, keeping vegetation clear of power lines
19 and use of better equipment and materials will prevent interruptions and improve
20 the SAIF index.

21 Q. What are the Distribution Department's general strategies to improve the CAID
22 index?

23 A. Because the CAID index is related to the duration of service interruptions that
24 occur, strategies and actions that reduce interruption times will result in
25 improvements to the CAID index. Strategies such as increasing available

1 responders to expedite response, providing more alternate circuits or routes to
2 serve customers, installation of remotely controlled switching devices and
3 installation of devices to locate electrical faults will reduce interruption times
4 and improve the CAID index.
5 Q. What are the trends in service reliability indices for causes related to T&D?
6 A. The table on page D-3 of the "Annual Service Reliability Report 2005" provides
7 reliability indices for T&D related outages for the years 2000 to 2005. In the
8 table the SAIF (not-normalized) for years 2002 to 2004 remained at
9 approximately 2.660 each year. In 2005 the SAIF dropped to 1.932. The same
10 table indicates an upward trend for CAID (not-normalized) from 59.88 minutes
11 in 2000 to a high of 103.59 minutes in 2004. In 2005 the CAID decreased to
12 93.81.
13 In general the SAIF index indicates a relatively high number of customer
14 interruptions occurred during the years 2002 to 2004 with an improvement
15 occurring in 2005. The CAID index indicates duration of interruptions has been
16 increasing from 2000 to 2004 with an improvement occurring in 2005.
17 Q. What is the reason for the recent trends in T&D reliability?
18 A. There are multiple reasons for the recent trends in T&D reliability but evaluation
19 of the leading causes indicate that weather related interruptions have negatively
20 impacted T&D reliability in recent years. There are areas of improvement and
21 areas of decline that combine towards the overall T&D reliability trend. To
22 understand the trends in T&D reliability an analysis of the leading causes of
23 interruptions is provided in subsequent sections of this testimony.
24 Q. During the period of 2000 to 2005 what were the leading causes of T&D-related
25 customer hours of interruption?

A. Trees and branches, lightning, automobile accidents, high wind, cable fault, equipment failure, and deterioration were the leading causes of customer interruptions during the past six years. HELCO-610 provides graphs of Customer Hours of Interruption, CAID and SAIF for the years 2000 to 2005 for the leading causes listed above. Ensuing are discussions of each leading cause of T&D related interruptions.

Interruptions Due to Trees and Branches

Q. How do trees and branches cause power interruptions?

A. In most cases power interruptions caused by trees and branches involve trees and branches contacting bare transmission or distribution conductors. The contact causes an electrical fault that causes circuit breakers to open or fuses to blow out as designed to isolate the faulted area and prevent further damage and/or interruption on the system.

Q. How is power restored after a tree or branch causes a power interruption?

A. The tree or branch that causes the electrical fault needs to be removed from the conductors before the circuit breaker can be closed or the fuse replaced. Because of the electrical hazards involved, qualified line personnel from the Hilo C&M, Kona C&M and Waimea C&M divisions respond to clear the trees and then replace the fuses or operate a breaker to restore power.

Often trees or branches that fall into power lines break the conductors or break other facilities such as insulators, crossarms or poles. In these instances repairs are also required to restore service. These repairs are also done by qualified line workers in the Hilo C&M, Kona C&M and Waimea C&M divisions. Clearing of the tree or branch and making repairs to damage facilities can take hours or even days to complete. If reasonable and possible, line personnel will

1 perform switching to isolate the problem area and reroute the power flow to
2 restore service to as many of the affected customers as possible before clearing the
3 tree or branch or making repairs. Customers in the immediate area remain without
4 service until the tree or branch is removed and other required repairs are
5 completed.
6 Q. How do storms increase power interruptions related to trees and branches?
7 A. During storm conditions high winds cause entire trees to topple over and fall into
8 power lines or branches are blown into the power lines or branches break and fall
9 into power lines, causing damage and power interruptions in numerous locations.
10 Heavy rains also contribute to entire trees uprooting and falling into power lines or
11 tree branches sagging into power lines or tree branches breaking and falling into
12 power lines.
13 Q. What is the impact to operations when storms cause trees and tree branches to fall
14 into power lines?
15 A. During storms line workers work extended hours to clear trees and branches and
16 make repairs to restore service. The availability of line workers is vital to the
17 power restoration efforts.
18 Q. Please describe the trend for service interruptions related to trees or branches.
19 A. Page 3 of HELCO-610 shows the SAIF index has trended upward from 0.257 in
20 2000 to a high of 0.971 in 2004. In 2005 the SAIF decreased back down to 0.345.
21 The number of hours of customer interruptions also shows an upward trend from
22 15,906 hours in 2000 to an unusually high 142,547 hours in 2004. In 2005 the
23 number of customer hours was back down to 36,289. The CAID index also
24 trended upward from 58.8 minutes in 2000 to a high of 125.58 minutes in 2004.
25 In 2005 the CAID was back down to 87.09 minutes.

Q. Please explain why there was a trended increase in Customer Hours, SAIF and CAID from 2000 to 2004, and why the Customer hours, SAIF and CAID in 2004 was at unusually high values.

A. In years 2003, 2004 and 2005 a large portion of interruptions caused by trees and branches were due to storm conditions during the winter months of November to March. In year 2004, storm conditions experienced on January 14 to 15, January 23 to 29, February 27 to March 2, and November 23 to 28, caused most of the interruptions related to trees and branches for that year. Of the 68,108 customer interruptions due to trees or branches in 2004, 55,940 customer interruptions were related to stormy weather.

Q. Has HELCO taken measures to reduce interruptions due to trees and branches?

A. Yes. HELCO has increased expenditure for vegetation management to obtain additional clearances in areas that are more vulnerable to trees or branches falling into power lines during storms. Certain species of trees such as Albizzia and Eucalyptus are often the source of falling branches during storms. Increase in vegetation management spending began in 2005 to target additional trimming in areas where there is a proliferation of these species. Additional funds are also being used to remove potential hazardous trees that have termite damage, rot or are leaning toward power lines.

In 2005 HELCO performed additional trimming in the Ainaloa, Hawaiian Beaches, Hawaiian Shores, Orchidland, Nanawale, and Leilani Estates subdivisions which were the areas most vulnerable to falling branches. Additional trimming was also done in parts of Hilo, Kurtistown, Glenwood, Mountain View and South Kona. In 2006 HELCO is targeting additional trimming for the 34.5 kv Puna to Kilauea, 34.5 kv Pepeekeo to Paauilo, 34.5 kV Waimea to North Kohala,

69 kV Pepeekeo to Honokaa, 69 kv Haina to Waimea, and 69 kv Kilauea to Kealia transmission lines. Additional trimming is targeted for distribution lines in the Volcano, Kealia, Captain Cook, Hawi and South Point areas.

Q. Has additional trimming in 2005 reduced the number of hours of interruptions due to trees and branches?

A. Yes. In 2005 there were 25,001 customer interruptions due to trees and branches as compared to 68,108 customer interruptions due to trees and branches in 2004. In 2005 there were 36,289 hours of interruptions due to trees and branches which is a significant reduction from the 142,547 hours recorded in 2004. Although variation in weather from year to year and other factors make it difficult to determine the exact impact, it is evident that the additional trimming has significantly reduced the level of tree and branch-related outages. (See HELCO-610, page 1).

Q. Were there other factors that contributed to the increase in CAID for years 2000 to 2004?

A. Yes. Lower staffing levels in the C&M divisions and compliance with Federal Motor Carriers Safety Administration hours of service rules also contributed to longer interruption times.

Q. Please describe further how lower staffing levels impacted CAID related to trees and branches.

A. As described earlier in my testimony, damage caused by trees and branches during storms requires line workers from the C&M divisions to respond and make repairs. Fewer line workers available to make repairs results in longer outage durations. During the larger storms, crews have not been able to restore all customers before having to stop work to due to fatigue. Power restoration efforts

were suspended to allow crews to sleep and rest before resuming restoration efforts. This contributed to the increase in the CAID index.

HELCO-611 shows the Hilo C&M workforce was at its lowest level in 2003 with 25 employees, in Kona the lowest level was in 2001 with 17 employees and in Waimea the lowest level was in 2003 with 12 employees. With fewer employees in the C&M groups restoration times during storm situations have increased.

Q. Please explain how compliance with the Federal Motor Carrier Safety Administration's hour of service rules has led to longer restoration times.

A. HELCO utilizes line trucks (derricks) and bucket trucks (aerial lift devices) that are classified as commercial vehicles governed by the Federal Motor Carrier Safety Administration's rules and regulations. HELCO carefully reviewed the Federal Motor Carrier Safety Administration's hours of service rules for commercial vehicles and determined that exemptions for drivers of utility vehicles did not apply to HELCO drivers. Prior to 2002 HELCO presumed that as a utility the hours of service rules did not apply and did not adhere to the hours of service rules.

HELCO adopted the practice to adhere to the hours of service rules that limited driving hours for HELCO drivers of commercial vehicles. Driving of commercial vehicles are limited to 10 hours after an 8 hour period of rest, driving of commercial vehicles is prohibited after 15 hours of on-duty time after an 8 hour rest, and driving of commercial vehicles is prohibited after 60 hours of on duty time in a 7 day period. The hours of service rules limit the available hours that line personnel can drive large vehicles used to make repairs and restore service. On occasion repair work is ceased when hours of service limits are reached, thus extending power restoration times.

Q. What measures has HELCO taken to improve the restoration times related to trees and branches?

A. HELCO has increased C&M division staffing, utilized contract tree trimmers during storms and sought exemptions from hour of service rules.

Q. Please explain the staffing increases that were implemented to improve restoration times.

A. HELCO-611 shows that the Hilo C&M division staffing was increased from the low of 25 in 2003 to 30 in 2005, and staffing is budgeted for 34 in 2006. In the Kona C&M division the staffing was increased from the low of 17 in 2001, to 21 in 2005, and staffing is budgeted at 27 in 2006. In the Waimea C&M division staffing was increased from the low of 12 in 2003, to 14 in 2005, and staffing is budgeted at 16 in 2006.

Though staffing has increased in the C&M divisions in recent years, and the increases have helped with response, the newly hired employees do not have the skills and years of experience to make full contribution towards power restoration. As staffing continues to increase and newer employees are trained and provided experience, restoration times are expected to improve further.

Q. Please explain how the use of contract tree trimmers has improved restoration times for interruptions due to trees and branches.

A. To supplement HELCO's C&M workforce and to expedite power restoration HELCO now more frequently employs the services of contract trimmers during storms. The use of contract trimmers allows HELCO C&M crews to work in parallel with tree trimming crews. During power restoration efforts during storms, HELCO trouble inspectors assess damage to facilities and report requirements for repairs. In cases that require clearing of large trees and branches from power

1 lines, contract tree trimmers are used. HELCO crews are dispatched to make
2 repairs to damaged lines after trimmers clear the trees. Utilizing contract tree
3 trimmers allows HELCO crews to use their skills and equipment to make repairs
4 to power lines and restore power. Tree trimmers who are skilled with trees and
5 working near energized electrical facilities focus on clearing the trees to facilitate
6 repairs by the line personnel. The combination expands the available resources
7 and allows more problems to be worked on simultaneously, leading to shorter
8 restoration times.
9 Q. Please explain how exemptions from Federal Motor Carrier Safety Administration
10 hours of service rules have decreased restoration times for interruptions due to
11 trees and branches.
12 A. Federal Motor Carrier Safety Administration hour of service rules can be waived
13 if a local or state official declares a state of emergency. HELCO has in the past
14 sought and obtained emergency declarations by the Hawaii County Mayor during
15 storms that caused numerous power interruptions. The emergency declarations
16 allowed HELCO to continue driving commercial vehicles beyond the hours of
17 service limits in order to make repairs. Without the declaration crews would have
18 been released and provided the hours of rest necessary (8 hours) to allow driving
19 upon their return.
20 Q. Was a bill passed to exempt drivers of utility service vehicles from the Federal
21 Motor Carrier Safety Administration hours of service rules?
22 A. On August 10, 2005 President Bush signed a bill that exempts drivers of utility
23 service vehicles from the Federal Motor Carrier Safety Administration hours of
24 service regulations. The bill also prohibits states from enacting or enforcing hours
25 of service rules against utilities.

1 Q. With the passage of the bill to exempt drivers of utility service vehicles from the
2 Federal Motor Carrier Safety Administration rules, did HELCO still need to
3 follow the hours of service rules?
4 A. Yes. The Federal Motor Carrier Safety Administration did not issue guidelines on
5 how these exemptions apply until April 4, 2006. HELCO abided by the hours of
6 service rules until the guidelines were issued.
7 Q. Has the improvements implemented to reduce restoration times for interruptions
8 related to trees and branches been reflected in the CAID index for 2005?
9 A. Yes. The CAID index for 2005 for interruptions related to trees and branches was
10 87.09 in 2005 as compared to 125.58 in 2004. Although there are numerous
11 factors that affect the restoration times it does appear that the improvements
12 implemented have made a positive change in the CAID index for power
13 interruptions due to trees and branches. (See HELCO-610, page 2).
14 Q. Briefly describe HELCO's vegetation management program.
15 A. HELCO has a comprehensive vegetation management program to keep trees and
16 branches clear of transmission and distribution facilities. The Company uses a
17 combination of tree trimming, tree removals and herbicide treatment to manage
18 vegetation growth near power lines. HELCO has a System Forester on staff to
19 evaluate the requirements for trimming and herbicide treatment and to arrange the
20 use of contract crews to perform the vegetation management work. The System
21 Forester performs driving patrols, aerial inspections and receives trouble reports to
22 assess the state of the vegetation near the power lines. The System Forester
23 prioritizes and schedules the necessary work with contractors, interacts with the
24 public and property owners and inspects crews to monitor safety, productivity and
25 work quality.

1 Q. What is the forecasted 2006 test year expenditures for the vegetation management
2 program?
3 A. The 2006 test year estimated cost for HELCO's vegetation management program
4 is $1,633,112. See HELCO WP-612, page 2 of 2.
5 Q. What expenses are included in the 2006 test year estimated cost of $1,633,112 for
6 vegetation management?
7 A. All costs associated with HELCO's vegetation management program are captured,
8 including costs for outside contract services and HELCO labor.
9 Q. What is the estimated contract services cost for vegetation management in the
10 2006 test year?
11 A. HELCO forecasts to spend $1,468,000 for outside contract services for vegetation
12 management during the 2006 test year.
13 Q. How does the 2006 test year forecast of $1,468,000 for contract services for
14 vegetation management compare with prior years?
15 A. HELCO-612 provides data for actual expenditures for outside contract services
16 costs for vegetation management for the years 2000 to 2005. HELCO-612 also
17 provides the 2006 test year estimate for outside contract services for vegetation
18 management. The average of actual expenditures for the years 2000 to 2004 is
19 $1,126,632. The 2006 test year forecasted expenditure of $1,468,152 exceeds the
20 2000 to 2004 average by $341,520. The 2005 actual expenditure exceeds the
21 2001 to 2004 average by $413,548.
22 Q. Why is there a need for a higher level spending for outside contract services for
23 vegetation management above the 2001 to 2004 average?
24 A. As stated earlier in my testimony, the higher level of spending is to obtain
25 additional clearances in areas that are more vulnerable to trees and branches

1 falling into power lines during storms. Increased spending to target areas where
2 there is a proliferation of Albizzia and Eucalyptus trees began in 2005. Review of
3 the 2005 CAID and SAIF indices indicate that the additional trimming that was
4 started in 2005 is making an improvement in service reliability.

5 Interruptions Caused By Lightning

6 Q. How do lightning strikes cause service interruptions?

7 A. Direct lightning strikes to transmission or distribution circuits can cause
8 flashovers and/or damage to T&D equipment that create electrical faults that result
9 in service interruptions. Direct strikes can damage T&D facilities such as poles,
10 insulators, conductors or transformers. Lightning strikes nearby to transmission
11 and distribution facilities can also induce a voltage large enough to cause
12 flashovers that create electrical faults and result in service interruptions to
13 customers. Many power interruptions that are caused by lightning strikes are
14 temporary in nature. In many instances permanent damage to T&D equipment
15 does not occur and once the electrical fault caused by the lightning strike is
16 cleared by a circuit beaker, the transmission or distribution circuit breaker can be
17 reclosed to restore service. Lightning strikes that cause fuses to blow out as
18 designed require response by line workers to replace the fuses. Strikes that cause
19 damage to equipment require line workers to make repairs in order to restore
20 service.

21 Q. Are there other ways that lightning strikes can cause service interruptions to
22 HELCO customers?

23 A. Yes. Lightning strikes cause severe voltage disturbances and power swings on the
24 HELCO system that may cause generating plants to trip off-line. Sudden loss of
25 generating plants can lead to underfrequency load shedding that result in service

1 interruptions. Refer to Mr. Dan Giovanni's testimony, HELCO T-5, for further
2 details on regulating reserve and automatic load shedding.
3 Q. What has been the impact of thunderstorms on HELCO's system?
4 A. During the last six years the impact of thunderstorms on the HELCO system has
5 been significant. Lighting strikes on or near HELCO's transmission lines have
6 caused widespread power interruptions affecting many HELCO customers.
7 Q. Please describe the trend for the SAIF index for power interruptions caused by
8 lightning.
9 A. For the past five years, 2001 to 2005, the SAIF index has been relatively low
10 with the highest value of 0.309 occurring in 2004 and the lowest value of 0.058
11 occurring in 2005. In year 2000, a very high value of 2.931 was experienced.
12 (See HELCO-610, page 6). In that year thunderstorms on July 31 and November
13 2 caused numerous power interruptions. In both the July 31, 2000 thunderstorm
14 and the November 2, 2000 thunderstorm, interruptions to multiple transmission
15 lines simultaneously resulted because of lightning and led to widespread service
16 interruptions. For that year a total of 185,281 customer interruptions and
17 178,741 customer hours of interruption were attributed to lightning. (See
18 HELCO-610, page 4).
19 Q. Please describe the trend of the CAID index for customer interruptions caused by
20 lightning.
21 A. HELCO-610, page 5 provides the graph of CAID for customer interruptions
22 caused by lightning. The graph indicates a variable trend with 40.8 minutes in
23 2005 being the lowest value for all of the past 6 years. The highest value in the
24 past 6 years was in 102.7 minutes in 2004.
25 Q. What has HELCO done to mitigate the impacts of lightning on its system?

A. The high resistivity of the volcanic soil on the Big Island has made it difficult to prevent lightning from causing electrical faults on transmission and distribution facilities. Protective schemes such as shield wires and lightning arresters are not effective on the Big Island because lightning energy cannot be dissipated in the highly resistive soil. Thus HELCO has focused on mitigating the impacts of lighting strikes by upgrading and maintaining its substation equipment. In many instances faults on the transmission and distribution circuits due to lightning are temporary and circuits can be automatically reclosed after a fault has been cleared. To mitigate the impacts of lighting on the HELCO system it is critical to ensure that substation equipment is working properly so that it can clear the faults when they occur and quickly restore the circuits. This is especially critical on HELCO's transmission system since a single contingency criteria design is used. During severe thunderstorms lightning can cause transmission line trips in quick succession. If a breaker fails to clear a fault or is unable to reclose quickly after a fault is cleared, large system disturbances could occur. HELCO has thus focused on improving the substation breaker maintenance as one of the strategies to mitigate the effects of lighting. Refer to the Substation Maintenance section of this testimony for more details on substation equipment maintenance.

Q. What other measures has HELCO implemented to mitigate the impacts of lightning on its system?

A. Fast removal of electrical faults from the transmission system is also critical during lightning storms. Protective relays must properly detect the fault and send signals to transmission breakers to open and clear the fault. Failure to clear faults quickly could lead to system instability and widespread outages. HELCO has designed and built its transmission line protective scheme to clear faults

within seven cycles. Beginning in the early 1990s HELCO began upgrading its protective relays and communications system to achieve the seven cycle clearing time. Relay upgrade projects were done for each transmission line and in 2003 HELCO completed replacement of most of its transmission line relays.

Q. What has HELCO done to mitigate the impacts of lightning on its distribution system?

A. Lightning activity can cause transient voltages on the distribution system that can cause damage to distribution transformers. HELCO has purchased distribution transformers with lightning arresters installed internally within the oil filled transformer (under oil arresters). Installing the lightning arresters within the transformer provides the advantage of minimizing the lead lengths for the lightning arresters. Shorter lead lengths reduce the magnitude of the transient voltage the transformer winding is exposed to. The under oil design also allows the installation of the arrestor directly across the high voltage windings of the transformers. This provides protection of the high voltage windings independent of the ground resistance. Installing the lightning arrester within the transformer tank under the transformer oil protects the lightning arrester from moisture that can damage the arrester. Use of transformers with under oil arresters has been effective in reducing the number of transformer failures related to lightning.

<u>Interruptions Caused By Automobile Accidents</u>

Q. How do automobile accidents cause power interruptions to customers?

A. T&D facilities are often installed along public roads and rights of ways. Both underground and overhead facilities can be installed along roads and highways. Motorists will lose control of their vehicles and strike T&D facilities such as poles for overhead systems or padmounted devices for underground systems.

When poles are struck by vehicles often times the poles are damaged and other devices on the poles such as insulators and crossarms are broken as well. Electrical faults occur as a result of the damage to the facilities. When padmounted devices are struck extensive damage to the equipment and cables often result. Often times padmounted devices house multiple circuits so service may be interrupted to a large amount of customers.

Q. What actions are required to restore service to customers after an automobile accident damages T&D facilities?

A. In most cases the damage to wood poles and associated facilities are extensive and complete replacement is required. The focus of HELCO responders is first to secure the safety of the accident scene. Power restoration efforts are secondary to ensuring public safety. Securing an accident scene can take a long time and the duration of service interruptions due to automobile accidents is generally very long.

Even after the safety of the scene is secured, the repair work necessary to restore service also takes a long time to complete. Often times new pole holes need to be excavated to install poles. This excavation can take hours to complete. Poles are jointly owned with the telephone company and HELCO crews often need to work together with crews from the telephone company in order to execute repairs. This coordination can also add to the service restoration times.

Q. What is the trend for SAIF for service interruptions caused by automobile accidents?

A. Page 9 of HELCO-610 shows an increasing trend for SAIF related to service interruptions caused by automobile accidents. The lowest value of SAIF in the last 6 years was 0.074 in 2001. The highest value of SAIF for service

interruptions caused by automobile accidents was 0.411 in 2005. The number of service interruptions caused by automobile accidents is steadily increasing each year.

Q. What is the cause of the increasing trend for SAIF related to automobile accidents?

A. Growth on the Big Island is increasing the number of motorist on County and State roadways. The increased number of motorist increases the probability of automobiles damaging poles and other facilities.

Q. What is the trend for CAID for service interruptions caused by automobile accidents?

A. Page 8 of HELCO-610 shows that the CAID trended upward from a value of 69 minutes in 2000 to a value of 121 minutes in 2003. In 2004 and 2005 the CAID was at 115 minutes.

Q. What is the trend for Customer Hours of Interruption related to automobile accidents?

A Page 7 of HELCO-610 shows that there is an increasing trend from 14,822 customer hours in 2000 to 57,127 customer hours in 2005.

Q. What can be done to improve response for automobile accidents that damage T&D facilities?

A. Because response to the accident scene is crucial for public safety, the availability of HELCO trouble inspectors is critical. HELCO trouble inspectors can advise and keep persons at the scene clear of the hazards involved. If the trouble inspector can entrust police, fire or other personnel to secure the scene, the trouble inspector can then leave the scene to de-energize electrical facilities that may still be energized after the accident.

1 If possible and appropriate, the trouble inspector can isolate the area of the
2 accident and reroute power flow to adjacent circuits and restore service to as many
3 of the affected customers as possible.
4 At present HELCO has trouble inspector coverage for two shifts per day (16
5 hours per day), seven days per week. By mid 2006 HELCO anticipates to expand
6 the trouble inspector coverage to three shifts per day (24 hours per day), seven
7 days per week. The increased coverage should improve response to automobile
8 accidents that damage HELCO facilities.
9 Q. What other measures are being taken to reduce the CAID and SAIF for service
10 interruptions caused by automobile accidents?
11 A. Delineators (reflectors) are installed on poles along roadways. The delineators
12 make poles more visible to motorists during the evening hours. Delineators can
13 be damaged, removed or covered over the course of time. Maintenance and
14 replacement of delineators are part of HELCO's T&D facility inspection program
15 which will be discussed further in a later section of this testimony.
16 On occasion guy wires are struck by vehicles that cause damage to facilities
17 and cause power interruptions. Guy guards are placed on guy wires that are
18 exposed to vehicle and pedestrian traffic areas to make guy wires more visible.
19 Guy guards can be damaged, removed or fade considerably to become less visible
20 to motorists. Maintenance and replacement of guy guards are part of HELCO's
21 T&D facility inspection program.
22 The ability to isolate the accident area through switching and then
23 transferring customers to adjacent circuits to restore service is a critical process
24 that reduces service interruption times. If adjacent circuits are not readily
25 available, or if loading on adjacent circuits is so high that other loads cannot be

1 transferred to them, then power restoration requires the repair of the damaged
2 facilities before power can be restored. Capital improvement projects such as
3 distribution circuit conversions, substation unit additions and line extensions
4 create the ability to switch power around damaged areas and contribute to
5 reducing service interruptions times. See the section describing Capital
6 Improvements for Service Reliability for more information on these projects.
7 Interruptions Caused By High Wind
8 Q. How does high wind cause service interruptions?
9 A. High winds place additional physical loading on overhead transmission and
10 distribution facilities. High winds can cause damage to poles, insulators,
11 crossarms, conductors and other overhead facilities that result in electrical faults
12 that cause service interruptions. High winds can also cause conductors to swing
13 and contact other conductors or other facilities causing electrical faults and service
14 interruptions.
15 Q. Do service interruptions that occur when high winds blow trees and branches into
16 power lines get categorized as caused by high wind?
17 A. No. Interruptions that are caused by trees or branches contacting power lines are
18 categorized as caused by trees and branches regardless of the reason why the tree
19 or branch got into the line.
20 Q. How do you determine high wind as a cause?
21 A. The Assistant Technical Superintendent of Operations maintains the reliability
22 database and makes the determination of high wind as a cause. Notices and
23 weather reports from the National Weather Service are used to help make a high
24 wind cause determination. Field reports of windy conditions and other weather
25 conditions provided by HELCO responders also are used to make the

1 determination. Multiple reports of interruptions and outages in an area are also
2 used to determine high wind as a cause.
3 Q. What has been the trend for SAIF for service interruptions caused by high winds?
4 A. Page 12 of HELCO-610 shows that SAIF has increased from a value of 0.032 in
5 2000 to a high of 0.381 in 2002. For years 2003 and 2004 the SAIF remained
6 near the 2002 value, with 0.316 for 2003 and 0.343 in 2004. In 2005 there was a
7 significant drop to 0.057.
8 Q. What has been the trend for CAID for service interruptions caused by high winds?
9 A. Page 11 of HELCO-610 shows a steady increase in CAID from 29.49 minutes in
10 2000 to 100.98 in 2004. In 2005 the CAID dropped to 73.74.
11 Q. What has been the trend for customer hours of interruption for service
12 interruptions caused by high winds?
13 A. Page 10 of HELCO-610 shows the trend for customer hours of interruption has
14 increased from 989 hours in 2000 to 40,442 hours in 2004. In 2005 the customer
15 hours dropped back down to 5,124 hours.
16 Q. Please explain the SAIF and CAID trends for service interruptions caused by high
17 wind.
18 A. The trends for SAIF, CAID and customer hours of interruption for service
19 interruptions caused by high wind follow the same trend as SAIF, CAID and
20 customer hours of interruption for service interruptions caused by trees or
21 branches. The same factors such as storms, availability of C&M crews to
22 respond, hours of service rules, use of tree trimming contractors during storms and
23 additional tree trimming that apply to service interruptions caused by trees and
24 branches also apply to service interruptions caused by high winds.
25 Q. Are there other measures being taken to prevent service interruptions due to high

wind?

A. Yes. HELCO's T&D facility inspection program can locate defects that withstand normal conditions but could fail under high wind conditions. The inspection program reduces the probability of having services interruptions during high wind conditions. Refer to the section on the HELCO T&D facility inspection program for more information and details.

Interruptions Caused By Cable Fault

Q. Please provide a general description of HELCO's underground cable systems?

A. HELCO has only a limited amount of underground cables for transmission. Nearly all of the underground cables used at HELCO are for distribution systems. HELCO has used both cable in duct and direct buried cable systems. HELCO has stopped the use of direct buried cable systems because of problems with reliability and maintenance.

Most of HELCO's approximate 550 miles of underground cable is located in the west side of the Island. East Hawaii has a limited amount of underground cable systems near HELCO's Kanoelehua baseyard, the Banyan Drive resort area, Punaluu resort area, the State and County Government buildings in Downtown Hilo and a few residential subdivisions in the Hilo area. West Hawaii has underground systems in nearly all coastal developments and many residential subdivisions.

Underground systems are used in the South Kohala resort area, Waikoloa Village area, Kohala Coast, Anaehoomalu Resorts, North Kona Resort area, Kailua Town area, Keauhou Area, Hokulia Resort and residential subdivisions in the Huehue area.

Q. Please describe how service interruptions occur on underground cable systems.

A. Underground systems rely on insulating materials surrounding conductors to prevent electrical faults from occurring. Underground cables for primary voltage levels (15kv) have a conductive metal wire core surrounded by insulating material such as polyethylene, rubber or paper. An outer jacket surrounds the insulation to protect the insulation from scrapes and bumps that may occur during installation. Newer installations use cables with polyethylene insulation and vinyl jackets. Older installations used oil impregnated paper insulation with lead sheaths and vinyl jackets.

Cables are installed in sections in either concrete encased duct systems or in open trenches that are backfilled with select material such as sand or soil. The sections are joined together using specially designed insulated splices. Devices such as transformers and switches are usually mounted above ground on concrete pads where they are accessible to line workers for operation and maintenance. Underground cables are connected to these devices using special insulated terminations.

Any of the components in the underground cable system can fail and cause service interruptions. Points of failure are the cable insulation, the cable splices or the terminations. Failure of any of these components is classified as an underground cable fault. When an underground fault occurs, protective devices such as circuit breakers or fuses operate to de-energize the cable and remove the fault from the system. When the cable is de-energized service interruptions to customers result.

Q. Please explain how service is restored after a cable fault occurs.

A. Underground systems are designed to have a primary and a redundant cable to serve customers. If a fault occurs on the primary cable, trouble inspectors use the

switching devices to transfer customers to the redundant cable and restore service. Devices called fault indicators are installed in the underground system to provide information regarding the location of the faulted cable. Trouble inspectors use information from the fault indicators, circuit diagrams and operation of protective devices to help determine where the fault is located and decide appropriate switching activity.

Q. Please describe the process used to repair faulted cables.

A. After trouble inspectors perform switching to restore service, the repair of the cable is turned over to line workers from the C&M divisions to complete. Though the trouble inspector is capable of restoring service by switching, the exact location of the fault is not determined by the trouble inspector. Line workers need to respond and pinpoint the cause of the fault. Line workers use special diagnostic tools that are connected to the cable system and send electrical signals through the cable. The signals are reflected back through the cable much like a radar or sonar system and provide information to the diagnostic tool regarding the location of the fault. The faulted cable, splice or termination is then removed and replaced.

Although the above description of this process appears to be simple, the actual process is complex and time consuming. For cable in duct systems faulted cables can be pulled out of the duct and a new section of cable installed and spliced in. For direct buried cable systems, the faulted cable needs to be repaired. At the location of the fault the site is excavated and the faulted cable exposed. The faulted section of the cable is removed and a short section of cable is then spliced to the existing cable. After repairs are made the cable is reburied. Excavation to expose the faulted direct buried cable can be very expensive since the accuracy of the locating devices is not absolute and excavation is being done

in close proximity to other underground facilities.

Q. Please describe the trend in SAIF for service interruptions caused by underground cable faults.

A. Page 15 of HELCO-610 shows an increasing trend for SAIF for service interruptions caused by underground cable faults. The lowest value of SAIF occurred in 2001 at 0.023 with the highest being in 2005 with a value of 0.249.

Q. Please explain why the SAIF for underground cable faults is increasing.

A. As the age of underground systems increase, the insulation of the cables, splices and terminations are more prone to failure. Also as loads increase and higher currents flow through the cable systems, flaws in the splices and terminations can overheat and fail. Failures in the older underground cables systems at Waikoloa Village, Anaehoomalu, Mauna Lani, Mauna Kea Resorts, Keauhou Resorts, Palisades and Kona Heavens are occurring more frequently. Also as more customers connect to existing underground cable systems, underground cable failures affect a larger amount of customers thus resulting in an increase to the SAIF index.

Q. Please describe the trend for CAID for service interruptions caused by underground cable failure.

A. Page 14 of HELCO-610 shows the CAID index for service interruptions caused by underground cable failures remained near 100 minutes for the years 2000 to 2002. In 2003 the CAID dropped to 67.87 minutes. In 2004 the CAID increased to 146.46 and in 2005 CAID was at its highest at 171.92 minutes.

Q. Please explain the trend of increasing CAID for service interruptions related to underground cable faults.

A. In recent years from 2003 to 2005 cables at Waikoloa Village, Anaehoomalu,

1 Keauhou, Kahaluu and Kona Palisades subdivision have been prone to failure. In
2 2005 there were two incidents where both the primary and redundant cables
3 faulted and were out of service causing extended service interruptions to
4 customers. On April 15, 2005 an underground cable fault occurred on one of the
5 cables serving the Anaehoomalu resort area. Three days later on April 18, 2005,
6 before the first cable was repaired, a second cable serving the Anaehoomalu resort
7 area faulted. Service to 1,191 customers was affected and a total of 8,943
8 customer hours of interruption were incurred before one of the cables could be
9 repaired and service restored.
10 On October 26, 2005 a fault occurred in a handhole in the Waikoloa Village
11 underground system. Two separate cables housed in the common handhole were
12 damaged by the fault. A total of 2,180 customers were affected and a total of
13 11,029 customer hours were incurred in that single incident. A third significant
14 incident that contributed to the high CAID value in 2005 occurred on September
15 3, 2005 in the Kahaluu area. An underground cable faulted and 10,926 customers
16 were affected. The adjacent circuits were heavily loaded and interrupted
17 customers could not be restored by switching. The faulted cable needed to be
18 repaired before service could be restored. A total of 23,333 hours of interruption
19 were incurred for this one cable fault.
20 Q. Please describe the customer hours of interruptions for service interruptions
21 related to underground cable faults.
22 A. Page 13 of HELCO-610 shows that the number of customer hours of interruptions
23 has continued to increase each year from 5,319 in 2000 to 51,827 in 2005.
24 Q. What improvement actions has HELCO taken to address the rise in cable faults?
25 A. HELCO has taken the following actions to reduce cable faults:

- Used cable cure to restore insulating properties of older underground cables.
- Performed infrared inspections of splices, terminations, transformers and switches.
- Replaced direct buried underground cable systems with cable in duct systems.

Q. Please describe what cable cure is.

A. Cable cure is a trade name for a process of injecting a silicon solution into underground cables to restore the insulating properties of the cable. Cable cure is performed by the Utilix Corporation. HELCO injected approximately 213,000 feet of cable in 1996 and 1997 for an approximate cost of $1,349,000. Direct buried cables were initially targeted for the cable cure process because of their age, fault history and difficulty to repair. Before a cable was selected for cable cure treatment, the integrity of the cables neutral system was inspected and tested. If the neutral was in acceptable condition, the cable was selected for the cable cure process. Those cables that had degraded neutral conductors were not treated but were designated for replacement instead. Some of the older cables that were in duct systems were also cable cured after experience was gained with the direct buried systems.

Q. Has cable cure prevented underground cable faults?

A. HELCO believes that cable cure has reduced the number of cable faults in the long term. The cable cure process does create a short term increase in cable faults as the silicon solution moves from one end of the cable to the other. As the silicon solution moves through the cable it displaces moisture. This movement in moisture can cause underground cable faults. After the initial injection of the

cable and settling took place, the cable cured cable has demonstrated to be more reliable.

Q. Please describe the infrared inspection process for splices and terminations.

A. As stated earlier, flawed cable splices and terminations can overheat and fail. Infrared cameras that detect heat are used to inspect splices and terminations for hotspots. Hot spots indicate a high resistance connection that can over-heat, breakdown insulation and eventually cause an electrical fault. Splices and terminations that are found with hotspots are replaced before they fail.

The underground systems in West Hawaii are targeted for infrared underground inspections on a four year cycle. In 2005 the Keauhou Resort area, Hualalai Resort area, Anaehoomalu Resort area and Mauna Lani Resort area are targeted for infrared inspections.

Q. Where has HELCO replaced underground cables due to frequent cable failures?

A. HELCO has replaced direct buried underground cables in the Komohana Gardens subdivision in Hilo, portions of Sunrise Ridge subdivision in Hilo, Punaluu Resort in Kau, portions of the Palisades subdivision in Kona and the Kona Highlands subdivision.

Q. Does HELCO have plans to replace more underground cable due to frequent cable faults?

A. Yes. HELCO has plans to complete another portion of the Palisades subdivision in Kona in 2006 and replace another section of cables in the Sunrise Ridge subdivision in Hilo in 2007.

<u>Interruptions Caused By Equipment Failure</u>

Q. Please describe how equipment failure can cause service interruptions.

A. Failure of equipment such as protective relays, circuit breakers, reclosers,

1 insulators and hardware can cause power interruptions to customers. For instance,
2 if a circuit breaker bushing has an electrical fault then other circuit breakers would
3 need to trip open in order to remove the fault from the system. Customer
4 interruptions that result would be attributed to equipment failure.
5 Q. Would service interruptions be attributed to equipment failure if the equipment
6 deteriorated and failed or was damaged by high winds?
7 A. No. If failure of equipment is caused by deterioration, high winds, lightning or
8 other cause, the service interruptions are attributed to those other causes.
9 Q. Please describe the trend for SAIF for service interruptions caused by equipment
10 failure.
11 A. Page 18 of HELCO-610 shows that prior to 2005 there was an upward trend from
12 a value of 0.155 in 2000 to a value of 0.369 in 2004. In 2005 the SAIF value
13 dropped to 0.031, the lowest value since 2000. In 2002 there was a large anomaly
14 in the SAIF to the value of 0.998. In that year substation equipment failures led to
15 the high value of SAIF.
16 Q. Please describe the trend for CAID for service interruptions caused by equipment
17 failure.
18 A. Page 17 of HELCO-610 appears to show a downward trend for CAID caused by
19 equipment failure with two anomalous data points in 2001 and 2003. The CAID
20 appears to trend downward from 46.78 minutes in 2000 CAID to 36.40 minutes in
21 2005 with anomalous points in 2001 (74.86 minutes) and in 2003 (81.91
22 minutes).
23 Q. Please describe the actions being taken to improve the SAIF and CAID for
24 interruptions caused by equipment failure.
25 A. Much of the equipment failures occur on substation equipment. Proper operation

of substation equipment is critical to maintaining low CAID and SAIF values for service interruptions caused by equipment failure. HELCO has taken steps to improve the substation maintenance program. The improvements are described in the following section.

Substation Maintenance Program

Q. Please describe the improvements to the substation maintenance program.

A. Beginning in 2004 HELCO has firmed up its internal substation maintenance requirements as shown in HELCO-613. HELCO-613 provides a summary of HELCO's Substation Preventive Maintenance Program targets and the completion rates for years 2004 and 2005. This program consists of the following components:

- substation equipment inspections
- substation battery maintenance
- substation transformer maintenance
- transmission breaker maintenance
- distribution breaker maintenance
- relay maintenance

Q. Please describe HELCO's substation inspection program.

A. In test year 2006 HELCO is targeting monthly inspections of each of its substations for safety and security reasons. These monthly visual inspections check for perimeter fencing defects and any obvious defects in substation equipment. Every two months the Company inspects at each substation items such as transformer oil levels, transformer temperatures, relay targets and demand meters. Every six months HELCO performs infrared inspections of substations to detect any loose connections and collects and stores inspection

data in a data management system using field computers. Other defects or conditions requiring attention are recorded in the data management system and prioritized and scheduled for repair.

Q. Please describe HELCO's substation battery maintenance program.

A. Battery banks at substations are critical for proper operation of substations. Substation equipment such as breakers and protective relays rely on DC voltage sources from the battery banks to operate. Because failures of battery banks pose serious risks to the HELCO system, the Company targets a six-month maintenance cycle for each battery bank. Battery maintenance consists of cleaning battery cases, checking and topping off fluid levels, and testing loads. In addition HELCO has established a battery bank replacement program to replace three substation battery banks each year for the next five years.

Q. Please describe HELCO's substation transformer maintenance program.

A. There are approximately 127 substation transformers in the HELCO system. HELCO has categorized approximately 37 of these transformers, primarily generator step-up transformers, as priority 1 transformers. Priority 1 transformers are targeted for maintenance every five years. Priority 2 transformers are targeted for maintenance as needed. Oil samples from both priority 1 and priority 2 transformers are obtained and dissolved gas analysis and moisture analysis are performed every year. Transformer maintenance consists of power factor testing, turns ratio testing, winding dielectric testing, oil dielectric testing, protective relay testing, painting and addressing oil leaks. Results of the testing determine the health of the transformer and whether corrective maintenance or replacement of the transformer is necessary. Power factor testing provides an assessment of the insulating properties of the

transformer windings and bushings. Unfavorable results from the power factor tests can indicate an imminent failure of the transformer. The turns ratio testing of the transformer checks for proper voltage transformation, shorted windings or open windings. Dissolved gas analysis of the transformer oil provides information regarding possible arcing within the transformer, overheating, water intrusion or insulation breakdown. If problems are detected through the oil analysis the transformer is taken out of service, inspected and repaired before catastrophic failure occurs. The Company's target is to perform dissolved gas analysis on transformers every year.

Q. Describe HELCO's transmission breaker maintenance program.

A. Each transmission breaker is targeted for maintenance every fifth year. As there are 120 transmission breakers on the HELCO system, approximately 24 transmission breakers are maintained each year. Breaker maintenance consists of diagnostic testing of the breaker and using the results of the testing to determine whether corrective maintenance or replacement is required. If no corrective maintenance is required, the Company performs only general servicing of the breaker. In addition, HELCO has implemented planned replacements of two transmission breakers each year for the next five years. Some of the diagnostics tests performed on the breaker are power factor testing, control current profiling, breaker timing testing, contact resistance testing and insulating oil testing. Power factor testing provides an assessment of the breaker's insulating properties. Control current profiling digitally records the profile of the current drawn by the breaker during operations. Changes in the profile could indicate problems with breaker mechanisms. A breaker timing test checks to ensure breaker contacts open and close within specified speeds. A

slow operating breaker would lead to longer clearing times and possible failure of the breaker. Contact resistance testing check the health of the breaker contacts. High resistance on the breaker contacts could indicate damage to the breaker contacts. Insulating oil testing for breakers are similar to the testing done for transformers.

Q. Describe HELCO's distribution breaker maintenance program.

A. There are approximately 112 distribution breakers in the HELCO system. Approximately 16 distribution breakers have been categorized as priority 1 and 96 breakers have been categorized as priority 2. HELCO targets maintaining both priority 1 and priority 2 breakers on a two-year cycle, but performs maintenance on the priority 1 breakers first. Distribution breaker maintenance consists of diagnostic testing of the breaker and using the results of the testing to determine whether corrective maintenance or replacement is required. If no corrective maintenance is required, the Company performs only general servicing of the breaker. The diagnostic testing of the distribution breakers is similar to the testing done for transmission breakers.

Q. Describe HELCO's relay maintenance program.

A. Relays are devices that monitor voltages and currents to detect electrical faults and other problems on the HELCO power system. When a relay detects a problem it controls breakers, switches or other devices to remove the fault or problem from the HELCO system. Proper operation of relays is critical to service reliability. Improper operation of relays could cascade into widespread outages and system instability.

HELCO's relay maintenance program targets maintaining each transmission and distribution protective relay on a five year cycle. Maintenance of generating

1 station protective relays is targeted for an annual cycle. HELCO has upgraded
2 many of its relays to microprocessor based relays. The relay maintenance
3 program does not perform any planned maintenance on microprocessor relays.
4 Instead alarms and event reports generated by the microprocessor relays are
5 evaluated to confirm proper operation. Calibration and testing of
6 electromechanical relay is still performed.
7 Q. Has HELCO met the targets of its substation maintenance program?
8 A. HELCO-613 presents how HELCO has actually performed in 2004 and 2005 in
9 comparison to the substation preventive maintenance program targets. As
10 HELCO-613 demonstrates, HELCO has not met all of the targets of the program.
11 This is primarily due to lower staffing levels during 2004 and 2005.
12 Q. Does HELCO expect to meet all of the substation maintenance program targets
13 in 2006?
14 A. Yes. HELCO expects to meet all of the substation maintenance program targets
15 in 2006. Increased staffing of substation electricians and helpers has increased
16 the labor resources available to perform maintenance. HELCO anticipates
17 having 11 substation electricians and six helpers available in 2006 to perform the
18 planned maintenance. Use of contractors is also planned to supplement the
19 crews.
20 Q. Has HELCO realized any benefits from its substation maintenance program?
21 A. Yes. HELCO-614 lists some of the more serious problems with substation
22 equipment that the Company's substation maintenance program detected and
23 resolved, thereby avoiding equipment failure or outage. Infrared inspections
24 have located poor connections on switches and splices, which, if left alone,
25 would have eventually failed. Diagnostic testing on transformer and breaker

bushings have detected possible bushing problems and prompted bushing replacements. A bushing is an insulated device that transitions the external connection to a breaker or transformer, to the internal connections. HELCO had experienced costly bushing failures on breakers and transformers before implementing its program of proactive diagnostic testing. Gas analysis of transformer oil detected internal arcing in substation transformers and enabled repair prior to serious damage occurring.

Q. What is the estimated cost for HELCO's substation maintenance program?

A. The 2006 test year estimate for HELCO's substation maintenance program is $1,155,039 as detailed in HELCO-WP-616.

Q. What is the estimated cost for HELCO's substation inspection program?

A. The 2006 test year estimate for HELCO's substation inspection program is $93,370. See HELCO-WP-616, page 1 of 2.

Q. Why is the O&M expense for the substation inspection program and substation maintenance program justified?

A. As explained earlier in my testimony the proper operation of HELCO substation equipment is vital in preventing large system disturbances. The substation inspection and maintenance programs are key in targeting reductions in service interruptions due to equipment failure and lightning.

<u>Interruptions Caused By Deterioration</u>

Q. Please describe how deterioration causes service interruptions.

A. Service interruptions caused by deterioration include wood rot on wooden structures, termite damage on wooden structures, rust on steel hardware and corrosion on non-steel metals. Wood rot and termite damage can cause poles to fail resulting in service interruptions. Rust can cause hardware supporting

1 insulators, guy wires and conductors to fail resulting in service interruptions.
2 Corrosion on aluminum conductors can cause the conductor to fail resulting in
3 service interruptions. These are a few examples of how deterioration can cause
4 service interruptions.
5 Q. Please describe the trend in SAIF for service interruptions caused by deterioration.
6 A. Page 21 of HELCO-610 shows the SAIF index for service interruptions caused by
7 deterioration has extreme variability over the past six years, with the lowest value
8 being 0.040 in 2002 and the highest value being 0.327 in 2005. There appears to
9 be an upward trend based on the SAIF of 0.114 in 2000, SAIF of 0.161 in 2001,
10 SAIF of 0.248 in 2003 and SAIF of 0.327 in 2005. However, four of the six data
11 points in the graph are at or below 0.161, with high values only occurring in 2003
12 and 2005. This appears to indicate that the 2003 and 2005 data points are more
13 anomalies rather than an indication of an increasing trend.
14 Q. What was the reason for the high value of SAIF in 2005?
15 A. In 2005 the value of SAIF for service interruptions caused by deterioration was
16 0.327, the highest value in the last six years. On August 24, 2005 a suspension
17 insulator supporting a 69kv transmission conductor failed due to corrosion on the
18 metal fixtures. The insulator failure caused an electrical fault that resulted in
19 service to 18,362 customers being interrupted and 9,612 customer hours of
20 interruption. The one incident contributed 0.253 to the total SAIF of 0.327 for
21 2005.
22 Q. What was the reason for the high value of SAIF in 2003?
23 A. In 2003 the value of SAIF for service interruptions caused by deterioration was
24 0.248, the second highest in six years. The cause of the high SAIF in 2003 was
25 due to a series of problems with rusty guy wires on a 69kv transmission line in the

1 Hilo area. A special project to replace all of the problem guy wires on that
2 transmission line has since been completed.
3 Q. Please describe the trend in CAID for service interruptions caused by
4 deterioration.
5 A. Page 20 of HELCO-610 shows a plot of CAID for service interruptions caused by
6 deterioration. The chart shows large variations in CAID from the high of 171.25
7 minutes in 2002 to the low of 35.28 minutes in 2003. There does appear to be a
8 downward trend from 113.32 minutes in 2000 to 56.74 minutes in 2005.
9 Q. What measures are being taken to improve SAIF and CAID for service
10 interruptions caused by deterioration?
11 A. Most of the interruptions due to deterioration occur on the overhead transmission
12 and distribution facilities. HELCO has worked to improve inspection and
13 maintenance of its overhead facilities to reduce service interruptions due to
14 deterioration. A description of the improvements to HELCO's inspection
15 program follows.
16 <u>T&D Facility Inspection Program</u>
17 Q. Has HELCO made any improvements to its pole inspection and maintenance
18 program?
19 A. Yes, in 2003 HELCO began utilizing contractors to inspect poles and treat wood
20 poles.
21 Q. What are the advantages of using a contractor to inspect and treat poles?
22 A. Contractors perform below grade inspections that were not traditionally done by
23 HELCO personnel. Contractors excavate to expose two feet of the butt of the
24 pole to determine if below grade rotting or termite damage is occurring. The
25 contractor is also qualified to handle wood treatment chemicals and treats those

poles that do not need to be replaced. Chemical treatment of the poles prevents, slows or stops decay or termite infestation of the pole.

Q. What are the results of the pole inspections done by contractors?

A. HELCO-615 summarizes the work and accomplishments of the contract pole inspections. In 2003, 2,518 poles were inspected and treated at a cost of $163,854. Although HELCO did not budget or perform inspections in 2004, in 2005, it inspected and treated 4,684 poles at a cost of $313,191.

Q. What is HELCO' 2006 test year forecast of contractor pole inspections?

A. The 2006 test year estimate is to inspect approximately 4,300 poles in the Hilo and Hamakua areas for an estimated cost of $298,000. (See HELCO-615.)

Q. Does the use of contractors to inspect poles eliminate the need for HELCO inspectors?

A. No. HELCO inspectors still provide a valuable service. The contract inspectors specialize in poles and do not inspect other aspects of the T&D facilities. HELCO inspectors have linemen qualifications and are all experienced and knowledgeable on T&D facilities. They are capable of inspecting and detecting defects on other T&D facilities such as transformers, cutouts, switches, crossarms, connectors, lightning arresters, insulators and fixtures. They are also qualified electrical workers that can serve as observers and escorts for unqualified workers who perform work near electrical facilities. HELCO inspectors are capable of using volt meters, amp meters, infrared cameras and underground cable locating equipment. During emergency situations HELCO inspectors can troubleshoot problems and provide information to crews so repairs can be made. They are qualified to use hotline tools and work procedures to perform switching and address energized facilities. HELCO inspectors also

1 inspect underground duct systems that are built by developers and turned over to
2 HELCO as in-kind contributions and provide monitoring and assistance to
3 contractors constructing pole lines and underground systems.
4 Q. How will Act 141, which established the One Call Center, impact HELCO
5 operations?
6 A. Act 141 (2004 Session Laws of Hawaii), codified as Chapter 269E of the Hawaii
7 Revised Statutes, requires the Commission to establish and administer a One
8 Call Center by January 1, 2006. Act 141 generally requires excavators to notify
9 and provide pertinent information to the One Call Center of any plan to excavate
10 on either public or private property where operators are authorized to install
11 subsurface facilities. Once notified by the One Call Center of an excavator's
12 plan, the operator (e.g., HELCO) will inform the excavator of the approximate
13 location of its subsurface facilities at the excavation site. Although HELCO
14 responded to requests for facility location in the past, it expects the number of
15 requests for locating facilities to increase significantly in 2006 since state law
16 will require excavators to notify the One Call Center of their plans. In the past,
17 excavators would often excavate without inquiring about the location of
18 subsurface facilities. In 2005 there were a total of 99 requests from excavators to
19 locate HELCO underground facilities and HELCO expects the number of
20 requests in 2006 to be significantly higher.
21 Q. Did HELCO increase its 2006 test year labor expenses to address the impacts of
22 Act 141?
23 A. In effect, no. The position primarily responsible for locating underground
24 facilities for excavators is the senior inspector. Trouble inspectors also are
25 trained to locate underground facilities and can perform this function when they

are not responding to trouble. HELCO anticipated increases in location requests and in 2005 filled a Hilo senior inspector position that had been vacant since December 1999. A senior inspector in Waimea and a senior inspector in Kona are trained to locate underground facilities. In 2004 HELCO established trouble inspector positions in the Kona and Waimea districts to cover two shifts per day, seven days per week in order to be more responsive to trouble. These trouble inspectors can also assist with the anticipated increase in underground locating requests.

Q. Has HELCO forecasted an increase expense in the 2006 test year One Call Center fees?

A. No. HELCO has not included One Call Center fees in its 2006 test year estimates. At the time HELCO developed its 2006 test year forecasts for its direct testimony, a fee schedule for the One Call Center had not yet been established.

Q. Are there other improvements planned in the area of inspections?

A. Yes. HELCO is improving its data management system for storing and retrieving inspection data. In December of 2005 HELCO purchased and installed an inspection database software system called Fastgate. This new database system will be used to manage overhead and underground inspection data. The system uses mapping to link inspection data to geographical locations which will allow for easier location of defects in the field. It also provides for easier tracking of inspection activity and history. The Fastgate system will consolidate and map all of the information that records system defects into a single database. Currently, inspection and system defect information reside in paper inspection memo records, spreadsheets, HELCO's trouble database and the

1 Ellipse work order system. Having inspection information stored in a single data
2 base will reduce duplications and errors.
3 Further, in 2005 HELCO hired two staff engineers to manage inspection
4 data and improve prioritization and selection of corrective maintenance of
5 system defects.
6 Q. Does HELCO perform aerial inspections?
7 A. Yes. HELCO performs aerial inspections on a quarterly basis. The Company
8 uses a helicopter for visual and infrared inspections of its transmission facilities.
9 Q. What are the benefits of the aerial inspection program?
10 A. Aerial inspections provide an economical means to frequently inspect HELCO's
11 entire transmission system. These inspections can detect problems with
12 transmission hardware (e.g., broken insulators, damaged conductors, encroaching
13 vegetation and broken fixtures) before they cause transmission line faults.
14 Q. What problems did the aerial inspection program detect in 2005 and what
15 failures were averted as a result?
16 A. HELCO-616 lists the defects located by the aerial inspection program and the
17 failures averted.
18 Q. What is the 2006 test year estimate for overhead inspection program?
19 A. The estimated cost for the overhead inspection program is $890,221. See
20 HELCO-WP-613, page 2 of 2.
21 Q. What costs are included in this 2006 test year estimate of $890,221 for the
22 overhead inspection program?
23 A. All costs including outside services for pole inspection and treatment, aerial
24 inspection costs and HELCO labor costs.
25 Q. Why is the $890,221 test year estimate for overhead inspections justified?

A. As discussed earlier in my testimony, HELCO's overhead inspection program is necessary to prevent interruptions due to deterioration, equipment failure, high wind and trees and branches.

CAPITAL PROJECTS TO IMPROVE T&D RELIABILITY

Q. What major capital projects were completed since 2001 that were done to improve T&D reliability?

A. HELCO-617 provides a list of capital projects designed to improve T&D reliability that were completed since 2001 and were greater than $100,000 in expenditures. The recorded cost and description of each project is provided in HELCO-617.

Q. Please summarize the major capital improvements to improve T&D reliability and give a brief description of the benefits to reliability the projects accomplished.

A. In general the capital projects to improve T&D reliability replaced aging hardware or equipment to prevent service interruptions from occurring and increase public safety, increased distribution substation transformer capacity to accommodate load growth and reduce outage restoration times, created electrical ties to adjacent circuits to prevent outages while performing maintenance and to reduce outage times, and resolved existing or potential power quality problems.

Q. Which capital projects were done to replace aging hardware or equipment, or to remedy an existing deficiency?

A. The 6600 Line Upgrade Phase 1 project was done to replace poles that did not meet General Order No. 6 wind loading requirements. The RPR Paahau CP project replaced an old distribution pole line that was substandard and did not meet General Order No. 6 clearance requirements. The Mauna Kea Beach MOU

project modified handholes and installed ground rods to meet General Order No. 10 requirements for the underground system serving the Mauna Kea Beach resort area. The Volcano National Park Conversion project relocated a 34kv transmission line that was near a fault line (fissure) that posed a hazard to line workers. The Punaluu-Pahala 69kv insulator project replaced strain insulators between Punaluu to Pahala town that were failing due to deterioration. The RPR Hilo 6400 Line project reconductored portions of the 69kv transmission line from the Puna switching station to the Kanoelehua switching station to increase line capacity that did not meet the single contingency design criteria. The Kapoho Beach Lot Rpl project replaced pole line hardware and anchors in the Kapoho Beach Lot subdivisions that were corroded and posed a reliability and public safety risk. The Puueo 13.8kv Upgrade project was done to remove corroded steel structures at Puueo substation that were prone to failure and posed a risk to HELCO personnel. The RPL Kona Palisades project phases 2 and 3 were done to replace direct buried underground cable in portions of the Kona Palisades subdivision. The Kona Highlands project was done to rectify voltage complaints and address safety concerns. The RPL Ancs Puako-Wailea RD project replaced galvanized anchors and down guys that were prone to failure due to deterioration. The Recloser upgrades project replaced older and outdated type R reclosers.

Q. Which projects were done to increase distribution substation transformer capacity to accommodate load growth and reduce service interruption times?

A. The 2001 Unit Tsf Spare 1 transformer purchase provided a spare 10 MVA transformer for contingency purposes. The HPP Sub Upgrade increased the capacity of the Hawaiian Paradise Park Substation serving parts of the lower Puna

area. The substation upgrade also reduced the loading on the 34 kv subtransmission circuit serving the area and provided circuit ties between HPP, Ainaloa, Kurtistown and Panaewa substations.

The Royal Hawaiian Sub Upgrade project upgraded the Royal Hawaiian substation in upper Puna from a single phase system to a three phase system and increased the capacity of the substation to serve the growing load in the area. The upgrade also provided a circuit tie to the Orchid Isle substation and a potential tie to the Wright Road substation.

The Kauhale Sub Upgrade project increased the capacity of the Kauhale substation in the Pepeekeo area and provided a circuit tie to the Puueo Substation in Hilo. The Kealakehe Substation Upgrade increased the capacity of the Kealakehe Substation from 5 MVA to 10 MVA to meet growing load and to provide a circuit tie to Kaloko and Kailua substations.

The Kuakini Unit Sub 2 project added a second substation transformer to serve the growing load in the Kuakini area and load transfer capability from Kahaluu, Kailua and Keauhou substations and from Kuakini Unit 2. The Poopoomino #2 Tsf project added a second substation transformer at Poopoomino substation to serve the growing load in the Hualalai Resort area. The transformer addition also provides back up capability to the Poopoomino unit 1 transformer. The Transformer Mobile Substation project replaced the mobile substation transformer that failed. The mobile substation provides back up to transformation for 69kv and 34kv unit substations. The mobile substation also provides the ability to perform planned maintenance on unit substations.

Q. Which capital projects created electrical ties to adjacent circuits to minimize service interruptions while performing planned maintenance and to reduce service

interruption times?

A. The Milo Street Conversion project converted an older 2.4kv distribution system near Keaau town to the 12.47kv distribution voltage standard removing older hardware prone to failure and also creating circuit tie capability to Panaewa, Kurtistown and HPP substations. The Naalehu Conversion Ph 2 project converted older 4.16kv distribution hardware to the 12.47kv distribution voltage standard removing older hardware prone to failure and making the area compatible with Punaluu and Southpoint substation voltages. The Keahole-Host Park UG Feed created a 12.47 kV circuit tie between the Keahole Airport Substation and the Host Park substation.

Q. Which capital projects were done to resolve existing or potential power quality problems?

A. The Shipman Plt 5.4 MVAR Cap Bank project installed 5.4 MVAR of capacitors to provide voltage support on the 13.8kv distribution system near the Shipman Power Plant in Hilo. The Kailua Sw Sta-19.2 MVAR CAP project installed a 19.2 MVAR, 69kv capacitor bank at the Kailua Switching Station to provide voltage support in West Hawaii. The Kapoho Substation Grounding project improved the substation grounding to improve fault clearing for line to ground faults on the distribution system. The improved fault clearing increases public safety and lessens voltage disturbances in the area.

Growth in T&D Utility Plant

Q. How has the T&D utility plant increased in recent years?

A. As shown on HELCO-607, the amount of HELCO's T&D utility plant is estimated to increase from $408,125,000 in 2000 to $518,437,000 in 2006. This is an increase of $110,312,000.

Q. What factors contribute to the need for these increases to the T&D utility plant?

A. Increases to the T&D utility plant are the result of capital projects. These projects are initiated for a number of reasons:

- New customer service—new residential, commercial and industrial developments.
- Customer requests—line relocations, government improvement projects
- Increase in existing customer loads
- Reliability improvement projects
- Safety and system security

Q. What is the impact on T&D O&M expenses?

A. T&D plant additions represent new facilities that need to be operated, inspected, and maintained. The result is a need to increase staffing in the Distribution Department to address both capital, and operation and maintenance requirements of the growing T&D plant.

HELCO DISTRIBUTION DEPARTMENT

Q. Briefly describe HELCO's Distribution Department.

A. HELCO's Distribution Department is responsible for the construction, operation and maintenance of the T&D facilities on the Island. A total of 123 employees are forecasted to be in the Distribution Department for the 2006 test year. (See HELCO-611.) In addition to its own workforce, HELCO utilizes contractors for vegetation management, excavation, pole and line construction, underground cable installation and splicing, inspections and substation maintenance.

Q. Please describe how HELCO's Distribution Department is organized.

A. HELCO's Distribution Department is divided up in divisions (responsible areas) by function and geographic location. HELCO has adopted a system of letter

designations to identify the divisions. The divisions in the HELCO Distribution Department are as follows:

- HDA Administration Division
- HDC Technical Division
- HDH Hilo Construction and Maintenance Division
- HDK Kona Construction and Maintenance Division
- HDR Operations Division
- HDS Stores Division
- HDW Waimea Construction and Maintenance Division

HELCO-611 provides the positions and staffing count for each division in the 2006 test year.

Q. What are the functions of these divisions?

A. The Administration Division provides the leadership and technical resource for the Distribution Department. The Administration Division is comprised of the department Manager, Administrator, Staff Engineers and System Forester. The Technical Division's areas of responsibility are the switching stations and substations, communications facilities, metering and environmental management. The Technical Division is staffed by a Superintendent, Assistant Superintendents, Clerk, Working Foremen, Substation Electricians, Communication Technicians and Electrician Helpers. The Construction and Maintenance Divisions in Hilo, Kona and Waimea are responsible for the overhead and underground transmission and distribution facilities. Their divisions are staffed by Superintendents, Assistant Superintendents, Working Foremen, Servicemen, Linemen, Trouble Inspectors, Senior Inspectors, Warehouse Tool Room Attendants, Administrators and Linemen Helpers. The

Operations Division is responsible for the trouble dispatch function, transmission and distribution switching operations, reliability statistics, inspection program, and clerical support. The Operations Division is staffed by an Assistant Superintendent, Clerk Dispatcher, Shift Clerk Dispatchers, Senior Inspector and Inspector. The Stores Division purchases, warehouses and distributes materials for use by the other divisions in the Distribution Department and the Production Department. The Stores Division is staffed by a Stores Supervisor, Senior Warehouseman, Warehouse Attendant, Material Coordinator, Storekeeper, Tool Room Attendant/Repairer, and Warehouse Tool Room Attendants. The Storekeeper at Kanoelehua and the Warehouse Tool Room Attendant in Kona purchase and manage tools and materials for the Production Department.

Q. At what locations does the Distribution Department operate?

A. There are three bases for the Distribution Department. One is located at Kanoelehua in Hilo, another in Waimea and the third in Kailua-Kona. HELCO-618 provides a map showing the areas of coverage for each base.

Q. What is the coverage area for the Kanoelehua base?

A. The coverage area for the Kanoelehua base is the Hilo District which extends from the south of Ookala town on the Hamakua Coast to Kamaoa Windfarm near the Southern most part of the Island and has approximately 36,307 customers. This service territory includes the city of Hilo, the Hamakua communities of Laupahoehoe, Hakalau, Honomu, Pepeekeo and Papaikou, the Puna area subdivisions and communities of Keaau, Pahoa, Kapoho, Kurtistown and Volcano, and the Kau communities of Pahala and Naalehu. The Administration Division, Hilo Construction and Maintenance Division, Operations Division, most of the Technical Division and Stores Division operate from the Kanoelehua

1 base.

2 Q. What is the coverage area for the Waimea base?

3 A. The coverage area for the Waimea base is the Waimea District which extends
4 from south of Ookala town on the Hamakua coast to Kiholo Bay in North Kona
5 and has approximately 12,559 customers. The Waimea District includes Ookala
6 town, Honokaa town, Waimea town, the North Kohala communities of Hawi and
7 Halaula, and the subdivisions and resorts in South Kohala. The Waimea
8 Construction and Maintenance Division operates from the Waimea base. A
9 warehouse and a tool room are located at the Waimea base to house tools and
10 materials for use within the district. The Stores division at Kanoelehua
11 coordinates with the Waimea base to supply tools and materials for the Waimea
12 District.

13 Q. What is the coverage area for the Kona base?

14 A. The coverage area for the Kona base is the Kona District which extends from
15 Kiholo Bay in North Kona to the Kamaoa Windfarm near the southern most part
16 of the Island and has approximately 23,647 customers within this area. The
17 Kona District includes the Kau community of Hawaiian Ocean View Estates, the
18 south Kona communities of Milolii, Napoopoo, Captain Cook, Kealia and
19 Kainaliu and the North Kona communities of Keauhou, Kailua, and the resorts
20 north of Keahole. The Kona Construction and Maintenance Division (HDK)
21 operates from the Kona base. A warehouse and a tool room are located at the
22 Kona base to house tools and materials for use within the district. The Stores
23 Division at Kanoelehua coordinates with the Kona base to supply tools and
24 materials for the Kona District. Four employees from the Technical Division
25 operate from the Kona base to maintain the West Hawaii substations.

1 STAFFING FOR T&D WORK

2 Q. You stated earlier that HELCO uses contractors to supplement its T&D work
3 force. How is the work divided between HELCO employees and contract labor?
4 A. HELCO employees are qualified to perform nearly all tasks that contract labor
5 performs. However, HELCO has opted to contract nearly all of the tree
6 trimming and excavation work to contractors. For other work such as pole and
7 line construction, underground cable installation and splicing, and substation
8 equipment installation and maintenance HELCO uses a combination of contract
9 labor and HELCO employees. There are two primary types of contractors that
10 perform this work. Pole and line construction and underground cable installation
11 and splicing require journeymen linemen. Substation equipment installation and
12 maintenance require journeymen substation electricians.
13 Q. How does HELCO determine which work is performed by contractors versus
14 HELCO employees?
15 A. HELCO supervisors evaluate the work to be accomplished and determine if
16 HELCO employees or contractors will perform work. Many factors weigh into
17 the decision making such as the qualifications and availability of the contractor,
18 qualifications and availability of the HELCO workforce, and the urgency of the
19 work to be accomplished. Because HELCO employees are more familiar with
20 the HELCO power system, they are more likely to be used for the more complex
21 tasks and for responding to emergency repairs. With the exception of Trouble
22 inspectors, HELCO does not have an on shift work force dedicated to respond to
23 emergency repairs. The same HELCO workforce performs planned capital and
24 O&M work and responds to emergency repairs on a call out or extended
25 overtime basis. In general, contractors are used for trouble call and emergency

1 work only when the requirements exceed the capacity of the HELCO work force
2 such as during storms.
3 Q. Why does HELCO opt to utilize a combination of HELCO employees and
4 contractors rather than utilizing all HELCO employees?
5 A. The combination of HELCO employees and contract labor can best
6 accommodate variability in work demands. During periods when there are high
7 levels of capital construction, HELCO increases overtime for its employees and
8 expands the use of contract labor. When work demands diminish, contract labor
9 and planned overtime are reduced. If the Company did not use contractors,
10 during periods of high demand it would have to hire additional workers, and
11 during periods of low demand it would have to lay off those it no longer requires.
12 Journeymen linemen and electricians are not readily available in the labor market
13 and they require approximately five years of training and work experience to
14 become proficient. A strategy of hiring and releasing journeymen workers
15 would not be practical. Using contractors enables HELCO to quickly respond to
16 changes in work levels and to maintain a stable and efficient work force.
17 Q. How does HELCO determine the appropriate staffing level and mix of HELCO
18 and contractor labor resources?
19 A. HELCO monitors parameters such as the level of overtime being worked by
20 HELCO employees, extent of use of contractors, projected work requirements in
21 future years, HELCO employee retirement projections, economic outlook,
22 response to trouble and emergencies, and the skill level of the HELCO work
23 force. Based on those parameters HELCO determines staffing levels to increase
24 or decrease available HELCO labor resources.
25 Q. What has been the level of overtime for HELCO's Distribution Department

employees from 2000 to 2005?

A. HELCO-619 provides the level of overtime worked by the entire HELCO Distribution Department work force for years 2000 to 2005. HELCO-608 presents the overtime hours worked in the Technical Division (HDC) and Hilo, Kona, and Waimea Construction and Maintenance Divisions (HDH, HDK and HDW) for years 2000 to 2005. It is clear that all of the listed divisions have sustained high levels of overtime since year 2002.

Q. What has been the level of expenditures for use of contractors for pole and line construction and substation maintenance for the years 2000 to 2005?

A. HELCO-619 presents the expenditures for use of contractors for pole and line construction and substation maintenance for the years 2000 to 2005, and the year to date expenditures for 2006. It shows that expenditures for contract services have increased significantly in years 2002 to 2005, and the year to date expenditures are on track to meet or exceed the 2006 test year estimate. HELCO does not have available information regarding the number of labor hours incurred by contractors. Expenditures for contract services include costs for labor hours and equipment. In most cases contractors provide their own equipment and HELCO provides all of the materials. Thus, the expenditures for contract services reflect the labor and equipment costs.

Q. What is the expected staffing level for the Distribution Department in the 2006 test year?

A. HELCO-611 provides the expected staffing level by position for each division in the Distribution Department for the 2006 test year and the actual levels for years 2000 through 2005. HELCO-607, line 3 also summarizes the estimated end of test year staffing count for the Distribution Department and the actual levels for

1 years 2000 through 2005.

2 Q. Why did staffing levels decline from 111 in year 2000 to 91 in 2003?

3 A. From 2001 to 2003 the Company did not fill all vacancies created by retirements
4 and terminations. In 2004 HELCO began the process of hiring fully qualified
5 linemen and substation electricians and entry level personnel with no experience
6 to increase its HELCO Distribution Departmental staffing count from 91 at year
7 end 2003 to 109 at year end 2005. During that same period a total of 35
8 employees retired, terminated employment or transferred to other departments
9 within HELCO as detailed in HELCO-620. Other factors such as a limited
10 supply of fully qualified journeyman linemen and substation electricians, poor
11 retention rate of qualified journeymen personnel and a competitive local labor
12 market hindered hiring to the desired levels.

13 Q. What has HELCO done to accelerate hiring?

14 A. HELCO has utilized internet websites to recruit qualified linemen and
15 electricians. HELCO has also recruited from the mainland contractor that
16 performs work for HELCO.

17 Q. With 2006 staffing levels forecasted at 123 has HELCO reduced its forecast for
18 overtime and contract expenditures?

19 A. As shown on HELCO-608, overtime hours for the Technical Division (HDC) is
20 forecasted to be reduced by 4,579 hours from 2005 to 2006 test year. Overtime
21 hours for the Hilo, Kona and Waimea Construction and Maintenance Divisions
22 (HDH, HDK and HDW) are forecasted to be approximately the same levels in
23 2006 test year as compared to 2005. However, because of the increase in
24 staffing and the resulting higher levels of straight time, the overtime percentage
25 for all of the divisions is expected to decline. Forecasted levels of contract

expenditures are expected to be at approximately the same level in the 2006 test year as in 2005.

TROUBLE INSPECTORS

Q. Describe briefly the role and responsibility of the trouble inspectors at HELCO.

A. Trouble inspectors are qualified linemen who are the first responders to reports of service problems and power interruptions. When customers report service problems to HELCO, dispatchers collect the information and dispatch trouble inspectors to respond. Trouble inspectors work alone and respond to the location of trouble. For problems that involve a single or few customers trouble inspectors will travel directly to the customer location to diagnose the problem. For incidents affecting numerous customers or a transmission line, trouble inspectors patrol the lines to locate the problem. They then clear the problem if possible or perform switching to isolate the problem and restore service to as many customers as soon as possible. In many cases the trouble inspectors can correct problems without any assistance. For larger repairs, the trouble inspectors will provide a field report that specifies the personnel, equipment and materials required to correct the problem.

Q. Are there any other duties that the trouble inspectors perform?

A. Yes. When they are not responding to trouble, trouble inspectors perform switching for planned maintenance, conduct inspections, install voltage and current measuring devices, locate underground facilities, monitor work activity of unqualified personnel near energized facilities, update maps and records and perform incidental repairs and maintenance.

Q. How many s positions were filled at year end 2005?

A. HELCO effectively had six trouble inspector positions filled at year end 2005.

Three trouble inspectors were used to cover the Hilo district and three trouble inspectors were used to cover the combined Waimea and Kona districts. In the Hilo District there were two trouble inspector positions that were filled fulltime with the third position filled by linemen on a rotational basis. Trouble inspectors are assigned to eight hour shifts. Their schedules are arranged to cover from 7:00 a.m. to 11:00 p.m., seven days per week. The hours from 11:00 p.m. to 7:00 a.m. are not covered on-shift but the trouble inspectors are called out on an as needed basis.

Q. When did the use of trouble inspectors in West Hawaii begin?

A. The use of trouble inspectors in West Hawaii began in 2004 on a trial basis using linemen from the Kona and Waimea districts. Three regular trouble inspector positions were filled in 2005.

Q. What are the advantages of using trouble inspectors in West Hawaii?

A. During normal work hours, having trouble inspectors available to respond to trouble reports, crews can perform planned work (e.g., installation of new services) without interruption. Previously, these crews had to stop the work they were doing in order to respond to reports of trouble during the business day. Unless trouble inspectors are tied up with another trouble call, during normal working hours they are readily available to respond to power interruptions.

Outside of normal business hours past practice was to place linemen on standby duty and they were called out to respond to trouble calls. This led to fatigue to the linemen on standby due to having to respond after hours and work on the normal crews during the normal business day. Having trouble inspectors on shift provides for more certainty in availability and safer response.

Q. How many trouble inspector positions are in HELCO's 2006 test year estimate?

1 A. A total of six trouble inspector positions are forecasted from January to June
2 2006. The coverage for the first six months will be the same as it was in 2005.
3 In mid 2006, an additional four trouble inspectors is anticipated to be added to
4 provide coverage 24 hours per day, 7 days per week.
5 Q. What were the recorded costs of the six trouble inspectors in 2005?
6 A. We can not specifically identify the trouble inspectors actual costs since they are
7 grouped in the labor class, Dcrew with the linemen, helpers, and apprentices
8 actual costs.
9 Q. What are the forecasted costs of 10 trouble inspectors in the 2006 test year?
10 A. The 10 trouble inspectors charge primarily to operating expense which was
11 forecasted in the labor class, Dcrew with the rest of the labor force of linemen,
12 helpers, and apprentices as a group. The average forecasted operating expense
13 portion of the trouble inspectors in 2006 is $349,115. (See HELCO-WP-615).
14 REASONABLENESS OF THE 2006 TEST YEAR ESTIMATE
15 Q. Please summarize the 2006 test year estimate addressed by your testimony.
16 A. HELCO's 2006 estimate for T&D O&M expense for the 2006 test year is
17 $8,999,000, as shown on HELCO-601. Of this amount, $2,401,000 is for
18 transmission O&M expense and $6,598,000 is for distribution O&M expense.
19 Q. Why is the 2006 Test Year Estimate reasonable?
20 A. The 2006 test year estimate for O&M expense is reasonable because it is based
21 upon a historical data and plans for reliability improvement.
22 Q. Please summarize the leading causes of service interruptions and the HELCO
23 O&M programs to address these causes and the associated O&M costs.
24 A. As stated earlier in my testimony, the leading causes of T&D related service
25 interruptions are trees and branches, lightning, automobile accidents, high wind,

cable fault, equipment failure and deterioration. The programs to address the leading causes are the vegetation management program, overhead inspection program, substation inspection program, substation maintenance program and trouble inspectors. The vegetation management program will target preventing interruptions from trees and branches. The estimated 2006 test year cost for the vegetation management program is $1,633,112. (See HELCO-WP-612) As discussed earlier in my testimony, increased trimming is being performed to become more resilient to storm conditions.

The overhead inspection program targets preventing outages due to trees and branches, deterioration, automobile accidents, equipment failure and high wind. The 2006 estimated cost for the overhead inspection program is $890,221. (See HELCO-WP-613)

The substation inspection and maintenance program targets preventing service interruptions due to equipment failure, deterioration and lightning. The estimated test year O&M cost for the substation inspection program is $93,370. (See HELCO-WP-616) The estimated cost for the substation maintenance program is $1,155,039. (See HELCO-WP-616)

The use of trouble inspectors will address service interruptions for all causes. As stated earlier in my testimony trouble inspector coverage will be expanded from 2 shifts per day to three shifts per day. The test year O&M cost estimate for the trouble inspectors is $349,115. (See HELCO-WP-615) All of these programs were discussed in further detail earlier in my testimony.

Q. How does the 2006 test year estimate compare to previous years?

A. HELCO-607 shows HELCO's T&D O&M expenses from recorded 2000 through the 2006 test year estimate. The 2006 test year estimate is higher than

actual expense in years 2000 to 2004 but lower than the 2005 expense by approximately 0.2%.

Q. How does the test year 2006 T&D O&M expense compare with 2005 actual?

A. The 2006 T&D O&M expense is $8,999,000 compared to the 2005 actual amount of $9,013,000, which is a decrease of $14,000. (See HELCO-607).

Q. Why is the T&D O&M expense for the 2006 test year expected to decrease as compared to 2005?

A. The slight decrease in 2006 estimated O&M as compared to 2005 is due to a combination of certain costs that occurred in 2005 that are not expected in 2006, and increases in other areas of the 2006 O&M expense. The differences between 2005 actual and expense and 2006 test year estimate can be evaluated by reviewing labor and non-labor expense.

Q. From reviewing labor and non-labor expenses, how does the 2006 T&D O&M test year estimate compare with the actual 2005 T&D O&M actual expense?

A. HELCO-603 provides a summary of T&D labor and non-labor O&M expense for years 2000 to test year 2006. The 2006 T&D O&M test year estimate has total labor costs of $3,395,982 as compared to 2005 actual labor costs of 3,150,779. The higher labor costs of $245,203 in the 2006 test year are due to additional staffing and operational changes. The 2006 O&M test year estimate has total non-labor costs of $5,603,342 as compared to 2005 actual non-labor costs of $5,862,427. The lower non-labor costs of $259,085 in the 2006 test year are due to certain expenses that occurred in 2005 that will not be done in 2006 and offset by the non-labor charges related to additional staffing.

<u>Labor Costs</u>

Q. What are the staffing differences in the 2006 test year as compared to 2005?

A. HELCO-611 provides the staffing counts for years 2000 to 2006. The 2005 year-end staffing was 109 as compared to the expected 2006 year end staffing of 123.

Q. What are the O&M expenditure increases in 2006 related to the staffing increases?

A. The 2006 O&M expenditure is expected to increase by $268,501 in 2006 as compared to year end 2005 actual due to staffing increases. (See HELCO-WP-614)

Q. What positions are in 2006 test year that were not filled at year end 2005 and what are the associated O&M labor costs?

A. Four trouble inspector positions are added in the 2006 test year to expand to 24 hour coverage. Twenty four hour coverage will improve response to after hour problems such as automobile accidents or other incidents. This addition was discussed previously in my testimony. The anticipated increase in O&M expense for this addition is $59,788. (See HELCO-WP-614.)

Filling a helper position in the Technical Division is required to improve the Substation inspection and maintenance program. These programs were discussed previously in my testimony. The anticipated increase in O&M expense for this addition is $42,370. (See HELCO-WP-614)

Filling of six C&M personnel positions is required – one working foreman in DH, one lineman in DH, two helpers in DK, and two linemen in DW. Increased staffing in the C&M Divisions is required to improve response to storm related outages, manage overtime and improve operation and maintenance. The anticipated increase in O&M expense for these additions is $190,485. (See HELCO-WP-614)

Filling of a Material Coordinator Clerk position in the Technical Division is required to manage materials and perform clerical duties. The costs will be charged to the clearing accounts and no O&M labor costs are anticipated. (See HELCO-WP-614)

Filling of a Warehouse Tool Room Attendant position in the Stores Division at Hilo is required to manage materials and perform clerical duties. The costs will be charged to the clearing accounts and no O&M labor costs are anticipated. (See HELCO-WP-614)

Filling of an Administrative Assistant position in the Kona C&M division is in lieu of a Lineman position required to perform clerical duties and process work orders. The Administrative Assistant position costs will be charged to the clearing accounts and no O&M labor costs are anticipated, but the Lineman position reduction impacts O&M labor costs by ($24,142). (See HELCO-WP-614)

Filling of a Warehouse Tool Room Attendant position at Keahole is required to manage materials for the Production department. The costs will be charged to the clearing accounts and no O&M labor costs are anticipated. (See HELCO-WP-614)

<u>Non-Labor costs</u>

Q. What were the non-labor costs that occurred in 2005 that are not expected in the 2006 test year?

A. The non-labor costs that occurred in 2005 are:

- Contribution of $162,000 to the upgrade of the Hawaii County Microwave System that HELCO utilizes for microwave radio and mobile radio communications.

- A $130,000 purchase of the Fastgate Software program to track overhead inspection data
- A $126,988 expense to complete oil retrofills of generator step-up transformers for Hill Plant 6 and Hill Plant 5. The oil retrofills were done to reduce the probability of catastrophic transformer fires.
- A $146,000 expense for an upgrade of the SCADA platform by the Production department.

Q. What is the non-labor expense associated with the additional staffing in 2006?

A. The non-labor expense associated with additional staffing in 2006 is $256,537 as shown on HELCO-WP-614.

TRANSMISSION O&M EXPENSE

Transmission Operation Expense

Q. You stated earlier that HELCO's 2006 test year estimate of transmission O&M expense is $2,401,000. Of this amount, what is HELCO's 2006 test year estimate for transmission operation expense?

A. HELCO's 2006 test year estimate for transmission operation expense is $959,000 as shown on HELCO-603.

Q. What items are included in transmission operation expense?

A. Transmission operation expense includes labor and non-labor costs to support activities such as load dispatching and transmission switching operations, transmission substation inspections and operations, communications systems operations and inspections and transmission line, pole, and structure inspections. HELCO-WP-602 specifies the corresponding NARUC account numbers for transmission operation.

Q. How does the 2006 test year estimate of transmission operation expense compare

1 to recorded 2005 transmission operation expense?

2 A. HELCO's major variances identified in HELCO-WP-607 that were greater than or
3 equal to $45,000 and greater than or equal to 10% were a decrease of $146,000
4 primarily for the Scada Platform upgrade completed in 2005 for software and
5 training by the Production Department which is not forecasted to reoccur again.
6 In addition, there was a decrease of $65,000 for Fastgate Software costs incurred
7 in 2005 and purchased from Osmose Contracting. Note: the cost was equally
8 allocated between account 563.00 and 583.00.

9 Transmission Maintenance Expense

10 Q. Of the $2,401,000 test year estimate for transmission O&M expense, what is
11 HELCO's 2006 test year estimate for transmission maintenance expense?

12 A. HELCO's 2006 test year estimate for transmission maintenance expense is
13 $1,442,000 as shown on HELCO-603.

14 Q. What items are included in transmission maintenance expense?

15 A. Transmission maintenance expense includes labor and non-labor costs to support
16 activities such as maintenance and repairs for transmission substation equipment
17 and facilities, communications equipment and transmission lines and cables, and
18 tree trimming. HELCO-WP-603 provides the corresponding NARUC account
19 numbers for transmission maintenance.

20 Q. How does the 2006 test year estimate for transmission maintenance expense
21 compare to recorded 2005 transmission maintenance expense?

22 A. HELCO's 2006 test year transmission maintenance expense major variances that
23 were greater than or equal to $45,000 and greater than or equal to 10% are shown
24 in HELCO-WP-608. The $171,000 decrease primarily for additional substation
25 maintenance of equipment in 2005 for ABB oil retrofills for both Hill 5 and 6 for

GE Asset Protection, $126,988 is not anticipated to reoccur in 2006. In addition, the 2006 materials were budgeted under the planned substation maintenance, activity 348, and the recorded materials show under the planned and corrective substation maintenance, activity 348 and 350. Another major decrease of $162,000 was for the Purchase of County of Hawaii microwave digital system in 2005 that is not forecasted to reoccur. The additional cost variances are found in cycles of vegetation management program, $86,000; partial manning in 2005 for the Substation Shop maintenance, $50,000; and partial manning in the telecommunication area for Electronics Shop in 2005, $74,000 as detailed in HELCO-WP-609.

DISTRIBUTION O&M EXPENSE

Distribution Operation Expense

Q. You earlier stated that HELCO's test year estimate of distribution O&M expense is $6,598,000. Of this amount, what is HELCO's 2006 test year estimate of distribution operation expense?

A. HELCO's 2006 test year estimate of distribution operation expense is $2,487,000 as shown on HELCO-603.

Q. What items are included in distribution operation expense?

A. Distribution operation expense includes labor and non-labor costs to support activities such as trouble dispatching and distribution switching operations, distribution substation inspections and operations, distribution line, pole and structure inspections, connecting, disconnecting and locking meters, investigating customer complaints, and testing and treating of wood distribution poles. HELCO-WP-604 specifies the corresponding NARUC account numbers for distribution operation expense.

Q. How does the 2006 test year estimate for distribution operation expense compare to recorded 2005 distribution operation expense?

A. The major variances are identified in HELCO-WP-610 that were greater than or equal to $45,000 and greater than or equal to 10%. The major decrease of $225,000 for cycles in contract line inspection range over several years is detailed in HELCO-WP-610. In addition, there are increases for $98,000 for the replacement of the East Hawaii Engineering Office Air-conditioning Unit, meter expense from Customer Service of $50,000 since expenses were recorded to both HAR and HCR but the forecast is only in HCR for 2006 Test Year, and CWIP Transfers projects by Engineering Department in the 2006 forecast to be reversed at the next opportunity since it is also counted in the budget adjustment entry, $67K.

Distribution Maintenance Expense

Q. Of the $6,598,000 test year estimate for distribution O&M expense, what is HELCO's 2006 test year estimate of distribution maintenance expense?

A. HELCO's 2006 test year estimate of distribution maintenance expense is $4,111,000 as shown on HELCO-605.

Q. What items are included in distribution maintenance expense?

A. Distribution maintenance expense includes labor and non-labor costs to support activities such as maintenance and repairs to distribution substation equipment and facilities and distribution lines and cables, and tree trimming. HELCO-WP-605 specifies the corresponding NARUC account numbers for distribution maintenance expense.

Q. How does the 2006 test year estimate for distribution maintenance expense compare to the recorded 2005 distribution maintenance expense?

A. HELCO's major variances are identified in HELCO-WP-611 that were a decrease greater than or equal to $45,000 and greater than or equal to 10%. The primary variances were for variations in vegetation management cycles between the two years. It takes approximately three years to complete an entire sweep of the island for vegetation management and the amount spent differs by district from year to year. This is shown in HELCO-WP-611.

T&D MATERIALS INVENTORY

Q. What is the estimated test year 2006 T&D materials inventory?

A. The estimated 13 month average for T&D materials inventory in the 2006 test year is $2,512,000 as shown on HELCO-604.

Q. What is included in the T&D materials inventory?

A. The T&D materials inventory includes those items required for the day-to-day construction, operation and maintenance of the T&D system.

Q. How many warehouses does HELCO operate to store and distribute the T&D materials inventory?

A. HELCO operates three materials warehouses for T&D purposes which are located at the following base yards:

1) Kanoelehua
2) Kailua
3) Waimea

Q. Why is the test year 2006 T&D materials inventory reasonable?

A. Estimates for the 2006 test year T&D materials inventory were derived by reviewing historical trends and accommodating changes in operations or improvements.

Q. How does the 2006 test year T&D materials inventory compare with levels

1 recorded in preceding years?

2 A. The 13 month average T&D materials inventory for 2006 test year increased
3 $457,000 or 22% from the average T&D materials inventory for recorded 2005
4 as shown on HELCO-604.

5 Q. Why has the T&D materials inventory increase by $457,000?

6 A. Approximately $175,000 worth of items for the Technical Division was added to
7 the T&D inventory. The stocking level for underground materials was increased
8 by approximately $135,000. The stocking level for 35', 40' and 45' poles were
9 increased by approximately $95,000. Stocking levels were increased to improve
10 availability of materials for projects and emergencies.

11 SUMMARY

12 Q. Mr. Ignacio, please summarize your testimony.

13 A. As shown in HELCO-601, HELCO's 2006 test year T&D O&M expense is
14 $8,999,000, of which $2,401,000 is for transmission and $6,598,000 is for
15 distribution. HELCO's goal is to deliver reliable, cost-effective service to its
16 customers. HELCO has made improvements to its substation maintenance,
17 inspection program, vegetation management and trouble inspector programs to
18 improve reliability. HELCO continues to construct new T&D facilities to meet
19 the fast growing customer base and to make reliability improvements. HELCO
20 has evaluated historical expense and anticipated costs of improvements to staff
21 and fund T&D operations and maintenance activities in a cost-effective manner.
22 The T&D materials inventory is estimated to be an average of $2,512,000 in the
23 2006 test year as shown in HELCO-604.

24 Q. Does this conclude your testimony?

25 A. Yes, it does.

HELCO - 600

HAWAII ELECTRIC LIGHT COMPANY, INC.

JAY M. IGNACIO

EDUCATIONAL BACKGROUND AND EXPERIENCE

BUSINESS ADDRESS:	Hawaii Electric Light Company, Inc. 54 Halekauila Street, Hilo, HI 96720
POSITION:	Manager Distribution Department
YEARS OF SERVICE:	15 Years
UNIVERSITY:	University of Hawaii (1982)
DEGREE:	Bachelor of Science in Electrical Engineering
PREVIOUS POSITIONS:	Hilo Construction & Maintenance, Distribution Department, Hawaii Electric Light Company, Inc. (1994-1996) Electrical Engineer, Engineering Department, Hawaii Electric Light Company, Inc. (1990-1994)
OTHER QUALIFICATIONS:	Registered Professional Engineer, Hawaii Electrical Branch (1995)
PREVIOUS TESTIMONIES:	Docket No. 99-0207 – HELCO Transmission and Distribution Operations and Maintenance Expenses, T&D Materials Inventory, T&D System Docket No. 97-0420 – HELCO Transmission and Distribution Operations and Maintenance Expense, T&D Materials Inventory, T&D System

Hawaii Electric Light Company, Inc.

2006 TEST YEAR

TRANSMISSION AND DISTRIBUTION
OPERATION & MAINTENANCE EXPENSES
($ THOUSANDS)

line		2006 Test Year
1	Transmission O&M Expenses	$2,401
2	Distribution O&M Expenses	6,598
3	TOTAL	$8,999

Source:
HELCO-602, page 1, for lines 1 and 2.

Hawaii Electric Light Company, Inc.

2006 TEST YEAR

TRANSMISSION AND DISTRIBUTION
OPERATIONS & MAINTENANCE EXPENSE
($000K)

line		(A) BUDGET	(B) BUD ADJ	(C) NORM	(D) 2006 TEST YEAR
1	Transmission O&M Expense	$ 2,387	$ 14	$ -	$ 2,401
2	Distribution O&M Expense	6,447	151	-	6,598
3	TOTAL	$ 8,834	$ 165	$ -	$ 8,999

Source

Column A: HELCO-WP-601, pages 1 and 2.
Column B, Line 1: HELCO-602, page 3.
Column B, Line 2: HELCO-602, page 5.
Column D: HELCO-WP-601, page 1 and 2.

Hawaii Electric Light Company, Inc.		
Summary of Adjustments - 2006 Test Year		
Description		
	($)	
The adjustments were made for the following reasons:	Amount	Reference
An adjustment of $0 was made to the transmit and distribute blocks of account for the addition of a Warehouse Tool Room Attendant position at Keahole. Though the position was added to the department staffing, the labor costs will be charged to the stores clearing account which will not have an impact on T&D O&M.	$ -	HELCO-WP-601, page 3 of 5. Adjustment #1 for new hire, Keahole Warehouse Tool Room Attendant is charged to Stores Clearing, Account 163.00 which clears to Capital.
A decrease of $94K was made to the transmit and distribute blocks of account due to four additional trouble inspectors expected to be hired in July 2006 instead of January 2006 as originally forecasted. As stated earlier in my testimony, HELCO plans to expand trouble inspector coverage from 16 hours per day to 24 hours per day. Original plans were to have this change implemented at the beginning of 2006. Delays in hiring qualified linemen have delayed implementing this change until July 2006.	(93,630)	HELCO-602, pages 3 to 5. Sum of notes A1, B1, C1, D1, E1, F1 for Labor and Non-labor.
A decrease of $43K was made to the transmit and distribute blocks of account due to a Kona Lineman position being changed to an Administrative Assistant position.	(42,696)	HELCO-602, page 5. Sum of note D3 for Labor and Non-Labor.
An increase of $137K was made to the transmit and distribute O&M expense for Hilo and Kona crews to match 2005 actual expense. Planned 2006 O&M activities for the Hilo and Kona crews are the same as the O&M activities that were performed in 2005. The 2006 estimates were increased by $137K to match the actual 2005 O&M expenditures for Hilo and Kona crews after the 2005 data was available.	136,629	HELCO-602, pages 3 to 5. Sum of notes A2, B2, C2, D2, E2, and F2 for Labor and Non-labor.
An overall increase of $13K was made to the transmit and distribute blocks of account due to reclassification of costs between O&M and clearing accounts. These adjustments were made after reviewing the actual 2005 cost allocations.	12,697	HELCO-602, pages 4 and 5. Sum of notes E3, G1, G2, and G3 for Labor and Non-labor.
An increase of $152,000 to 2006 O&M costs was made to the transmit and distribute blocks of account for abandoned (cancelled) capital projects that were written off to O&M expense. Subsequent to making this adjustment it was learned that the 2006 T&D O&M budget included $86,000 for abandoned capital project costs. Therefore the adjustment should have been only $66,000. The adjustment will be reduced by $86,000 at HELCO's next opportunity. (See also Mr. Paul Fujioka's testimony at HELCO T-9.)	151,841	HELCO-602, pages 3 and 4. Sum of notes G4, H, I, and J for Non-labor.
Total Increase - Reference $165K in HELCO-602, page 1 of 5, column B.	$ 164,841	

Hawaii Electric Light Company, Inc.

2006 TEST YEAR

TRANSMISSION ADJUSTMENTS
OPERATIONS & MAINTENANCE EXPENSE

TRANSMISSION OPERATIONS			Note
LABOR			
Revised hiring date from January to July for (4) 24 hour inspectors in Hilo and Kona.	$	(2,152.0)	A1
Adjustment in labor allocation for the Hilo and Kona Crews for higher operation costs.		4,108.0	A2
SUB-TOTAL	$	1,956.0	
NON-LABOR			
Revised hiring date from January to July for (4) 24 hour inspectors in Hilo and Kona.	$	(2,004.0)	A1
Adjustment in labor allocation for the Hilo and Kona Crews for higher operation costs.		3,826.0	A2
Adjustment for abandoned capital project costs written off to O&M expense, account 566.		1,668.0	H
Adjustment for abandoned capital project costs written off to O&M expense, account 560.		8,147.0	I
SUB-TOTAL	$	11,637.0	
TOTAL TRANSMISSION OPERATIONS	$	13,593.0	
TRANSMISSION MAINTENANCE			
LABOR			
Revised hiring date from January to July for (4) 24 hour inspectors in Hilo and Kona.	$	(2,466.0)	B1
Adjustment in labor allocation for the Hilo and Kona Crews for higher operation costs.		2,700.0	B2
SUB-TOTAL	$	234.0	
NON-LABOR			
Revised hiring date from January to July for (4) 24 hour inspectors in Hilo and Kona.	$	(2,295.0)	B1
Adjustment in labor allocation for the Hilo and Kona Crews for higher operation costs.		2,514.0	B2
SUB-TOTAL	$	219.0	
TOTAL TRANSMISSION MAINTENANCE	$	453.0	
GRAND TOTAL TRANSMISSION O&M	$	14,046.0	

Source
HELCO-WP-601, pages 3 and 4 for detail of amounts for Notes A to I.

Totals may not add exactly due to rounding.

Hawaii Electric Light Company, Inc.

2006 TEST YEAR

DISTRIBUTION ADJUSTMENTS
OPERATIONS & MAINTENANCE EXPENSE

DISTRIBUTION OPERATIONS		NOTE
LABOR		
Revised hiring date from January to July for (4) 24 hour inspectors in Hilo and Kona, account 583.	$ (8,022.0)	C1
Adjustment in labor allocation for the Hilo and Kona Crews for higher operation costs, account 583.	10,643.0	C2
Revised hiring date from January to July for (4) 24 hour inspectors in Hilo and Kona, account 586.	(7,044.0)	F1
Adjustment in labor allocation for the Hilo and Kona Crews for higher operation costs, account 586.	7,160.0	F2
Reclassification of costs from account 588 to 184.06 Energy Delivery Clearing, activity 842.	(1,878.0)	G1
Reclassification of costs from account 588 to 184.06 Energy Delivery Clearing, activity 843.	(13,617.0)	G2
Reclassification of costs from account 588 to 184.06	(9,391.0)	G3
SUB-TOTAL	$ (22,149.0)	
NON-LABOR		
Revised hiring date from January to July for (4) 24 hour inspectors in Hilo and Kona, account 583.	$ (7,470.0)	C1
Adjustment in labor allocation for the Hilo and Kona Crews for higher operation costs, account 583.	9,911.0	C2
Revised hiring date from January to July for (4) 24 hour inspectors in Hilo and Kona, account 586.	(6,559.0)	F1
Adjustment in labor allocation for the Hilo and Kona Crews for higher operation costs, account 586.	6,669.0	F2
Reclassification of costs from account 588 to 184.06 Energy Delivery Clearing, activity 842.	(1,749.0)	G1
Reclassification of costs from account 588 to 184.06 Energy Delivery Clearing, activity 843.	(12,681.0)	G2
Reclassification of costs from account 588 to 184.06	(8,746.0)	G3
Adjustment for abandoned capital project costs written off to O&M expense, account 588.	17,262.0	G4
Adjustment for abandoned capital project costs written off to O&M expense, account 580.	124,764.0	J
SUB-TOTAL	$ 121,401.0	
TOTAL DISTRIBUTION OPERATIONS	$ 99,252.0	

Source:
HELCO-WP-601, pages 3 and 4 for detail of amounts for Notes C to J.

Totals may not add exactly due to rounding.

Hawaii Electric Light Company, Inc.

2006 TEST YEAR

DISTRIBUTION ADJUSTMENTS
OPERATIONS & MAINTENANCE EXPENSE

DISTRIBUTION MAINTENANCE		NOTE
LABOR		
Revised hiring date from January to July for (4) 24 hour inspectors in Hilo and Kona, account 593.	$ (26,803.0)	D1
Adjustment in labor allocation for the Hilo and Kona Crews for higher operation costs, account 593.	45,313.0	D2
Adjustment for change in new hire position in Kona from a lineman to an Administrator, account 593.	(22,108.0)	D3
Revised hiring date from January to July for (4) 24 hour inspectors in Hilo and Kona, account 598.	(1,996.0)	E1
Adjustment in labor allocation for the Hilo and Kona Crews for higher operation costs, account 598.	822.0	E2
Reclassify incorrect indicator from clearing to expense for Hilo Crews, account 598.	31,461.0	E3
SUB-TOTAL	$ 26,689.0	
NON-LABOR		
Revised hiring date from January to July for (4) 24 hour inspectors in Hilo and Kona, account 593.	$ (24,961.0)	D1
Adjustment in labor allocation for the Hilo and Kona Crews for higher operation costs, account 593.	42,198.0	D2
Adjustment for change in new hire position in Kona from a lineman to an Administrator.	(20,588.0)	D3
Revised hiring date from January to July for (4) 24 hour inspectors in Hilo and Kona, account 598.	(1,858.0)	E1
Adjustment in labor allocation for the Hilo and Kona Crews for higher operation costs, account 598.	765.0	E2
Reclassify incorrect indicator from clearing to expense for Hilo Crews, account 598.	29,298.0	E3
SUB-TOTAL	$ 24,854.0	
TOTAL DISTRIBUTION MAINTENANCE	$ 51,543.0	
GRAND TOTAL DISTRIBUTION O&M	$ 150,795.0	

Source:
HELCO-WP-601, pages 3 and 4 for detail of amounts for Notes D to E.

Totals may not add exactly due to rounding.

Hawaii Electric Light Company, Inc.
Rate Case Summary Report: Labor vs. Nonlabor
Comparative

Line		(A) 2000	(B) 2001	(C) Recorded 2002	(D) 2003	(E) 2004	(F) 2005	(G) Budget 2006	(H) Budget Adj 2006	(I) Test Year 2006
	Transmission Operation									
1	Labor	442,130	409,048	400,479	392,341	376,559	366,251	465,298	1,956	467,254
2	Non-Labor	415,991	310,270	353,539	351,789	303,371	572,982	479,879	11,637	491,516
3	Total Transmission Oper	858,121	719,318	754,018	744,130	679,930	939,233	945,177	13,593	958,770
	Transmission Maintenance									
4	Labor	310,472	191,182	384,514	385,142	352,421	350,224	461,881	234	462,115
5	Non-Labor	420,444	509,872	691,714	871,806	1,011,717	1,123,468	980,196	219	980,415
6	Total Transmission Maint	730,916	701,054	1,076,228	1,256,948	1,364,138	1,473,692	1,442,077	453	1,442,530
	Total Transmission									
7	Labor	752,603	600,230	784,993	777,483	728,980	716,475	927,179	2,190	929,369
8	Non-Labor	836,435	820,142	1,045,253	1,223,595	1,315,088	1,696,451	1,460,075	11,856	1,471,931
9	Grand Total Transmission	1,589,038	1,420,372	1,830,246	2,001,078	2,044,068	2,412,926	2,387,254	14,046	2,401,300

Source:
Columns A to G: HELCO-WP-101(A), Page 3.
Column H: HELCO-602, Page 3.
Column I: Column G plus Column H

Hawaii Electric Light Company, Inc.
Rate Case Summary Report: Labor vs. Nonlabor
Comparative

Line		(A) 2000	(B) 2001	(C) Recorded 2002	(D) 2003	(E) 2004	(F) 2005	(G) Budget 2006	(H) Budget Adj 2006	(I) Test Year 2006
	Distribution Operation									
1	Labor	944,229	932,012	914,738	893,915	884,521	981,307	1,164,619	(22,149)	1,142,470
2	Non-Labor	641,217	573,028	720,297	771,856	690,788	1,108,408	1,222,900	121,401	1,344,301
3	Total Distribution Operation	1,585,446	1,505,040	1,635,035	1,665,771	1,575,309	2,089,715	2,387,519	99,252	2,486,771
	Distribution Maintenance									
4	Labor	838,524	993,334	944,130	1,003,153	1,451,001	1,452,997	1,297,454	26,689	1,324,143
5	Non-Labor	1,875,861	1,512,216	2,227,611	2,156,789	2,331,857	3,057,568	2,762,256	24,854	2,787,110
6	Total Distribution Maint	2,714,385	2,505,550	3,171,741	3,159,942	3,782,858	4,510,565	4,059,710	51,543	4,111,253
	Total Distribution									
7	Labor	1,782,753	1,925,346	1,858,868	1,897,068	2,335,522	2,434,304	2,462,073	4,540	2,466,613
8	Non-Labor	2,517,078	2,085,244	2,947,908	2,928,645	3,022,645	4,165,976	3,985,156	146,255	4,131,411
9	Grand Total Distribution	4,299,831	4,010,590	4,806,776	4,825,713	5,358,167	6,600,280	6,447,229	150,795	6,598,024
10	Labor	2,535,356	2,525,576	2,643,861	2,674,551	3,064,502	3,150,779	3,389,252	6,730	3,395,982
11	Non-Labor	3,353,513	2,905,386	3,993,161	4,152,240	4,337,733	5,862,427	5,445,231	158,111	5,603,342
12	Grand Total T & D Expense	5,888,869	5,430,962	6,637,022	6,826,791	7,402,235	9,013,206	8,834,483	164,841	8,999,324

Source:
Columns A to G, Lines 1 to 9: HELCO-WP-101(A), Page 4.
Column H, Lines 1 to 9: HELCO-602, Pages 4 and 5.
Column I: Column G plus Column H.

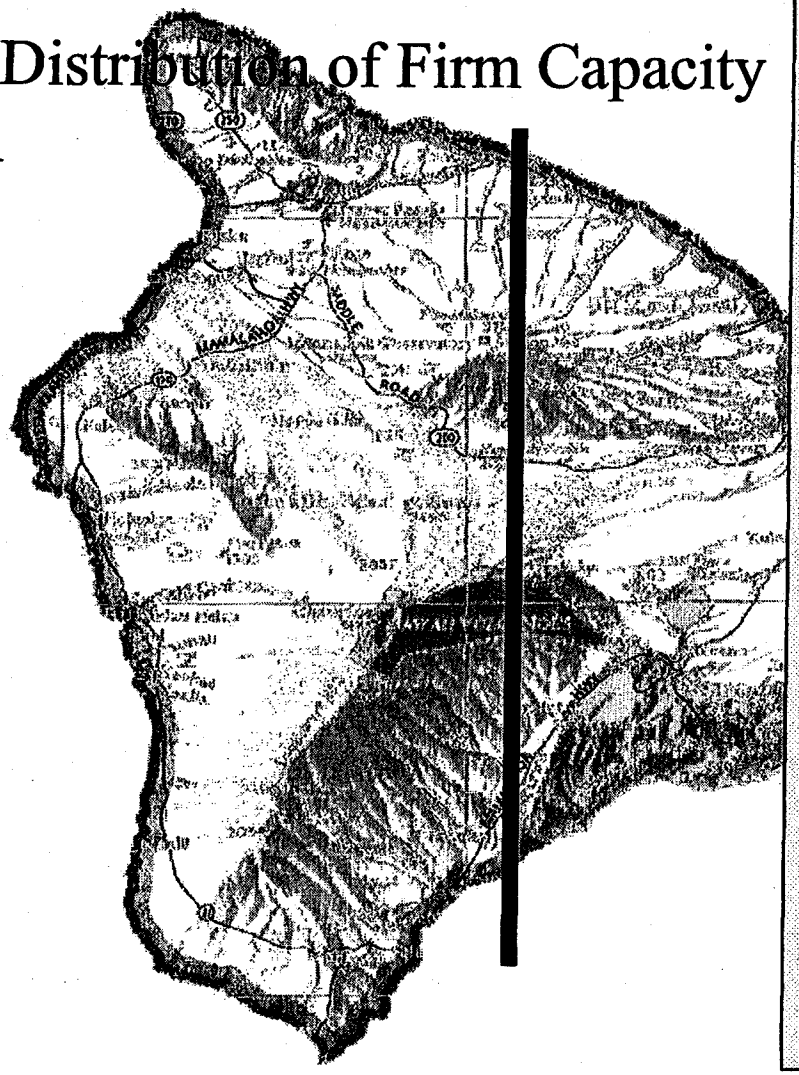
Hawaii Electric Light Company, Inc.

TRANSMISSION & DISTRIBUTION MATERIALS INVENTORY

line		A	B	C	D	E	F	G
		2000 Recorded	2001 Recorded	2002 Recorded	2003 Recorded	2004 Recorded	2005 Recorded	2006 Forecast
1	Inventory Level Year-End ($ Thousands)	1,579	1,385	1,636	1,742	1,871	2,501	2,547
2	13 Month Average Inventory Level ($ Thousands)	1,512	1,477	1,523	1,692	1,695	2,055	2,512
3	Total Issues ($ Thousands)	2,505	3,357	2,319	2,809	2,503	3,481	2,772
4	Annual Turnover Ratio	1.68	2.43	1.84	1.72	1.60	1.78	1.18

Source: HELCO-WP-606, pg. 1-9.

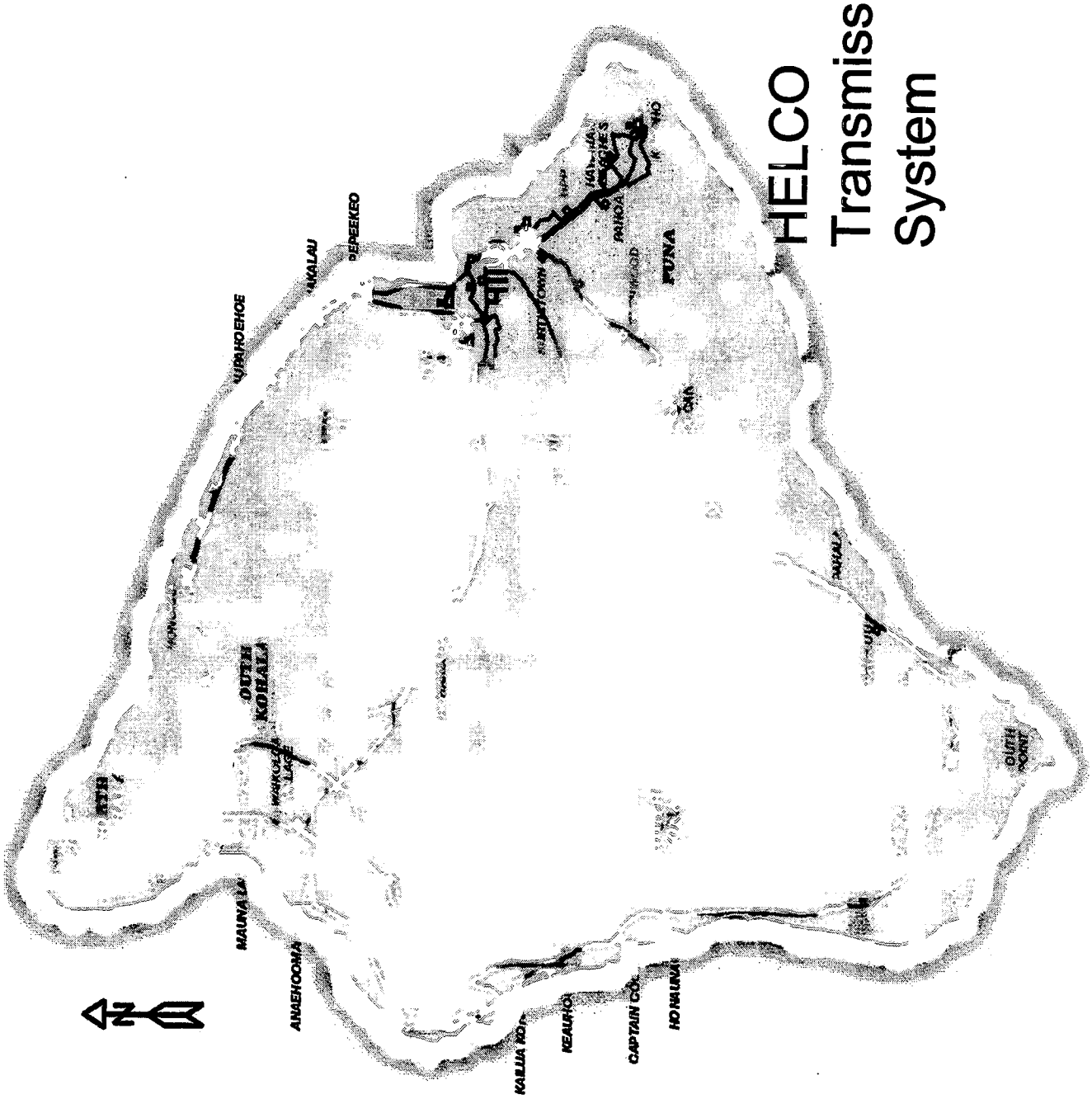
East-West Distribution of Firm Capacity Generation



East of Honokaa	
Kanoelehua/Hill	55.2 mw
Puna	34.5 mw
Shipman	13.5 mw
PGV	30.0 mw
HEP	60.0 mw
3 DGs	3.0 mw
Total	196.2 mw
West of Honokaa	
Keahole	64.8 mw
Waimea	7.5 mw
1 DGs	1.0 mw
Total	73.3 mw
Total	269.5mw

RECEIVED
AS
FOLLOWS

HELCO Transmission System



Hawaii Electric Light Company, Inc.

GENERAL DATA

line	A 2000 Recorded	B 2001 Recorded	C 2002 Recorded	D 2003 Recorded	E 2004 Recorded	F 2005 Recorded	G 2006 Test Year
1 T&D O&M Expenses ($ Thousands)	5,889	5,431	6,637	6,827	7,402	9,013	8,999
2 T&D Plant ($ Thousands)	408,125	416,032	428,052	441,715	460,868	490,787	518,713
3 T&D Employees (Year End)	111	95	98	91	94	109	123
4 HELCO Customers (Average)	63,208	64,660	66,034	67,909	70,124	72,521	74,174
5 T&D Employees/ 1000 Customers	1.756	1.47	1.48	1.34	1.34	1.50	1.66
6 O&M Expenses/T&D Plant (%)	1.44	1.31	1.55	1.55	1.61	1.84	1.74

Source: HELCO-WP-101(A), Pages 3 and 4 for line 1.
HELCO-WP-1204 for line 2.
HELCO-611 for line 3.
HELCO-207 for line 4.

Hawaii Electric Light Company, Inc.

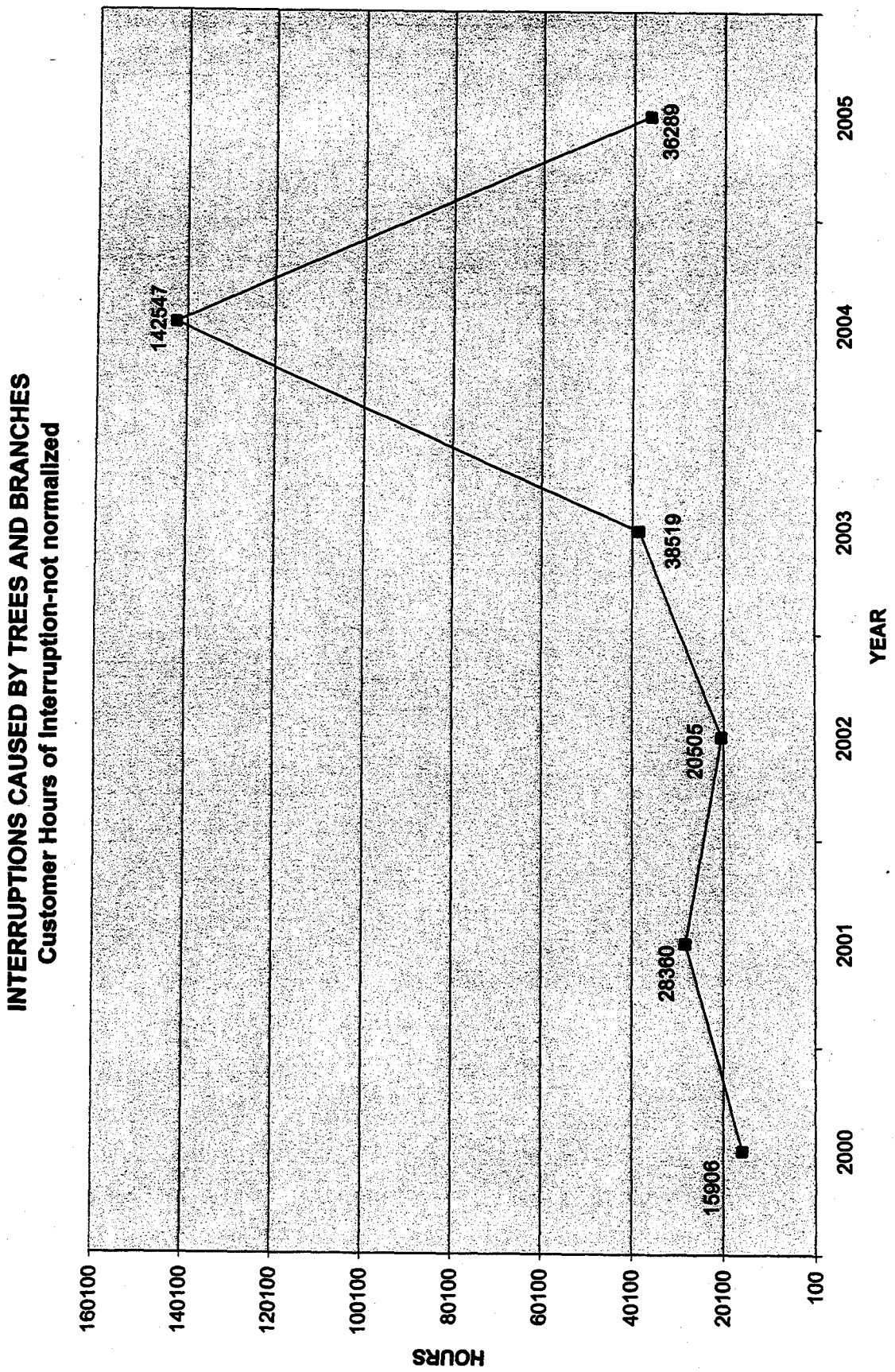
OVERTIME

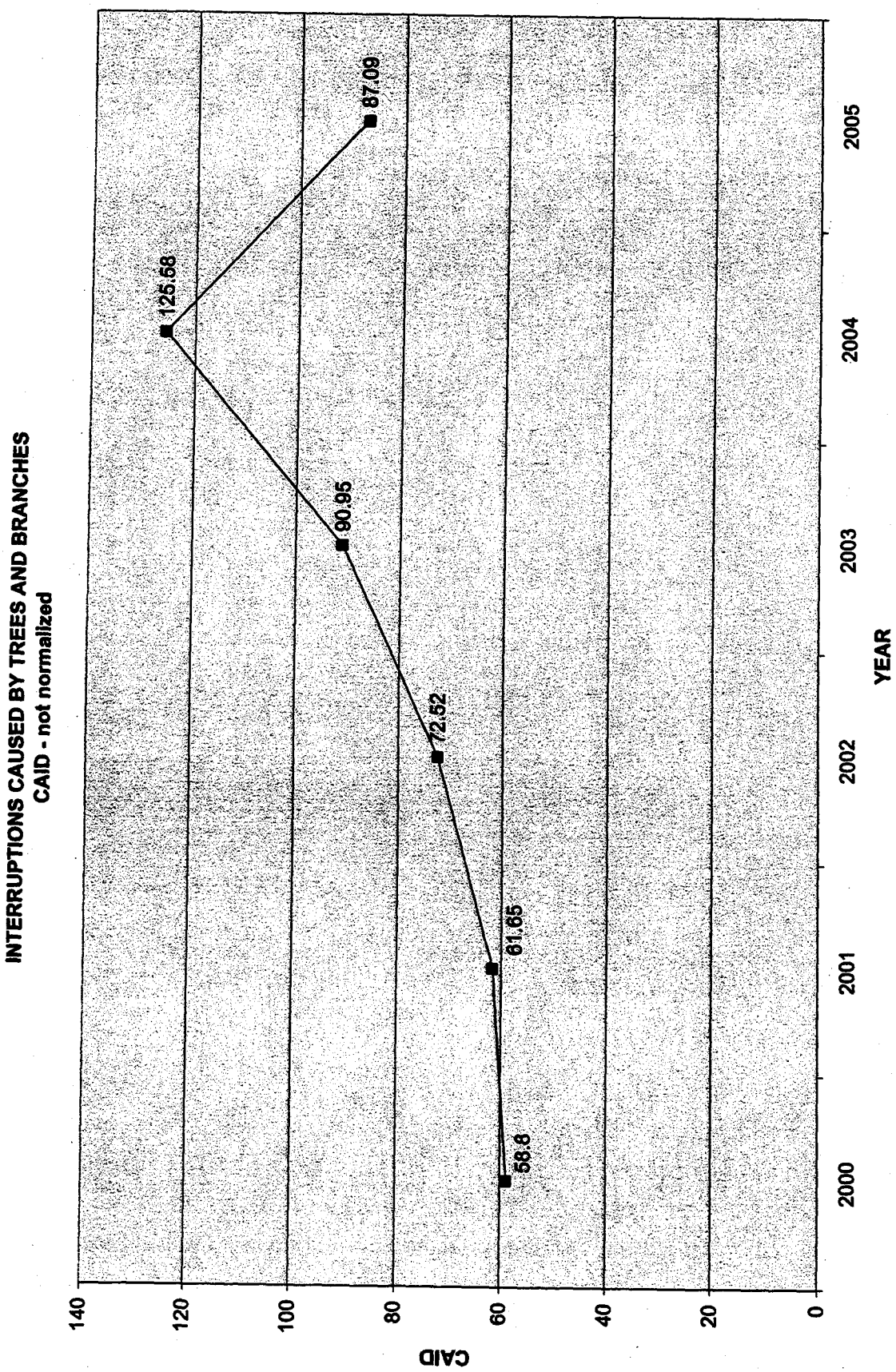
Line	A	B	C	D	E	F	G	H
	2000 Recorded	2001 Recorded	2002 Recorded	2003 Recorded	2004 Recorded	2005 Recorded	2006 Forecast	03/06YTD Recorded
Overtime Hours								
1 HDC-TECHCREW	2,823.7	1,813.6	3,355.7	4,078.7	4,261.2	7,375.4	2,796.0	2,395.4
2 HDH-CREW (Hilo)	15,859.3	8,306.3	11,655.9	14,627.1	14,845.6	15,485.0	14,796.0	6,202.0
3 HDK-CREW (Kona)	6,069.8	7,924.6	11,757.8	10,067.1	11,492.3	8,377.2	9,300.0	2,888.4
4 HDW-CREW (Waimea)	7,631.0	5,197.9	6,264.5	6,366.5	6,654.5	4,869.5	6,264.0	1,648.9
Overtime % of ST								
1 HDC-TECHCREW	9%	6%	13%	14%	17%	28%	7%	23%
2 HDH-CREW (Hilo)	30%	20%	31%	36%	36%	35%	28%	43%
3 HDK-CREW (Kona)	31%	40%	48%	42%	49%	35%	28%	33%
4 HDW-CREW (Waimea)	32%	29%	37%	36%	35%	29%	27%	27%

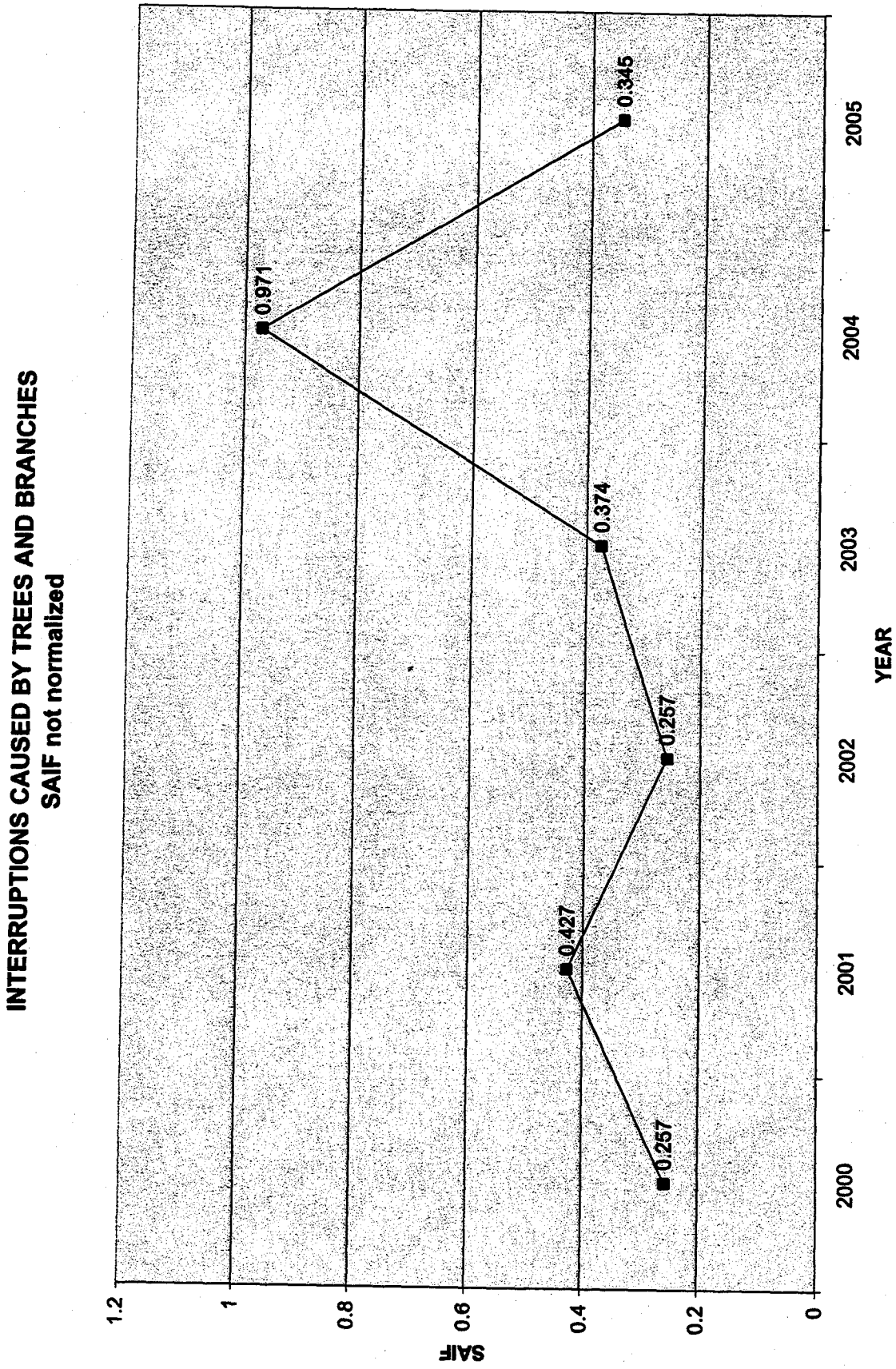
Hawaii Electric Light Company, Inc.

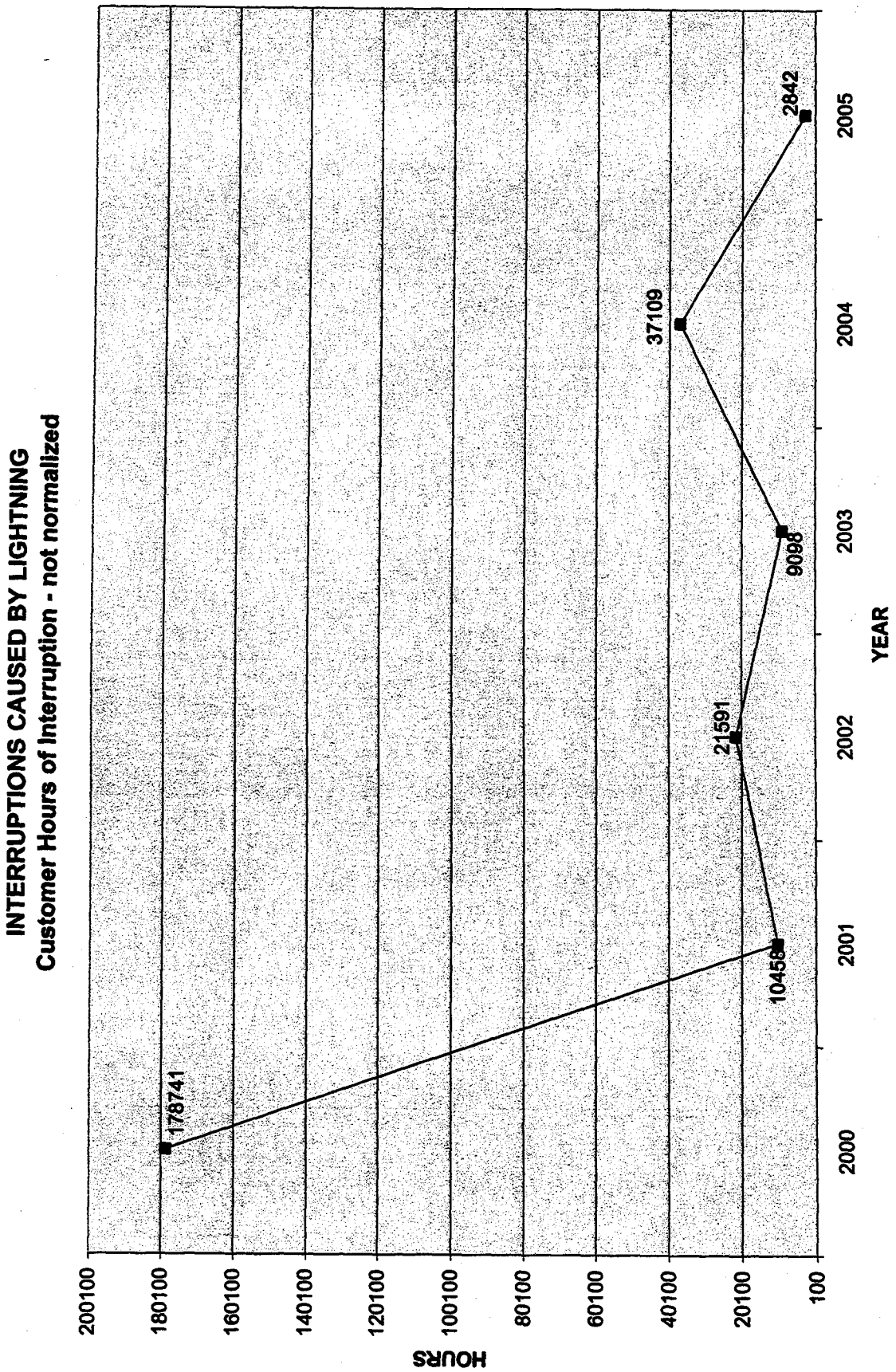
T&D SYSTEM RELIABILITY DATA (NOT NORMALIZED)

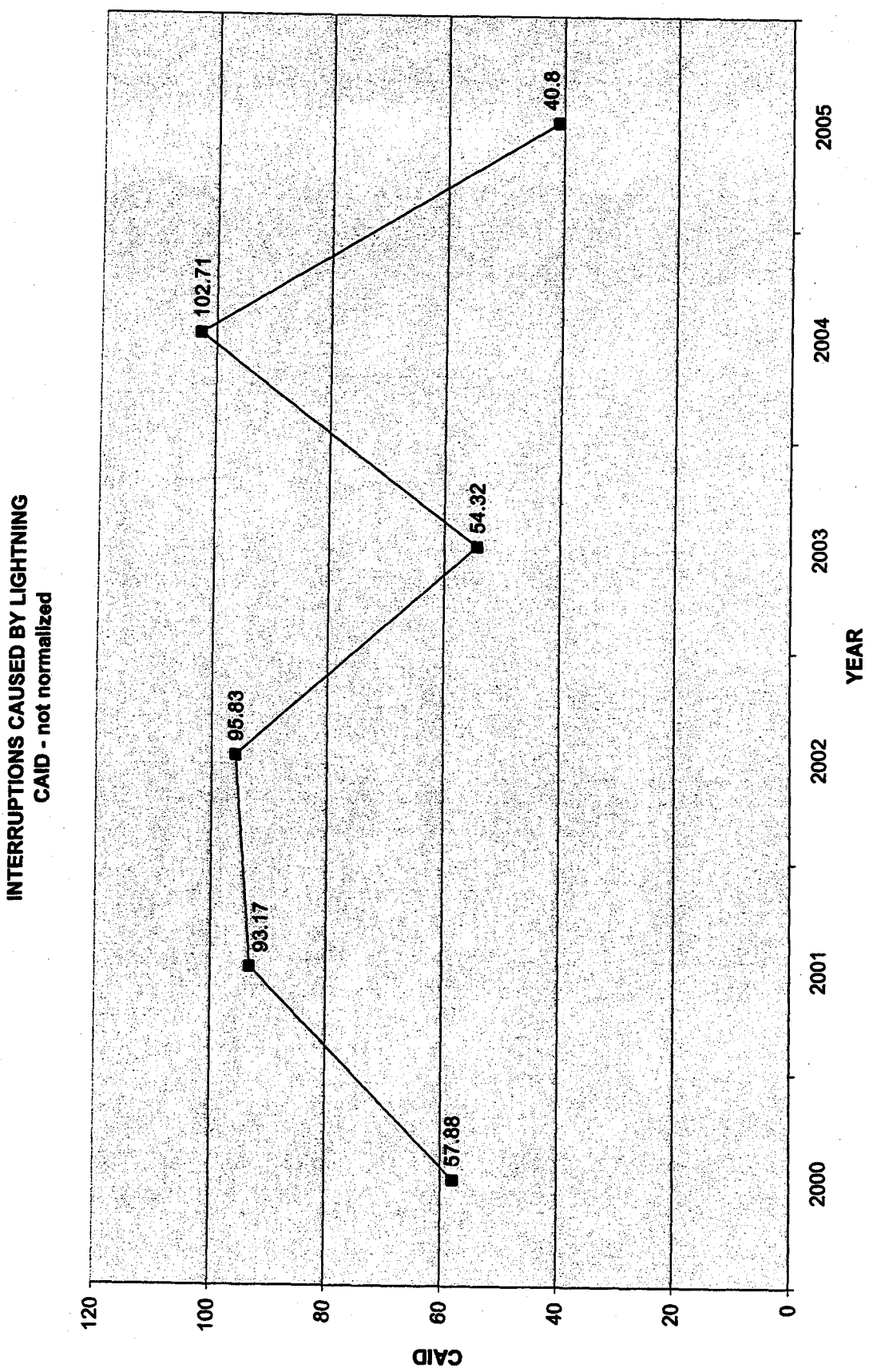
item		A	B	C	D	E	F
		2000 Recorded	2001 Recorded	2002 Recorded	2003 Recorded	2004 Recorded	2005 Recorded
1	**System Average Interruption Frequency** (SAIF)	3.912	1.294	2.668	2.627	2.664	1.932
2	**Customer Average Interruption Duration** (CAID)	59.88	70.86	60.51	71.74	103.59	93.81
3	**Annual System Availability** (ASA)	99.955	99.982	99.969	99.964	99.947	99.965
4	**Trees or Branches** (Customer Hours)	15,906	28,360	20,505	38,519	142,547	36,289
5	**Lightning** (Customer Hours)	178,741	10,458	21,591	9,098	37,109	2,842
6	**High Winds** (Customer Hours)	989	7,406	15,627	27,923	40,442	5,124
7	**Auto Accident** (Customer Hours)	14,822	7,162	12,745	41,541	20,732	57,127
8	**Cable Fault** (Customer Hours)	5,319	2,469	9,317	11,239	15,310	51,827
9	**Deterioration** (Customer Hours)	13,561	12,721	7,526	9,916	10,966	22,413
10	**Equipment Failure** (Customer Hours)	7,620	4,106	38,739	19,270	20,261	1,360

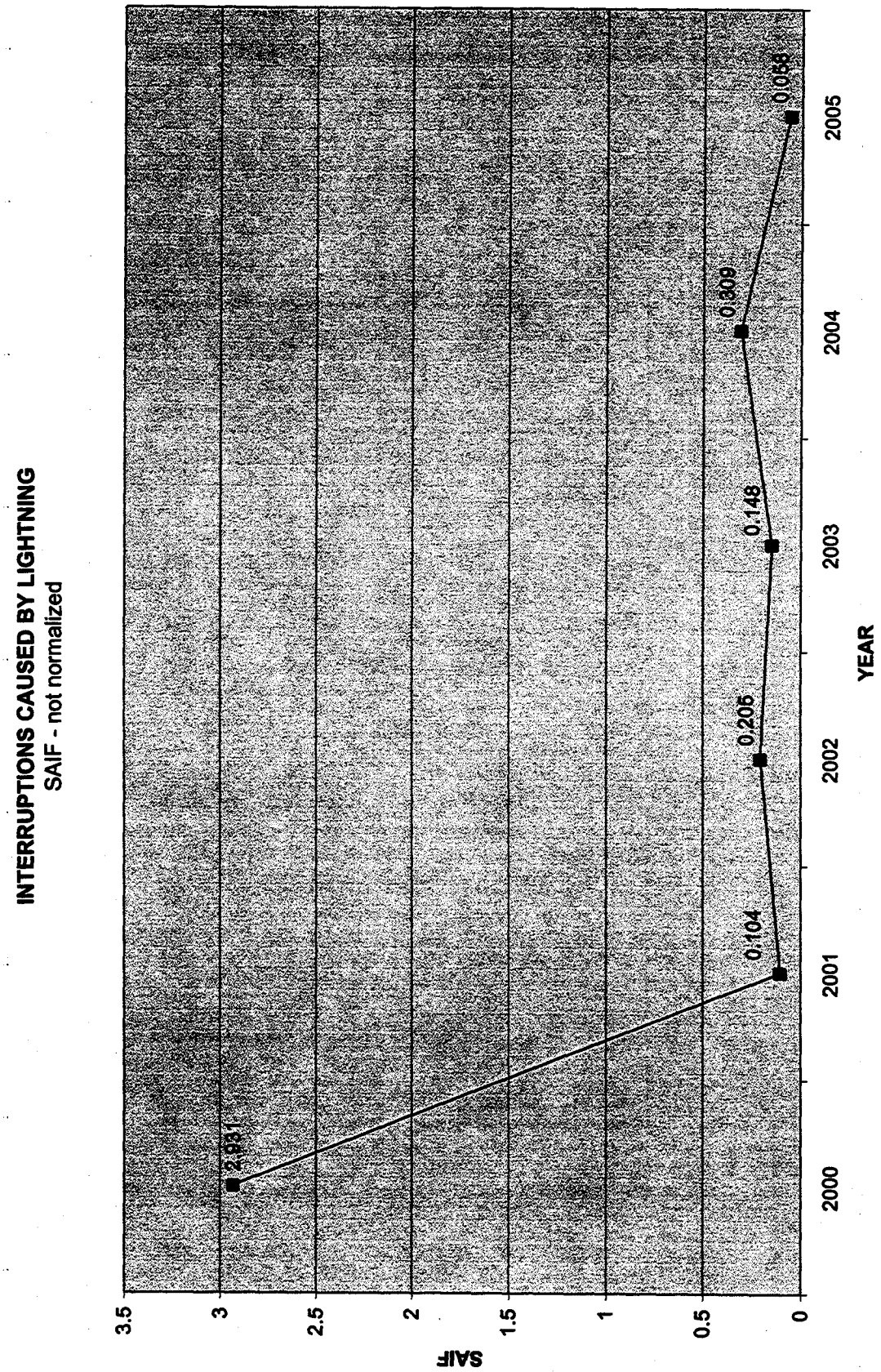

INTERRUPTIONS CAUSED BY TREES AND BRANCHES
Customer Hours of Interruption-not normalized
HOURS
160100
140100
120100
100100
80100
60100
40100
20100
100
YEAR
2000
2001
2002
2003
2004
2005
15906
28360
20505
38519
142547
36289

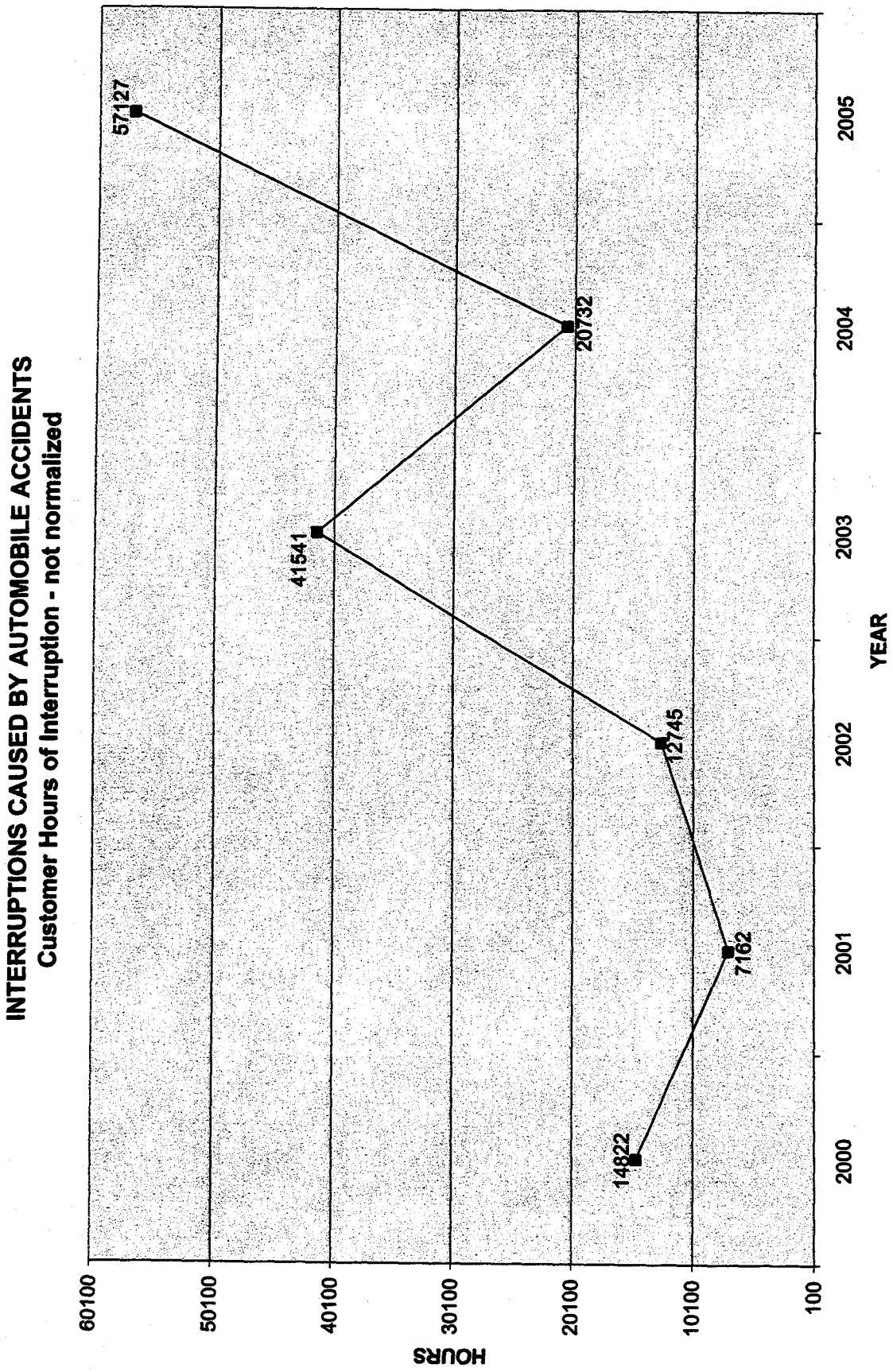

INTERRUPTIONS CAUSED BY TREES AND BRANCHES
CAID - not normalized
CAID
140
120
100
80
60
40
20
0
YEAR
2000
2001
2002
2003
2004
2005
58.8
61.65
72.52
90.95
125.58
87.09

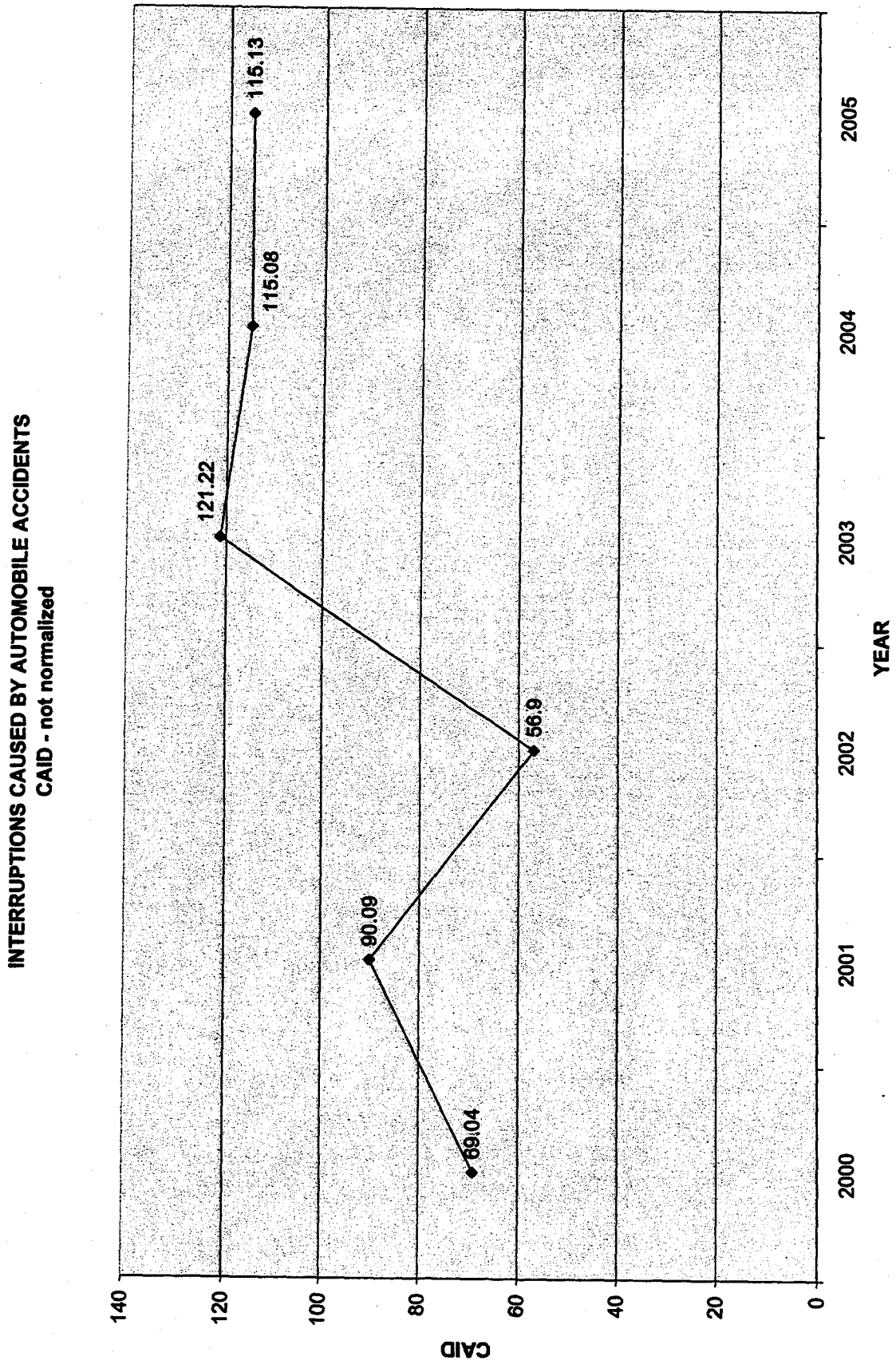

INTERRUPTIONS CAUSED BY TREES AND BRANCHES
SAIF not normalized
SAIF
1.2
1
0.8
0.6
0.4
0.2
0
0.257
0.427
0.257
0.374
0.971
0.345
2000
2001
2002
2003
2004
2005
YEAR

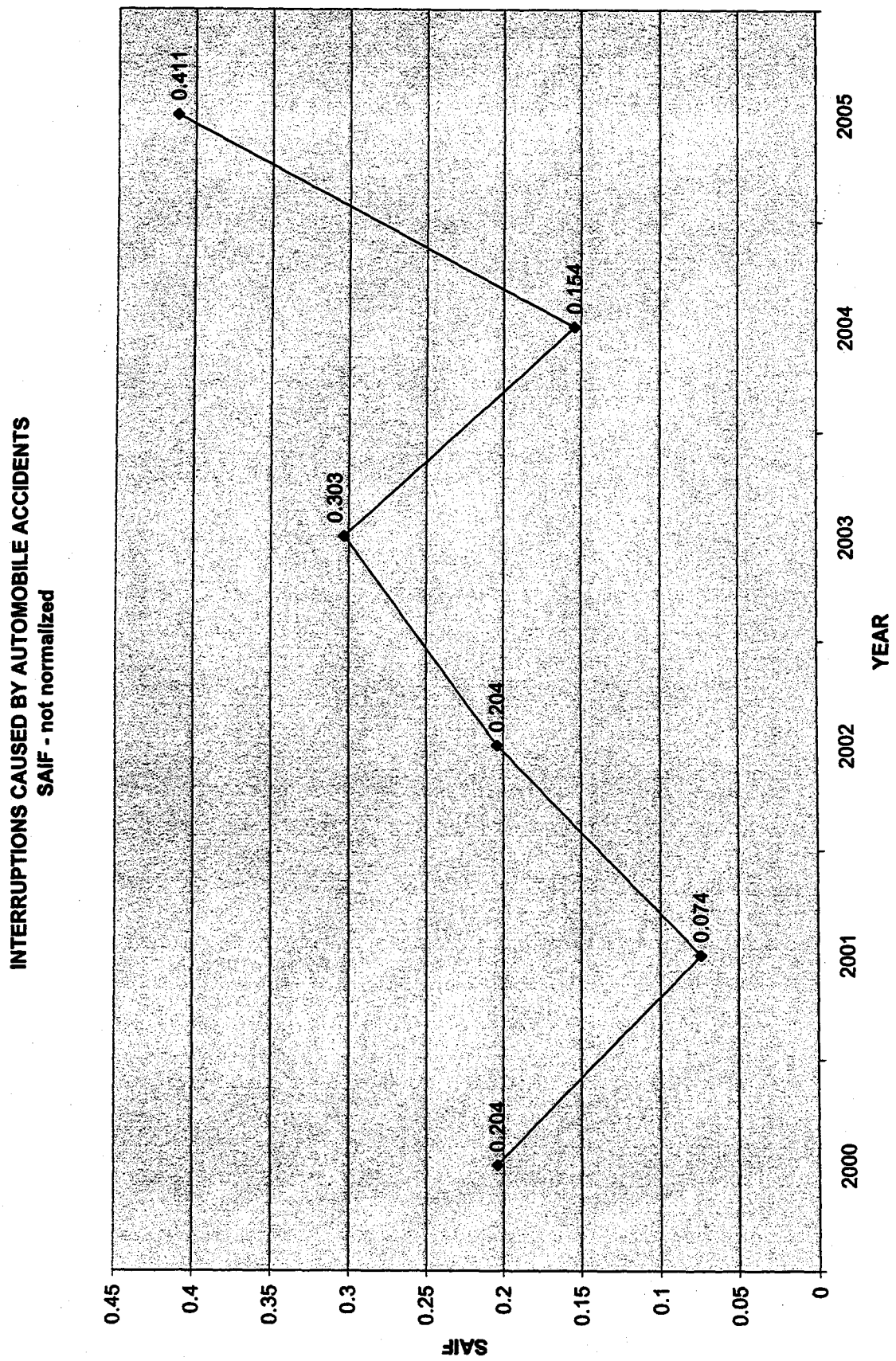

INTERRUPTIONS CAUSED BY LIGHTNING
Customer Hours of Interruption - not normalized
HOURS
200100
180100
160100
140100
120100
100100
80100
60100
40100
20100
100
YEAR
2000
2001
2002
2003
2004
2005
178741
10456
21591
9098
37109
2842

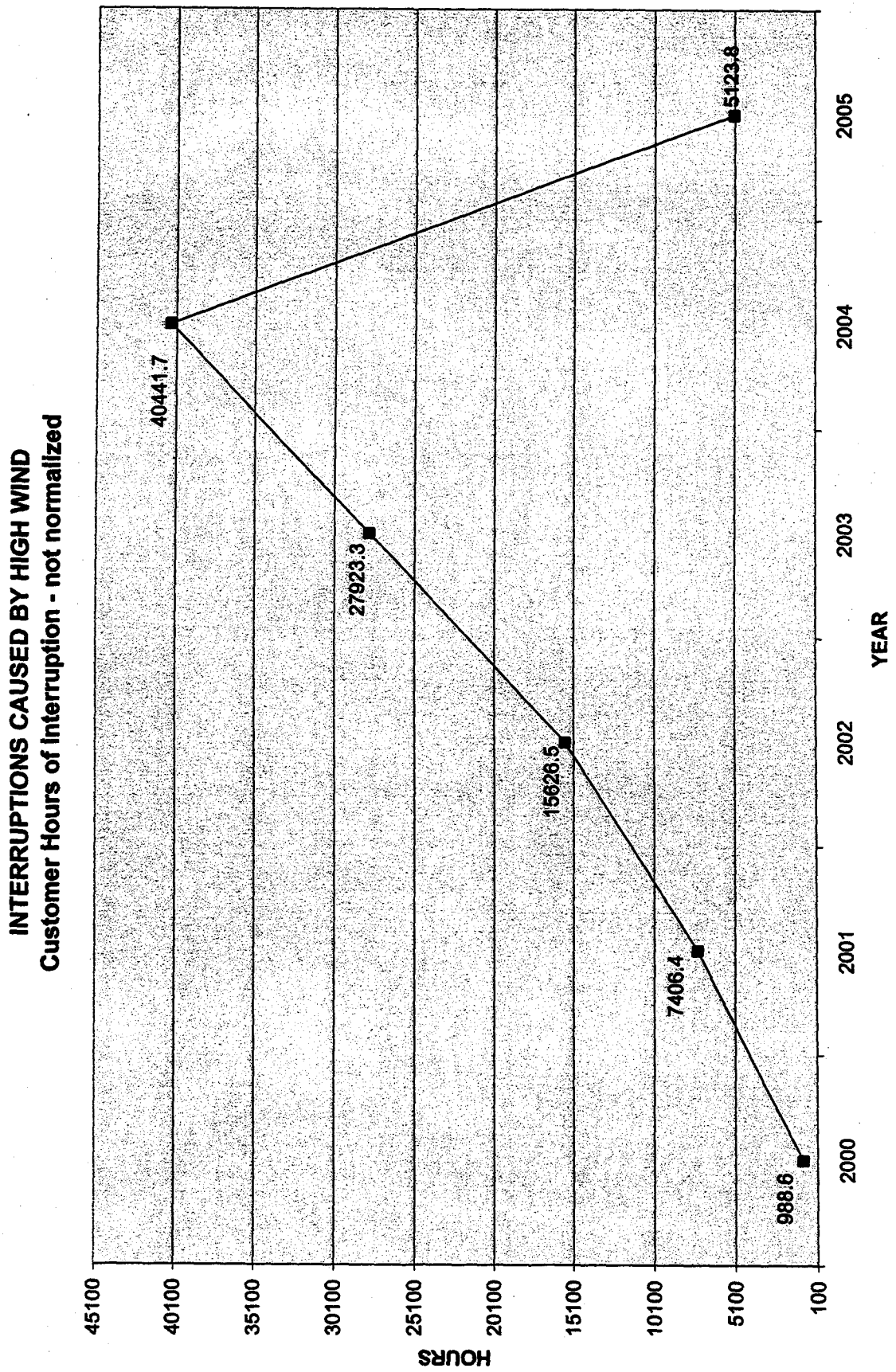

INTERRUPTIONS CAUSED BY LIGHTNING
CAID - not normalized
CAID
120
100
80
60
40
20
0
57.88
93.17
95.83
54.32
102.71
40.8
2000
2001
2002
2003
2004
2005
YEAR

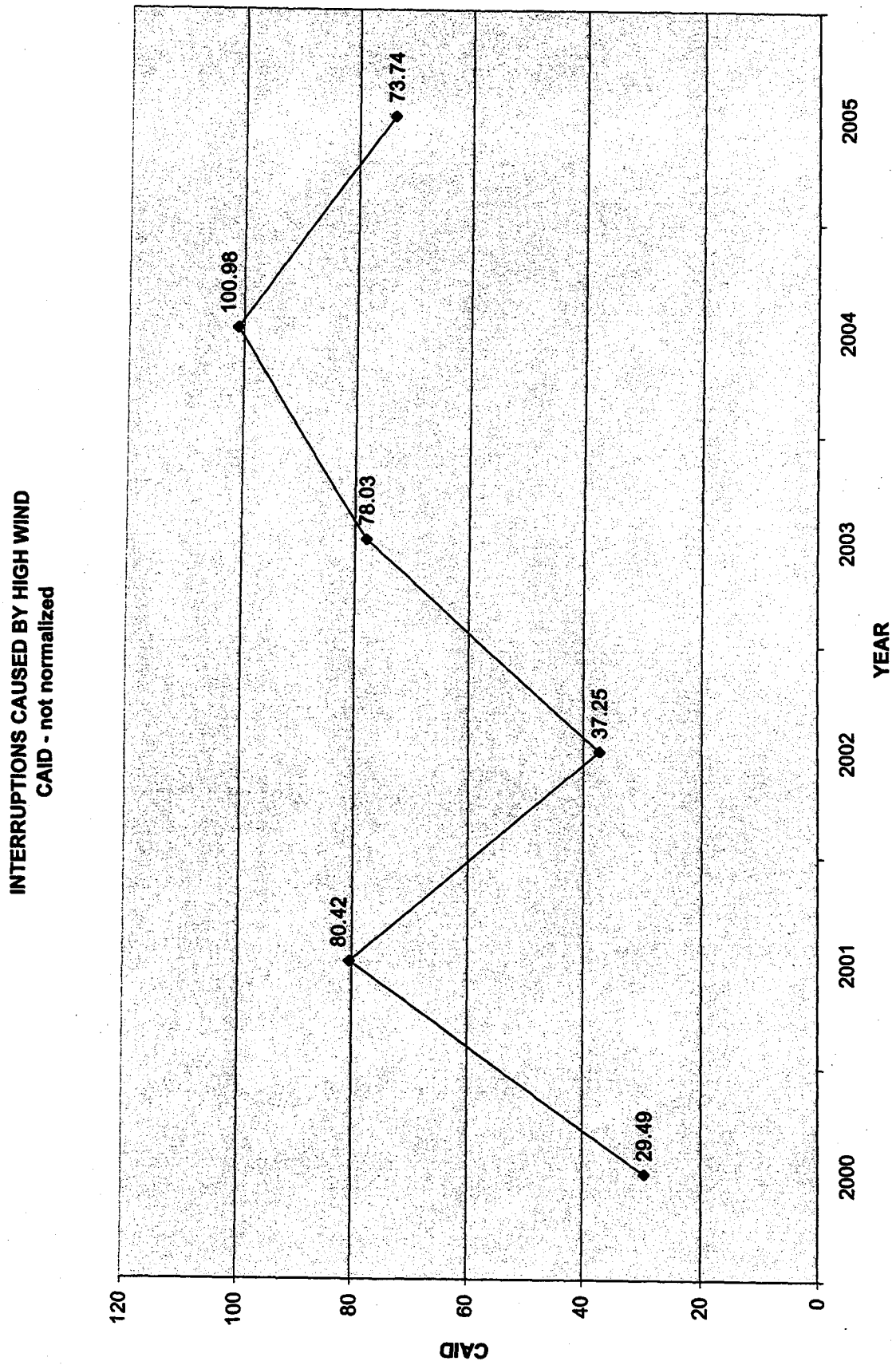

INTERRUPTIONS CAUSED BY LIGHTNING
SAIF - not normalized
SAIF
3.5
3
2.5
2
1.5
1
0.5
0
2.931
0.104
0.206
0.148
0.309
0.058
2000
2001
2002
2003
2004
2005
YEAR

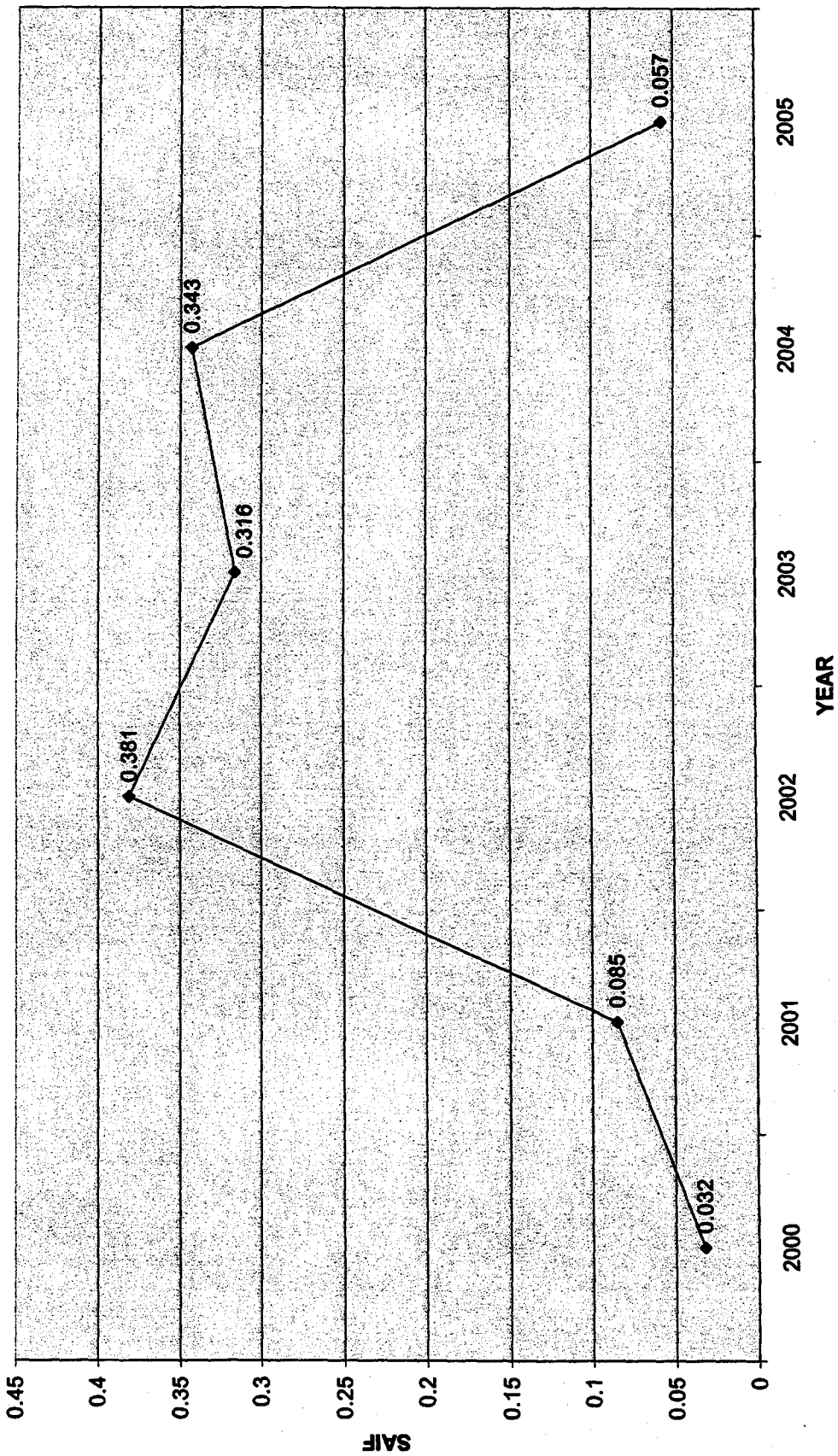

INTERRUPTIONS CAUSED BY AUTOMOBILE ACCIDENTS
Customer Hours of Interruption - not normalized
HOURS
60100
50100
40100
30100
20100
10100
100
YEAR
2000
2001
2002
2003
2004
2005
14822
7162
12745
41541
20732
57127

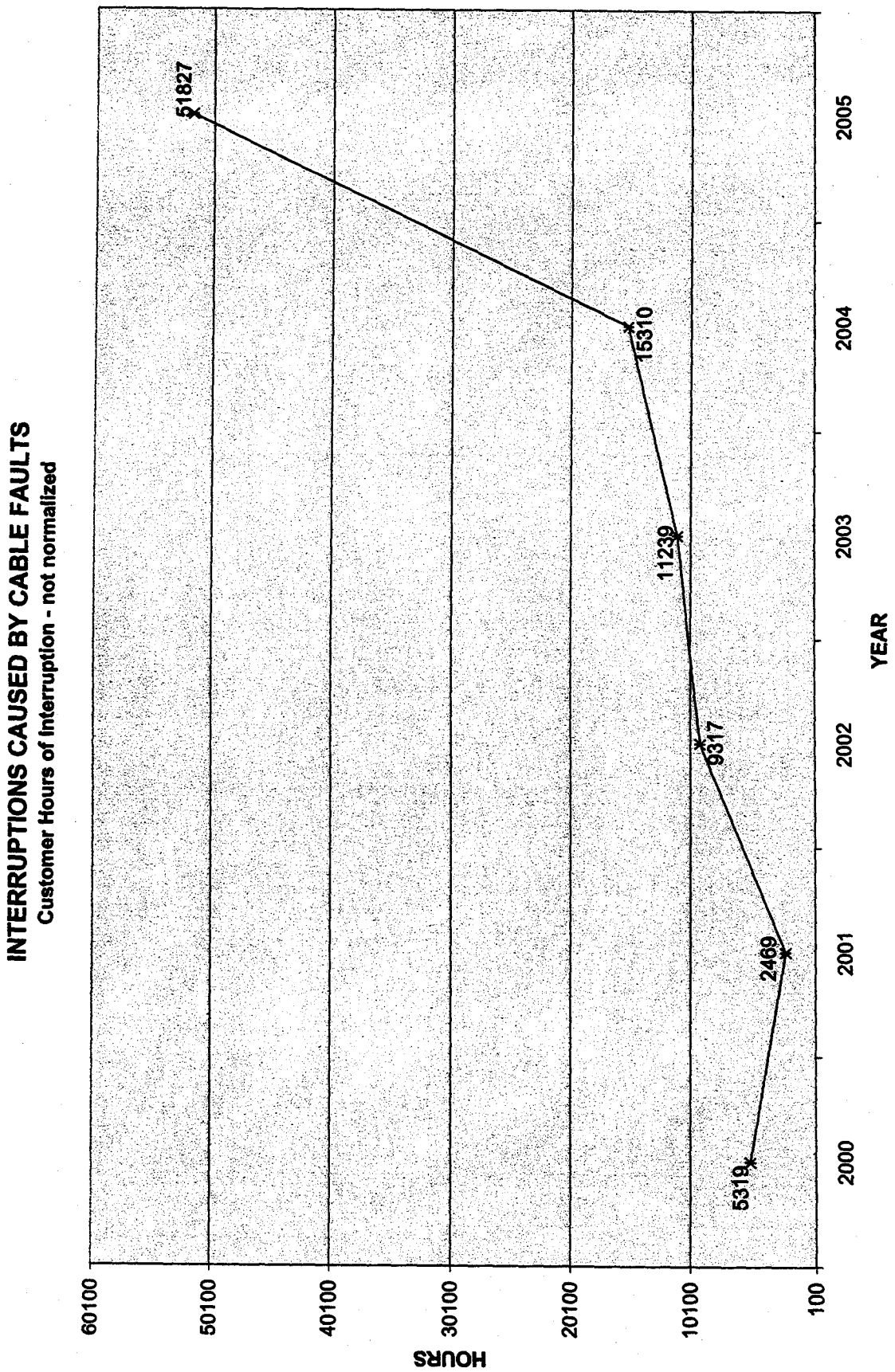

INTERRUPTIONS CAUSED BY AUTOMOBILE ACCIDENTS
CAID - not normalized
CAID
140
120
100
80
60
40
20
0
YEAR
2000
2001
2002
2003
2004
2005
69.04
90.09
56.9
121.22
115.08
115.13

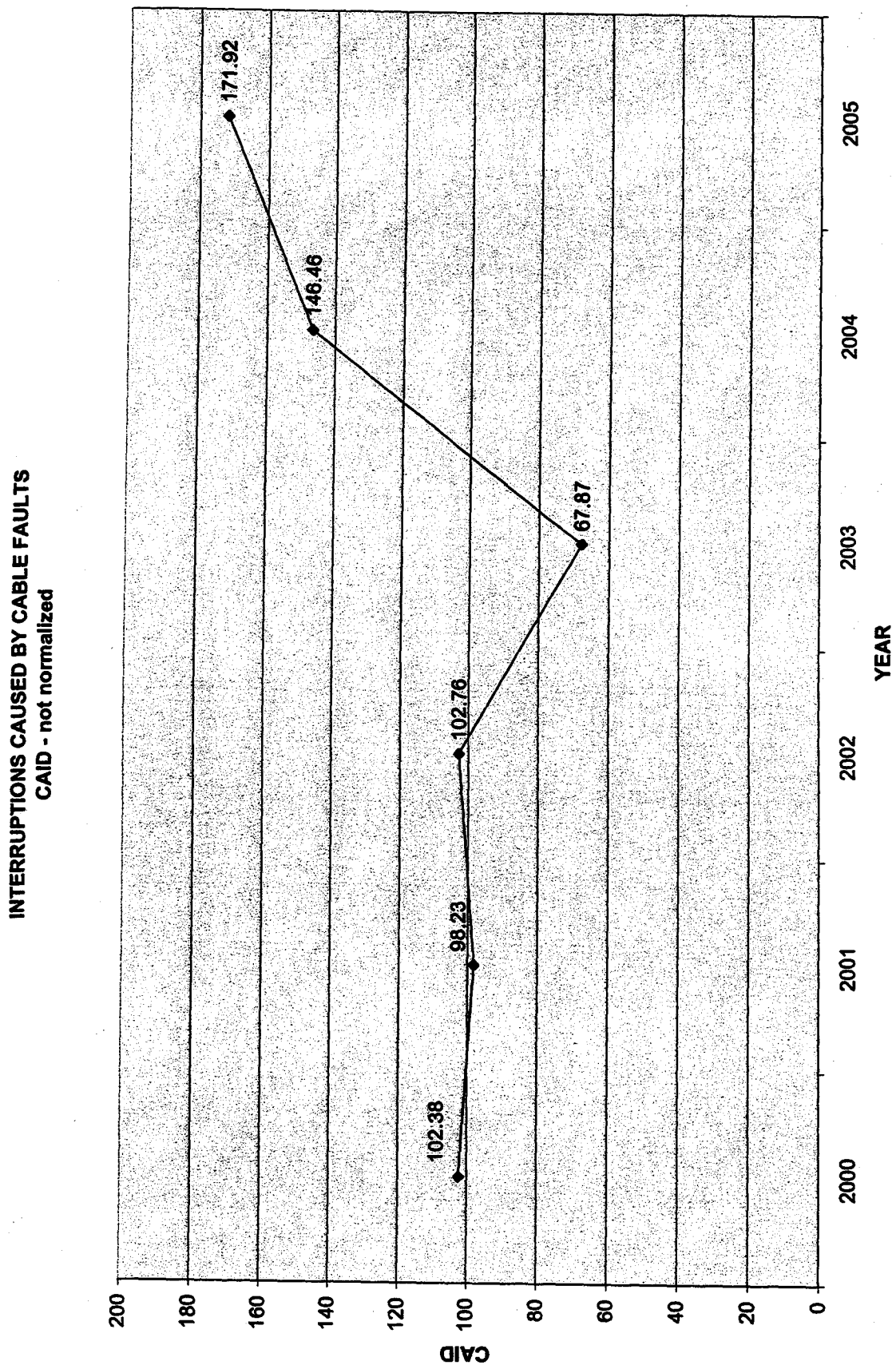

INTERRUPTIONS CAUSED BY AUTOMOBILE ACCIDENTS
SAIF - not normalized
SAIF
0.45
0.4
0.35
0.3
0.25
0.2
0.15
0.1
0.05
0
0.204
0.074
0.204
0.303
0.154
0.411
2000
2001
2002
2003
2004
2005
YEAR

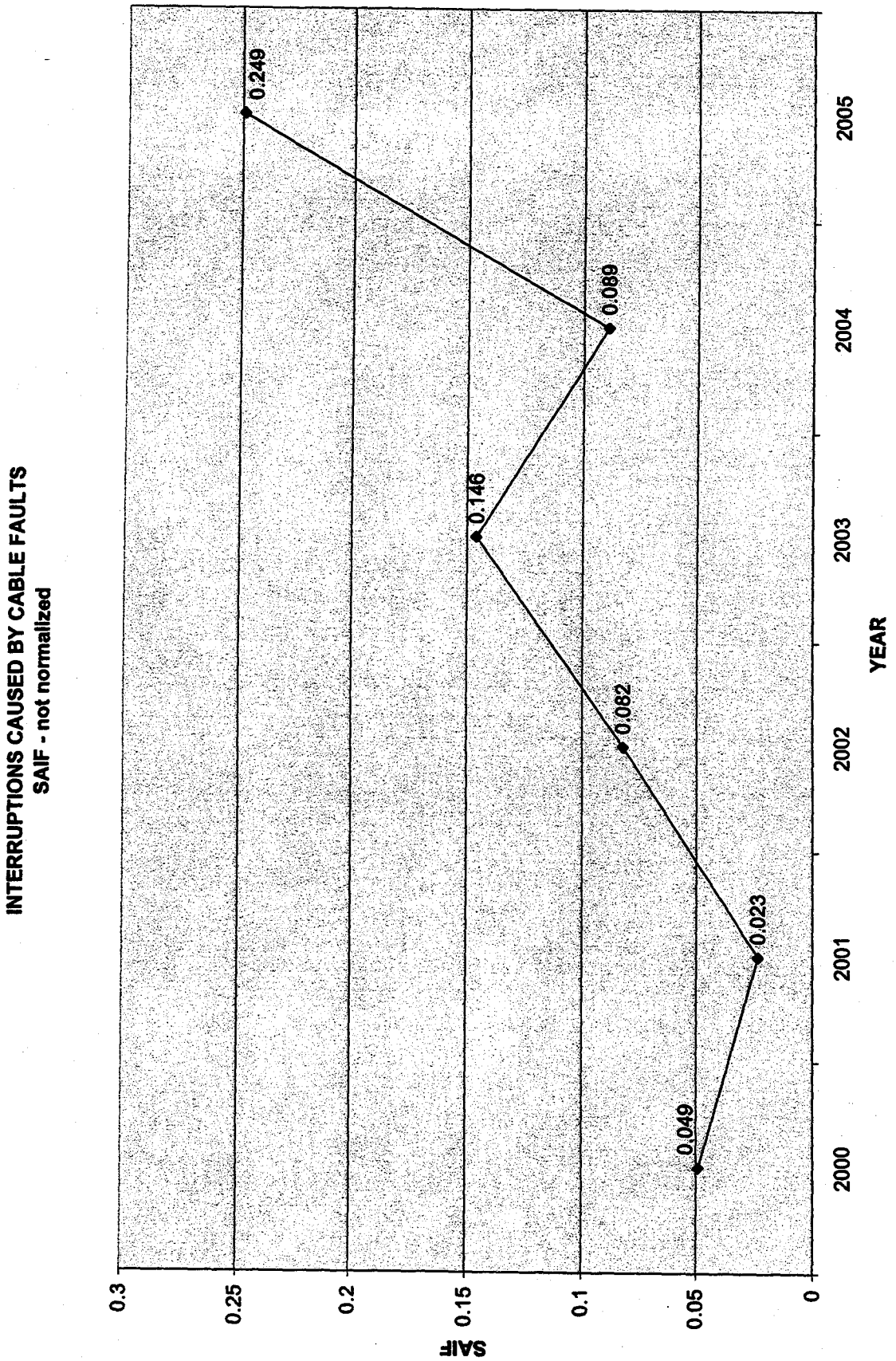

INTERRUPTIONS CAUSED BY HIGH WIND
Customer Hours of Interruption - not normalized
HOURS
45100
40100
35100
30100
25100
20100
15100
10100
5100
100
YEAR
2000
2001
2002
2003
2004
2005
988.6
7406.4
15626.5
27923.3
40441.7
5123.8

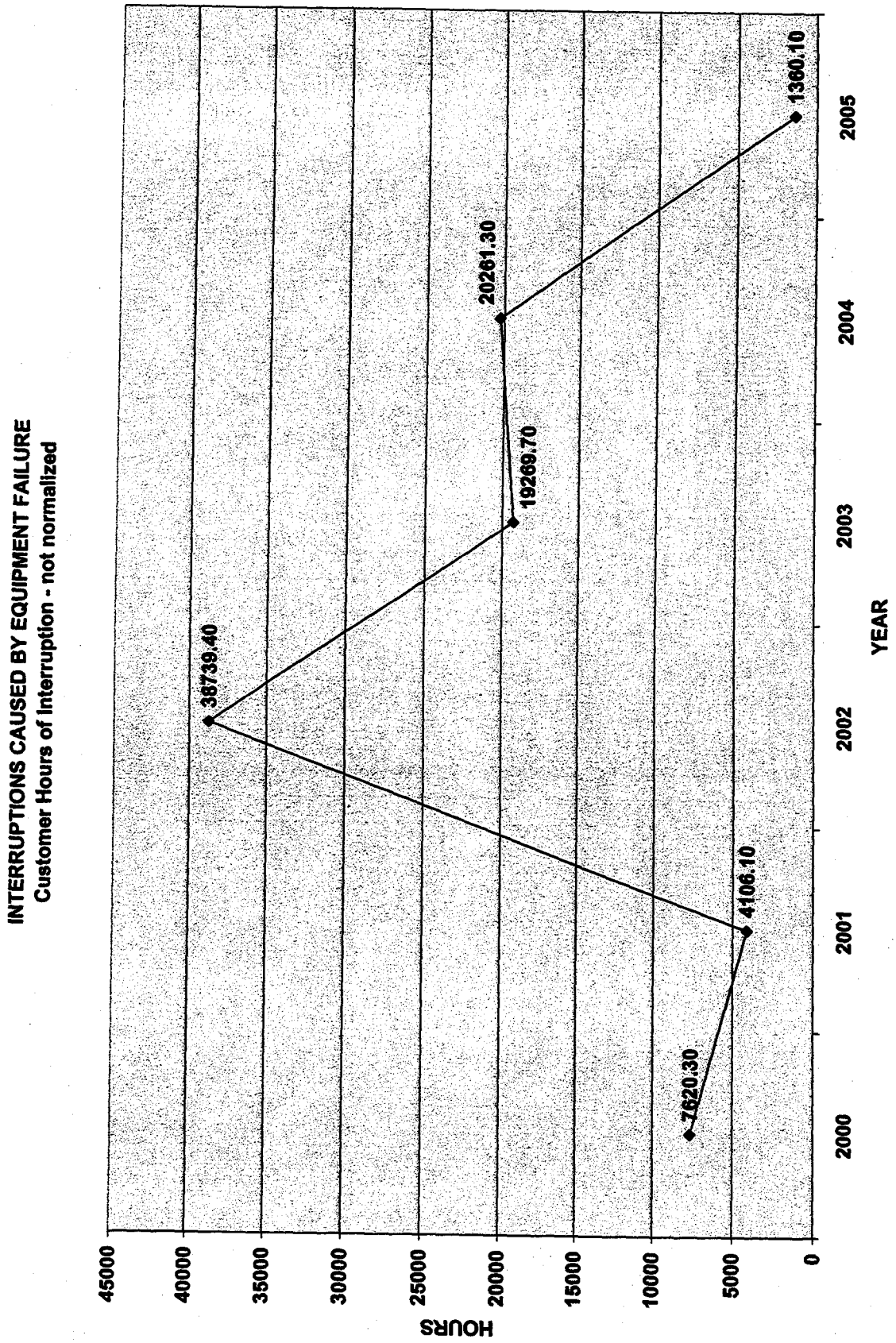

INTERRUPTIONS CAUSED BY HIGH WIND
CAID - not normalized
CAID
120
100
80
60
40
20
0
29.49
80.42
37.25
78.03
100.98
73.74
2000
2001
2002
2003
2004
2005
YEAR

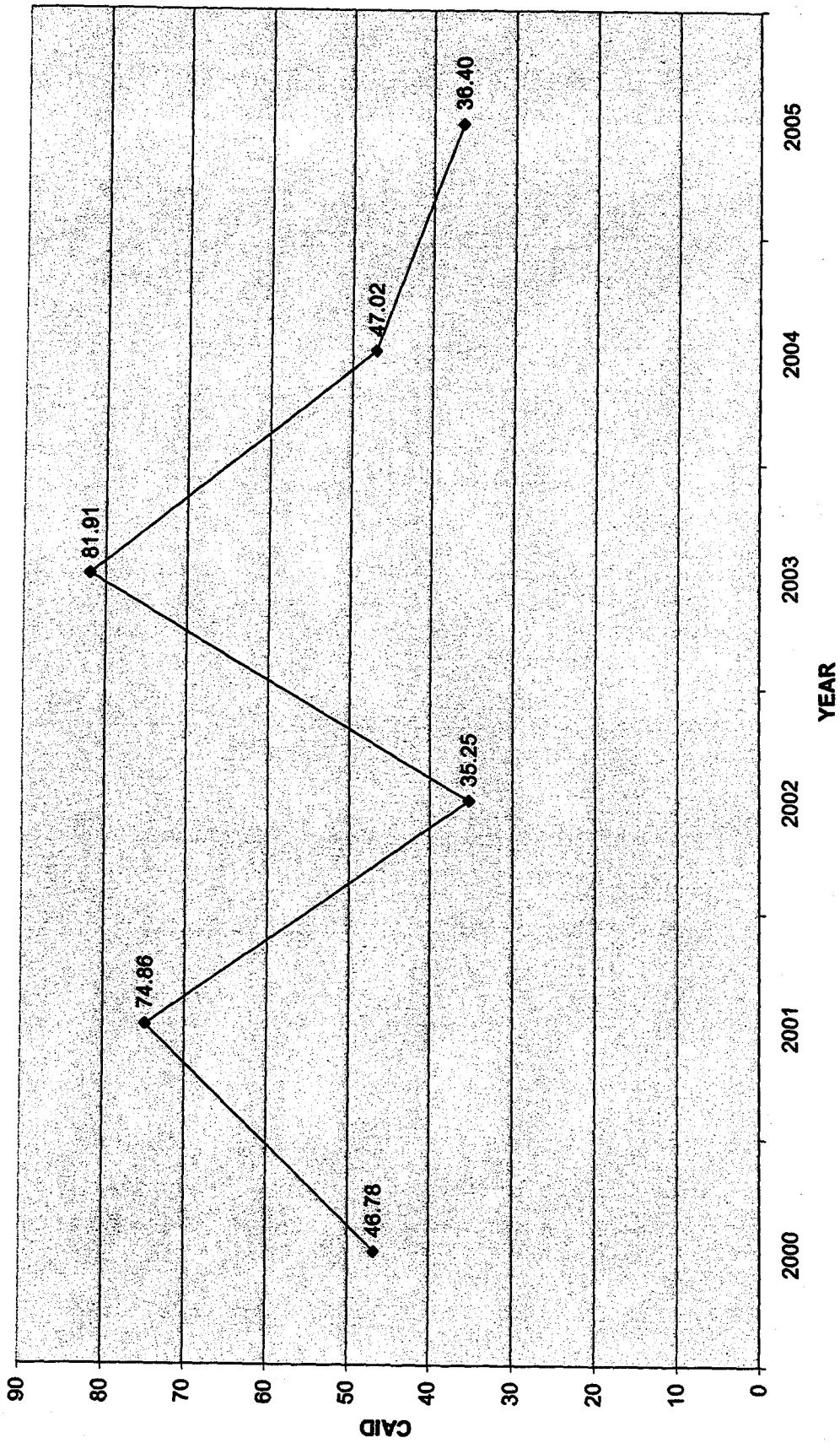

INTERRUPTIONS CAUSED BY HIGH WIND
SAIF - not normalized
SAIF
0.45
0.4
0.35
0.3
0.25
0.2
0.15
0.1
0.05
0
0.032
0.085
0.381
0.316
0.343
0.057
2000
2001
2002
2003
2004
2005
YEAR

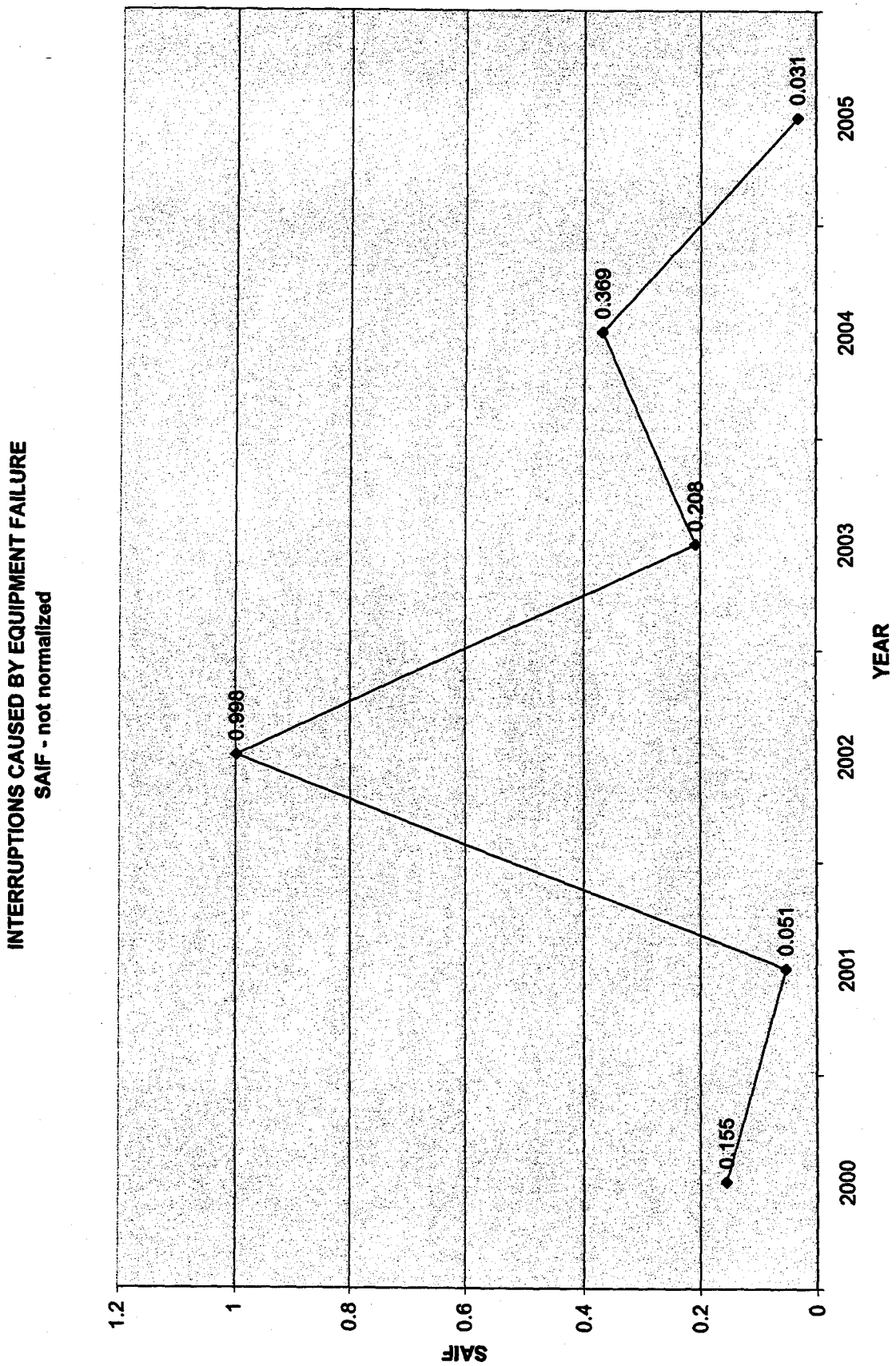

INTERRUPTIONS CAUSED BY CABLE FAULTS
Customer Hours of Interruption - not normalized
HOURS
60100
50100
40100
30100
20100
10100
100
YEAR
2000
2001
2002
2003
2004
2005
5319
2469
9317
11239
15310
51827

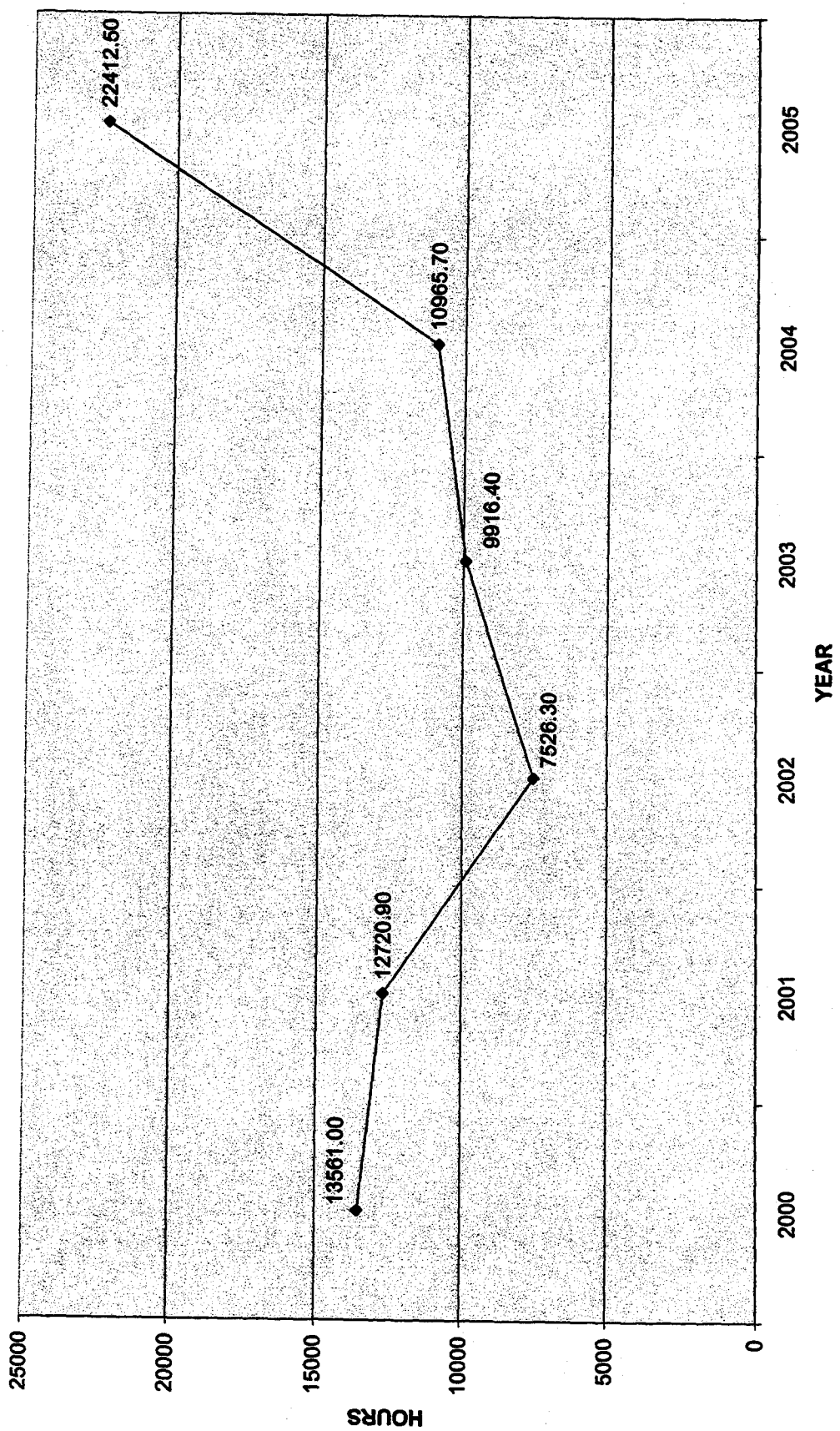

INTERRUPTIONS CAUSED BY CABLE FAULTS
CAID - not normalized
CAID
200
180
160
140
120
100
80
60
40
20
0
YEAR
2000
2001
2002
2003
2004
2005
102.38
98.23
102.76
67.87
146.46
171.92

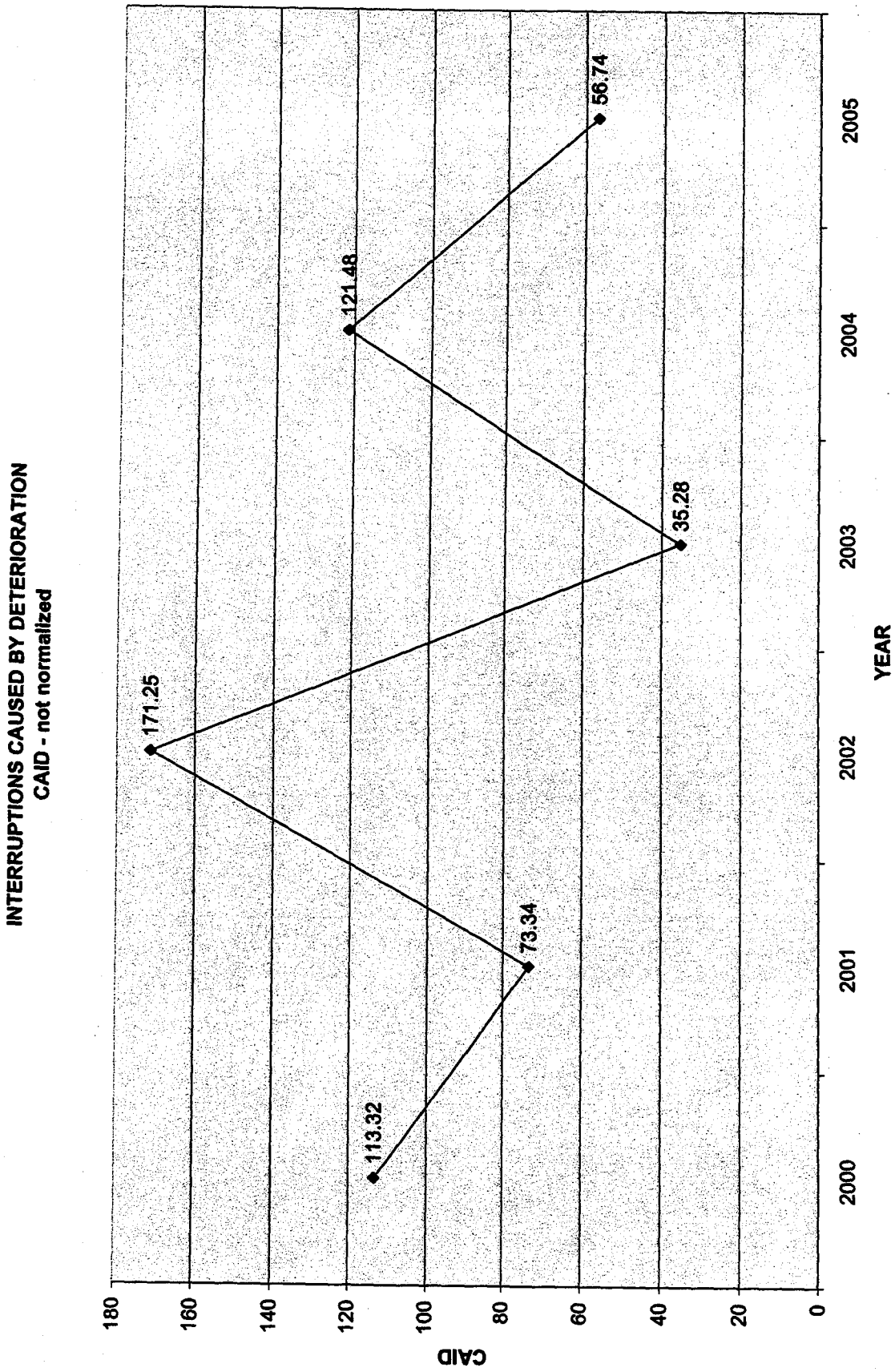

INTERRUPTIONS CAUSED BY CABLE FAULTS
SAIF - not normalized
SAIF
0.3
0.25
0.2
0.15
0.1
0.05
0
0.049
0.023
0.082
0.146
0.089
0.249
2000
2001
2002
2003
2004
2005
YEAR

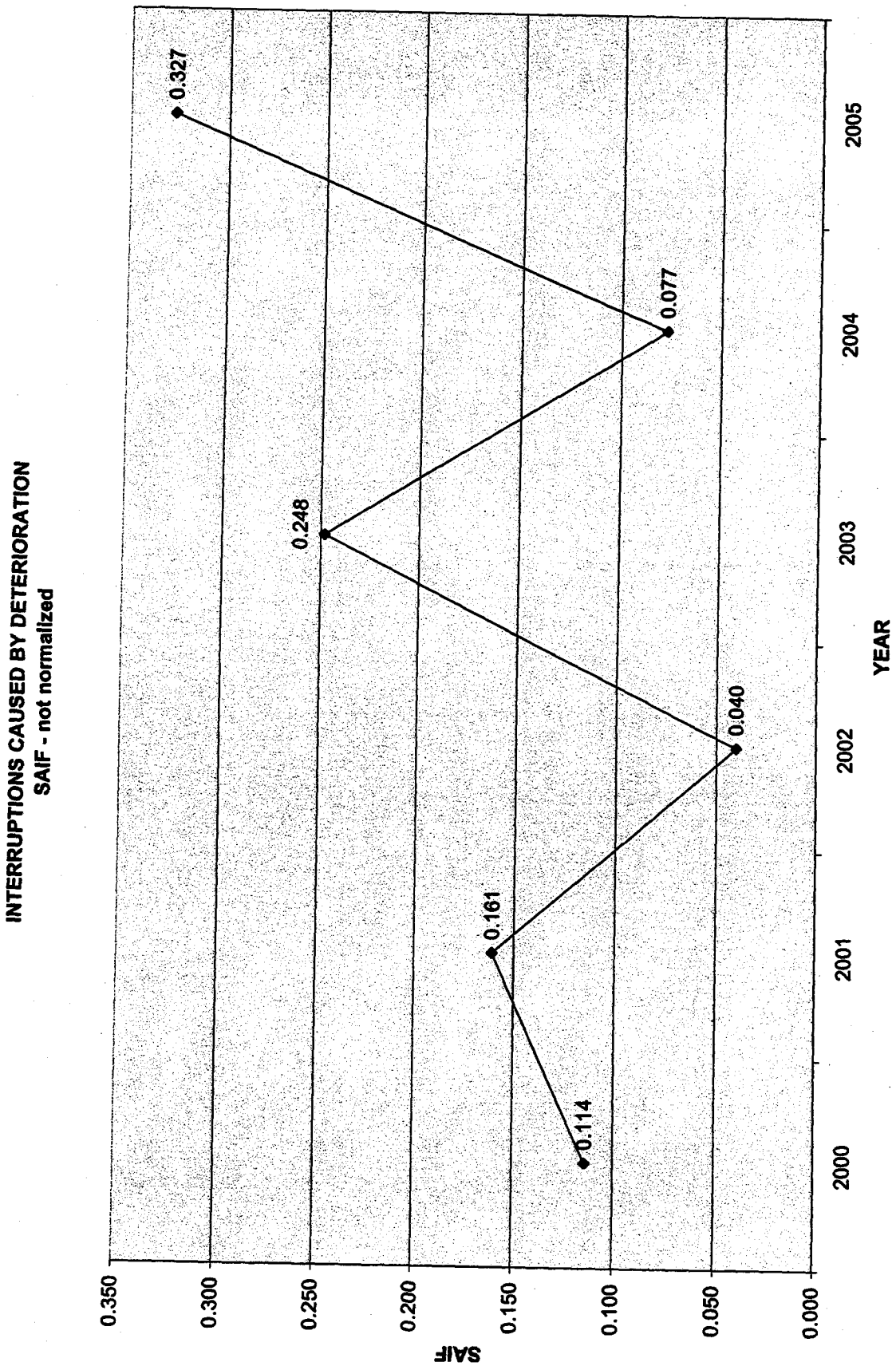

INTERRUPTIONS CAUSED BY EQUIPMENT FAILURE
Customer Hours of Interruption - not normalized
HOURS
45000
40000
35000
30000
25000
20000
15000
10000
5000
0
YEAR
2000
2001
2002
2003
2004
2005
7620.30
4106.10
38739.40
19269.70
20261.30
1360.10


INTERRUPTIONS CAUSED BY EQUIPMENT FAILURE
CAID - not normalized
CAID
90
80
70
60
50
40
30
20
10
0
46.78
74.86
81.91
35.25
47.02
36.40
2000
2001
2002
2003
2004
2005
YEAR


INTERRUPTIONS CAUSED BY EQUIPMENT FAILURE
SAIF - not normalized
SAIF
1.2
1
0.8
0.6
0.4
0.2
0
0.155
0.051
0.998
0.208
0.369
0.031
2000
2001
2002
2003
2004
2005
YEAR


INTERRUPTIONS CAUSED BY DETERIORATION
Customer Hours of Interruption - not normalized
HOURS
25000
20000
15000
10000
5000
0
YEAR
2000
2001
2002
2003
2004
2005
13561.00
12720.90
7526.30
9916.40
10965.70
22412.50


INTERRUPTIONS CAUSED BY DETERIORATION
CAID - not normalized
CAID
180
160
140
120
100
80
60
40
20
0
113.32
73.34
171.25
35.28
121.48
56.74
2000
2001
2002
2003
2004
2005
YEAR


INTERRUPTIONS CAUSED BY DETERIORATION
SAIF - not normalized
SAIF
0.350
0.300
0.250
0.200
0.150
0.100
0.050
0.000
YEAR
2000
2001
2002
2003
2004
2005
0.114
0.161
0.040
0.248
0.077
0.327

Hawaii Electric Light Company

Distribution Department

		2000 Total	2001 Total	2002 Total	2003 Total	2004 Total	2005 Total	2006 Budget	2006 Bud Adj	2006 Test Year	2005 2006 Diff
DIVISIONS:											
Administration	HDA	3	2	3	3	2	5	4	0	4	(1)
Technical	HDC	23	21	20	20	17	23	25	0	25	2
Hilo C&M	HDH	33	26	26	25	27	30	34	0	34	4
Kona C&M	HDK	18	17	20	18	20	22	27	0	27	5
Operations	HDR	8	8	8	7	9	9	9	0	9	0
Stores	HDS	7	7	7	6	6	6	7	1	8	2
Waimea C&M	HDW	19	14	14	12	13	14	16	0	16	2
		111	95	98	91	94	109	122	1	123	14

Hawaii Electric Light Company

Administration Employee Count

Position	RA	2000 Total	2001 Total	2002 Total	2003 Total	2004 Total	2005 Total	2006 Budget	2006 Bud Adj	2006 Test Year	2005 2006 Diff
Administration -	HDA										
Manager		1	1	1	1	1	1	1	0	1	0
System Forester		1	1	1	1	1	1	1	0	1	0
Distribution Administrator		0	0	1	1	0	1	1	0	1	0
Staff Engineer		1	0	0	0	0	2	1	0	1	(1)
		3	2	3	3	2	5	4	0	4	(1)

Hawaii Electric Light Company

Technical Division Employee Count

Position	RA	2000 Total	2001 Total	2002 Total	2003 Total	2004 Total	2005 Total	2006 Budget	2006 Bud Adj	2006 Test Year	2005 2006 Diff
Technical -	HDC										
Superintendent, Technical		1	1	1	1	1	1	1	0	1	0
Assistant Superintendent, Technical - Elect		0	1	1	1	1	1	1	0	1	0
Assistant Superintendent, Technical - Subst		1	1	1	0	0	1	1	0	1	0
Working Foreman		3	3	4	4	4	5	5	0	5	0
Electrician		10	8	9	9	5	7	7	0	7	0
Apprentice Electrician		1	1	1	2	2	2	1	0	1	(1)
Technician - Relayman		3	2	1	1	1	1	1	0	1	0
Lineman		1	1	1	1	1	1	1	0	1	0
Senior Helper		0	1	0	0	0	0	1	0	1	1
Helper		1	1	0	0	1	4	5	0	5	1
Material Coordinator/Clerk		2	1	1	1	1	0	1	0	1	1
		23	21	20	20	17	23	25	0	25	2

Hawaii Electric Light Company
Hilo C&M Employee Count

Position	RA	2000 Total	2001 Total	2002 Total	2003 Total	2004 Total	2005 Total	2006 Budget	2006 Bud Adj	2006 Test Year	2005 2006 Diff
Construction & Maintenance -	HDH										
Superintendent, C&M		1	1	1	1	1	1	1	0	1	0
Assistant Superintendent, C&M		2	2	2	2	2	2	2	0	2	0
Working Foreman		4	3	4	3	4	3	4	0	4	1
Lineman		19	16	14	13	13	12	13	0	13	1
Apprentice		0	0	0	2	3	3	3	0	3	0
Troubleman-Inspector		2	2	2	2	2	2	4	0	4	2
Serviceman		1	2	2	2	2	2	2	0	2	0
Senior Helpers		0	0	0	0	0	5	5	0	5	0
Helpers		4	0	1	0	0	0	0	0	0	0
		33	26	26	25	27	30	34	0	34	4

Hawaii Electric Light Company
Kona C&M Employee Count

Position	RA	2000 Total	2001 Total	2002 Total	2003 Total	2004 Total	2005 Total	2006 Budget	2006 Bud Adj	2006 Test Year	2005 2006 Diff
Construction & Maintenance -	HDK										
Superintendent, C&M		1	1	1	1	1	1	1	0	1	0
Assistant Superintendent, C&M		2	2	2	1	2	2	2	0	2	0
Administrative Assistant		0	0	0	0	0	0	0	1	1	1
Staff Engineer		0	0	0	0	0	0	1	0	1	1
Working Foreman		3	3	3	2	2	3	3	0	3	0
Lineman		9	9	8	8	8	5	5	(1)	4	(1)
Apprentice		0	0	0	1	4	3	3	0	3	0
Troubleman-Inspector		0	0	0	0	0	2	4	0	4	2
Serviceman		1	1	1	1	1	1	1	0	1	0
Senior Inspector		1	1	1	1	1	1	1	0	1	0
Senior Helpers		0	0	0	0	0	3	5	0	5	2
Helpers		0	0	4	2	0	0	0	0	0	0
Warehouse/Tool Room Attendant		1	0	0	1	1	1	1	0	1	0
		18	17	20	18	20	22	27	0	27	5

Hawaii Electric Light Company
Operations Employee Count

Position	RA	2000 Total	2001 Total	2002 Total	2003 Total	2004 Total	2005 Total	2006 Budget	2006 Bud Adj	2006 Test Year	2005 2006 Diff
Operations -	HDR										
Asst. Tech Superintendent, Operations		0	0	0	0	1	1	1	0	1	0
Clerk Dispatcher		1	1	1	1	1	1	1	0	1	0
Shift Clerk Dispatcher		5	5	5	5	6	5	5	0	5	0
Mapper		1	1	1	0	0	0	0	0	0	0
Senior Inspector		0	0	0	0	0	1	1	0	1	0
Inspector		1	1	1	1	1	1	1	0	1	0
		8	8	8	7	9	9	9	0	9	0

Hawaii Electric Light Company
Stores Employee Count

Position	RA	2000 Total	2001 Total	2002 Total	2003 Total	2004 Total	2005 Total	2006 Budget	2006 Bud Adj	2006 Test Year	2005 2006 Diff
Stores -	HDS										
Supervisor, Stores		1	1	1	1	1	1	1	0	1	0
Senior Warehouse Attendant		1	1	0	1	1	1	1	0	1	0
Warehouse Attendant		2	2	3	2	1	2	2	0	2	0
Toolroom Attendant Repairer		1	1	1	0	1	0	1	0	1	1
Materials Coordinator		1	1	1	1	1	1	1	0	1	0
Helper		1	0	0	0	0	0	0	0	0	0
Warehouse Toolroom Attendant Keahole		0	0	0	0	0	0	0	1	1	1
Store Keeper		0	1	1	1	1	1	1	0	1	0
		7	7	7	6	6	6	7	1	8	2

Hawaii Electric Light Company
Waimea Employee Count

Position	RA	2000 Total	2001 Total	2002 Total	2003 Total	2004 Total	2005 Total	2006 Budget	2006 Bud Adj	2006 Test Year	2005 2006 Diff
Waimea -	HDW										
Assistant Superintendent		1	1	1	1	1	1	1	0	1	0
Working Foreman		3	2	3	1	1	2	2	0	2	0
Lineman		9	8	6	6	6	3	5	0	5	2
Senior Inspector		1	1	1	0	1	1	1	0	1	0
Trouble Inspector		0	0	0	0	0	1	1	0	1	0
Serviceman		1	1	1	1	1	1	1	0	1	0
Apprentice		0	0	0	1	2	2	2	0	2	0
Senior Helper		0	0	0	0	0	2	2	0	2	0
Helper		3	0	1	1	0	0	0	0	0	0
Warehouse/Tool Room Attendant		1	1	1	1	1	1	1	0	1	0
		19	14	14	12	13	14	16	0	16	2

Hawaii Electric Light Company, Inc.

Contract Vegetation Management

line		A 2000 Recorded	B 2001 Recorded	C 2002 Recorded	D 2003 Recorded	E 2004 Recorded	F 2005 Recorded	G 2006 Test Year
1	Transmission Vegetation Expenses Contract Services ($ Thousands)	154,185	247,573	209,541	167,799	313,465	142,877	276,390
2	Distribution Vegetation Expenses Contract Services ($ Thousands)	997,599	832,043	1,189,847	726,160	794,950	1,397,303	1,191,762
3	Total Vegetation Expenses Contract Services ($ Thousands)	1,151,784	1,079,616	1,399,388	893,959	1,108,415	1,540,180	1,468,152

Source: HELCO-WP-612

Hawaii Electric Light Company, Inc.

Substation Preventive Maintenance

Substation infrared inspections	every 6 months	78 substations	50%	50%	
Maintenance of Priority 1 transformers	every 5 years	37 priority 1 transformers	29%	71%	
Transformer Dissolved Gas Analysis	every year	127 transformers	45%	50%	
Battery Maintenance	every 6 months	50 battery banks	75%	100%	
Distribution Breakers	every 2 years	112 distribution breakers	21%	75%	
Transmission Breakers	every 5 years	120 transmission breakers	46%	71%	
Relay Testing	Power plants every year, substations every 5 years (8 substations/year)	39 Substations	50%	113%	

Hawaii Electric Light Company, Inc.

Substation Averted Failures - 2003 to 2005

Station	Description	Year
Anaehoomalu	During scheduled preventive maintenance, Power Factor tests on CB 7102 were performed. Multiple bushings had high readings and CB 7102 was replaced.	2003
Halaula	Visual inspections revealed badly deteriorated insulators and structure members at the substation. During an annual planned outage of North Kohala, crews replaced deteriorated components on the structure and rebuilt the bus and replaced insulators as needed.	2003
Hawi	Visual inspections indicated the need to replace badly deteriorated support brackets and components on the structure. During an annual planned outage of North Kohala, crews replaced components as needed.	2003
Kaumana	During scheduled preventive maintenance, resistance tests were performed on CB 6502. Test results indicated a problem with the main contacts of the breaker. Further investigation revealed pitted contact rods, loose leaf springs on the contact and high resistance on the upper adapter. The contacts on CB 6502 were replaced and the upper adapter was cleaned.	2003
Islandwide	Systematically replacing all epoxy bushings on 69KV breakers prior to failure. These bushings have been identified by the manufacturer as needing to be replaced. Replaced Kaumana bushings in 2004. Three breakers remain.	2004
Pohoiki	During routine infrared inspections of the substations, discovered multiple "hot spots". Scheduled and addressed "hot spots" on 6501LD, 8701LD and CB 6501.	2004
Puna	During routine infrared inspections of the substation, discovered multiple "hot spots". Scheduled and addressed "hot spots" on the breaker and line.	2004
Shipman	Breaker maintenance revealed high PF readings on the B-bus 13.8KV breakers indicating high moisture content and leakage. Attempted to remove moisture in a dehumidifying chamber. Test results improved but were still unacceptable. Replaced 4 breakers prior to failure.	2004
Various	Replaced transformer bushings with high power factor readings - Orchid Isle, Keahole Airport, Kilauea 69/34KV, Kauhale, ordered spare bushings for inventory. 2004 and 2005	2004
Various	Inspections discovered deteriorated fence posts at the base and below grade. Repaired/replaced substation fencing prior to failure - Wright Road, Kilauea, Kanoelehua, Leilani, Pepeekeo, Puukapu, Honokaa, Laupahoehoe, Mauna Lani, Anaehoomalu, Host Park, Kealakehe, Kahaluu and Kealia. 2004 and 2005.	2004

Hawaii Electric Light Company, Inc.		
Substation Averted Failures - 2003 to 2005		
Station	**Description**	**Year**
Kanoelehua	Through routine transformer oil dissolved gas and moisture analysis, discovered a problem with Unit 3 at Kanoelehua. The gassing transformer was removed from service and the problem was later found and repaired. A loose connection in the LTC was causing arcing to occur in the transformer.	2005
Kanoelehua	Through breaker maintenance, discovered an over-travel problem and signs of arcing on 13.8KV converted vacuum breakers in Bldg 6. Purchased ten new 13.8KV breakers to replace breakers with known problems. Breakers are similar to the generator breaker that failed and started a fire at Shipman Plant.	2005
Kaumana	Through routine infrared inspections, discovered multiple "hot spots" on the 69KV bus and disconnects. Investigation found that dissimilar metals at connection points were corroding and causing the "hot spots". The connections were cleaned, transition plates were installed and a follow-up infrared scans performed to ensure problems were addressed.	2005
Kaumana	Fixed leaking oil tank on CB 6102 through planned breaker maintenance. The circuit breaker required extensive repair to the tank.	2005
Keauhou	Through visual inspections, discovered signs of tracking on fiber boards in the transition cabinet. Replaced on scheduled outage of substation.	2005
Maliu Ridge	During the scheduled annual maintenance outage of North Kohala, replaced fiber boards and redesigned transformer secondary cable terminations to eliminate fiber boards that have failed twice due to high moisture in the area.	2005
Papaaloa	Visual inspections reported badly deteriorated primary tranformer fuse structure. Outaged substation to replace deteriorated fuse structure.	2005
Pohoiki	Routine infrared inspections revealed multiple "hot spots" on the 69KV bus and connectors. Addressed hot spots and verified with follow-up infrared scans that problems were addressed.	2005
Puna	Addressed high power factor readings on CB 3401 through planned breaker maintenance.	2005
South Point	Discovered signs of tracking on fiber boards in the transition cabinet during visual inspections. Replaced on scheduled outage of substation. Additional work scheduled to replace deteriorated transition cabinet.	2005
Various	Established a minimum five-year ten 69KV breaker replacement program to replace aged and obsolete three-tank breakers prior to failure. Replaced CB 7701 and 6802. Breakers were very old and protected important transmission lines.	2005

HELCO Contract Pole Inspections

	2003 Actual	2004 Actual	2005 Actual	2006 Forecast
Poles Inspected	2,518	0	4,684	4,300
Inspection Cost	$163,854	0	$313,191	$297,625
Poles Replaced	45	0	21	
Poles Restored	4	72	66	

Source: HELCO-WP-613

Hawaii Electric Light Company, Inc.
AVERTED FAILURES
2005
Problems found by Aerial Inspections

Problem Description	Comments/Averted Failure
Line 6600 P-238, Neutral conductor on cross arm due to broken tie wire (TC#501207K, 3/18/2005).	Repaired 3/21/2005 Averted fault on Line 6600 (cross island tie) and voltage problems in South Kona
Line 6600 P-248, deteriorated cross arm (TC#501207K, 3/18/2005)	Repaired 3/21/2005 Averted fault on Line 6600 (cross island tie) and voltage problems in South Kona
Line 6600 P-313, deteriorated 1118 insulators (TC#501211K, 3/18/2005)	Repaired 3/22/2005 Averted fault on Line 6600 (cross island tie) and voltage problems in South Kona
Line 6800 P-4, Conductor touching pole (TC#502348K, 6/8/2005)	Repaired 6/13/2005 Averted fault on Line 6800
Line 6800 by old pump house, transformer bank sweating (TC#502348K, 6/8/2005)	Removed unsigned service 6/13/2005 Averted oil spill and environmental clean-up
Line 6300 between P-104 and P-105, broken 101 ASCR static wire strands (TC#503760H, 9/12/2005)	Repaired 9/12/2005 Averted fault on Line 6300 and interruption to customers serviced by Kawailani, HPP and Kapoho Substations
Line 8500 P-65, broken insulator saddle clamp (TC#504962W, 11/28/2005)	Repaired 12/2/2005 Averted fault on Line 8500 (cross island tie)

Hawaii Electric Light Company, Inc.
2006 Test Year
Major Capital Projects for T&D Reliability Improvement

2001

TRANSMISSION

H1012000 2001 Unit Tsf Spare 1 $323,040.83

A new spare transformer was purchased to serve as a spare for the existing Kanoelehua transformer. This spare unit was eventually installed at Kahaluu Substation after a transformer failed in 2002.

H0000347 6600 Line Upgrade Phase 1 $262,344.54

Poles for the 6600 line , 69kv transmission line (Kilauea Switching Station to Kealia Switching Station) that were not in compliance with General Order 6 wind loading requirements were replaced.

DISTRIBUTION

H0000339 HPP Sub Upgrade $157,717.24

The project was done to increase the capacity at Hawaiian Paradise Park substation from 2.5 mva to 7.5 mva and convert the substation source from 34.5kV to 69KV. The project replaced 3-833kVA , 34.5 -12.47kv transformers with one 69-12.47kV, 7.5MVA transformer. The scope of the project required the installation of a new transformer pad and upgrade of the 12kV bus structure and conductors for 7.5MVA capacity. The structure and conductor upgrade also eliminated clearance problems.

The prior HPP transformers were frequently overloaded as the demand readings were near 150%. The upgrade in transformer size alleviated the overloading problem and provided capacity for growth in the area. Being served off the 69kV also improved reliability for the HPP customers and reduces the load on the Puna 69-34.5 kV transformers.

Additional capacity at HPP also simplified operational switching situations and provided backup for Ainaloa, Kurtistown and Panaewa. Finally, existing clearances to primary conductors were brought up to safety standards.

H0000390 Milo St Conversion $244,066.37

The Milo Street conversion project converted 2.4 KV distribution system along Milo street, just outside of Keaau town to the 12.47kv distribution voltage standard. The conversion was prompted by new customer loads in the area but it also replaced older hardware and conductors that were prone to failure and created circuit tie capability to Panaewa, Kurtistown and HPP substations.

Hawaii Electric Light Company, Inc.
2006 Test Year
Major Capital Projects for T&D Reliability Improvement

2002

DISTRIBUTION

H0000345 Naalehu Conversion Ph 2 $194,233.40
Conversion 4.160Y KV to 12.47/7.2 KV distribution system.

H0000651 Rpr Paauhau CP $104,852.66
This project relocated an older, substandard distribution pole line that was inaccessible by line construction equipment. The distribution pole line was located between rows of houses and posed a potential hazard to residents. The relocation of the line created a safer and more reliable distribution system in the area.

H0000656 Mauna Kea Beach MOU $195,795.91
The handholes in the underground distribution system serving the Mauna Kea Beach Resort area were upgraded to meet current standards. Ground rods were installed in the handholes to comply with safety requirements. A 12.47kv circuit tie to the Ouli substation was installed to reduce service interruption times in the event of an outage.

2003

TRANSMISSION

H0000186 Volcano Natl Park Conv $113,538.97
A total of 4 sub-transmission poles were relocated away from a fissure near the Volcano National Park boundary. The fissure posed a safety hazard to line personnel who were often required to respond to the area during evening hours. The relocation of the poles also reduced exposure to corrosive fumes that emanated from the fissure improving reliability of the subtransmission line.

H0000783 Punaluu-Pahala 69KV Insul $126,909.25
This project replaced 69 kv transmission strain-insulators between the Punaluu Resort area and Pahala town. The strain insulators required replacement because of frequent failures due to deterioration of galvanized metal pieces on the porcelain insulators. The insulators caused faults on the transmission line serving communities in Pahala, Punaluu, Naalehu, South Point, Hawaiian Ocean View and Kealia.

Hawaii Electric Light Company, Inc.
2006 Test Year
Major Capital Projects for T&D Reliability Improvement

H0000804 RPR Hilo 6400 Line $148,997.80
Portions of the 6400 line (Puna Switching Station to Kanoelehua Switching Station) were reconductored from existing #4/0 and 336.4 MCM AAC conductors with #556.4 MCM AAC. The reconductoring provided contingency for the loss of other transmission lines such as the 6300 (Kanoelehua to Kilauea), 6500 (Pohoiki to Kaumana), and 8700 (Pohoiki to Puna). Part of the project also replaced strain insulators that were prone to failure due to deterioration.

DISTRIBUTION
H0000854 Kapoho Beach Lot Rpl $138,626.38
A portion of the Kapoho Beach Lots subdivision was rebuilt due to corrosion to metal fixtures, hardware, anchors, guy wires and conductors. The close proximity to salt spray prompted the use of stainless steel hardware for the replacement pole line.

2004

TRANSMISSION
H0000759 Royal Hawaiian Sub Upgrade $274,000.60
This project upgraded the Royal Hawaiian Substation from single phase substation to three phase substation. The capacity of the substation was increased from 833 KVA to 2.5 MVA to serve the growing load in upper Puna. The upgrade required the installation of new structures, ground grid, fencing and regulators. The upgrade allows back up to the adjacent Orchid Isle substation.

H0001023 Shipman Plt 5.4 MVAR Cap Bank $131,656.58
A 5.4MVAR capacitor bank was installed at Shipman Plant to provide voltage support on the 13.8KV system in the Hilo area. The bank was built with three 1.8MVAR groups that could be switched independently. Installation of the capacitors at Shipman Power Plant avoids the use of diesel generating units at Kanoelehua to provide voltage support. This is especially critical during overhauls of the Steam Units at Kanoelehua. The capacitor units at Shipman Plant also allow maintenance of the capacitor units at Kanoelehua.

Hawaii Electric Light Company, Inc.
2006 Test Year
Major Capital Projects for T&D Reliability Improvement

DISTRIBUTION

H0000448 Kauhale Sub Upgrade $241,099.54

A 5.0 MVA transformer was installed at Kauhale substation to serve the growing load in the area. The installation of the substation also provided partial back up capability to the Puueo Substation. The loads were redistributed between Puueo substation and Kauhale substation to reduce circuit exposure to the Puueo circuit customers. The project involved the installation of a new 5.0 MVA, 69 – 12.47kV transformer with LTC, 69kV fused disconnects, 69kV lightning arrestors, 15kV recloser and wood pole structures to provide a new 12.47kV circuit. Construction of a transformer pad, substation grounding, duct lines and new fencing were also required. The upgrade of the substation also raised clearances to meet present safety standards.

H0000817 Kapoho Substation Grounding $150,935.92

The Kapoho substation grounding was upgraded to improve relay detection and clearing of ground faults. The upgrade of the substation grounding increased safety for HELCO personnel while within the substation and improved public safety to increase probability of fault clearing during down conductor situations.

H0000854 Kapoho Beach Lot Rpl $100,330.55

A portion of the Kapoho Beach Lot subdivision was rebuilt to replace corroded hardware, conductors, guy wires and anchors due. The close proximity to salt spray prompted the use of stainless steel hardware to prevent corrosion problems. The rebuild of the distribution system improved reliability and safety of the distribution system.

H0000957 Keahole-Host Park UG Feed $223,443.36

This project installed underground infrastructure related to the 12.47 KV overhead Host Park to Keahole tie line circuit. The new underground circuit installation consisted of excavating trenches and installing new duct packages, a 5 way vacuum switch at Keahole, new 15KV 1000MCM conductors, riser poles and riser pole terminations at Host Park and Keahole Substations.

H0001019 Kealakehe Substation Upgrade $143,029.61

The capacity of Kealakehe substation was increased from 5MVA to 10MVA to meet growth in the area and also to enable transfer of loads from Kaloko and/or Kailua Substations. The increase in Kealakehe Substation capacity will help to transfer loads off of Huehue Substation as well. The project also required the replacement of the reclosers.

Hawaii Electric Light Company, Inc.
2006 Test Year
Major Capital Projects for T&D Reliability Improvement

H0001072 Puueo 13.8kV Upgrade $560,344.06
The Puueo Switching station 13.8kv switchgear upgrade allowed the removal of a steel substation structure that posed a safety hazard to HELCO personnel. 13.8kv overhead conductors were re-routed to provide clearance from the power plant building in the area. The switchgear upgraded also replaced older instrumentation that was prone to failure.

2005

TRANSMISSION
H0000832 Kailua SW Sta-19.2 MVAR Cap $1,211,277
A 19.2MVAR 69KV capacitor bank was installed at Kailua switching station to provide voltage support in West Hawaii. A study by HECO transmission planning identified possible undervoltage conditions for loss of certain transmission lines and/or generation. The installation of the capacitor bank mitigates the undervoltage risk in West Hawaii.

DISTRIBUTION
H0000648 RPL Kona (Palisades) $586,776
Direct buried underground cables were replaced in a portion of the Kona Palisades subdivision because of frequent cable faults. Approximately 2,150ft of #2 PEICN primary UG cable from T807 on Ahi Ahi St. to T806 on HoloHolo St. were replaced. Scope of work included the excavation of 2,480 feet of trench in the road easement, installation of 9 hand holes, concrete encased ducts, and repair of driveways and roadway.

H0001120 Kuakini Unit Sub 2 $499,012
A second 10.0 MVA substation transformer was added at Kuakini substation to serve the growing load in the area. The second unit also provides capability to transfer loads from adjacent substations to expedite power restoration during service interruptions. New steel structures, concrete pads, switchgear and a 12.47kv underground cable system were also required as part of this addition.

H0000445 Poopoomino #2 Tsf $826,699
A second 10 mva transformer was added at Poopoomino Switching station to serve the growing loads in the Hualalai Resort area. The second unit also provides backup capability to the first unit. A 69kV circuit switcher, transformer differential relaying, 15kV switchgear with dual feeders, 5-way vacuum switch, associated concrete pads, handhole, and ductlines were also installed as part of this project.

Hawaii Electric Light Company, Inc.
2006 Test Year
Major Capital Projects for T&D Reliability Improvement

H0001105 Transformer Mobile Substation $438,952
A 14.5 mva transformer for HELCO's mobile substation was purchased and installed. The mobile substation improves our contingency plan for reliability of substations without backup service. In addition, the mobile substation allows for maintenance of substations which otherwise would not be able to be taken offline.

H3406000 Recloser Upgrades $302,926
Outdated type R reclosers were replaced. The new reclosers are equipped with electronic controls that provide improved circuit protection and coordination, making the distribution system safer and more reliable. The type R reclosers were also more difficult to operate and posed safety hazards during bench testing.

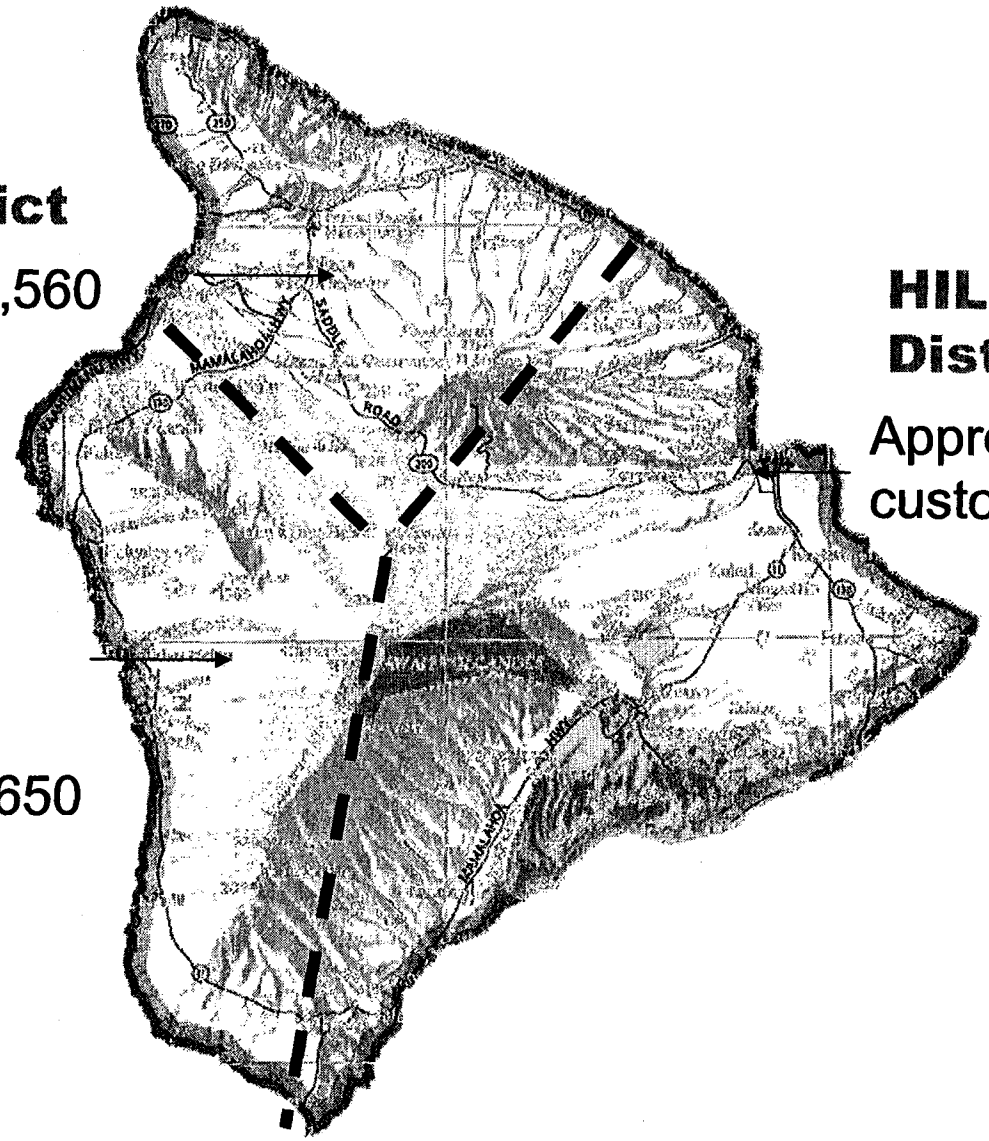
HELCO Districts

WAIMEA District

Approximately 12,560 customers

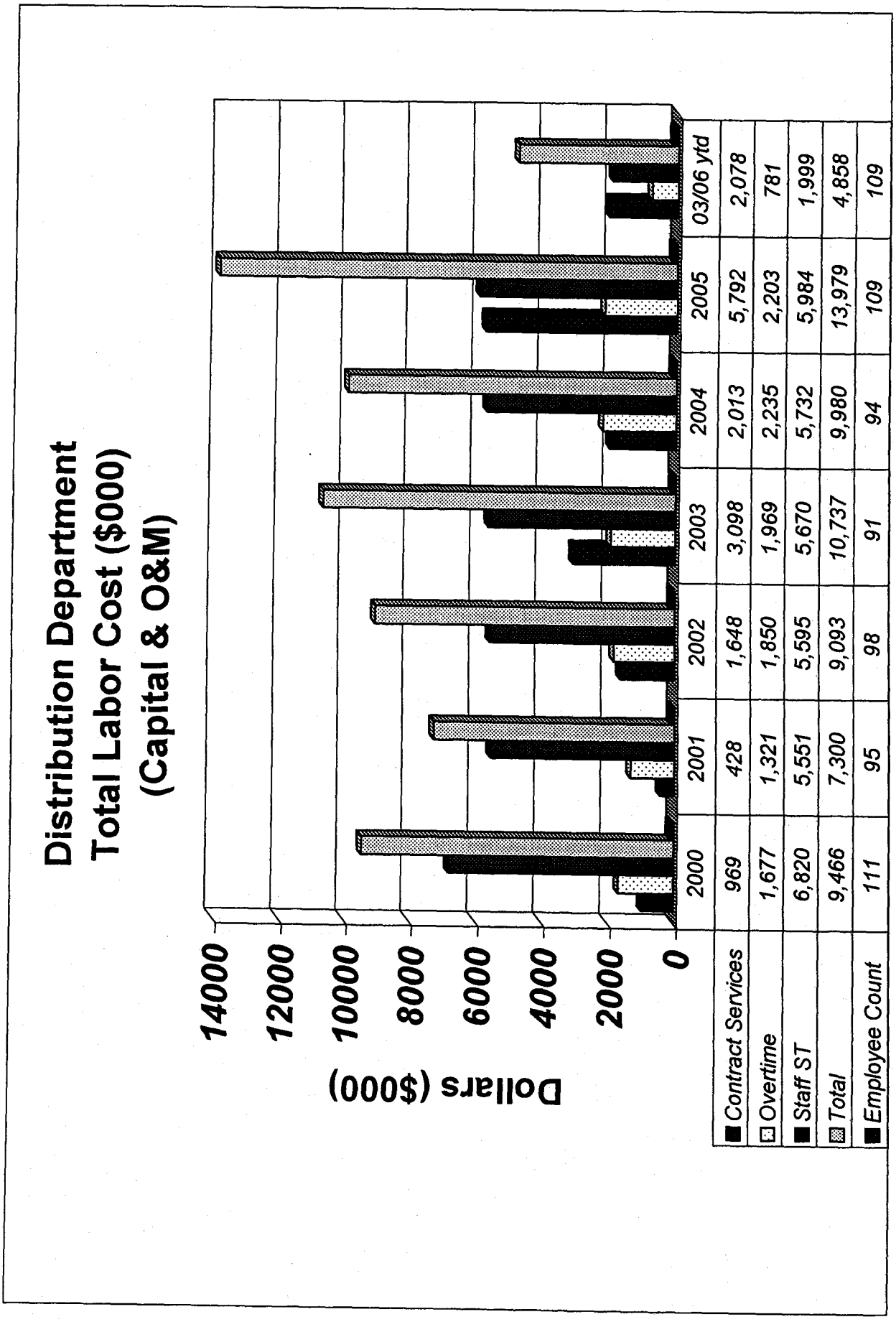
KONA District

Approximately 23,650 customers



HILO District

Approximately 36,310 customers



	2000	2001	2002	2003	2004	2005	03/06 ytd
Contract Services	969	428	1,648	3,098	2,013	5,792	2,078
Overtime	1,677	1,321	1,850	1,969	2,235	2,203	781
Staff ST	6,820	5,551	5,595	5,670	5,732	5,984	1,999
Total	9,466	7,300	9,093	10,737	9,980	13,979	4,858
Employee Count	111	95	98	91	94	109	109

TOTAL LABOR COST
O&M and Capital
BACKUP DATA

		2000	2001	2002	2003	2004	2005	03/06 YTD	
See below	Contract Services	969000	427,631	1,648,135	3,098,171	2,013,471	5,791,614	2,077,382	
	Penalty	70922.13	64,060	72,476	100,806	147,320	204,678	73,322	
Payroll Recap Dist. Dept.	Overtime $100K	1606376.84	1,256,704	1,777,961	1,867,772	2,087,711	1,998,155	708,086	
Payroll Recap Dist. Dept.	Staff ST $100K	6819955.58	5,551,205	5,595,343	5,670,114	5,732,372	5,984,089	1,998,205	
	Total	9466254.55	7,299,600	9,093,915	10,736,863	9,980,875	13,978,536	4,856,995	
	Employee Count	111	95	98	91	94	109	109	
	Contractor Costs:								
substation construction	ACA Services							8,460	
substation construction	Electrical Services							10,344	
line construction	PAR		0	0	0	0	3,513,093	1,551,451	
line construction	Mauna Kea		427,631	1,648,135	2,924,777	1,240,336	1,099,212	191,310	
line construction	Telecable		-	-	-	491,327	1,179,309	315,817	Note: as of 11/04 line construction
line construction	Asplundh		-	-	173,394	281,808	-	-	
	Total		427,631	1,648,135	3,098,171	2,013,471	5,791,614	2,077,382	
	Total Overtime	1677298.97	1320764.11	1850437.37	1968578	2235031.71	2202832.83	781408.18	

Hawaii Electric Light Company, Inc.

TRANSMISSION & DISTRIBUTION EMPLOYEE CHANGES

line		A	B	C	D	E	F	G
		2000 Recorded	2001 Recorded	2002 Recorded	2003 Recorded	2004 Recorded	2005 Recorded	2006 Forecast
1	T&D Employees (Beginning Year)	108	111	95	98	91	94	109
2	New Hires	14	2	11	7	9	20	14
3	Separations	11	18	8	14	5	8	--
4	Transfers In	1	3	2	1	3	6	--
5	Transfers Out	1	3	2	1	4	3	--
6	T&D Employees (Year End)	111	95	98	91	94	109	123