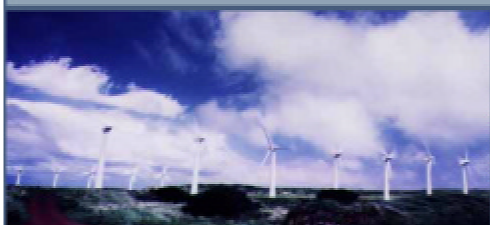
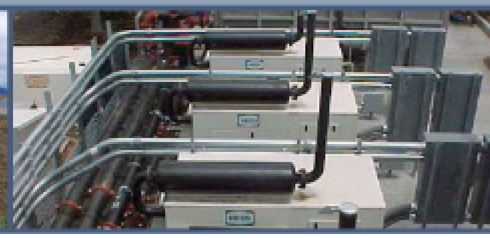
Managing High Saturations of Distributed Energy Resources (DER) as a Microgrid on the Big Island of Hawaii





Prepared by:

Hawaii Electric Light Company

a subsidiary of

Hawaiian Electric Company, Inc.

in conjunction with

SENTECH, INC.

Sponsored by:

U.S. Department of Energy

State of Hawaii
Department of Business,
Economic Development and Tourism

DBEDT

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Executive Summary

The electric generation, transmission and distribution system on the Big Island of Hawaii faces complex reliability, environmental, and economic issues. While the west side of the island is experiencing rapid load growth, the majority of power plants are located on the island's east side. Recent load surveys indicate that at the day and evening peaks, approximately 50% of the load demand is on the West side. At minimum load, 54% of the load is on the West side. Only 21% of the installed capacity is located on the West side. Thus the West side load is supported from the East side generation through the cross-island transmission system. There are a limited number of cross-island transmission lines. Some of these lines have low ampacity ratings and three are already operating at or near capacity. This can lead to voltage or stability problems during atypical generation dispatch or transmission configurations. In several cases, a single line outage or loss of a single critical generator can create line overloads and low voltages in the West side transmission system.

These challenges have resulted in HELCO's investigating various technological options that may help reduce costs and improve system reliability. In an effort to address these issues, the Hawaii Electric Light Company (HELCO), the island's electricity supplier, together with the State of Hawaii Department of Business, Economic Development and Tourism (DBEDT) conducted this study, funded by the US Department of Energy, to assess the potential impact of distributed energy resources (DER) on the island's electric system. The study examines how on-site power generation, including combined heat and power, at high load growth sites could lessen the transmission system challenges caused by the large West-side load being served primarily by East-side generation. The primary objective of the study is to ascertain whether a micro-grid approach – with DER on the distribution system and at customer locations, and controlled by the utility's centralized computer control system – is a technically and economically viable option to reduce the operating issues and constraints faced by the island's current electric network.

Sites on the Island of Hawaii with the greatest potential to utilize DER technologies to reduce HELCO's peak loads were identified. Technical (load flow analysis) and economic assessments were made for each of those sites. By looking at potential DER technologies as parts of integrated hybrid systems, dispatched by HELCO as a micro-grid, many functions could be combined to offer benefits to the utility and its customers that would not be realizable under single-function customer-controlled installations.

Three distribution feeders (Kailua 15, Kahaluu 12, and Anaehoomalu 13) located in the high growth areas on the west side of the island were selected for assessing possible micro-grid configurations. Each of these feeders serves a mix of commercial and residential customers representative of the high load growth sectors of the Island's economy, including resorts, integrated commercial facilities such as shopping malls, and residential subdivisions.

For each feeder, a load flow analysis was run using current (2003) data to ascertain whether there were any equipment overload or voltage problems. Next, each feeder's peak loads were projected for 6 years – to 2009 – at an 8% per year load increase* to see what the peak loading and voltage profile will be. Then a high penetration of DER – distributed generation (DG) and combined heat and power (CHP) – was added to each feeder at points deemed "logical candidates" for DER siting because:

- Voltage at peak load was low;
- The feeder section was loaded near or over capacity at peak; and/or
- There were one or more customers at that site with the characteristics favoring DER.

A load flow was run for the feeder with the assumed DER micro-grid installations, and the voltage profile and peak feeder loading were calculated.

The following table illustrates the findings of the micro-grid scenario analyses for each of the three feeders:

FEEDER			BASE CASE	DER CASE		
	Study Year	**Nominal Peak Load (MW)**	**Highest Device Loading (%)**	**Highest Device Loading (%)**	**DER Penetration (%)**	**DG/CHP Capacity (kW)**
Kailua 15	2003	6 MW	61%	30%	47.0%	2,700
	2009	10 MW	105%	69%	33.1%	3,300
Kahaluu 12	2003	7 MW	77%	46%	36.5%	2,540
	2009	14 MW	155%	103%	32.7%	4,640
Anaehoomalu 13	2003	7 MW	105%	52%	45.0%	2,790
	2009	10 MW	153%	63%	55.5%	5,080

The planning objective is for maximum device loading at peak load to be at or lower than 50%. At over 100%, nominal capacity is exceeded. If peak load is much over 50%, then the feeder cannot pick up another feeder's loads in the event of an outage or contingency. It should be noted that even with DER installed, Kahaluu 12 in 2009 will still need some relief from another feeder – a construction project is included in HELCO's system plan.

HELCO is faced with the challenge of providing electricity as inexpensively as possible while meeting the reliability needs of its customers and the environmental and land use requirements of the Island of Hawaii. Given the constraints on the island's current electric network, installing distributed energy resources (including combined heat power systems) at certain customer sites appears to have many advantages, including improved efficiency and thermal energy utilization, potential reduction or deferment of investment in distribution system expansion, reduced loading of cross-island transmission systems, and improved electric and thermal reliability. In order for these benefits to be fully realized for the HELCO electric system, the utility must be able to

* 8% per year is the average historical load increase for this area. However, some locations are seeing growth rates of 10% or more per year.

monitor and control the DER systems to ensure the units can be dispatched to meet system needs as well as customer economics. This can be accomplished if HELCO:

- Owns and operates the DER,
- Co-owns the DER with the customer and is able to dispatch it, or
- Develops a service contract with the customer that enables HELCO to monitor the DER and dispatch it if system conditions warrant.

A micro-grid solution requires identifying a technically feasible control system and generation configuration to perform the dispatch and control of the distributed generation resource. There are also complicated system protection issues that must be addressed before considering the DER as part of the dispatchable generation resources from the transmission system perspective. The reliability of distributed generators being encountered at other micro-grid test sites would need to be improved.

This study found that a DER micro-grid approach, with systems sited on the HELCO distribution system, can be a technically sound and economically viable option for HELCO and its customers to pursue providing these technical issues can be resolved at reasonable expense. HELCO is considering installation of DG and CHP at customer sites and HELCO substations. HELCO has applied to the State of Hawaii to actively pursue this option where detailed engineering studies identify specific locations where DER technologies are cost-effective and can benefit the individual customer while improving HELCO's system reliability and lowering its costs to serve. The building of the distributed generation is the first step to develop and prove the micro-grid concept. The next steps are to address the complicated system integration issues, and develop the control interfaces necessary to operate the distributed generation as a dispatchable generation resource, available to assist with electric grid stability.

1.0 Background

The electricity supplier on The Big Island of Hawaii is the Hawaii Electric Light Company (HELCO), a subsidiary of Hawaiian Electric Company. HELCO's electric system encompasses about 270 MW of scheduled thermal power plants (both owned by HELCO and by Independent Power Producers), primarily fueled by residual fuel oil, diesel fuel and naptha, but also including 30 MW of geothermal power and 22 MW of coal-fired plants. Unscheduled energy sources include 14.35 MW of run or river hydropower and 9.3 MW of wind power. All these are connected by more than 468 circuit miles of 69 kV transmission lines. The grid is isolated to the Big Island and is not electrically interconnected with any other utility. This system serves more than 65,500 customers and covers 4,028 square miles.

HELCO utilizes a modern centralized control system to monitor and control the transmission/distribution system. This system is called a Supervisory Control and Data Acquisition / Energy Management System (SCADA/EMS). Also incorporated into the SCADA/EMS is a program (Automatic Generation Control) that assists the System Operator in economically dispatching the controllable generating resources to meet load demand. The voltage regulation, load following, fault support and frequency control needed to provide power system stability are presently only provided by the fossil-fuel fired steam generators, diesel, and gas turbines. The system frequency is stable when the power being produced matches the system demand, which is determined by customer load demand and transmission/distribution losses.

The Big Island's electric system faces a complex series of reliability, environmental, and economic issues. These include:

- Rapid load growth on the Kona (west) side of the island, without proportional addition of West-side generation, means that the West-side load is served by power flow from the East-side generation through the cross-island transmission lines. This situation has resulted in the following transmission system problems:
    - Potential for low transmission voltages if any of several single transmission lines are lost;
    - Potential for critical transmission line overloads of three transmission lines that are operating at or near their capacity,
    - Transmission system losses incurred in transporting the energy to the West-side customer loads, resulting in higher fuel costs;
    - West-side generation must be dispatched out of the economic order to avoid reduce transmission system risk of low voltage and line overloads from single contingencies, resulting in higher fuel costs
- The rapid load growth on the Kona side of the Island will soon necessitate distribution system expansion/reinforcement.
- A large portion of the generation capacity on the HELCO power system is not dispatchable by the system operator, and does not provide ancillary services (load following, frequency regulation, voltage regulation). The geothermal plant, hydropower plants, and wind farms do not provide load-following and frequency regulation.
- Addition of significant amounts of as-available power generation sources (primarily wind and solar) will increase the burden on the dispatchable units. In particular, the volatile wind energy, which can change output at a relatively fast rate, will add significant stress to the existing electric system. Increased connection of intermittent generating capacity will require additional system frequency and could affect system stability. In addition, the as-available generation replaces conventional generation on the grid and reduces the number of generating resources available to provide the necessary ancillary services.
- Distributed generation that does not provide ancillary services can further reduce the number of conventional generators on the grid (they appear to the system operation as a reduction in system load). This further increases the burden on those generating units proving the ancillary services.
- Although technological improvements have been made, wind farms and customer-installed distributed generation do not presently have the same ability to stay online during system disturbances as the conventional fossil-fuel generation. This can lead to system instability during upset conditions (storms, accidents, loss of generation or load).
- Increasing amounts of as-available energy can result in excess energy production. HELCO must keep online a minimum number of conventional generation to provide the load-following, voltage regulation, and frequency control.

Hawaii Electric Light Company has experienced operating constraints at both peak and light load conditions.

Of particular concern are the transmission system vulnerabilities created by the large power flow from East to West, the result of 79% of the HELCO's generating capacity being on the East side, while approximately 50% of the load demand is on the West side during day time loads. There are a limited number of cross-island transmission lines, and at peak load one line is close to fully loaded. Under single contingency conditions, three are overloaded. Several single contingencies can result in wide-spread low voltages in the West side of the HELCO grid. To manage this risk, HELCO is forced to dispatch the simple-cycle gas-turbines at Keahole Power Plant, on the West side of the island during daytime. The generation must be online to prevent loss of single transmission lines creating system instability that could lead to transmission line damage or system instability. This "must-run" dispatch of the Keahole generation increases system fuel costs.

Much of the load growth is at resorts, and this will soon require investment to reinforce the distribution system.

HELCO purchases a large amount of non-dispatchable renewable energy from Puna Geothermal Ventures (PGV) geothermal plant, three run of river hydropower plants, and from two large wind farms.

PGV provides firm power and is dispatched to a fixed amount of output by contract schedule. It is not dispatchable by the system operator under SCADA/EMS control, and does not help with load following or frequency regulation. Due to its location, at a remote location interfacing at a grid point congested with other generation sources, it has limited ability to support voltages (in fact, problems keeping the transmission voltages within limits require PGV to operate in constant power factor control).

The hydropower plants on the HELCO system are run-over-river. They do not provide frequency regulation or load-following. With no water storage available, the power production from these units is treated as must-run except during periods of excess energy production.

Independent power producers are planning developments that may soon more than triple the Big Island's wind turbine capacity. However, wind turbines are non-dispatchable, and variations in wind result in significant fluctuations in power input to the HELCO grid. This rapidly changing power output must be matched by controlled changes in the dispatchable HELCO generation in order to keep system frequency constant. The rate of change in the wind farm generation places much greater burden on those generating units providing frequency regulation than the changes in customer load demand.

Additional as-available power increases the possibility of excess energy production. At light load (from midnight to 6 am HELCO's load is about 70 to 80 MW), HELCO's load is typically served by PGV, run of river hydro, the three larger HELCO steam plants (Hill 5, Hill 6, and Puna) and one of HEP's combined cycle units. HELCO has an operating policy to keep at least three units on the grid that are under AGC control and immediately dispatchable for frequency regulation. To conserve fuel costs, HELCO runs with limited regulating reserve (about 4 MW reserve capacity (up) during increasing load and 3 MW reserve capacity (up)during decreasing load). HELCO has found that at times of high wind penetration, this typical reserve must be increased by approximately half the wind energy (for example, if wind production is 8 MW, HELCO will carry an additional 4 MW reserve for typical wind patterns – depending upon observed volatility of the wind0. The renewable sources' and regulating units' energy production can exceed HELCO's load, requiring curtailment of the excess energy (hydro, wind and/or geothermal). This has not happened in recent years due to reduced geothermal and wind production, combined with increased off-peak demand. However as more wind is added to the system, this problem of excess energy production will return and, with projected wind farm additions, may even occur during day and evening peak.

Distributed energy resources (DER) – energy storage and local generation – have the potential to resolve some of these problems, although there are difficulties in practice to installing DER as well as the potential to increase problems. Some of the practical issues include 1) the availability of land in the area available for installation of DER equipment, 2) the development of fuel supply and maintenance resources, 3) interconnection requirements and 4) permitting issues. In addition, 5) reduction in apparent system load results in conventional generators online and may require greater curtailment of new as-available resources than presently forecast for excess energy production; 6) if distributed generators are unable to ride-through grid fault conditions, this could cause apparent system load increase under fault conditions and worsen the fault's effects; and 7) distributed generation will add complexity to distribution protection systems.

Distributed generation has many potential benefits, but, many of these have yet to be realized under real-world situations in complex electrical networks. DER could offer choice to customers and electricity service providers by reducing emissions; avoiding construction of new transmission or distribution lines; improving service reliability and system stability; and/or offering small, modular power plants that are cost-competitive with larger, central station power plants.

HELCO and the State of Hawaii Department of Business, Economic Development & Tourism (DBEDT) have undertaken a study of DER technologies' applicability to the Big Island's energy supply planning. Specifically:

- Energy storage can increase nighttime loads, enabling HELCO to keep dispatchable generators on-line to more efficiently provide regulating reserve and to avoid having to back down geothermal and wind sources. Discharging storage can lower peak loads, reducing use of high cost (or higher emissions) peaking generation, reducing transmission or distribution loads, and/or providing load shedding to prevent equipment overloads in a contingency situation. Some energy storage technologies can provide regulating reserve. This will enable HELCO to accept more non-dispatchable renewable generation (i.e., wind) on its system.

- Distributed generation at high load growth sites can also decrease distribution or transmission overloads and help support voltages at the point of demand. Given the constraints on new or increased capacity trans-island transmission facilities, is distributed generation a viable way for HELCO to accommodate significant rapid growth on the western side of the Island?

A separate report, "HELCO Operational Issues: Bulk Energy Storage," looks at the effects of installing energy storage on the HELCO transmission system, including:

- 30 MW pumped hydro
- One 20 MW, and one or two 10 MW battery systems

The present report describes the analysis of on-site power generation, including combined heat and power (CHP) that uses the waste heat from the generator to help meet the overall energy needs of the facility. Table 1 lists the operational problems each technology – energy storage and on-site generation – might address.

DER Technology	Provide regulating reserve	Accept more renewable generation (by increasing minimum load)	Accept more renewable generation (by reducing generation fluctuations)	Improve generation production efficiency	Reduce equipment overloads	Improve stability and power quality	Serve anticipated load growth	Maintain system during transmission outages
Energy storage – pumped hydro		X		X	X			X
Energy storage – batteries	X	X	X	X	X	X	X	X
Distributed generation (and waste heat utilization) at customer sites	X				X	X	X	X

Table 1. DER Technologies and HELCO Operations Issues

DER, in the form of on-site power generation, energy storage and/or responsive load, is usually installed by the customer, based on analysis of the DER's effects on the customer's energy costs, calculated according to the utility's tariff. The DER technologies may be cost-justified because they reduce demand charges or shift energy usage from peak to less expensive off-peak periods. Such analyses evaluate DER from the customer's point of view, but they miss potential benefits of DER to a utility. Theoretically, DER can be installed to defer utility transmission and distribution investment, and DER can be dispatched to respond to system emergency or equipment overload situations as they occur (providing ancillary services, such as reserves) or help shift loads to correct area control error (ACE). In practice, these benefits of DER are rarely realized when DER is customer-installed and –operated because:

- The DER installations may not be large enough or flexible enough to offer system benefits to the utility system.
- Customer-installed DER tend to be single-function, rather than multi-function hybrid systems, which limits their potential applications.
- Customer-designed CHP installations tend to be sized to match thermal loads rather than electrical loads. In such cases, their potential value to the HELCO *system* is limited.
- The customer is unaware of power grid conditions and unable to dispatch the DER to respond to system emergencies.
- The utility is not involved in the DER design sufficiently in advance for it to consider DER as an alternative to system expansion.
- The DER is usually unable to survive grid disturbances (it trips offline for low-voltage or low-frequency conditions).
- The utility does not have assured communication and control of the DER; this is necessary to include the DER as an operations resource (i.e., to provide ancillary services).
- The costs to establish remote control and dispatch of the distributed generation are prohibitively high.
- The O&M, such as fuel-cost, storage and delivery, of this type of generation often result in expenses that exceed centralized conventional power-plants.

Properly designed, dispatched and maintained DER (energy storage and/or distributed generation) might help to alleviate several of HELCO's system problems. HELCO, along with Hawaiian Electric Company (HECO) and Maui Electric Company, are seeking to offer utility-owned and -operated Combined Heat and Power (CHP) systems at customer facilities (see Appendix D from Docket No. 03-0371 and Appendix E). However, the key to realizing all of DER's potential benefits will be to look at multi-function hybrid systems that are dispatchable[*] by the utility – often referred to as a "micro-grid" because the combination of distribution lines and transformers, local generation, and local loads resemble a utility system in miniature. This report evaluates various aspects of high saturations of DER in an integrated grid management approach.

[*] Utility-owned or -managed distributed generation (DG) should be able to respond to network conditions as well as customer-site conditions. Thus it can be dispatched and maintained to balance customer and system benefits. The choice of equipment and configuration may also be influenced to select systems compatible with the utility's distribution construction standards, voltage control procedures and protection systems; to allow the utility to efficiently stock spares and maintenance tools; and to enable the utility's line personnel to be trained to service the DG installations. The utility may enforce DG maintenance requirements to improve DG reliability, something that historically has often been neglected with customer-owned emergency generators. These issues are described in Hawaiian Electric Company's (HECO) proposed CHP Program (Appendix E) and HECO's response CA-IR-13 of Docket No. 03-0371 (included as Appendix D).

2.0 Project Goals and Objectives

HELCO's resource planning is designed to optimize its electric network – generation, transmission and distribution – in order to achieve the lowest electricity costs consistent with high reliability and power quality, and low emission levels. *The primary objective of this project is to ascertain whether DER on the distribution system and at customer locations – a micro-grid approach – is a technically and economically viable option, warranting further study.*

The overall goal of the integrated project (energy storage and micro-grid) is to identify the types, sizes and locations of DER technologies that could reduce energy costs and improve quality of electric service on the island of Hawaii. To do this for the micro-grid study, candidate DER technologies were chosen, sites where they potentially seemed to yield the most benefit were identified, and a technical – load flow analysis – and preliminary economic assessment was made.

3.0 Assumptions and Qualifications

3.1 <u>General assessment, not site-specific</u>

For this study, we examined possible micro-grid configurations on feeders located in the high-growth areas on the west side of the Island. If we were to evaluate a potential DER installation at a specific customer's site, it would be necessary to complete a comprehensive engineering and economic evaluation that would include:

- Customer energy use patterns – current and projected.
- Space availability at the site, including access to fuel sources.
- Existing electric service to the customer (including loading of the distribution system at peak and emergency – single contingency – conditions).
- Distribution line impedances, ratings, and other relevant characteristics tied to feeder/substation maps.
- Customer's electricity and fuel tariffs.
- Candidate DER equipment, including capital and operating costs, maintenance requirements, efficiency, reliability, interconnection equipment needed, emissions, noise levels, etc.
- Electric system protection issues.
- DER design requirements for the DER to provide the reliability and ancillary services to be considered as dispatchable generation.
- Technical Design and Implementation Cost for the SCADA/EMS system integration and required communications to dispatch the DER.

However, this is meant to be a *technology assessment, not a project assessment.* Therefore, the analyses were based on general assumptions and approximations meant to represent the overall situation on the Island of Hawaii. The case studies and analyses presented here should not be taken as a recommendation of the viability of DER for any specific site; rather, they are meant to provide an estimate of the overall costs, potential benefits, and concerns associated with incorporating DER into the HELCO system.

3.2 DER installations are linked to HELCO dispatch center and planning department

A distinguishing assumption of this analysis is that all of these DER technologies will be monitored and controlled through HELCO's SCADA (Supervisory Control and Data Acquisition) system, enabling the DER to be dispatched to respond to system conditions and costs. Only then could DER be "credited" with full system benefits and represent a viable planning option for HELCO. This integration is complex, since HELCO is a small, non-interconnected grid. A technical study would determine generator characteristics required for the distributed generators to remain online and reliable during transitory grid disturbances. In assessing the SCADA/EMS interface, the following questions would be considered:

- What type of communications control interface would be utilized?
- If the micro-grid is capable of operating in an islanded configuration (separate from the grid), a sophisticated self-contained micro-grid electric management system is required and the means to reconnect to the HELCO grid must be identified. Separation from the primary grid would also create greater complexity in post-disturbance recovery for the HELCO system operators.
- Would DG include sufficient on-site reserve capacity – in excess of the local load requirement - for regulating up and down?
- How would the EMS detect separation of the DG from the primary grid due to loss of distribution circuit?

The cost of a conventional EMS interface for generation control can be significant, and a complete engineering design and cost evaluation is required to do a complete assessment of the total cost for the DER system integration as a micro-grid, as dispatchable generation, providing frequency regulation and enhancing system reliability.

Also, maintenance of the DER system will be scheduled in conjunction with HELCO's planned maintenance of all DER, central station generation, and transmission facilities, in order to maintain adequate reserve capacity to ensure system reliability. Independently, a resort would schedule maintenance of its DER equipment according to its projected occupancy, its own need for energy, and availability of its facility maintenance personnel. This could have adverse system effects if HELCO is counting on that DER capacity to supplement system capacity during scheduled maintenance outages of its large generators.

The protection issues are also quite complicated. An engineering study must be performed to analysis the distribution protection requirements for the particular point of interconnection. The protection needed to preserve the integrity of the distribution system during faults, may require protection settings that are contrary to the objective of keeping the generation online during transmission system faults. The distributed generation may need to trip offline during off-nominal conditions to reduce chances of subjecting the distribution loads to unacceptable power quality conditions.

4.0 The Role of Micro-Grid-Sited DER on the HELCO System

Currently, HELCO is experiencing rapid load growth on the Kona side of the island, while the bulk of its generation is on the Hilo side. Much of this load is new commercial customers or expanded commercial customer facilities, especially resorts. Some resorts are considering or have already installed DER technologies, including local generation, CHP, photovoltaics, small wind, or other energy management technologies.

Traditional thermal energy storage, CHP, or responsive load (e.g., demand-side management) technologies may prove cost-effective from the customer's point of view, but customer-operated and -dispatched DER offer little or no *assured* relief for HELCO's system loading and stability concerns unless HELCO has some real-time control over their availability, dispatch and operating level and the generating units are designed for the similar ancillary services and fault ride-through as the conventional generation it replaces. Commercial customers may install on-site back-up generation for reliability, but such installations usually are not available to the utility in emergency situations and not dispatchable in real-time to reduce peak production costs.

By looking at potential DER technologies as parts of integrated hybrid systems, dispatched by HELCO as a micro-grid, many functions could be combined to offer benefits to the utility and its customers that would not be realizable under single-function customer-controlled installations.

4.1 Potential DER Micro-Grid Benefits

The following potential benefits of DER in a micro-grid installation were considered:

- Reduce peak loading on distribution feeders or transformers.
  - Overloading distribution systems may cause equipment to fail – cables or transformers especially – but even if the equipment is not overloaded, high loads accelerate thermal aging of equipment, shortening its useful lifetime.
  - HELCO plans its distribution systems to be able to serve loads even after a contingency – failure of a system element. For a distribution feeder, this means that if a substation transformer fails or a section of the feeder is faulted, the unfaulted sections of the feeder should be isolated and then back-fed through another feeder (and distribution transformer) to pick up the load. If feeders are too heavily loaded, then all loads would not be able to be served in the event of equipment failure.
- Maintain feeder voltage within prescribed limits.
- Reduce loading (kW and kVar) on cross-Island transmission lines.
- Provide additional generating reserves for the HELCO system.
- Reduce customer energy costs.
- Back-up (emergency) electricity supply for the customer.

4.2 DER Micro-Grid Technologies Considered

The study considered local generation and local generation with combined heat and power as possible DER technologies for in-depth analysis.

The local generation could come from "conventional" sources such as diesel (reciprocating) engines or small combustion turbines*. It could also be provided from fuel cells or renewable sources such as solar photovoltaics or wind; however, at present such sources are not economically competitive with conventional distributed generation to warrant *widespread* implementation. Appendix G provides data on these local generation technologies. For this analysis, the renewable sources were not considered to be economically feasible for widespread implementation within the next 5 to 10 years.

Of the conventional sources, the specific product to be chosen for a site will depend upon the site's load characteristics, available space, size of the load to be served, etc. For the purposes of this analysis, the following economic parameters were used, corresponding to a reciprocating engine:

- The installed cost of the distributed generation (DG) system is about $1100/kW. This includes the generator as well as its auxiliary/interconnection equipment.
- If DG has already been installed at a customer site, then the cost of adding to its capacity is about $800/kW.

Examining the existing and projected loads and customers on HELCO's western feeders, the following characteristics indicate potential locations for DG:

- New or rapidly growing customer loads.
- Heavy electric usage during peak periods.
- Feeders with voltage or overload problems.

The types of facilities matching these characteristics include:

- Resorts undergoing significant expansion.
- Large and/or growing integrated commercial facilities, such as malls.
- New or rapidly growing residential subdivisions served by a single feeder.

Facilities with significant off-peak electric loads, such as the pumping loads to irrigate golf courses, were not considered. Since the pumps don't operate during the system peak, DG would not provide load relief to HELCO's distribution or transmission facilities. Reducing system load during the off-peak minimum load period is not helpful to HELCO and may necessitate backing down HELCO's purchases from renewable sources, such as PGV geothermal or wind farms.

Perhaps the most promising DER application for micro-grids in Hawaii is combined heat and power. The heat produced by the generator is recovered and used for:

- Domestic hot water,
- Laundry,

* In general, microturbines are not effective in Hawaii because, with no source of natural gas, they must run on propane or diesel – with these fuels, their performance is degraded. Propane-fueled microturbines are not commercially available for larger (above 30 kW) units.

- Heating a swimming pool, or
- Powering an absorption chiller.

Such applications are feasible only where the customer has a need for the waste heat. Based on the types of facilities on the Kona side of the Island and the characteristics of successful CHP installations throughout the nation, the following are candidates for CHP installations:

- Resorts and hotels.
- Hospitals.
- Restaurants.
- Schools or office buildings with significant cooling loads.
- Waste water treatment facilities.

Based on existing CHP installations in Hawaii, the following economic parameters were used, corresponding to the use of waste heat to power an absorption chiller for air conditioning:

- The installed cost of the CHP for power generation is about $1600 - 1800/kW. This includes the generator, waste heat recovery, and auxiliary/interconnection equipment. For a CHP installation, some of the capital cost is properly allocated to the equipment that utilizes the recovered heat (e.g., additional cost for absorption versus conventional chiller). The $1750 number used for this report’s analysis already accounts for this.
- The recovered heat will be used to reduce the facility’s need for outside power or other energy. A 1.0 kW CHP installation would produce heat for a 0.25 kW absorption chiller. Thus a 1000 kW nameplate CHP installation would reduce the feeder peak load by 1250 kW. (i.e., 80% power, 20% heat recovery output).

Two additional demand-side possibilities – thermal energy storage (TES) and demand-side management (DSM) or responsive load – were initially considered in the study.

TES is an effective means to reduce peak electric demand and shift load to off-peak periods. It is applicable for facilities with a large central thermal load such as a central air-conditioning system. Customer benefits of TES accrue only if the customer can reduce its peak electric demand charge significantly and/or take advantage of lower nighttime prices for electricity. The attractiveness of TES from a customer’s point of view will depend upon its electric tariffs, expected growth in HVAC load (e.g., is another or larger chiller needed?), and the age and efficiency of current HVAC equipment (e.g., does an aging chiller need to be replaced?). The decision to install TES, from a customer perspective, is dependent upon very specific customer equipment, energy use and financial characteristics.

The benefits of TES to HELCO would be:

- Reduced peak feeder loading.
- Reduced loading of cross-Island transmission lines during peak period.
- Higher minimum loads during nighttime (when the TES would re-charge) could reduce the curtailment of renewable energy sources.

However, TES did not appear, by itself, to be an attractive option for HELCO:

- There are not enough concentrated thermal loads on the feeders to appreciably reduce peak distribution system or transmission loading with TES.
- For TES to be able to contribute to system regulation (during light load periods), HELCO would have to be able to monitor and dispatch the TES system. In addition to a communications link, this would require detailed on-site monitoring so HELCO could know not just the current operating mode of the TES (charge/discharge/idle), but also its energy charge level, forecasted thermal demands of the facility, and indoor environmental conditions (comfort levels) of the facility. Such detailed monitoring and facility modeling is not practical for HELCO to undertake, nor would it be acceptable to most commercial customers.

Similarly, DSM was ruled out as a HELCO-dispatched option. There does not appear to be adequate interruptible load on the Kona-side feeders to be used, on a routine basis, to reduce system peak loading. Moreover, the possibility of inconveniencing resort guests makes this unattractive to the resort operators.

5.0 Project Approach

5.1 Case Study Analysis

Three feeders were selected for case study analysis, and their operation was simulated using the Aspen DistnView software, Version 6.7:

- Kailua 15
- Kahaluu 12
- Anaehoomalu 13

Each is located on the west side of Hawaii and serves a mix of commercial and residential customers representative of the high load growth sectors of the Island’s economy. On two of these feeders, resorts either have installed or are planning to install DG or CHP. For each feeder, a load flow was run using current (2003) data to ascertain whether there were any equipment overload or voltage problems. Next, each feeder’s peak loads were projected for 6 years – to 2009 – at an 8% per year load increase[*] to see what the peak loading and voltage profile would be.

Then a high penetration of DER – DG and CHP – was added to each feeder at points deemed “logical candidates” for DER siting because:

- Simulated voltage was low at peak load was low at points on the feeder,
- The feeder section was loaded near or over capacity at peak, and/or
- There were one or more customers at that site with the characteristics favoring DER (see Section 4.2).

[*] 8% per year is the average historical load increase for this area. However, some locations are seeing growth rates of 10% or more per year.

A load flow was run for the feeder with the assumed DER micro-grid installations, and the voltage profile and peak feeder loading were calculated.

5.2 Competing Technologies

DER is not the only alternative HELCO has to serve the growing load on the Kona side of the Island. The following alternatives were addressed in the study analysis:

Capacitors. Adding capacitors – fixed or switched – will help maintain voltages within prescribed limits. Capacitors will also reduce feeder loading (current) to some extent.

Distribution system reinforcement. To serve increased loads, HELCO has plans to reinforce feeders and substations that are projected to be overloaded by:

- Adding another transformer to a substation,
- Constructing a new substation,
- Replacing a section of cable with higher capacity conductor, and/or
- Constructing new distribution feeders or feeder sections, with more sectionalizing capability and more ties to alternate feeders.

Additional west-side generation. Adding generating capacity on the west side of the Island will not reduce distribution system loads, but it will reduce loading on the cross-Island transmission lines during peak or contingency conditions.

5.3 Distributed Generation/Micro-grid Scenarios

Distributed generation installed at the customer's site appears to be an effective means to serve anticipated load growth at large commercial and institutional sites. On Mauna Lani 13, combined heat and power units have been effective in reducing the effective load of the Fairmont Orchid seen by HELCO. Kona Community Hospital and Hilo Medical Center have also benefited from installation of CHP units.

In order to determine the operating schedules for DG and CHP, the study team first examined the distributed generator load profile of Kona hospital and the Orchid to estimate a typical distributed generator's output. Kona Hospital has a 455 kW generator. The Kona hospital CHP unit shows a loading profile that mirrors HELCO's system. For the most part, the Kona CHP load varies between 250 and 450 kW, with an additional 70 to 80 kW provided by HELCO.

While difficult to generalize, the approximate CHP loads for a June day are given in Table 2. By contrast, the Fairmont Orchid distributed generator supplies about 800 kW constantly, with the facility's load variation met by the purchases from HELCO.

Time	Approximate kW
0000 – 0059	300
0100 – 0559	250
0600 – 0659	300
0700 – 0859	350
0900 – 0959	400
1000 – 1359	450
1400 – 1759	400
1800 – 1859	350
1900 – 2359	300

Table 2. "Typical" Profile of Kona Community Hospital 455 kW CHP Unit

From HELCO's perspective, distributed generation on-peak might help reduce transmission loading and reduce possible future low voltage problems. A customer installing local generation may desire to maximize the generator's output, operating it at close to nameplate capacity for 24 hours a day. Under HELCO's proposed CHP program, the utility would also seek to maximize customer benefits. However, distributed generation off-peak will reduce HELCO's minimum load, and this already presents a problem requiring HELCO to reduce its purchases of wind and geothermal generation. Most CHP/DG units will not be operated at 100% capacity all the time, because HELCO's dispatch center will seek to coordinate and prioritize their outputs with that of other DG sources, green power sources, other HELCO generation, and system loads. Thus, HELCO's and its customers' preferred distributed generation dispatch strategies may differ. Similarly, the optimal settings to protect the distribution system are counter to the protection required for the generation to remain online during fault conditions to support the high voltage power system.

Table 3 suggests 3 basic DG profiles: constant (I), peak-emphasis (II), and peak-only (III).

Time of Day	Output (kW per 800 kW Nameplate Capacity)		
	Schedule I	Schedule II	Schedule III
0000 – 0759	800 kW	400 kW	0
0800 – 2059	800 kW	800 kW	800 kW
2100 – 2359	800 kW	400 kW	0

Table 3. Suggested Distributed Generation Operating Schedules

5.4 Kailua 15 Case Study

Kailua 15's major loads are resorts (Royal Kona), commercial customers (Coconut Grove & Waterfront, Alii Drive, Kailua Village, Kuakini Highway, Palani Road, Kaiwi Street), and residential customers. The King Kameahama Kona Beach Hotel has an alternate feed from Kailua 15, but is not normally served by it. The DER scenario will aggressively off-load Kailua 15 by installing DG at the primary resort and commercial loads. Figure 1 shows a 1-line diagram of the feeder. Kailua 15 is tied to Kahaluu 12 just beyond point A7; if there is an outage or fault on Kailua 15, then service to the unfaulted sections of the feeder can be restored by back-feeding it from Kahaluu 12. (Conversely, Kailua 15 can restore service to unfaulted sections of Kahaluu 12.) Table 4 gives the scenario for Kailua 15 distributed generator siting.

Location	Type of Load	Nameplate DG & Type	Year Installed & Cost/kW	Peak Load Reduction
Kua 1 – Kuakina Hwy.	Commercial North Kona Shopping Center	300 kW - DG	2003 - $1100/kW	300 kW
P2 – Palani Rd.	Commercial Kona Coast/Lanihau Shopping Center	450 kW - DG	2003 - $1100/kW	450 kW
A3 – Waterfront & CG	Commercial Coconut Grove Waterfront Row	450 kW - CHP	2003 - $1750/kW	562.5 kW
		300 kW - DG	2009 - $800/kW	300 kW
A4 – Royal Kona	Resort Royal Kona	600 kW - CHP	2003 - $1750/kW	750 kW
		300 kW - DG	2009 - $800/kW	300 kW
A6 – Alii Drive	Commercial Various Condos	450 kW - DG	2003 - $1100/kW	450 kW
A7 – Alii Drive	Commercial Various Condos	450 kW - DG	2003 - $1100/kW	450 kW

Table 4 – Kailua 15 DG and CHP Scenario

The peak load changes are equal to the DG nameplate capacity plus, if the installation is a CHP installation, an additional 25% peak load reduction is assumed due to use of the DG’s waste heat by an absorption chiller. For example, for point A4, with 600 kW nameplate of DG installed, the heat output would enable an additional 150 kW worth of cooling, for a total electric load reduction (as seen by the HELCO feeder) of 750 kW.

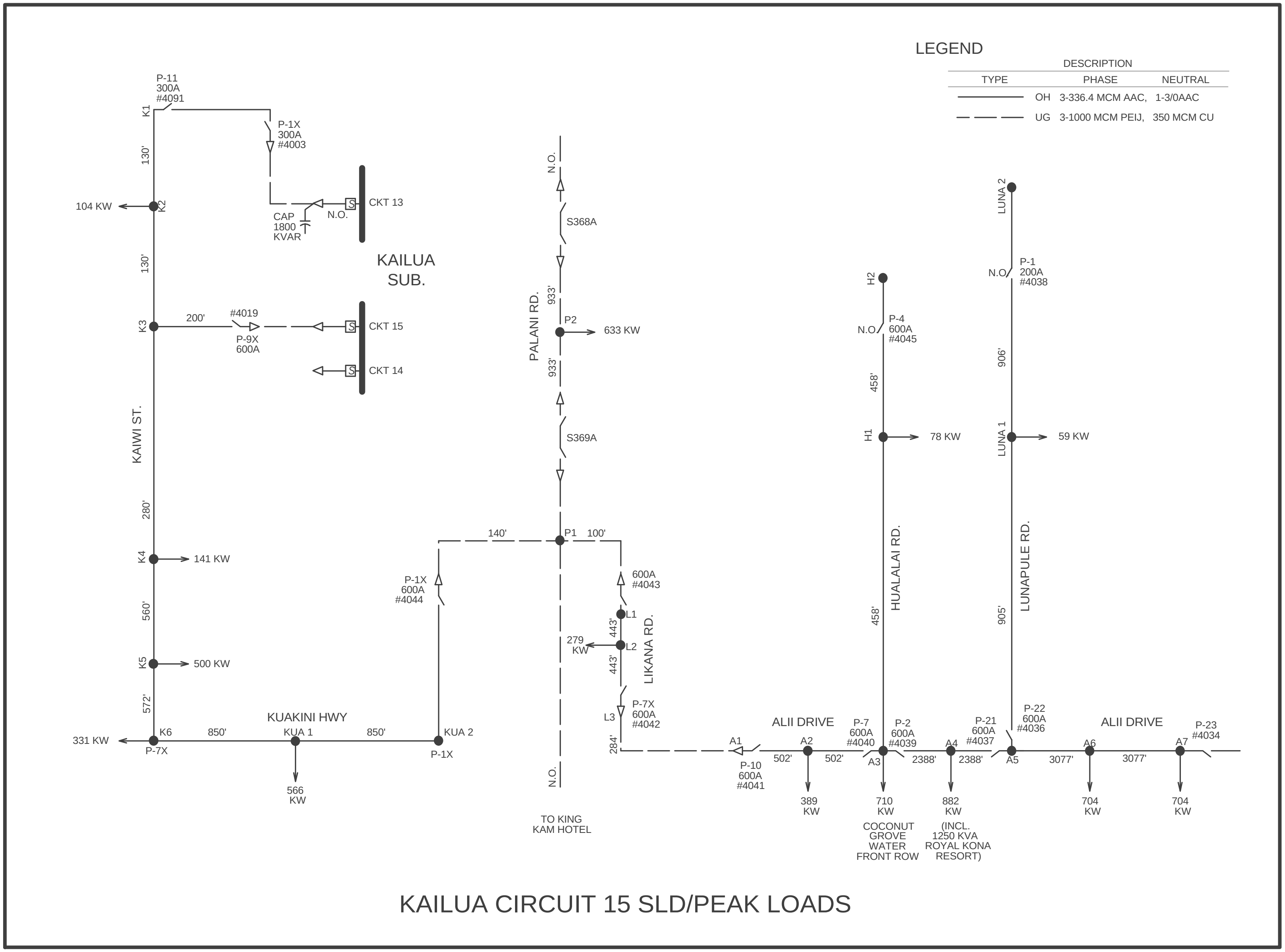
Table 5 shows the results of the Table 4 scenario at peak load – at present peak load condition and in 2009. Three load flows are presented for 2003 and for 2009:

- Base Case – feeder with present configuration
- DER Case – adding DG and CHP as shown in Table 4
- Adding capacitors to increase voltage to minimum acceptable level

Appendix A shows the voltage profiles for the peak load scenarios of Table 5:

- Base Case
- DER Case
- Capacitor Case

Figure 1. Kailua 15



						Lowest Voltage		Highest Voltage				
Description Of Run	**Load KW**	**Load kVar**	**DG kW or Cap kVar**	**DG Penetration**	**Highest Device Loading**	**% P.U.**	**@Bus**	**% P.U.**	**@Bus**	**$/KW or $/kVar**	**Capital Cost ($)**	**Comments**
Kailua Max Ld 6MW - Base	5,860	3,163	0		61.0%	97.2%	A7	100.0%	Sub 12KV	0	0	
Kailua Max Ld 6MW - DG/CHP	5,740	3,098	2,700	47.0%	30.0%	99.0%	A7	100.0%	Sub 12KV	1,750	6,315,000	
Kailua Max Ld 6MW - Caps	5,961	3,218	3,087		54.0%	98.5%	A7	100.0%	Sub 12KV	35	108,045	Cap @ $35/kVar
Kailua Max Ld 10MW - Base (Yr 2009)	9,968	5,380	0		105.0%	95.5%	A7	100.0%	Sub 12KV	0	0	Kailua Feeder to K3 at 114% current
Kailua Max Ld 10MW - DG S1-2 (Yr 2009)	9,974	5,384	3,300	33.1%	69.0%	97.5%	A7	100.0%	Sub 12KV	Various	6,795,000	Add 2-300KW DGs
Kailua Max Ld 10MW - Caps (Yr 2009)	10,262	5,539	5,844		94.0%	97.4%	A7	100.0%	Sub 12KV	35	204,540	Kailua Feeder to K3 at 94.0% current

Table 5. Results of Kailua 15 Load Flow Runs

Currently, Kailua 15 is not overloaded (highest device loading is 61% of capacity at feeder peak load of 6 MW). However, HELCO prefers to keep peak loading well below maximum, in case the feeder must pick up unfaulted sections of another that has suffered an outage. Kahaluu 12 currently has a peak load of 7 MW. If Kailua 15 tries to back feed any significant portion of Kahaluu 12 during peak periods, it will not be able to do so. Adding capacitors will reduce the loading and improve the voltage profile, but not enough for Kailua 15 to serve Kahaluu 12. DER will reduce the loading to 30% of capacity and enable Kailua 15 to offer reliability support to Kahaluu 12. However, the capital cost of DER – $6.3 million – is significantly higher than the cost of adding capacitors – $100 thousand. For present loads, “conventional” system support and reinforcement measures should suffice.

In 2009, Kailua 15’s peak load is projected to be almost 10MW, and the situation changes. The load forecast projects that the feeder will be overloaded and there will be low voltage at A7 (Alii Drive), the farthest point of the feeder. Adding capacitors prevents the overload, and restores voltage out on the feeder, but at almost all times Kailua 15 would be unable to offer service to Kahaluu 12 in the event of a fault or outage on the latter. DER reduces the peak loading to 69% of capacity and provides significant reserves if Kailua 15 must support Kahaluu 12 (or vice versa).

The cost of DER ($6.8 million) versus capacitors ($200 thousand) in 2009 is not very relevant, since capacitors alone will not be enough. HELCO, however, is prepared for the forecasted load growth in the area; it plans to construct a new substation at Palani (approximately $1.3 million) and install a second transformer bank to Kuakini Substation (approximately $800 thousand). To determine to what extent DER would be cost-justified compared to these construction projects, it would be necessary to:

- Perform a comprehensive technical and engineering assessment to determine DER’s site-specific technical feasibility, costs and benefits. This includes the site-specific protection requirements and contributions of each DG unit to system reliability.
- Determine to what extent DER could defer or substitute for the planned substation construction project(s).
- Determine whether the utility-installed DER could defer other planned generating capacity additions.
- Determine required SCADA/EMS interface and associated communications and controls costs.

Such an analysis is outside the scope of this study. The results of this study should be interpreted as answering the question, “Can a DER micro-grid approach enable HELCO to meet expected load growth while maintaining acceptable power quality and reliability?” The proposed scenarios are not meant to represent alternative distribution system expansion plans for these feeders, but to see if DER is a credible alternative that should be considered as part of the integrated resource planning (IRP) process.

5.5 *Kahaluu 12 Case Study*

Kahaluu 12 serves resorts (notably the Sheraton), large residential subdivisions, and numerous – and growing – condo developments. The feeder is very long, with the branch that ties to Kailua 15 being over 5 miles from the substation. Towards the end of this branch is a school and several large residential developments; voltage support is a problem here. Its current peak load of 7 MW is expected to grow to about 14 MW by 2009. Figure 2 shows the 1-line diagram of Kahaluu 12. The Sheraton is undergoing renovations and HELCO plans to install 740 kW of utility-owned CHP under contract with the hotel; this has been included in the DER implementation case. For the other possible DER sites, only the school seems a viable user of waste heat during the peak periods (for absorption cooling or domestic hot water). The residences (houses and condos) are too dispersed and small individually for CHP, and the health care and other commercial facilities served by the feeder do not have large peak loads. Table 6 shows the DER implementation for the case study. The resulting peak load reductions are about 3 MW in 2003 and 5 MW in 2009.

Location	Type of Load	Nameplate DG & Type	Year Installed & Cost/kW	Peak Load Reduction
S211– Keauhou Bay Sheraton	Resort Sheraton	740 kW - CHP	2003 - $1750/kW	925 kW
P47X –School & Condos	Commercial Kahaki School & Condos	600 kW - CHP	2003 - $1750/kW	750 kW
AliiOH3 – Subdivision	Residential Single Family Home Subdivision	600 kW - DG	2003 - $1100/kW	600 kW
		900 kW - DG	2009 - $800/kW	900 kW
AliiOH2 – Condos	Residential Multi-family Condos	None for 2003	2003 - 0	-
		600 kW - DG	2009 - $110/kW	600 kW
KamIIITap – Kanaloa	Residential Kanaloa Resort Condos	600 kW - DG	2003 - $1100/kW	600 kW
		600 kW - DG	2009 - $800/kW	600 kW

Table 6 – Kahaluu 12 DG and CHP Scenario

Table 7 gives the results of the Table 6 scenario at peak load – at present and in 2009. Three load flows are presented for 2003 and for 2009:

- Base Case – feeder with present configuration
- DER Case – adding DG and CHP as shown in Table 6
- Adding capacitors to increase voltage to minimum acceptable level

Appendix B shows the voltage profiles for the peak load scenarios of Table 7:

- Base Case

- DER Case
- Capacitor Case

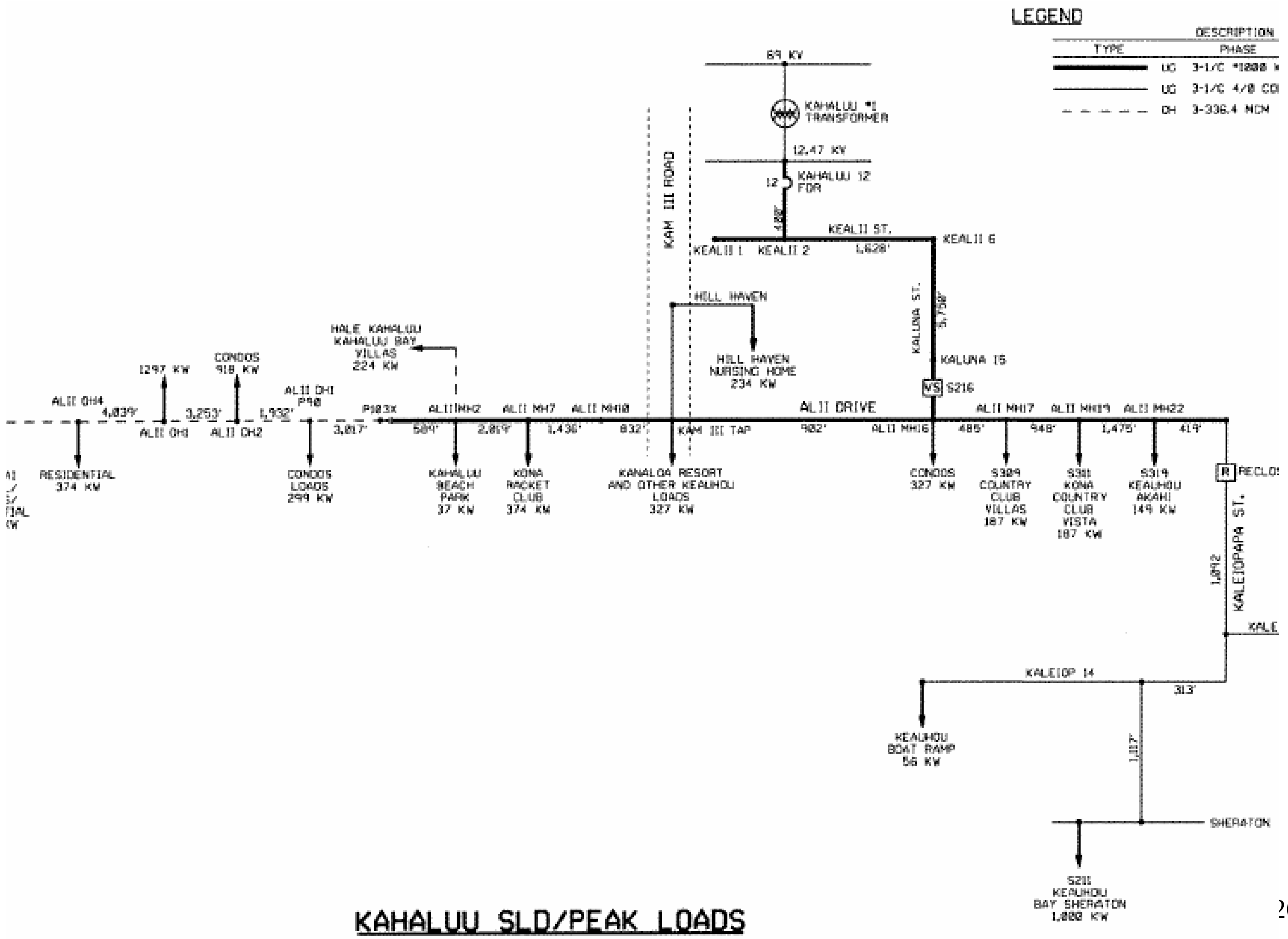
Kahaluu 12 is already heavily loaded; one section of feeder cable in particular must soon be upgraded. Voltages are low at peak loads near the far end of the feeder (the school, residential developments, and the tie to Kailua 15). For the existing maximum load condition (2003 peak), capacitors will improve the low voltage problems, but the load on the critical feeder section remains a problem. The use of capacitors will enable Kahaluu 12 to operate below its capacity, but it may be unable to provide reliability support to Kailua 15 if needed. In 2009, projected load increases will overload the feeder, even with capacitors and large (33%) penetration of DER. However, the DER installations are the most effective in managing the overload and voltage problem. HELCO plans to build new substations in the area to relieve Kahaluu Substation; DER may enable this construction to be deferred. (The Kuakini Unit #2 transformer addition is scheduled for the end of 2004 and estimated to cost $800,000. The Palani Substation unit #1 addition is scheduled for 2006 and is estimated to cost $1.3 million. These costs do not include additional distribution lines or cables that may be needed to relieve the overload conditions.)

5.6 Anaehoomalu 13 Case Study

The Anaehoomalu Substation does not have any ties with other HELCO substations. Thus, for reliability reasons, HELCO installed two transformer banks and 4 feeders (two on each bank) to serve these loads. As a consequence, none of the feeders or transformer banks is heavily loaded, nor are they likely to be in the near future, despite extensive development and rapid load growth in the area. For this situation, the study team decided to look at Anaehoomalu to see whether, if DER had been used, fewer feeders might have sufficed. Therefore, for this analysis, all the Anaehoomalu loads (for the 4 feeders) were put on a single circuit – Anaehoomalu 13 – as a study exercise. The resulting “combined” feeder serves resorts (Outrigger, Hilton), golf course clubhouse (King), irrigation pumps, wastewater reclamation plant, and much residential (e.g., Kolea) and condominium load. Figure 3 is a 1-line diagram of the combined Anaehoomalu feeder.

To site the DER installations, the study team first examined the base case feeder voltage profile and the size and nature of the major connected loads. Irrigation pumps are exactly the type of load HELCO wants to serve – almost exclusively nighttime operation. It does not make sense to try to serve this with local generation. Residential customers (i.e., condos) have a large diversity and can be expected to peak in the early morning or evening hours; these also are not good candidates for local generation. Resort and golf clubhouses are primarily daytime loads. The DER implementation strategy was to use local generation at the resorts, clubhouse, and constant loads (wastewater reclamation plant). We did not site DER to serve individual residential loads and small commercial loads (e.g., King’s shops, condos and villas), as they are small and have large diversity. Also, DER support to the Hilton and golf clubhouse will help with voltage support and line unloading.

Figure 2 – Kahaluu 12



KAHALUU SLD/PEAK LOADS

						Lowest Voltage		Highest Voltage				
Description Of Run	**Load KW**	**Load kVar**	**DG kW or Cap KVar**	**DG Pene-tration**	**Highest Device Loading**	**% P.U.**	**@Bus**	**% P.U.**	**@Bus**	**$/KW or $/kVar**	**Capital Cost ($)**	**Comments**
Kahaluu Max Ld 7MW – Base	7,106	3,835	0		77.0%	95.4%	P37X	99.9%	Sub 12KV	0	0	
Kahaluu Max Ld 7MW – DG/CHP	6,963	3,758	2,540	36.5%	46.0%	97.6%	P37X	99.9%	Sub 12KV	1,750	3,665,000	
Kahaluu Max Ld 7 MW – Caps	7,176	3,873	1,850		73.0%	96.4%	P37X	99.7%	Sub 12KV	60	111,000	Padmount Capacitor Addition, 2.4 Mvar existing at Sub Fdr
Kahaluu Max Ld 14MW - Base (Yr 2009)	13,824	7,463	0		155.0%	90.5%	P37X	100.0%	Sub 12KV	0	0	
Kahaluu Max Ld 14MW - DG 4640KW (Yr 2009)	14,205	7,667	4,640	32.7%	103.0%	94.2%	P37X	100.0%	Various	Various	4,805,000	DG & CHP added plus add'l DG as load grows
Kahaluu Max Ld 14MW - Caps (Yr 2009)	14,538	7,848	6,036		141.0%	94.2%	P37X	100.0%	Various	60	362,160	Padmount Capacitor Addition, 2.4 Mvar existing at Sub Fdr

Table 7. Results of Kahaluu 12 Load Flow Runs

Table 8 shows the DG implementation scenario used for the Anaehoomalu case study. CHP was installed at the resorts and a small CHP unit was assumed installed at the wastewater reclamation facility (continuous load, ability to make use of waste heat). DG was installed at some significant commercial sites, and additional DG was assumed installed in 2009 at the resorts' CHP installations. The result is a 45% penetration of DG/CHP technologies that reduces a fully loaded feeder to 50% load. Capacitors again provide relief at a much lower cost, but in this hypothetical case they still leave the feeder loaded at 80% of capacity.

In 2009, only DER provides sufficient capacity relief for the combined Anaehoomalu feeder. The ability of DER to reduce the feeder's loads suggest that, if distributed generation had been installed on the Anaehoomalu feeders, possibly only two – not four – would have been needed, as two could have picked up all of the loads during a distribution outage. Thus it is possible that DER could have substituted for or deferred over $2.7 million in distribution system reinforcement costs.

Appendix C shows the voltage profiles for the peak load scenarios of Table 5:

- Base Case
- DER Case
- Capacitor Case

Location	Type of Load	Nameplate DG & Type	Year Installed & Cost/kW	Peak Load Reduction
Q5 – Wastewater Treatment	Constant Load Wastewater Reclamation Utility	60 kW - CHP	2003 - $1750/kW	75 kW
W2 - Outrigger	Resort Outrigger Resort	300 kW - CHP	2003 - $1750/kW	375 kW
		200 kW – DG	2009 - $800/kW	200 kW
A2 - Hilton	Resort Waikoloa Hilton	2250 kW – CHP	2003 - $1750/kW	2812.5 kW
		2000 kW - DG	2009 - $800/kW	2000 kW
A5 – Golf Clubhouse	Commercial Daytime King's Golf Clubhouse	180 kW – DG	2003 - $1100/kW	180 kW
		90 kW – DG	2009 - $800/kW	90

Table 8 – Anaehoomalu DG and CHP Scenario

5.7 *<u>Other Costs and Benefits of Micro-Grid DER</u>*

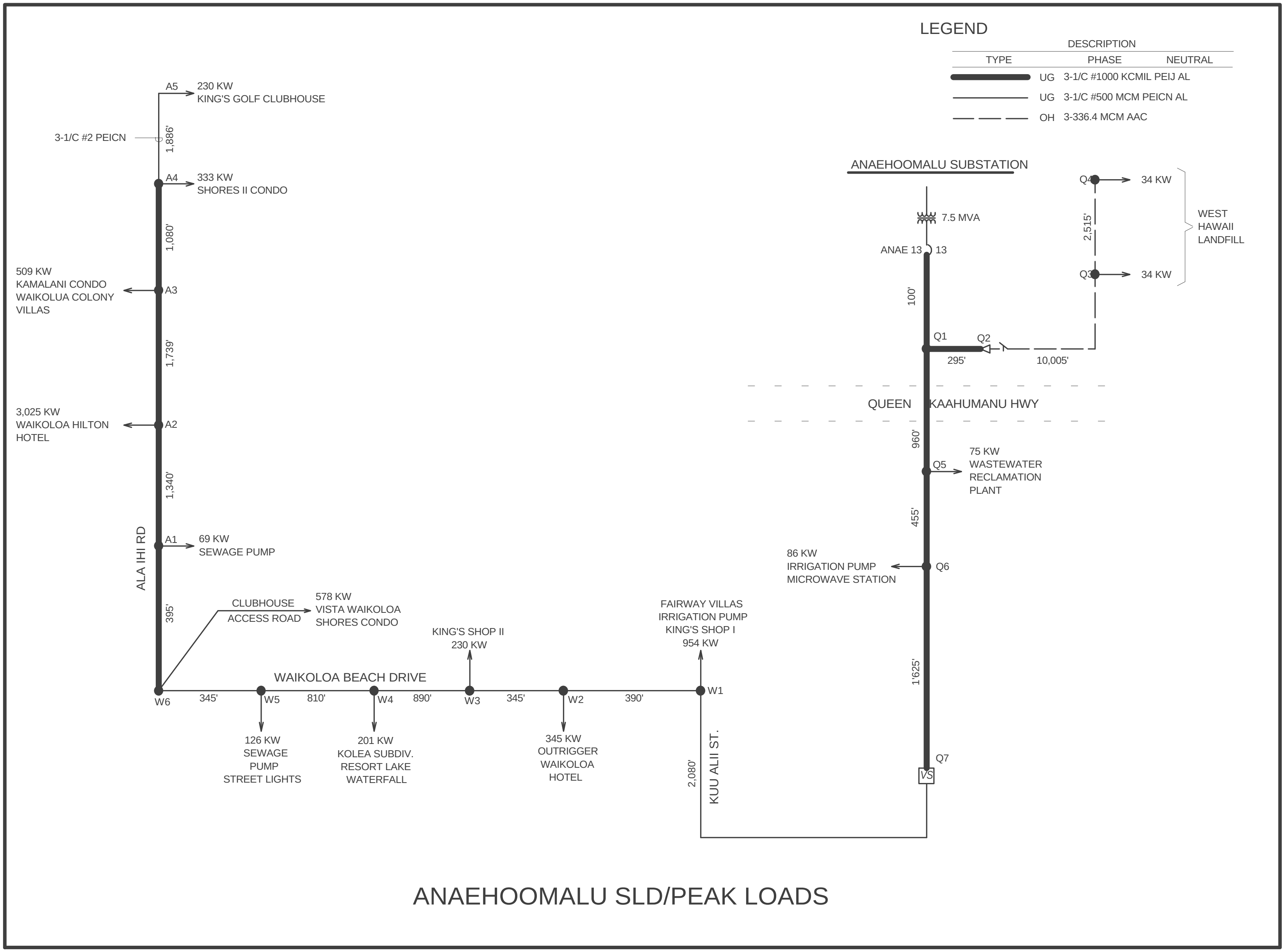
The above case study descriptions focused on the primary costs and benefits of DER installed as a micro-grid on the HELCO system. However, there are other potential benefits that are usually associated with DER:

- How does the operating cost and efficiency of on-site DER compare with that of HELCO's other generators?
- Will micro-grid-sited DER be able to off-load HELCO's cross-Island transmission lines?
- What is the customer reliability value of DER (i.e., as an emergency generator)?
- What is the ability of the DER to provide similar services (fault ride-through, frequency regulation, voltage regulation) compared with conventional generation?
- Can a balance be found between protection settings required for the distribution system and the ability for the generation to remain available during transmission faults and underfrequency events?
- What is the technical feasibility and cost to allow control and integration with the HELCO centralized SCADA/EMS system?

Operating cost. The heat rate of reciprocating engines typically used for DG in Hawaii is about 8800 – 8950 BTU/kWh – about 20% more efficient than the central station units that they would displace. In addition, if Kona-side DG displaces Hilo-side generation, then losses would be about 3% less because the electricity would not use the cross-Island transmission lines. Assuming diesel prices of about $7/MBTU, and 14 hours/day of DER operation, this would yield a fuel savings of about $60/kW of DG per year (about $80/kW on nameplate DG per year if it is a CHP installation). This estimate does not include fixed and variable maintenance costs or the probability that HELCO can purchase fuel in bulk for its central generators for less than smaller quantity purchases for DG units. HECO plans to develop CHP for some of its customers (see Appendix D) and has a pending Docket with the State for tariffs (for heat and for electricity) associated with such HECO-developed projects (see Appendix E). The study team has not attempted to analyze the operating costs of CHP/DER versus central station generation for customers or for HELCO, or to see if operating cost savings for a CHP installation offset its capital costs, as such an analysis would be dependent upon the site-specific characteristics of each DER installation. However, the above screening analysis does show that properly designed and appropriately sited DG and CHP can yield savings in fuel costs for each kWh produced.

Using micro-grid-sited DER to reduce transmission overloads. The potential impact was considered as a possible alternative to reconductoring the 7300 and 7200 lines. However, the overload conditions were large enough to require very large installations of DG – and were not as cost effective as the reconductoring solution. HELCO has completed an extensive study of alternatives to reconductoring the cross-Island transmission lines 7200 and 7300. ["7300 and 7200 Line Overload Study," Prepared by the Planning & Engineering Department, Hawaiian Electric Company, Inc., Final Draft Form May 2004]. The study found that DG, CHP, and/or load shedding on the west side of the Island could ameliorate the HELCO system problems to some extent. Depending upon the HELCO generation dispatch order, from 20 MW to 52 MW of CHP sited along the Kona Coast would reduce the 7300 line overloading during a 7200 line contingency (outage) at the peak load levels now present (in 2004) on the HELCO system. The magnitude of customer-owned CHP (21 to 61 MW) or HELCO-owned DG (23 to 66 MW) in the HECO study is consistent with the amounts postulated in the previous case studies, when extrapolated to the entire west side of the Island. However, the HECO study also found that west-side CHP and DG were not as economically attractive as reconductoring the 7300 and 7200 lines, and that in the future (by 2009) there would not be sufficient CHP and DG available to take the place of the proposed reconductoring. Therefore, while DG and CHP will undoubtedly

Figure 3 – Anaehoomalu



						Lowest Voltage		Highest Voltage				
Description Of Run	**Load KW**	**Load kVar**	**DG kW or Cap kVar**	**DG Pene-tration**	**Highest Device Loading**	**% P.U.**	**@Bus**	**% P.U.**	**@Bus**	**$/KW or $/KVar**	**Capital Cost ($)**	**Comments**
Anae Max Ld 7MW – Base	6,665	3,828	0	0.0%	105.0%	97.6%	A5	99.8%	Sub 12KV	0	0	500 Kcmil cable 105% Loaded.
Anae Max Ld 7MW - DG/CHP	6,203	3,542	2,790	45.0%	52.0%	99.0%	A5	100.0%	Sub 12KV	1,750	4,765,500	500 Kcmil cable 52% Loaded.
Anae Max Ld 7MW – Caps	6,126	3,498	3,504		81.0%	98.4%	A5	99.5%	Variou s	60	210,240	500 Kcmil cable 81% Loaded.
Anae Max Ld 10MW - Base (Yr 2009)	9,435	5,847	0	0.0%	153.0%	96.8%	A5	99.9%	Sub 12KV	0	0	500 Kcmil cable 152% Loaded.
Anae Max Ld 10MW - DG/CHP (Yr 2009)	9,157	5,675	5,080	55.5%	63.0%	98.8%	A5	100.0%	Sub 12KV	Variou s	6,597,500	500 Kcmil cable 63% Loaded.
Anae Max Ld 10MW - Caps (Yr 2009)	9,625	5,965	7,618		132.0%	97.9%	A5	100.0%	Sub 12KV	60	457,080	500 Kcmil cable 132% Loaded.

Table 9. Results of Anaehoomalu 13 Load Flow Runs

reduce transmission losses and reduce loading of critical transmission lines to some extent, no quantified "transmission credit" has been given to DER, as micro-grid-sited DER cannot justify delay in reconductoring these lines. Excerpts from the 7300 and 7200 Line Overload Report, which uses analyses of the use of CHP to resolve 7300 and 7200 line overload situations, are included in Appendix F.

DG for Emergency Power. A major customer motivation to install DG is to have a back-up power supply in the event of a HELCO grid outage. The benefits are significant, but they are customer-specific and accrue to the customer. Thus, the reliability benefits of micro-grid-sited DER should be considered by the end user when deciding whether to install DG; they should not quantitatively factor into HELCO's IRP process. Some other evaluations of micro-grid technology have suggested that the micro-grid be capable of separating from the main system grid during times of trouble and operate as an electrical island. This theoretically could improve the reliability for the loads served within the micro-grid. However, this solution requires complicated power-balancing and control within the microgrid, and a means to reconnect to the primary electric grid once the system has stabilized. From a power system perspective, the fragmentation of the electric grid into various electrical islands during disturbances would create a much more complicated system with decreased stability during upset conditions. The smaller the electrical island, the more difficult it is to stabilize and operate. Reconnection of islands requires a synchronizing interface. Post-disturbance recovery would be much more complicated and it is probable that the overall reliability of the electric grid could be reduced, so that the customer base as a whole experienced reduced reliability than if the system remained interconnected during disturbances.

6.0 Study Conclusions

HELCO's challenge is to provide electricity as inexpensively as possible while meeting the reliability needs of its customers and the environmental and land use requirements of the Island of Hawaii. This is a challenge, since:

- The largest load growth is occurring across the Island from the majority of HELCO's generators.
- Three existing cross-island transmission lines on HELCO's system are already operating at capacity.
- Increasing construction of intermittent and non-dispatchable electric generation (from renewable sources) has significant cost, reliability and stability consequences for HELCO. These demands create a greater need for dispatchable generation that can provide frequency regulation, voltage regulation, and load-following support.
- The growing electric loads will necessitate feeder and substation reinforcement and construction in the Kona area.

In this set of circumstances, distributed energy resources – local generation and combined heat and power systems – at certain customer sites seem to have many advantages, including:

- Improved efficiency in generating electricity and providing thermal energy in an environmentally acceptable manner.
- Possibility to reduce or defer distribution system expansion investments.
- Reduced loading of cross-island transmission systems.
- Improved reliability of electric and thermal service to the consumer.

In order for all these potential benefits of DER to be realized from the HELCO system perspective, dispatchability, reliability, and operability of the systems are critical. If a DER installation is owned by the utility, these factors can effectively be controlled and benefits realized. If owned by a customer, suitable contractual arrangements would be required between the customer and the utility to assure minimum design, operability, reliability, and dispatchability requirements are met. There are significant system design issues in incorporating large amounts of distributed generation to identify:

- What ancillary services can be provided by the distributed generation as compared to conventional generation (frequency regulation, voltage regulation, and supporting the grid during system disturbances (faults, loss of generation, loss of load))
- Control system design both on the low-voltage side of the microgrid, and the SCADA/EMS interface: overall technical design to integrate the generation into the total system dispatch and to implement the controls and communications systems – and assess the costs

6.1 Study Results and Conclusions

Three HELCO feeders and substations were analyzed, in a case study approach, to determine if these potential benefits of DER are in fact realistic. The results of those assessments are summarized in Tables 10 and 11 below. (Line impedances, ratings, conductor sizes, connected KVA loading, estimated peak loads, etc. were obtained for the three circuits under study, and 1-line diagrams were created for the DistnView simulation runs. Such complete distribution system and customer load data integrated with 1-line diagrams are not available for every HELCO circuit.)

However, the study was not aimed at deciding, for example, whether hotel X should install Y MW of local generation or combined heat and power systems. The scenarios examined in this study did NOT represent full engineering and detailed cost studies of alternative distribution system expansion plans for these feeders and customers. The decision to install DG or CHP of a given size and type and a specific customer location will be dependent upon:

- The feeder, site and load characteristics of the location;
- The equipment costs (DG/CHP, installation, auxiliary equipment site preparation, etc.), fuel and energy costs, and expected energy needs of the location; and
- The permitting requirements of the location.

Rather, the results should be interpreted as answering the question, “Can a DER micro-grid approach enable HELCO to meet expected load growth while maintaining acceptable power quality and reliability?” This study has found that distributed generation and combined heat and power sited on the HELCO distribution system are indeed technically sound and economically viable options for HELCO and its customers to consider.

The study focused on reciprocating engines for distributed generation, with possible waste heat utilization for CHP systems. For this analysis, distributed renewable sources were not considered as their current costs and technical characteristics are not competitive with “conventional” distributed generation technologies, making them not economically feasible *for widespread implementation* within the next 5 to 10 years.

The study’s recommendation is that distributed energy resources warrant consideration as an alternative in HELCO’s resource planning process.

6.2 Next Steps

In order to take full advantage of DER, it will be necessary for HELCO to develop additional analysis and implementation (design/construction/installation) procedures that enable a full evaluation of proposed DER installations and a comparison of DER with other system reinforcement options. Four research, design or development activities are recommended:

1. Develop a methodology for assessing HELCO’s grid stability and security with large amounts of non-dispatchable and intermittent (i.e., renewable) generation. Determine the regulating reserve requirements – capacity up and down, location, response time – under various load, weather, and generator unit commitment conditions.
2. Develop a specification for communications, monitoring, and control (dispatch) requirements – both equipment and software – for DER to be dispatched by HELCO’s control center, KOCC, so that DER can be applied to HELCO’s system needs.
3. Determine the interconnection strategy of the micro-grid during disturbances: to remain interconnected or to separate. The protection and control strategy is different depending upon this strategy.
4. Determine the characteristics required of distributed generators for them to meet the reliability standards to be considered firm dispatchable generation and to supply ancillary services – voltage regulation, frequency regulation, ride-through capability during fault conditions - under various system conditions.
5. Study a high-growth area of interconnected feeders and substations in the HELCO distribution system over a multi-year period. The objectives are to determine the best size, type, location and installation times of DER and to better evaluate DER’s benefits and costs to HELCO and to its customers.

Feeder	Year	Bus	Site	Customer Load	Gen Unit Type	DER Capacity (KW)	Unit Cost ($/KW)	Total Capital Cost ($)	Load Reduction (KW)
Kailua 15	2003	KUA1	North Kona Shopping Ctr	Commercial	DG	300	1,100	330,000	
Kailua 15	2003	P2	Kona Coast/Lanihau Shopping Ctr	Commercial	DG	450	1,100	495,000	
Kailua 15	2003	A3	Coconut Grove Water Front Row	Commercial	CHP	450	1,750	787,500	112.5
Kailua 15	2003	A4	Royal Kona Resort	Hotel	CHP	600	1,750	1,050,000	150
Kailua 15	2003	A6	Various Condos	Multi-Family	DG	450	1,100	495,000	
Kailua 15	2003	A7	Various Condos	Multi-Family	DG	450	1,100	3,157,500	
			TOTAL DG/CHP Capacity & Cost			**2,700**		**6,315,000**	
Kailua 15	2009	A3	Coconut Grove Water Front Row	Commercial	DG	300	800	240,000	
Kailua 15	2009	A4	Royal Kona Resort	Hotel	DG	300	800	240,000	
			Add'l DG/CHP Capacity			**600**		**480,000**	
			TOTAL DG/CHP Capacity & Cost			**3,300**		**6,795,000**	
Kahaluu 12	2003	Sheraton	Keauhou Bay Sheraton	Hotel	CHP	740	1,750	1,295,000	185
Kahaluu 12	2003	P47X	Kahakai School/Condos	School	CHP	600	1,750	1,050,000	150
Kahaluu 12	2003	AliiOH2	Condos	Multi-Family	DG	0	0	0	
Kahaluu 12	2003	AliiOH3	Residential Subdiv	Residential	DG	600	1,100	660,000	
Kahaluu 12	2003	KamIIITap	Kanaloa Resort/Condos	Condos	DG	600	1,100	660,000	
			TOTAL DG/CHP Capacity & Cost			**2,540**		**3,665,000**	
Kahaluu 12	2009	AliiOH2	Condos	Multi-Family	DG	600	1,100	660,000	
Kahaluu 12	2009	AliiOH3	Residential Subdiv	Residential	DG	900	800	720,000	
Kahaluu 12	2009	KamIIITap	Kanaloa Resort/Condos	Condos	DG	600	800	480,000	
			Add'l DG/CHP Capacity			**2,100**		**1,140,000**	
			TOTAL DG/CHP Capacity & Cost			**4,640**		**4,805,000**	
Anaehoomalu	2003	Q5	Wastwater Reclamation Plant	Utilities	CHP	60	1,750	105,000	15
Anaehoomalu	2003	W2	Outrigger Waikoloa Hotel	Hotel	CHP	300	1,750	525,000	75
Anaehoomalu	2003	A2	Waikoloa Hilton	Hotel	CHP	2,250	1,750	3,937,500	562.5
	2003	A5	King's Golf Clubhouse	Commercial	DG	180	1,100	198,000	
			TOTAL DG/CHP Capacity & Cost			**2,790**		**4,765,500**	
Anaehoomalu	2009	W2	Outrigger Waikoloa Hotel	Hotel	DG	200	800	160,000	
Anaehoomalu	2009	A2	Waikoloa Hilton	Hotel	DG	2,000	800	1,600,000	
Anaehoomalu	2009	A5	King's Golf Clubhouse	Commercial	DG	90	800	72,000	
			Add'l DG/CHP Capacity			**2,290**		**1,832,000**	
			TOTAL DG/CHP Capacity & Cost			**5,080**		**6,597,500**	

Table 10. Summary DG and CHP Installations

						Lowest Voltage	
Description Of Run	Load KW	Load kVar	DG kW or Cap kVar	DG Penetration	Highest Device Loading	% P.U.	@Bus
Kailua Max Ld 6mw - Base	5,860	3,163	0		61.0%	97.2%	A7
Kailua Max Ld 6mw - DG/CHP	5,740	3,098	2,700	47.0%	30.0%	99.0%	A7
Kailua Max Ld 6mw - Caps	5,961	3,218	3,087		54.0%	98.5%	A7
Kailua Max Ld 10mw - Base (Yr 2009)	9,968	5,380	0		105.0%	95.5%	A7
Kailua Max Ld 10mw - DG S1-2 (Yr 2009)	9,974	5,384	3,300	33.1%	69.0%	97.5%	A7
Kailua Max Ld 10mw - Caps (Yr 2009)	10,262	5,539	5,844		94.0%	97.4%	A7
Kahaluu Max Ld 7mw - Base	7,106	3,835	0		77.0%	95.4%	P37X
Kahaluu Max Ld 7mw - DG/CHP	6,963	3,758	2,540	36.5%	46.0%	97.6%	P37X
Kahaluu Max Ld 7 mw - Caps	7,176	3,873	1,850		73.0%	96.4%	P37X
Kahaluu Max Ld 14mw - Base (Yr 2009)	13,824	7,463	0		155.0%	90.5%	P37X
Kahaluu Max Ld 14mw - DG 4640KW (Yr 2009)	14,205	7,667	4,640	32.7%	103.0%	94.2%	P37X
Kahaluu Max Ld 14mw - Caps (Yr 2009)	14,538	7,848	6,036		141.0%	94.2%	P37X
Anae Max Ld 7mw - Base	6,665	3,828	0	0.0%	105.0%	97.6%	A5
Anae Max Ld 7mw -DG/CHP	6,203	3,542	2,790	45.0%	52.0%	99.0%	A5
Anae Max Ld 7 mw - Caps	6,126	3,498	3,504		81.0%	98.4%	A5
Anae Max Ld 10mw - Base (Yr 2009)	9,435	5,847	0	0.0%	153.0%	96.8%	A5
Anae Max Ld 10mw - DG/CHP (Yr 2009)	9,157	5,675	5,080	55.5%	63.0%	98.8%	A5
Anae Max Ld 10mw - Caps (Yr 2009)	9,625	5,965	7,618		132.0%	97.9%	A5

Table 11. Summary of Load Flow Runs

APPENDIX A: Kailua 15 Voltage Profiles

Figure 1. Kailua Max Load 6MW SLD Base Case

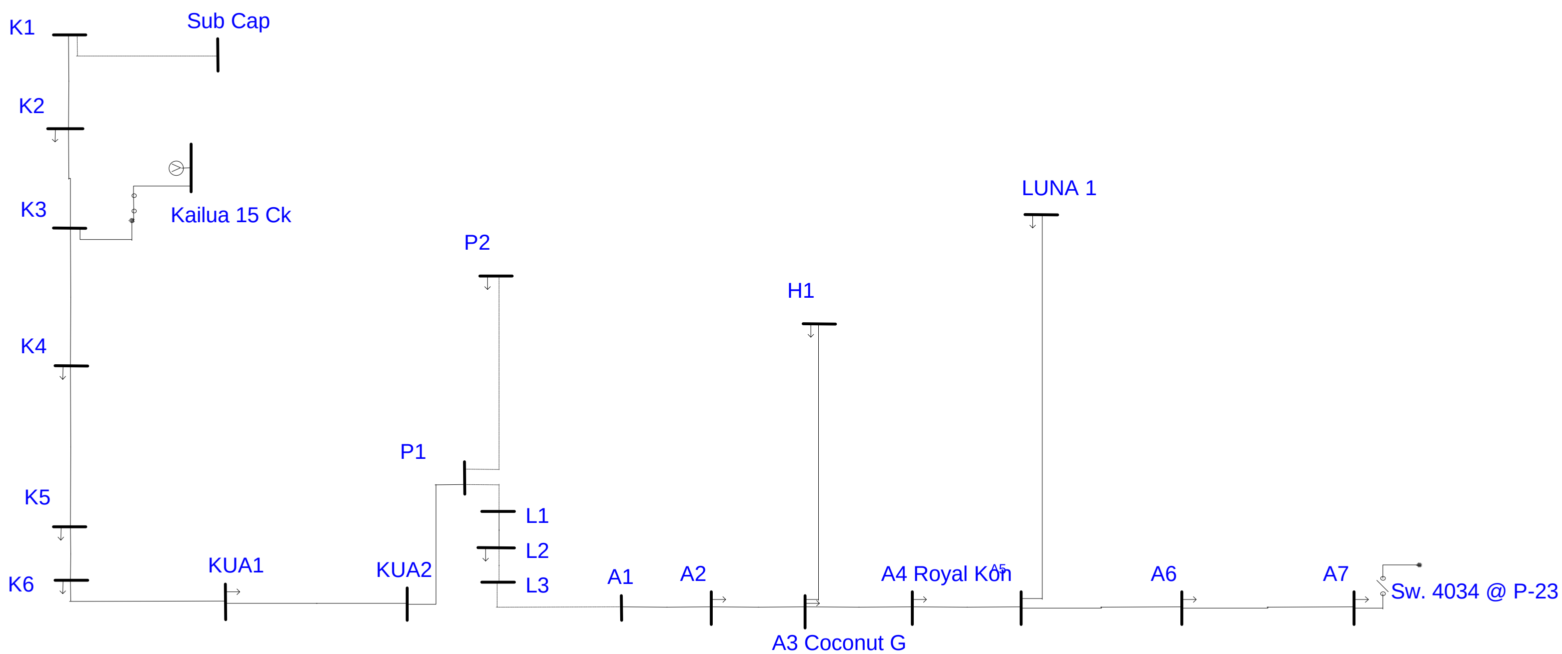


Figure 2. Kailua Max Load 6MW Voltage Profile Base Case

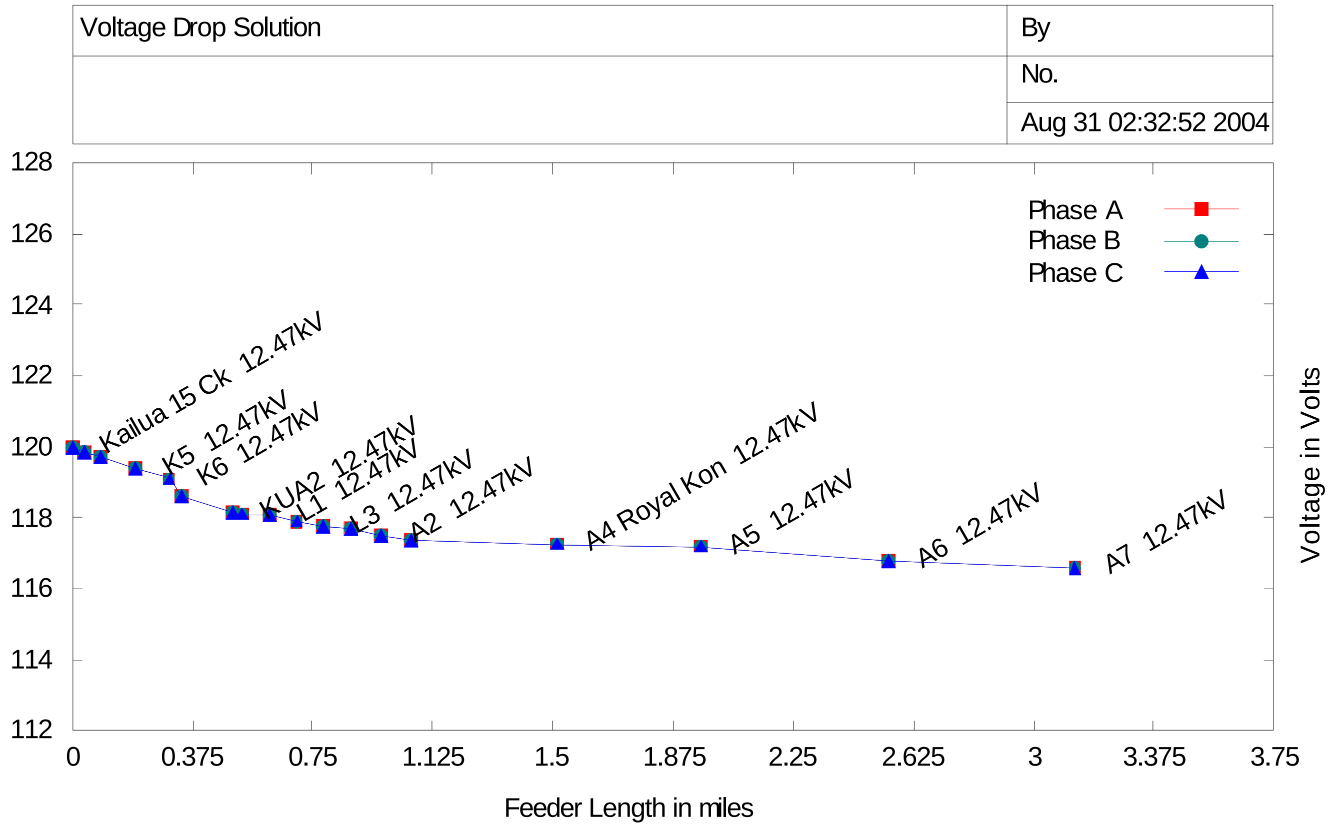


Figure 3. Kailua Max Load 6MW SLD Add DG/CHP 2,700kw

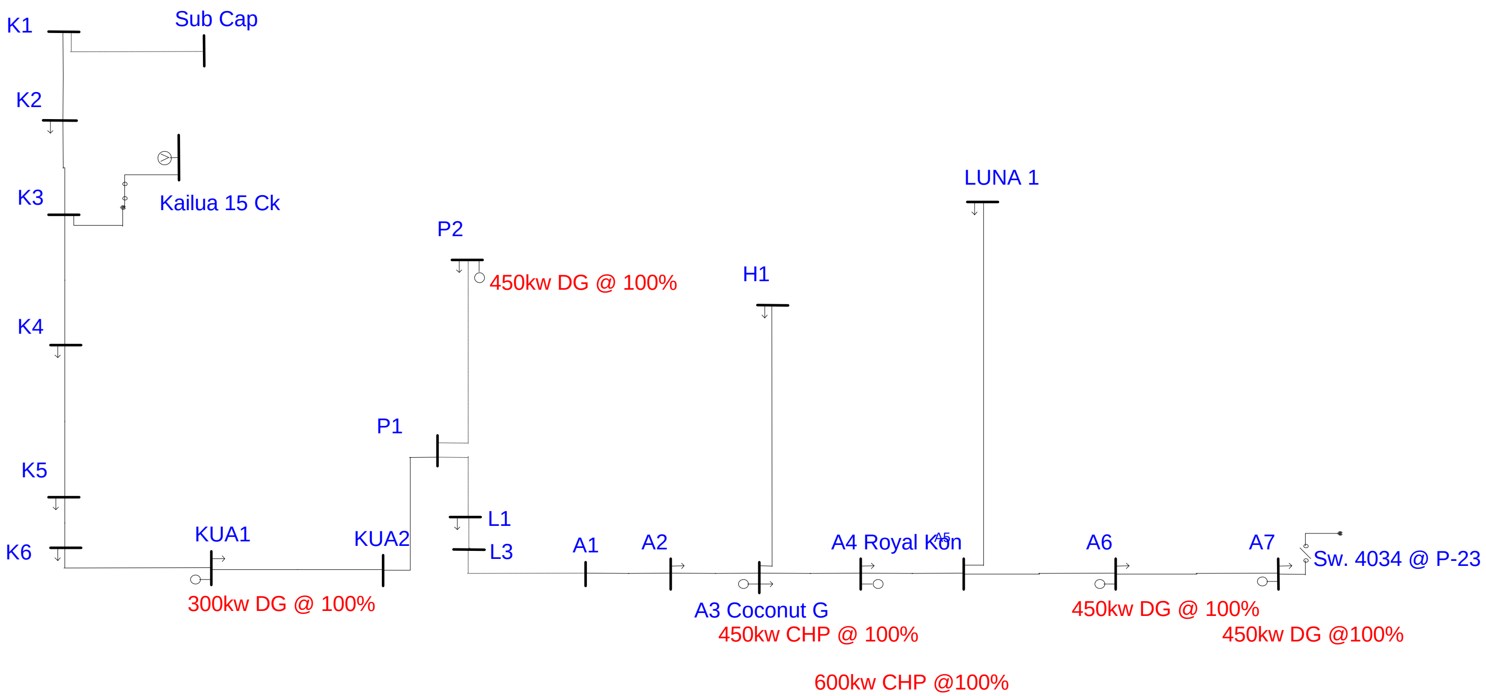


Figure 4. Kailua Max Load 6MW Voltage Profile, Add DG/CHP 2,700kw Scenario 1-2

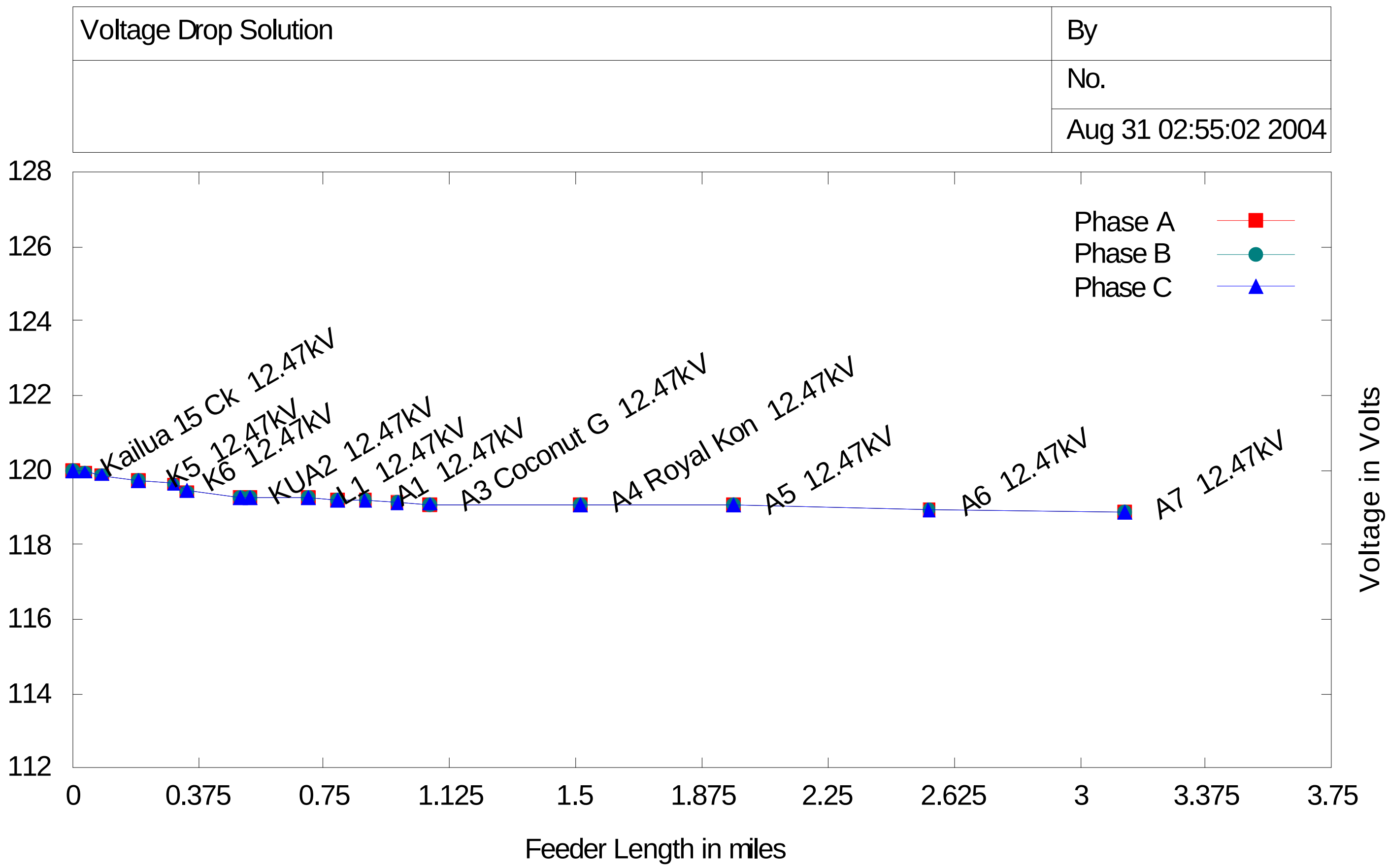


Figure 5. Kailua Max Load 6MW SLD Add 4 Mvar Capacitors

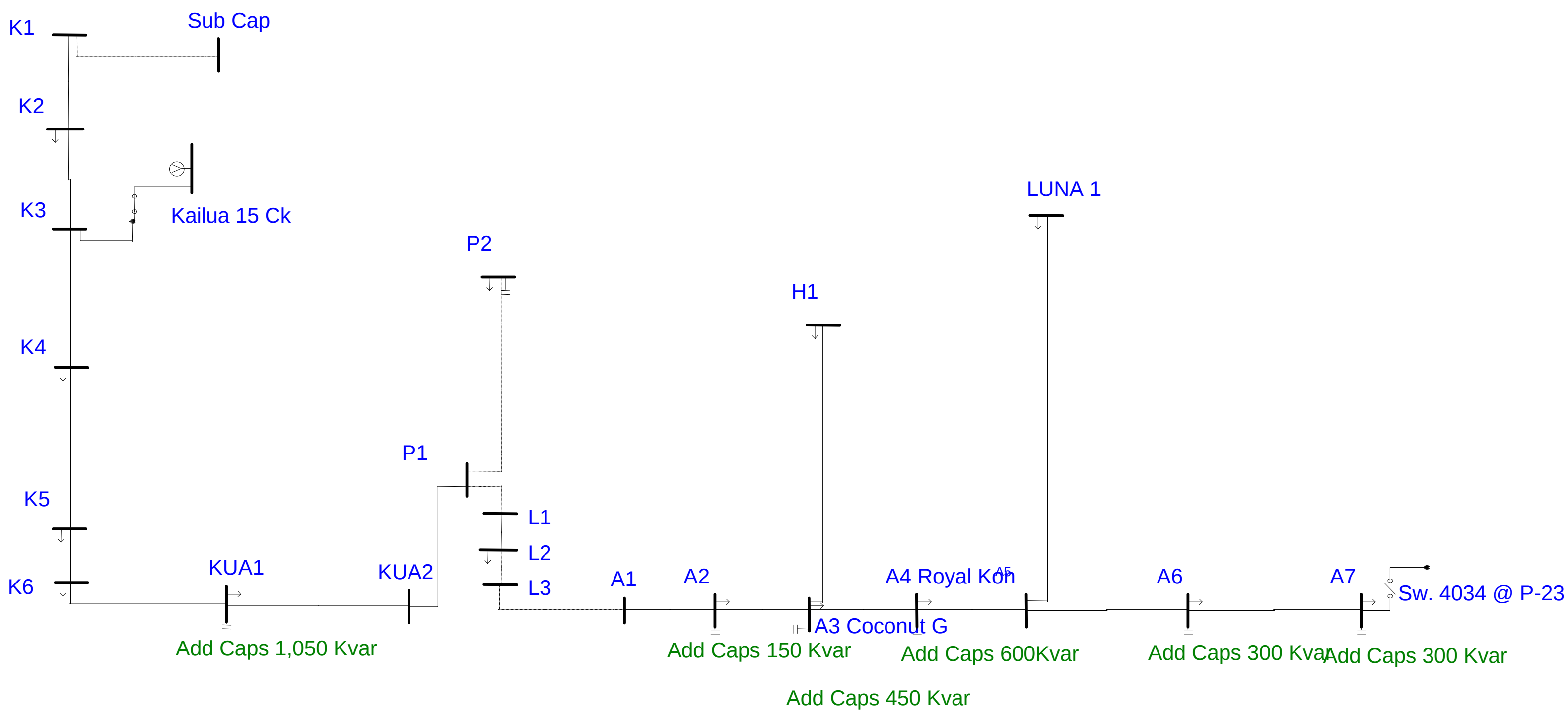


Figure 6. Kailua Max Load 6MW Voltage Profile Add 4 Mvar Capacitors

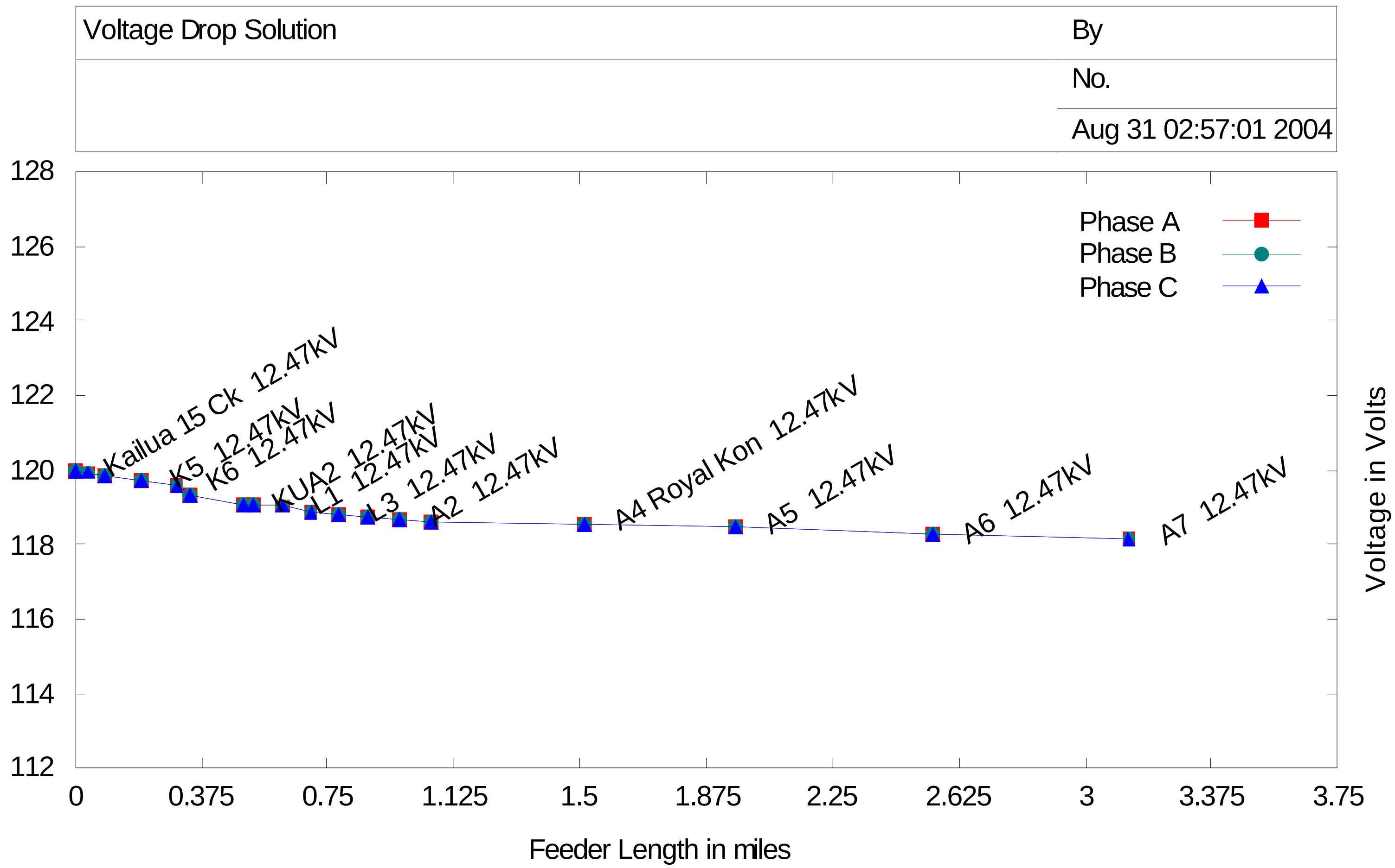


Figure 7. Kailua Max Load 10MW SLD Base Case

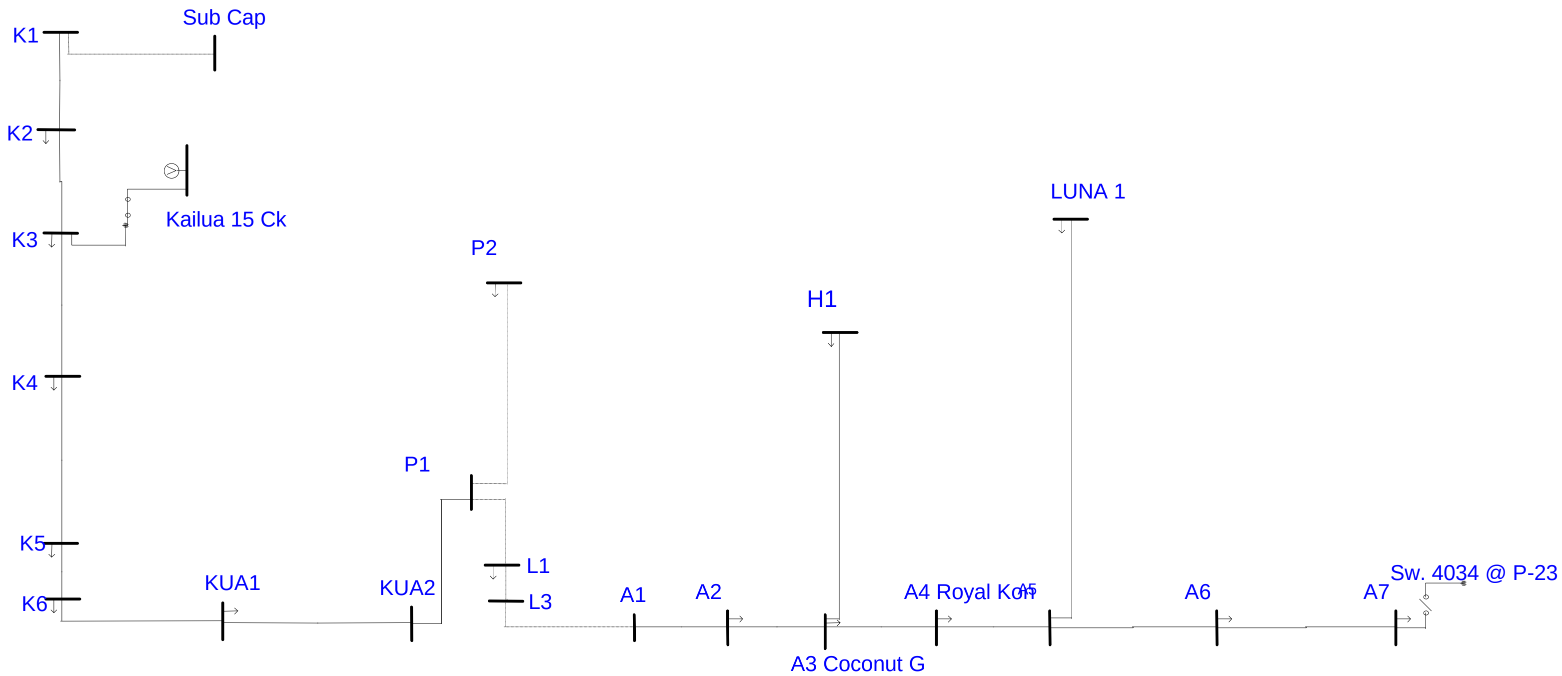


Figure 8. Kailua Max Load 10MW Voltage Profile Base Case

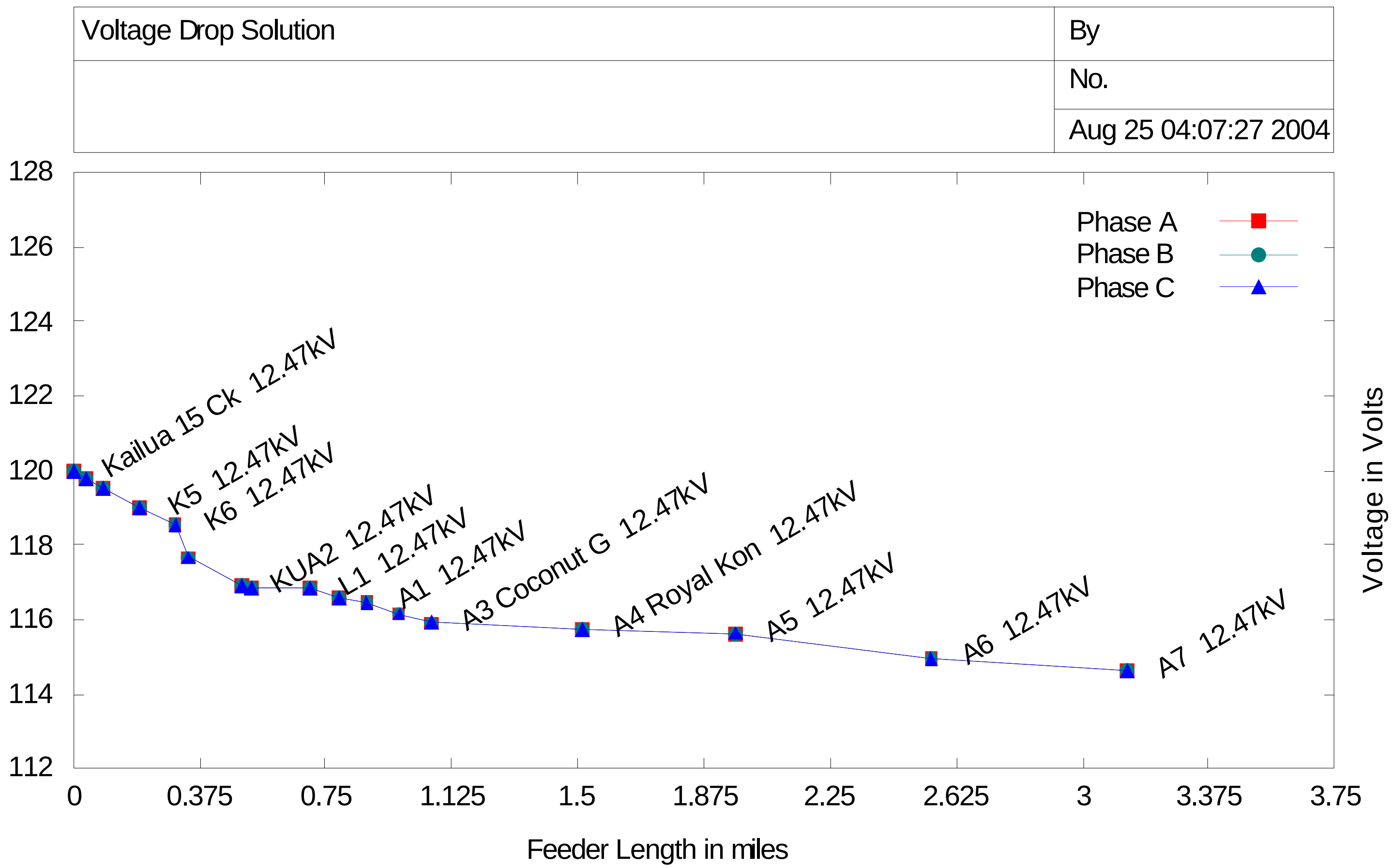


Figure 9. Kailua Max Load 10MW SLD Add DG/CHP

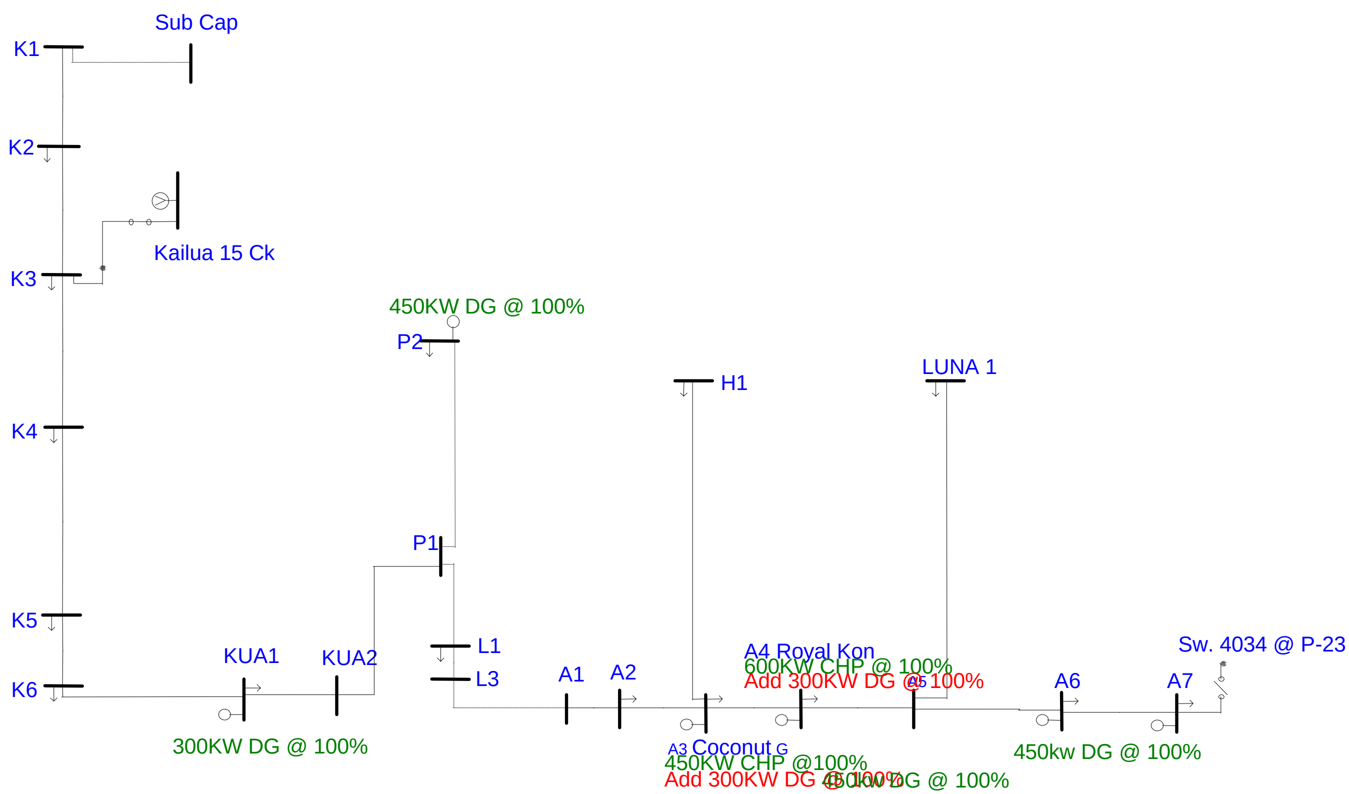


Figure 10. Kailua Max Load 10MW Voltage Profile Add DG/CHP

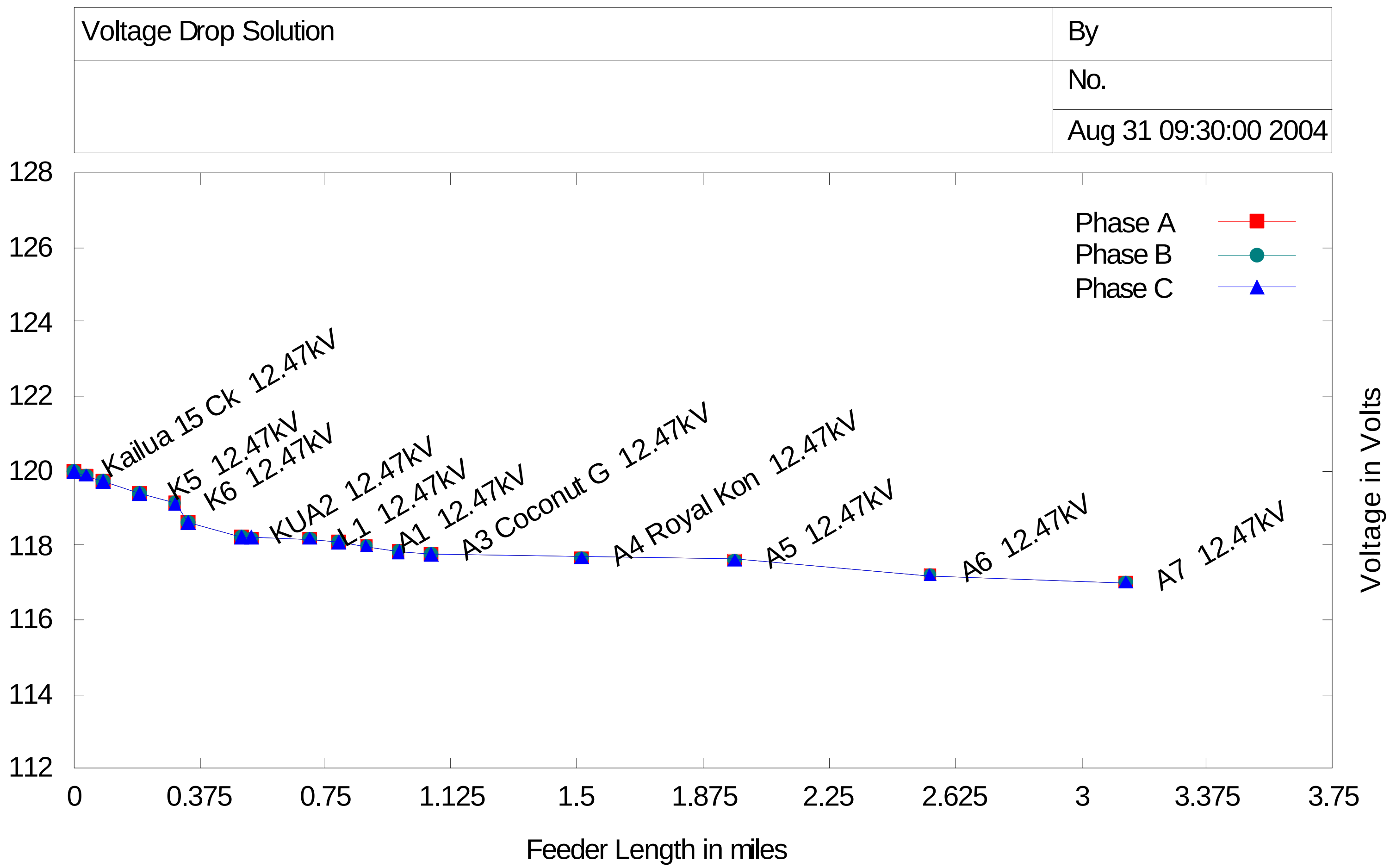


Figure 11. Kailua Max Load 10MW SLD Add 5.8 Mvar Capacitors

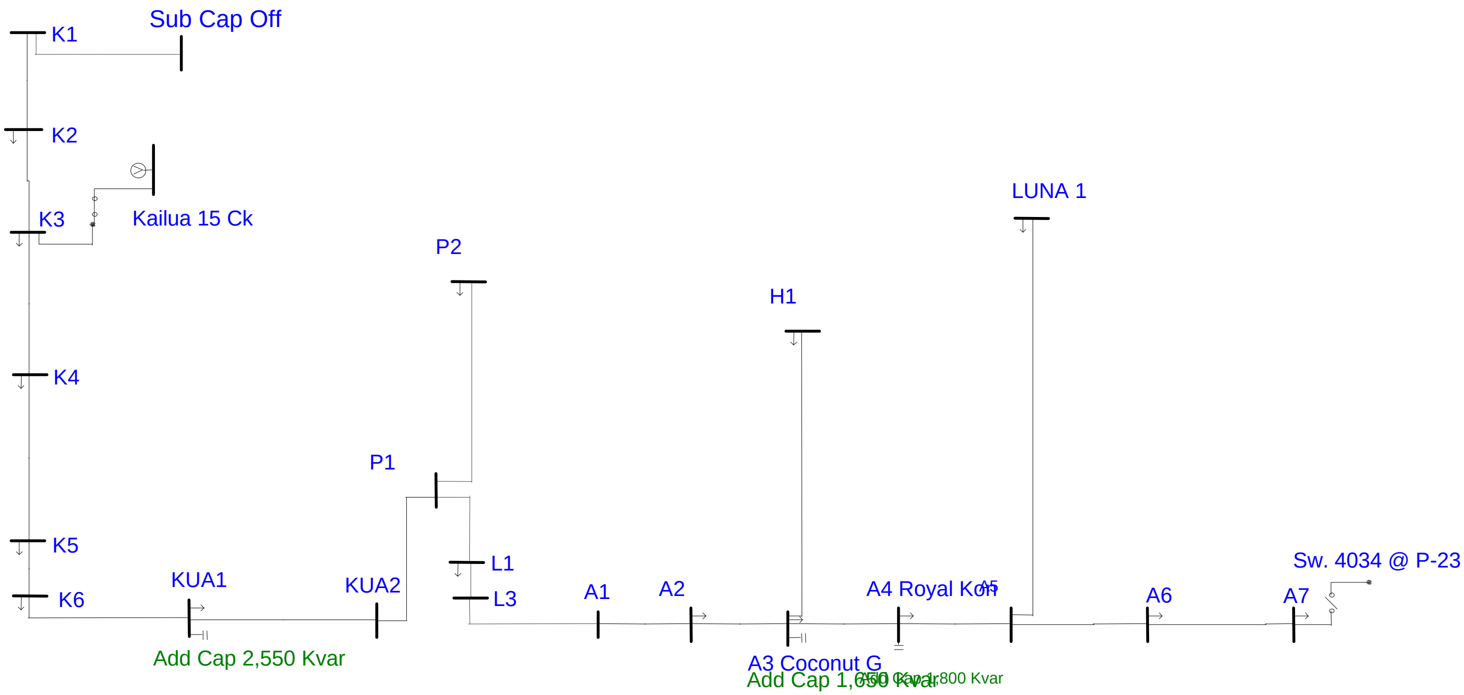
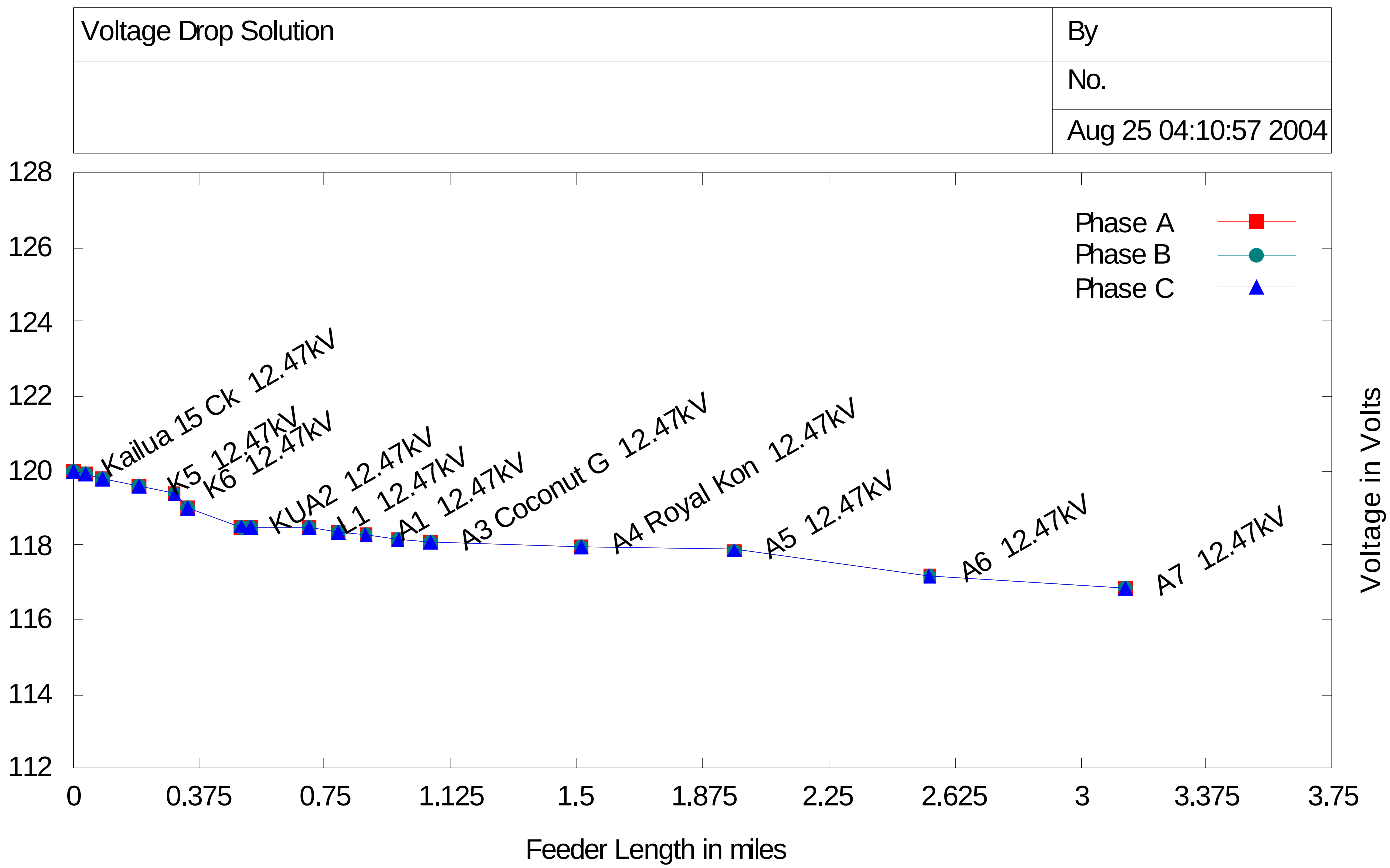


Figure 12. Kailua Max Load 10MW Voltage Profile, Add 5.8 Mvar Capacitors



APPENDIX B: Kahaluu 12 Voltage Profiles

Figure 1. Kahaluu 12 Max Ld 7MW SLD Base Case

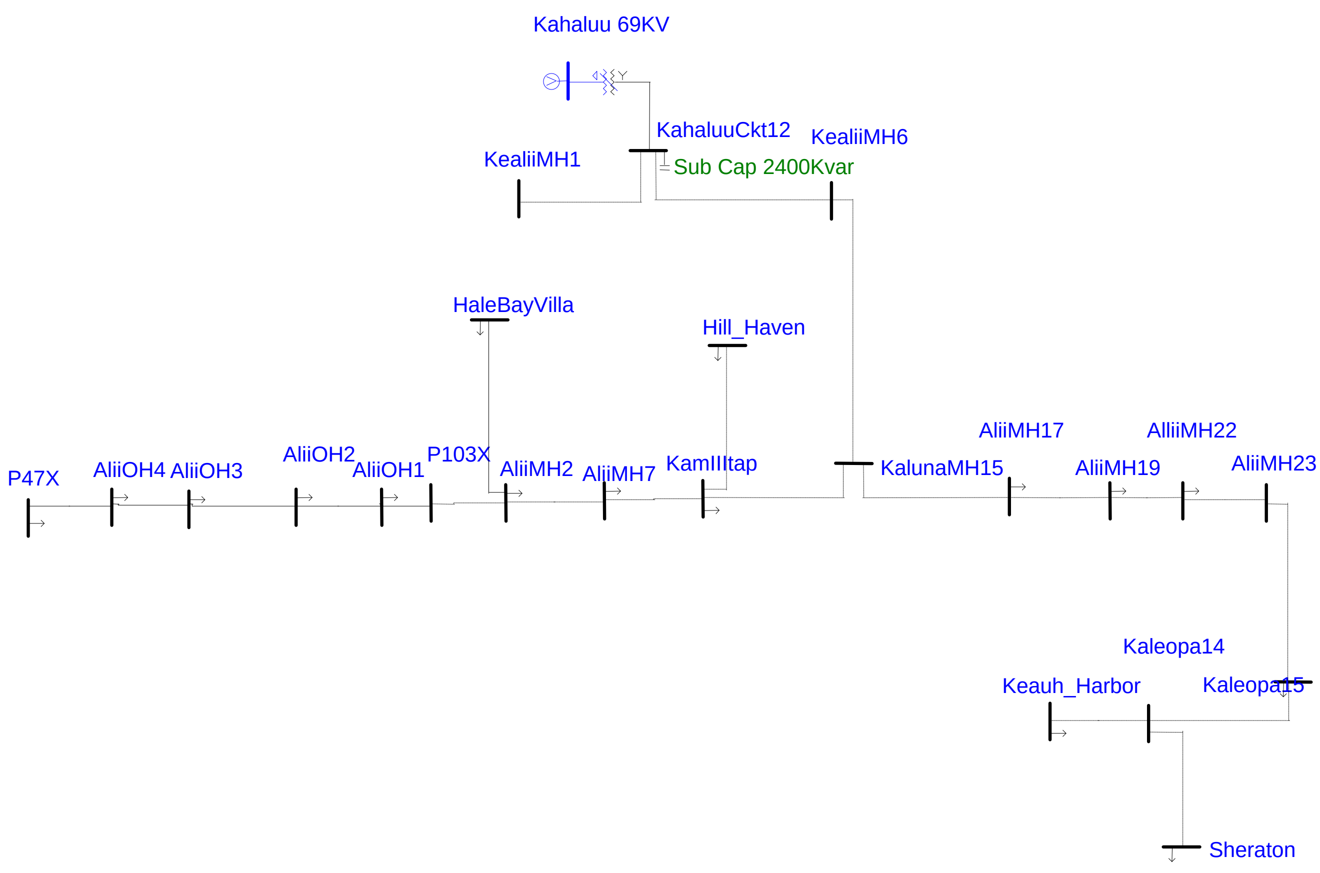


Figure 2. Kahaluu 12 Max Ld 7MW Voltage Profile Base Case (North)

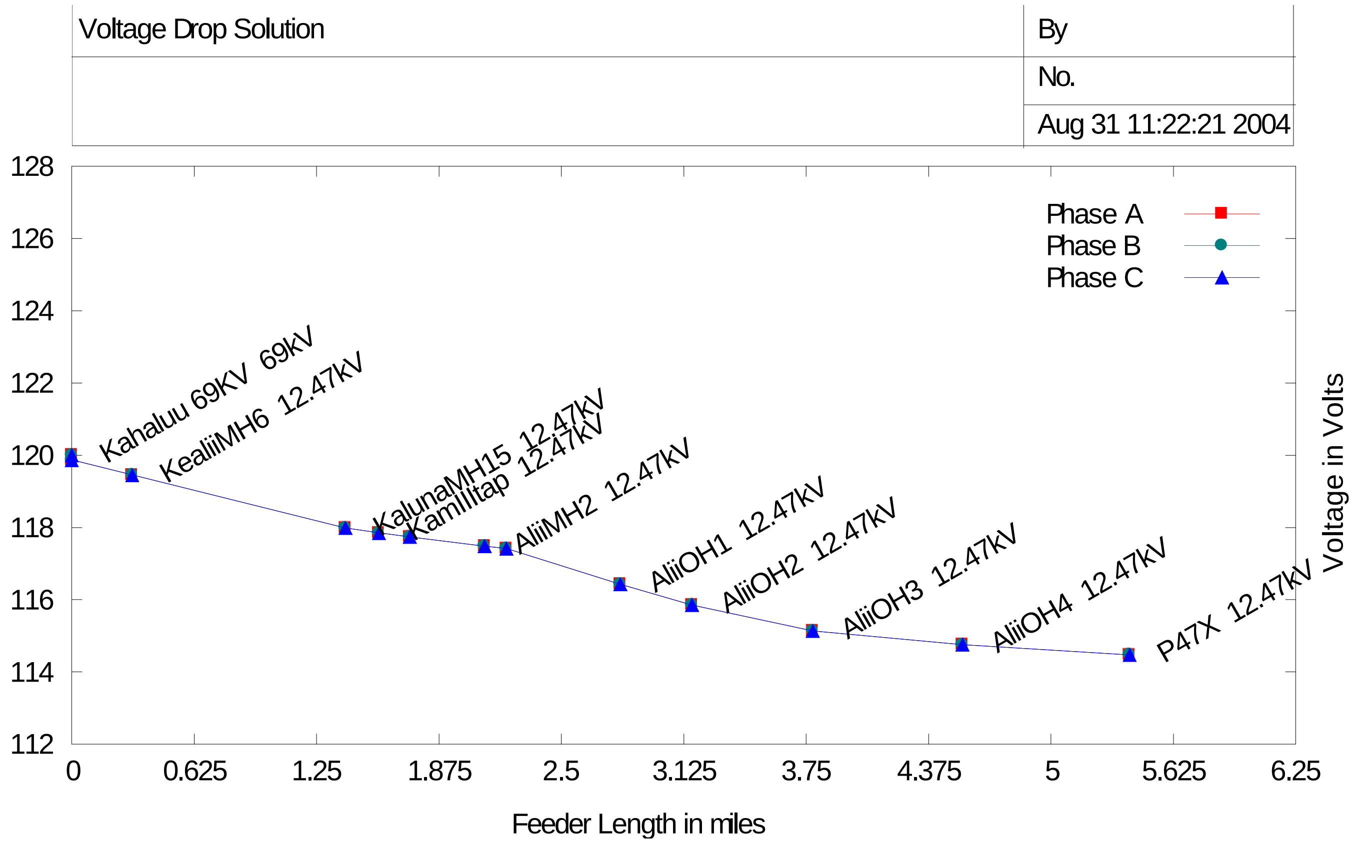


Figure 3. Kahaluu 12 Max Ld 7MW Voltage Profile Base Case (South)

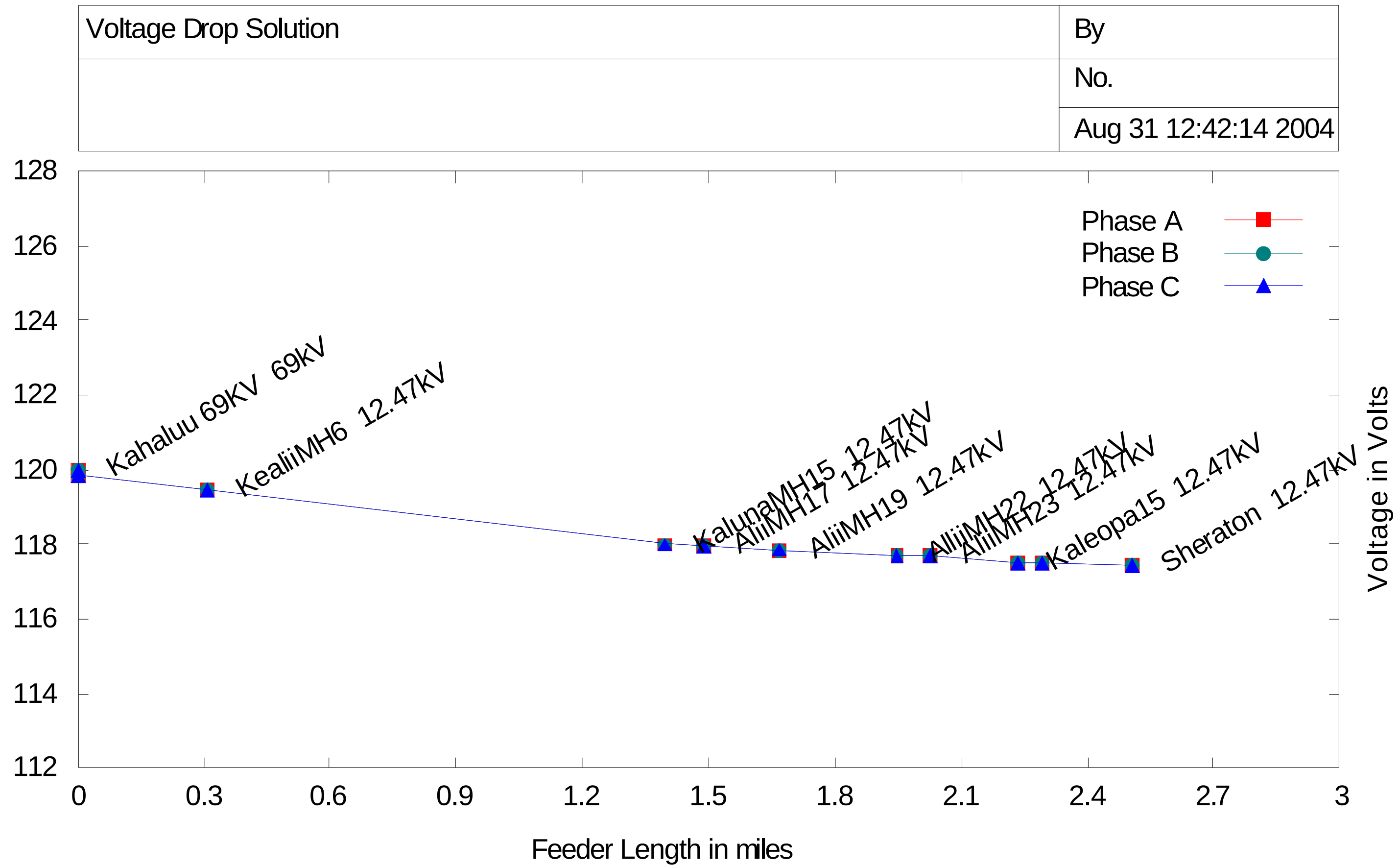


Figure 4. Kahaluu 12 Max Ld 7MW SLD Add DG/CHP 2,540kw

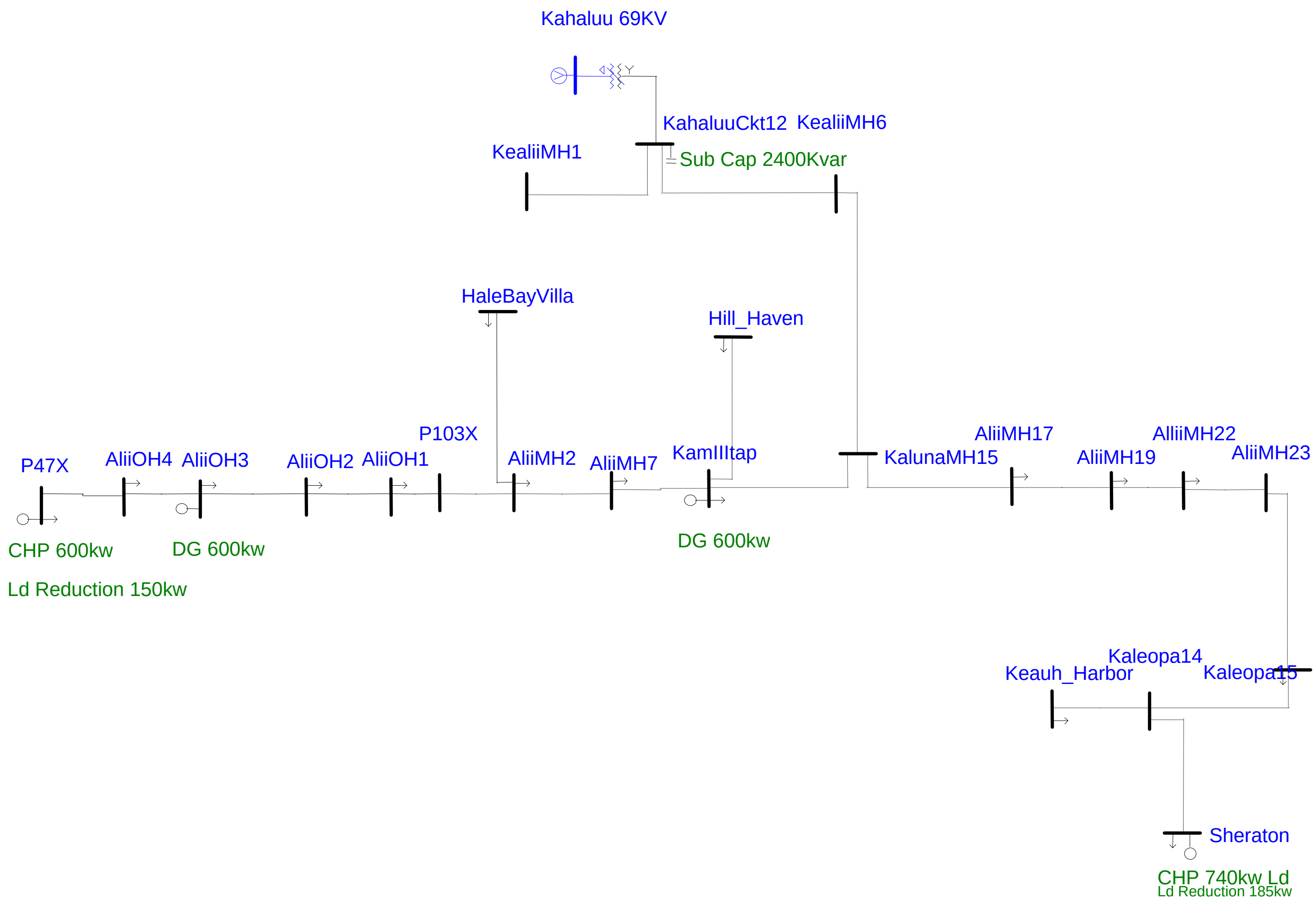


Figure 5. Kahaluu 12 Max Ld 7MW Voltage Profile, Add DG/CHP 2,540kw (North)

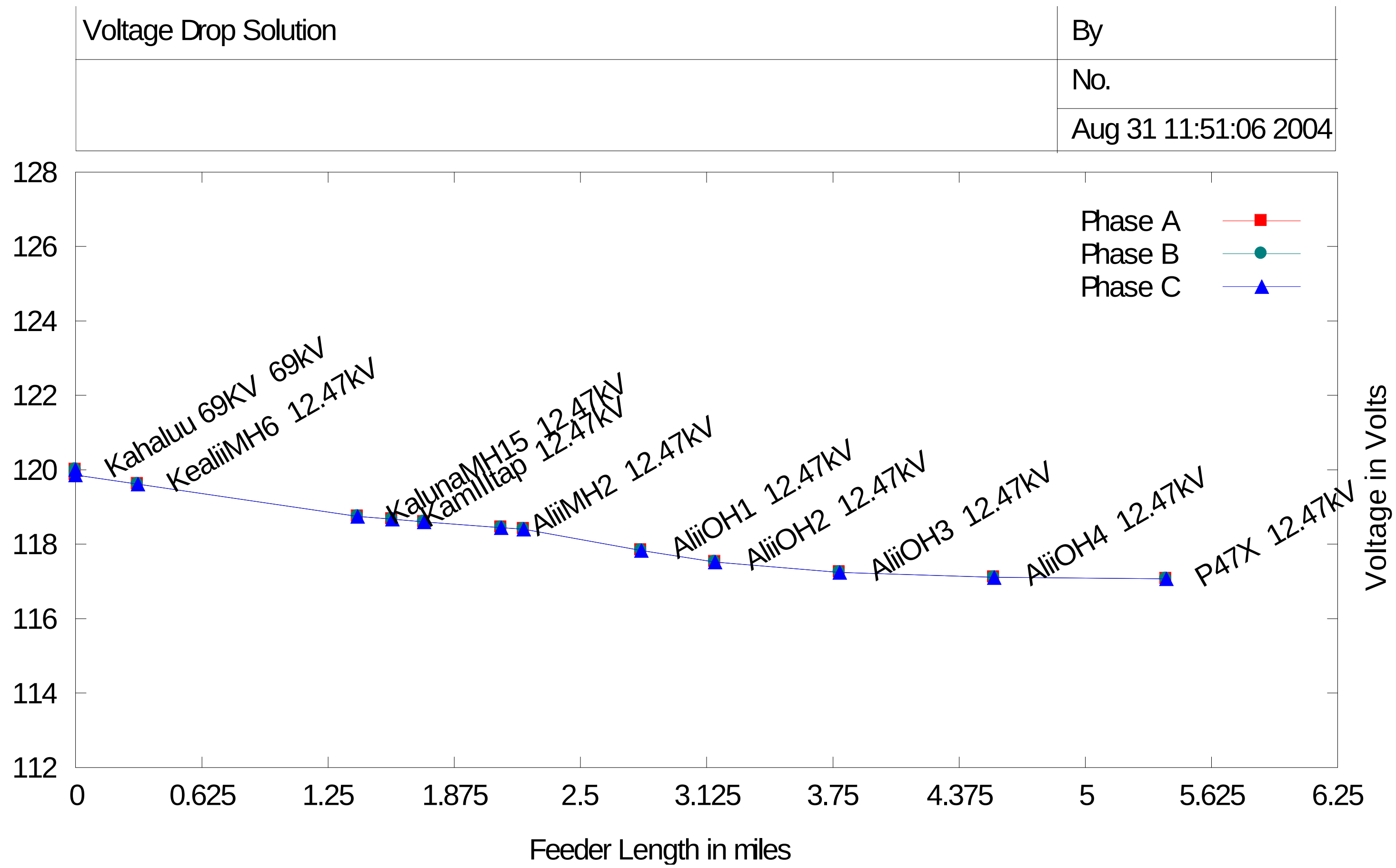


Figure 6. Kahaluu 12 Max Ld 7MW Voltage Profile, Add DG/CHP 2,540kw (South)

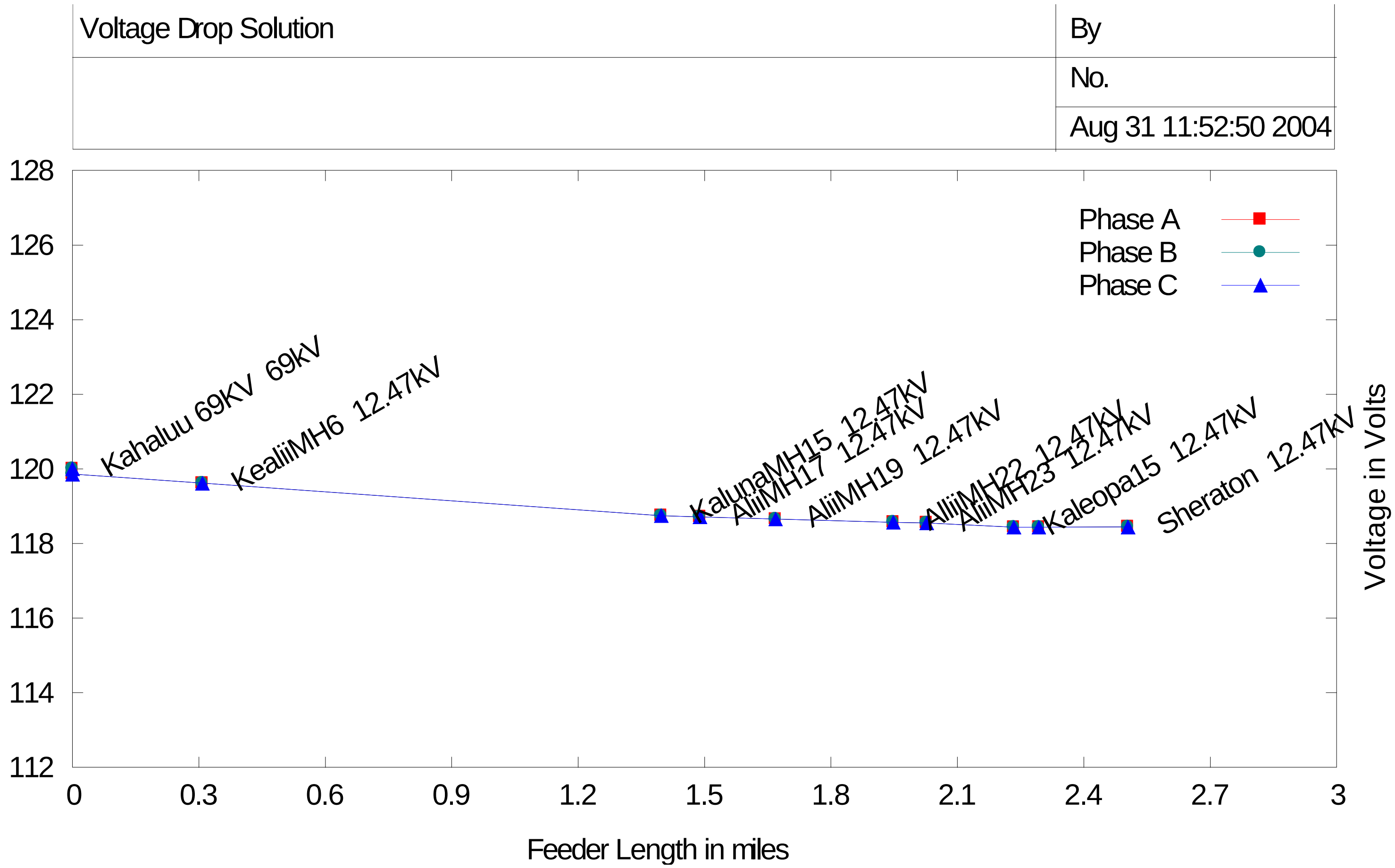


Figure 7. Kahaluu Max Load 7MW SLD, Add 1,850 Kvar Capacitors

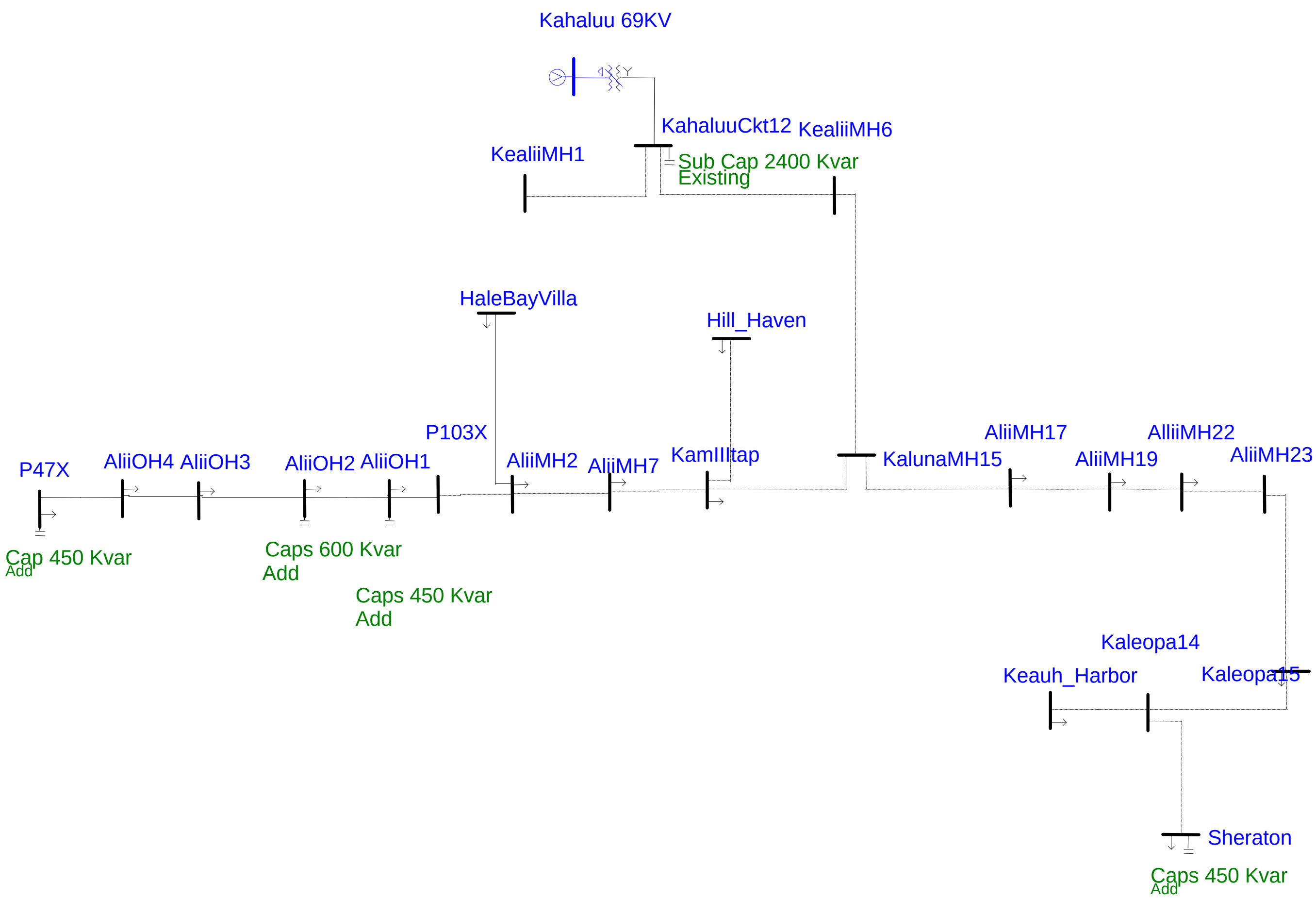


Figure 8. Kahaluu Max Load 7MW Voltage Profile, Add 1,850 Kvar Capacitors (North)

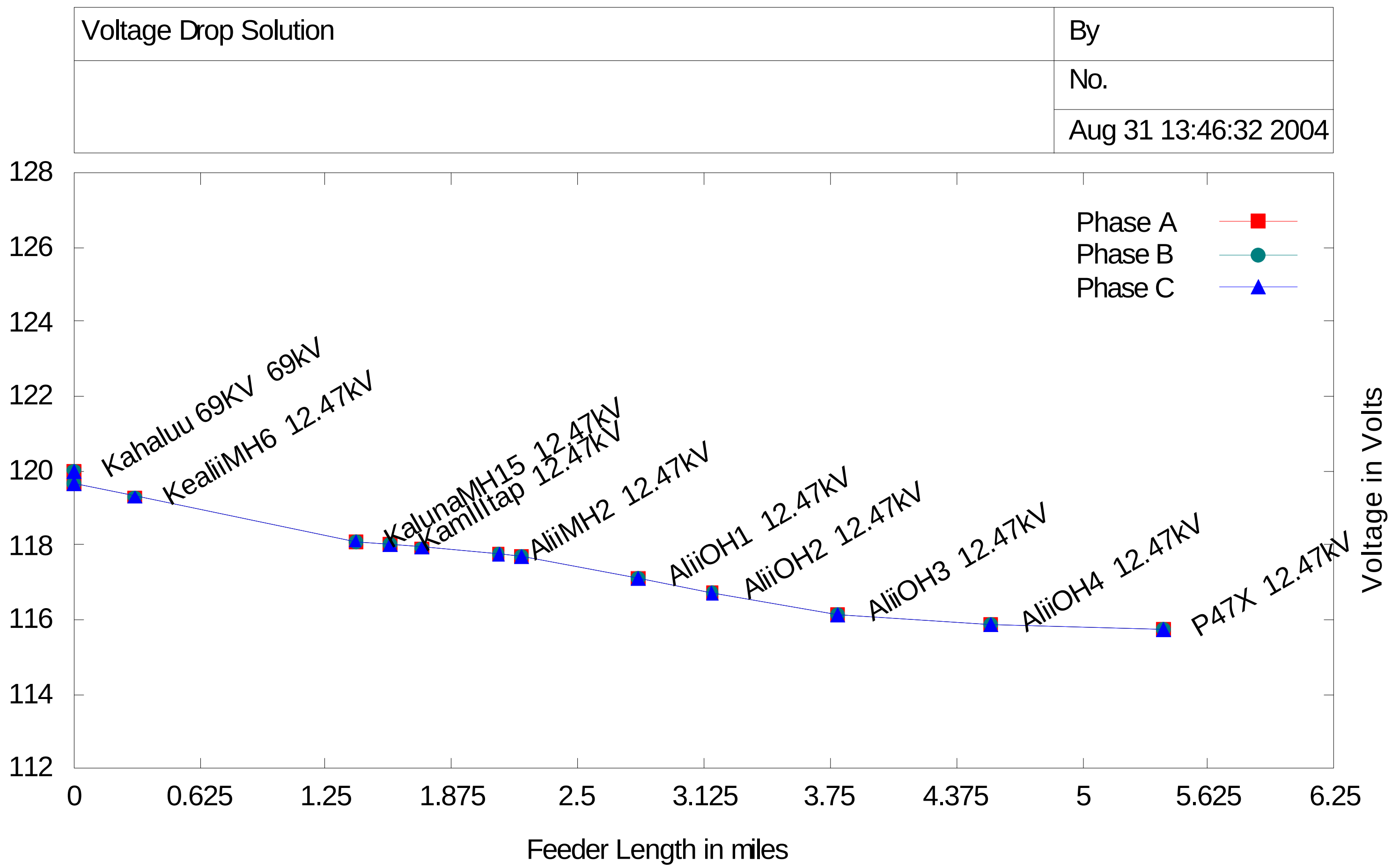


Figure 9. Kahaluu Max Load 7MW Voltage Profile, Add 1,850 Kvar Capacitors (South)

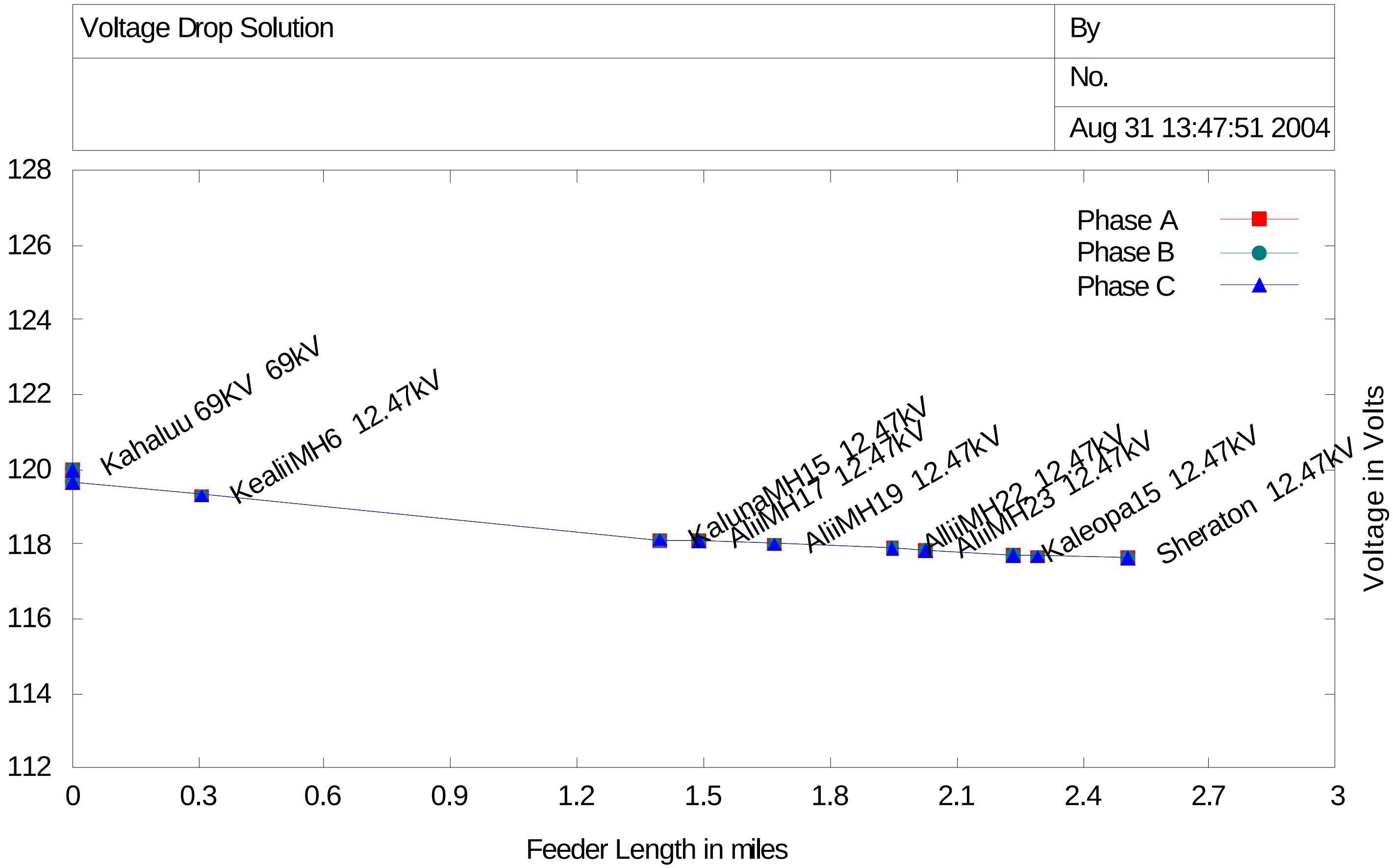


Figure 10. Kahaluu Max Load 14MW SLD Base Case

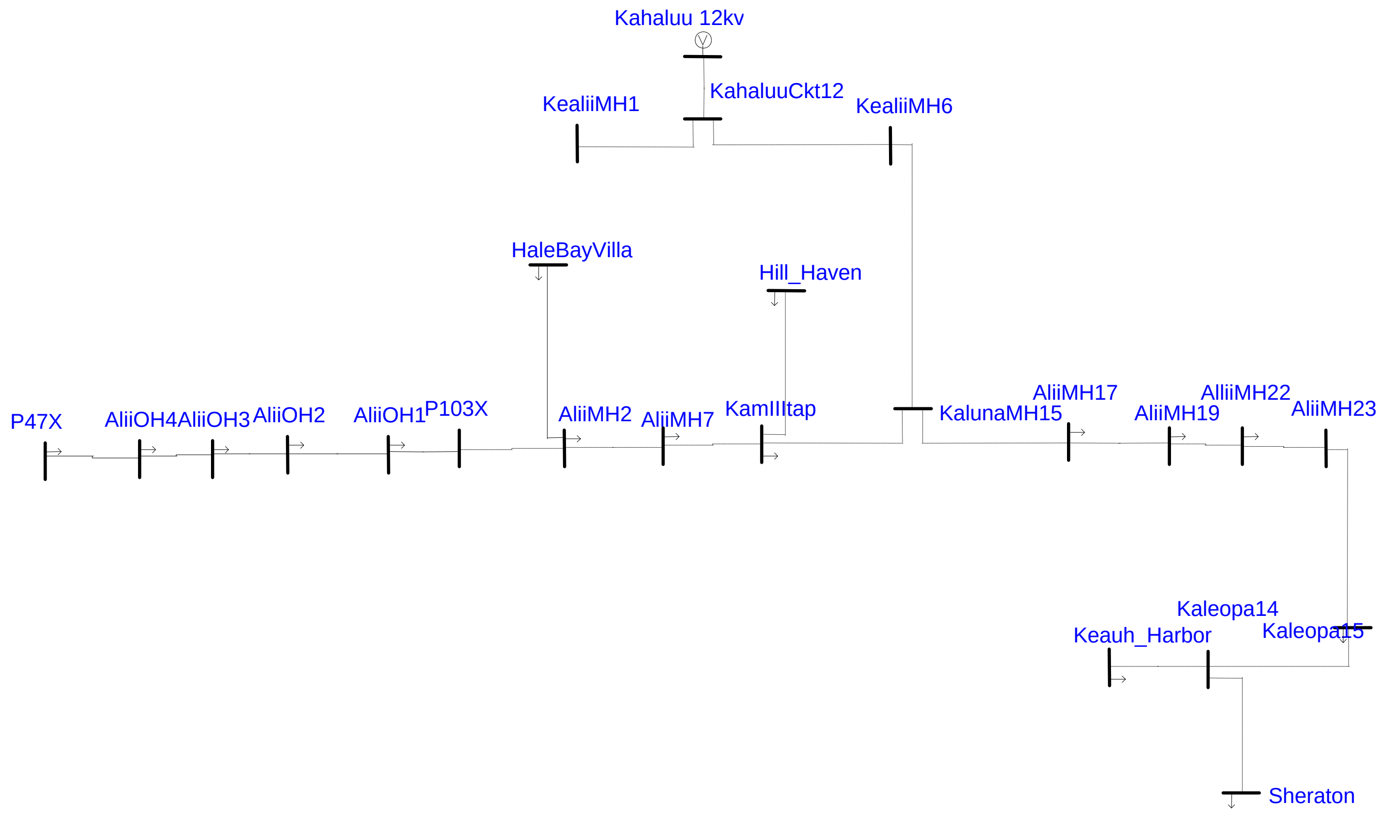


Figure 11. Kahaluu Max Load 14MW Voltage Profile Base Case (North)

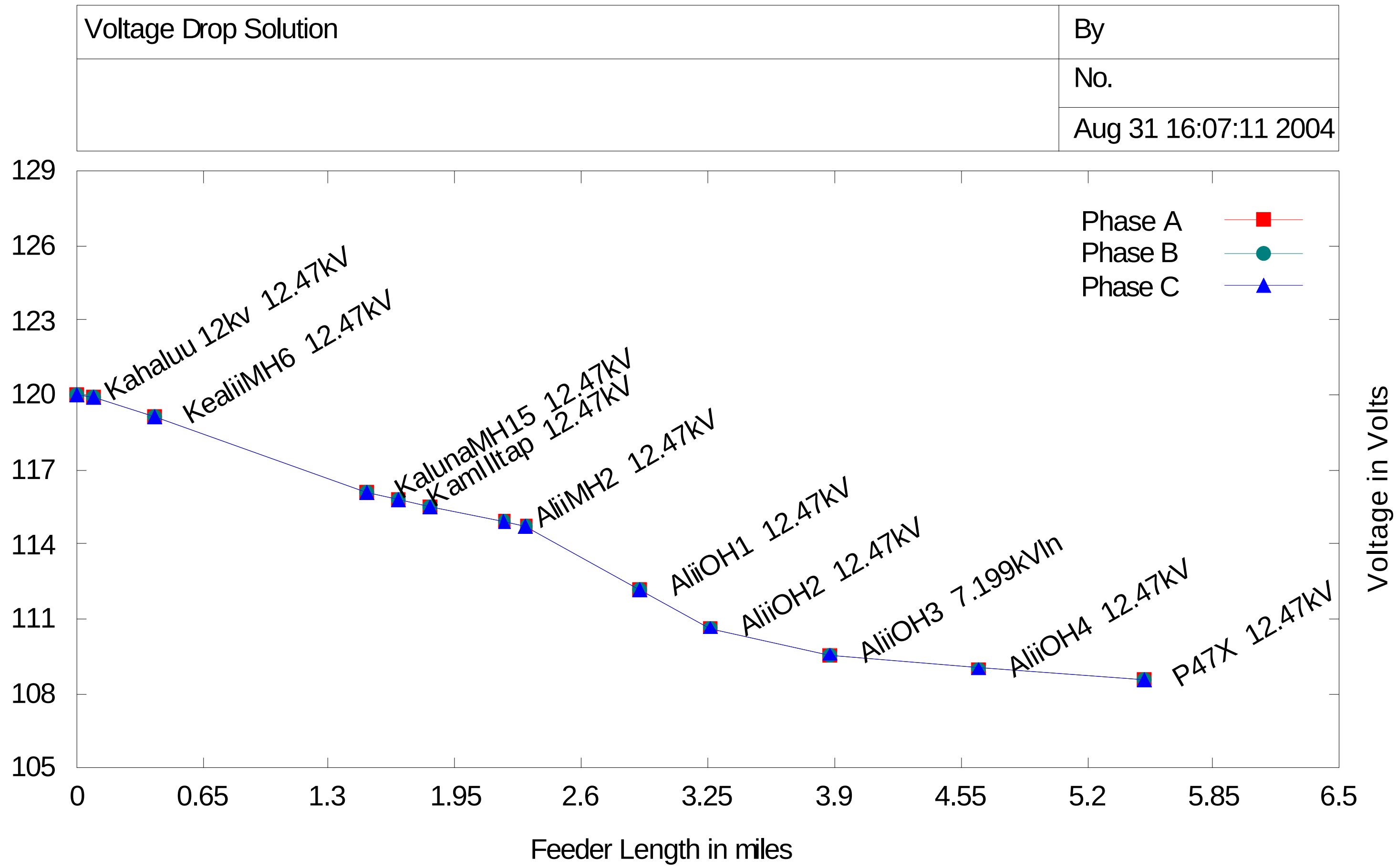


Figure 12. Kahaluu Max Load 14MW Voltage Profile Base Case (South)

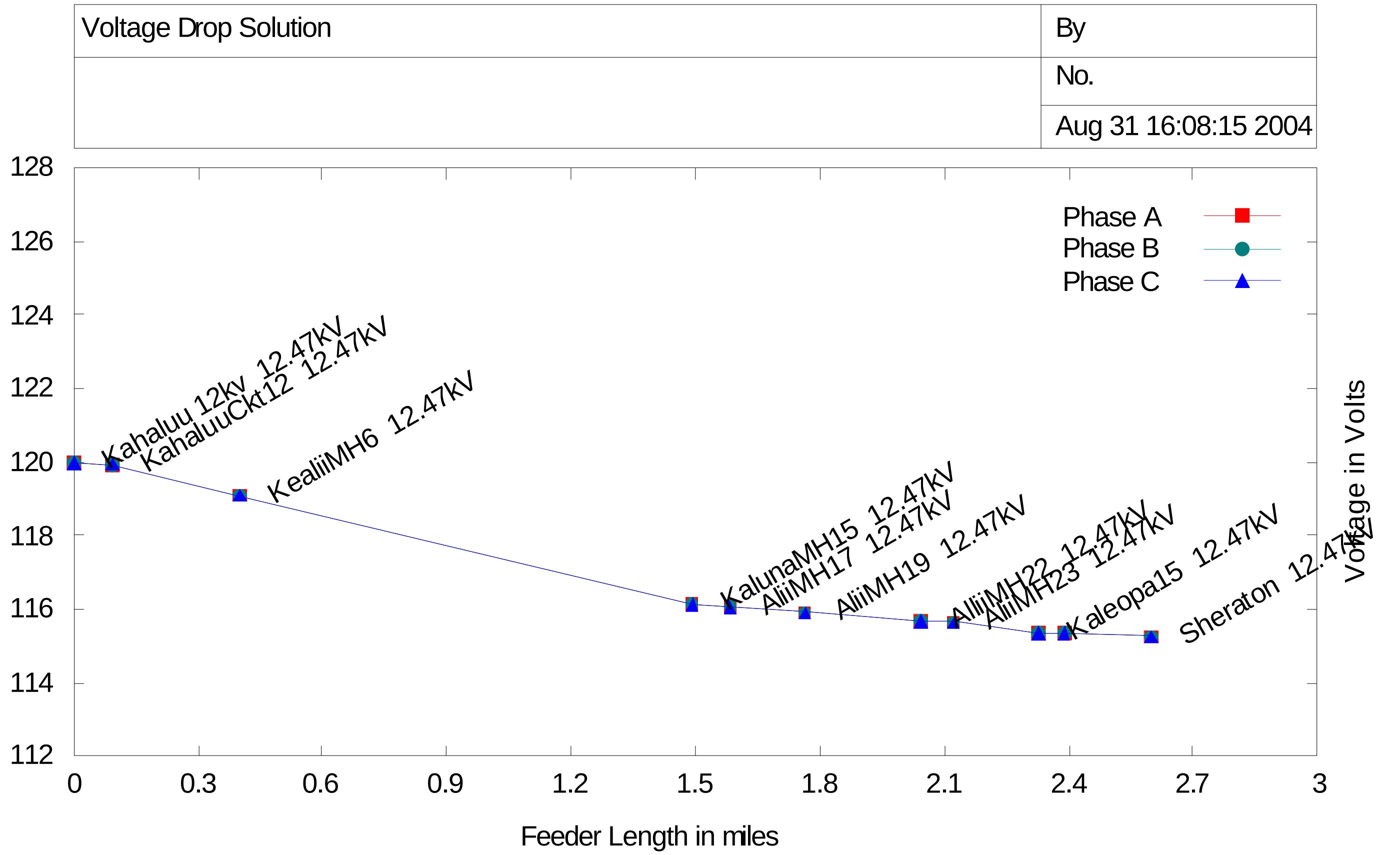


Figure 13. Kahaluu Max Load 14MW SLD Add DG/CHP (North)

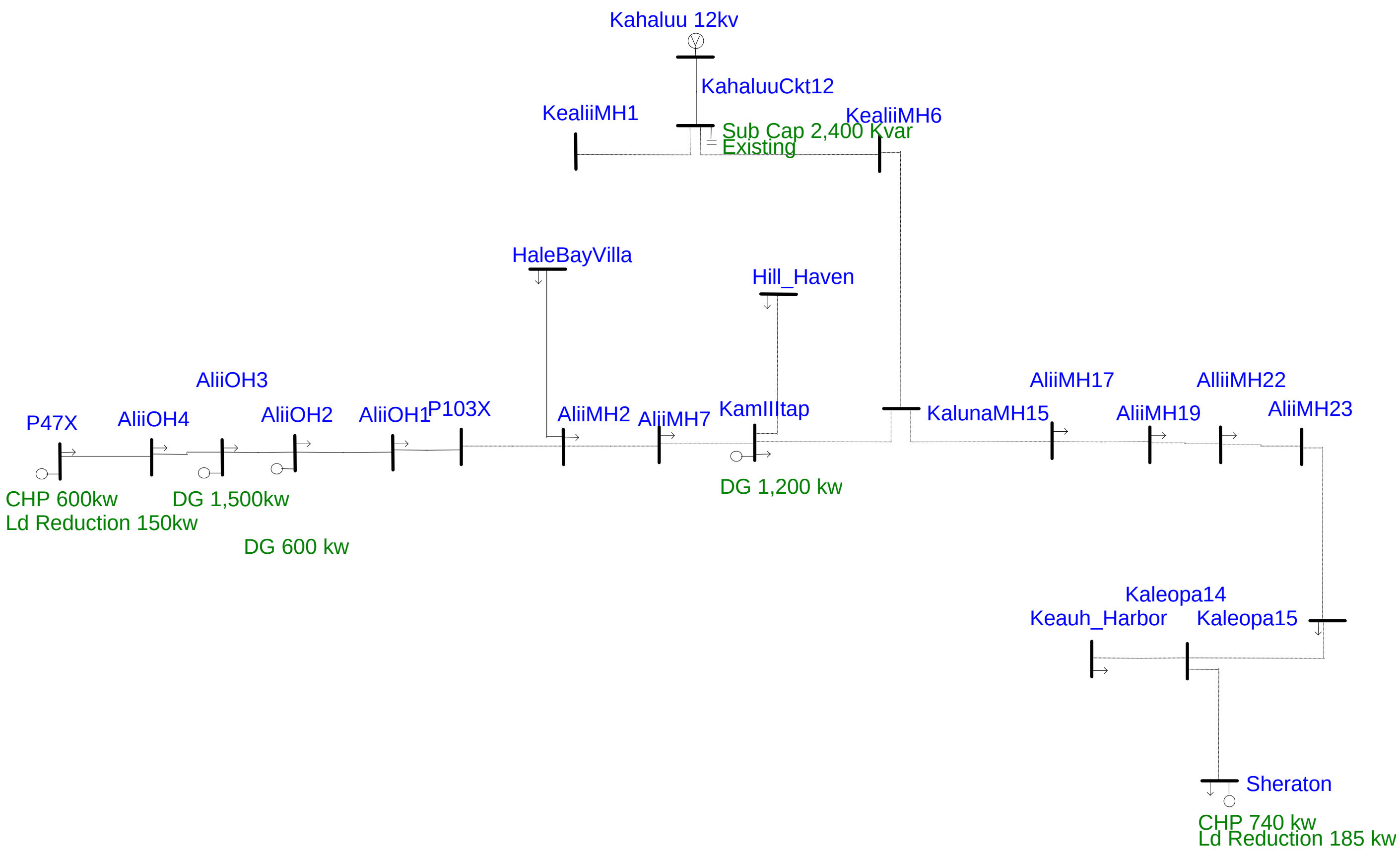


Figure 14. Kahaluu Max Load 14MW Voltage Profile, Add DG/CHP 4,640 Kw (North)

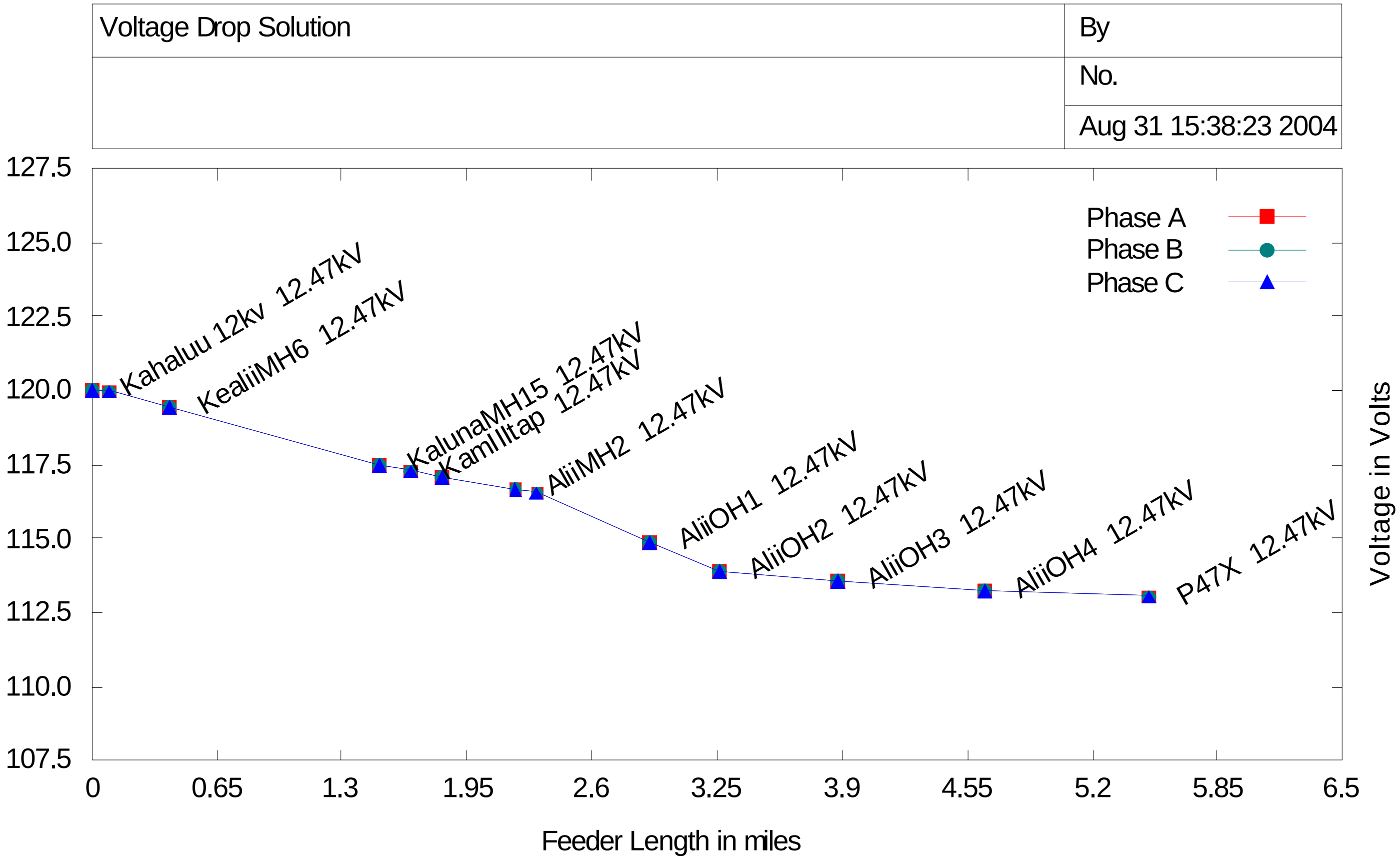


Figure 15. Kahaluu Max Load 14MW Voltage Profile, Add DG/CHP 4,640 Kw (South)

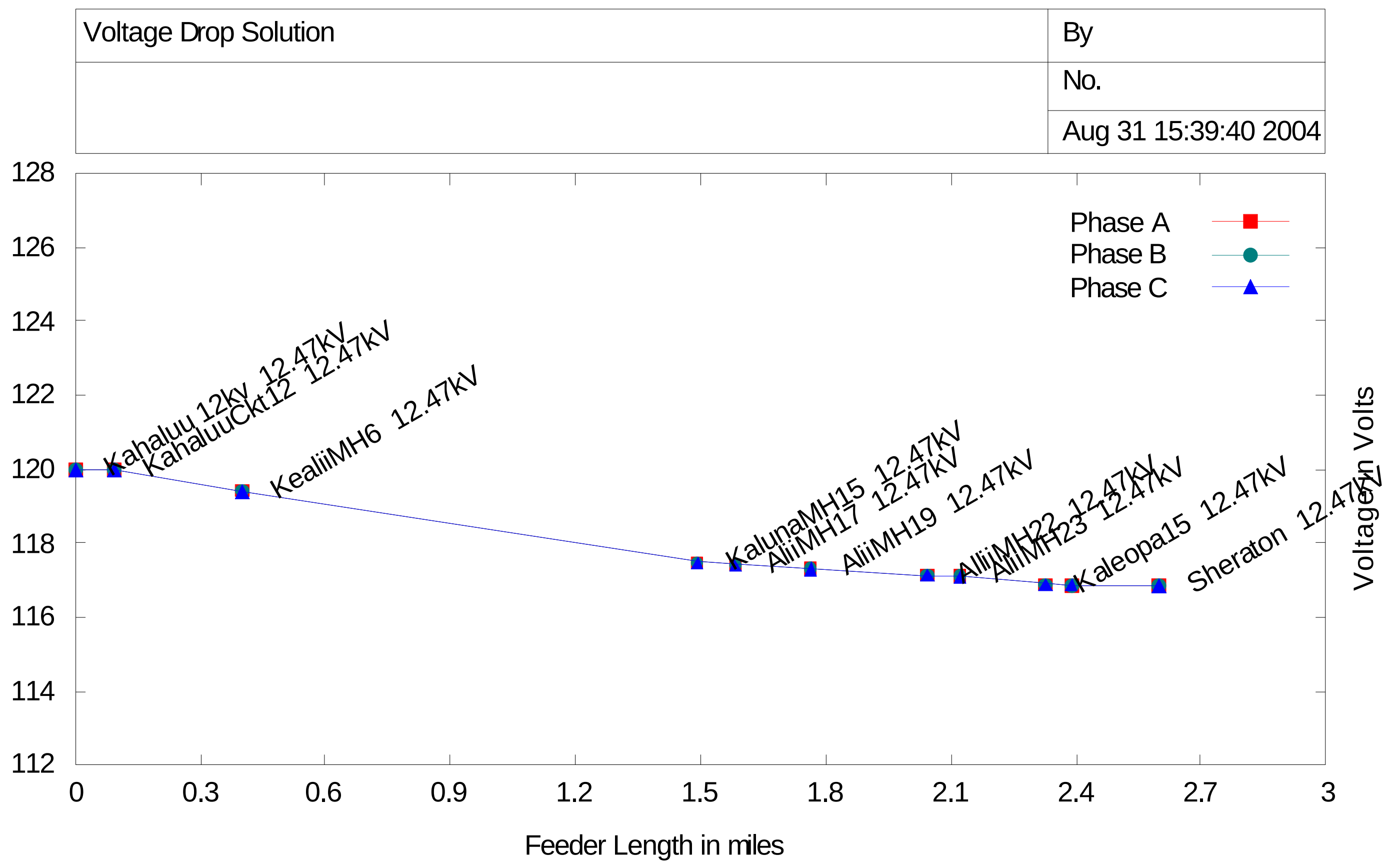


Figure 16. Kahaluu Max Load 14MW SLD Add Capacitors

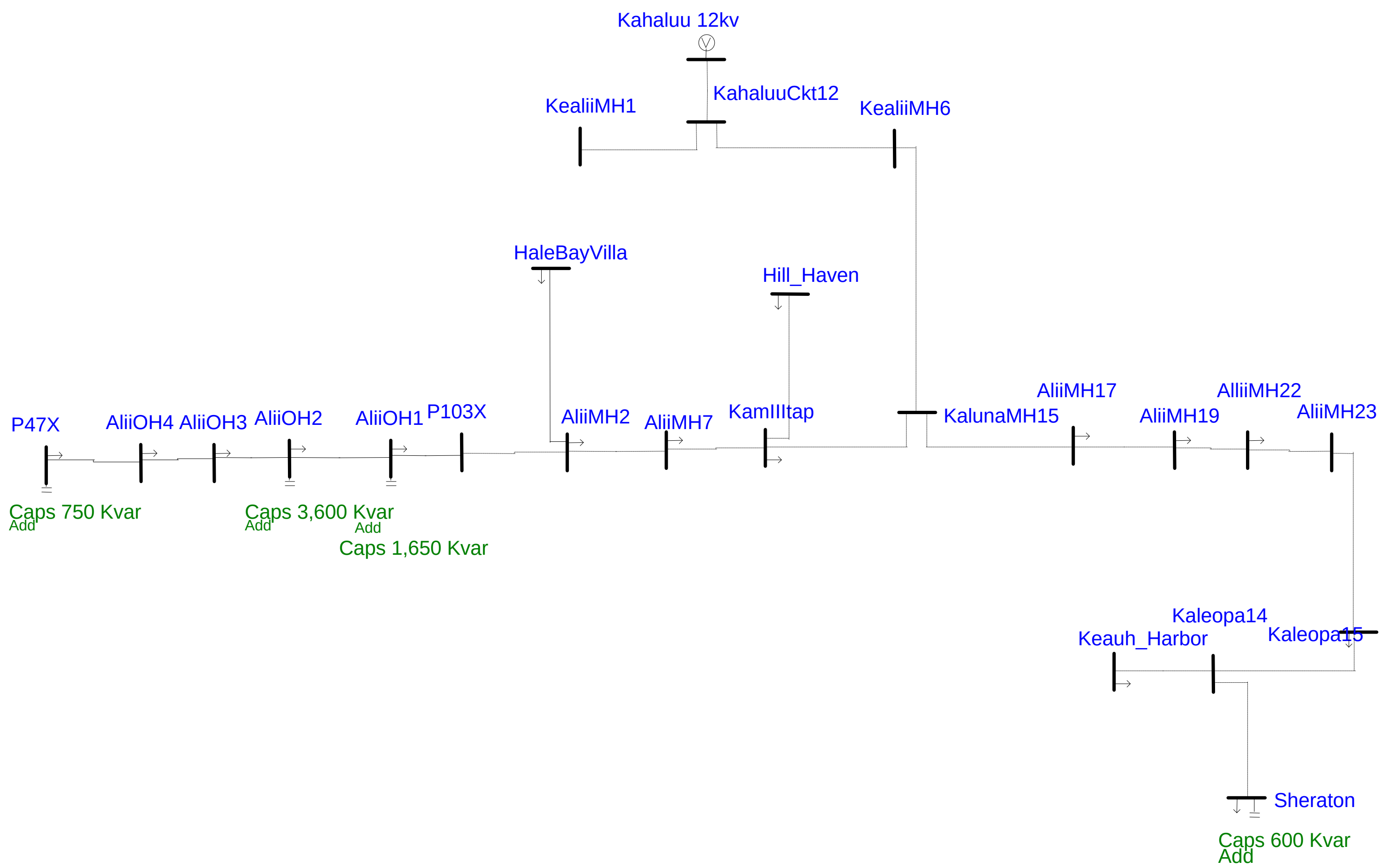


Figure 17. Kahaluu Max Ld 14MW Voltage Profile Add Capacitors (North)

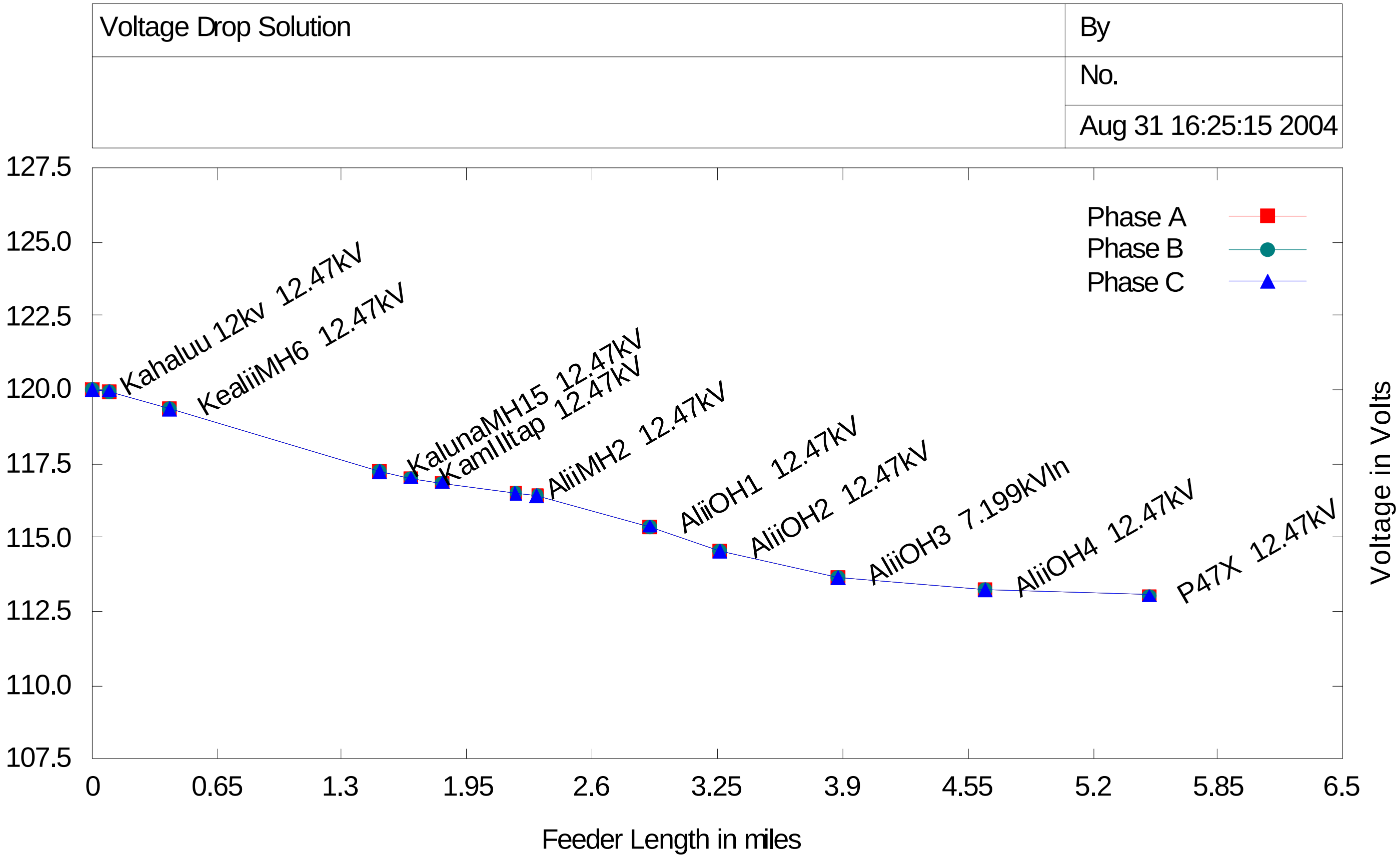
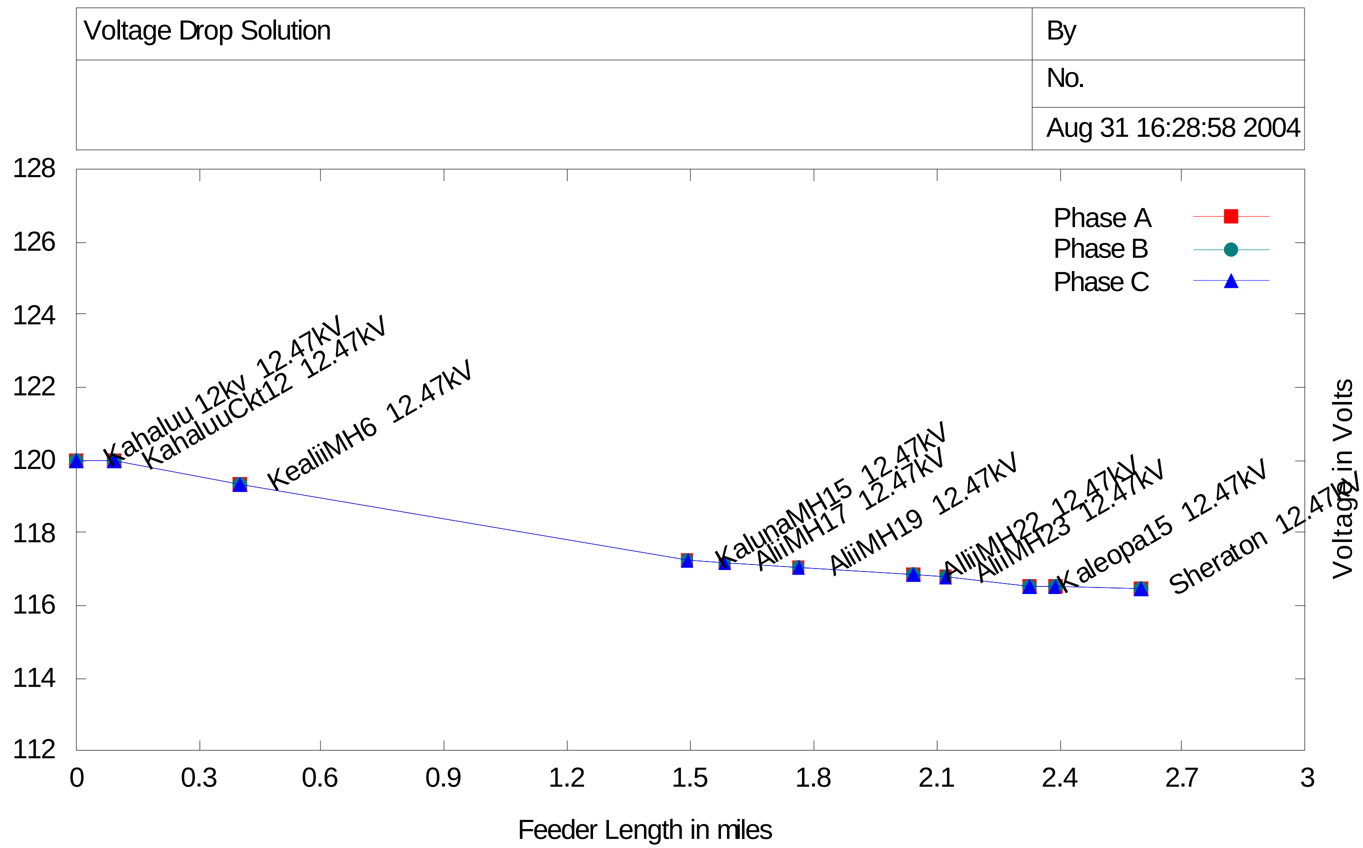


Figure 18. Kahaluu Max Ld 14MW Voltage Profile, Add Capacitors (South)



APPENDIX C: Anaehoomalu 13 Voltage Profiles

Figure 1. Anaehoomalu Max Ld 7MW SLD Base Case

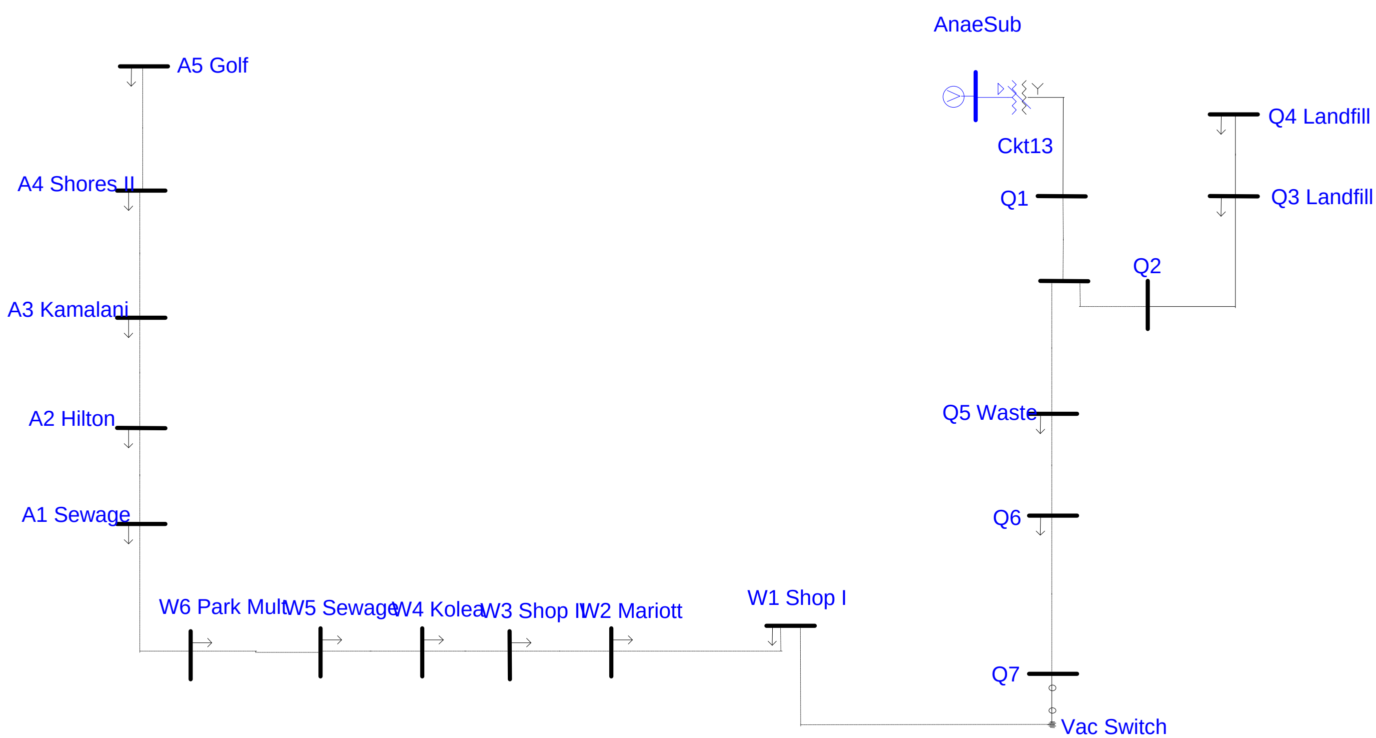


Figure 2. Anaehoomalu Max Ld 7MW Voltage Profile Base Case

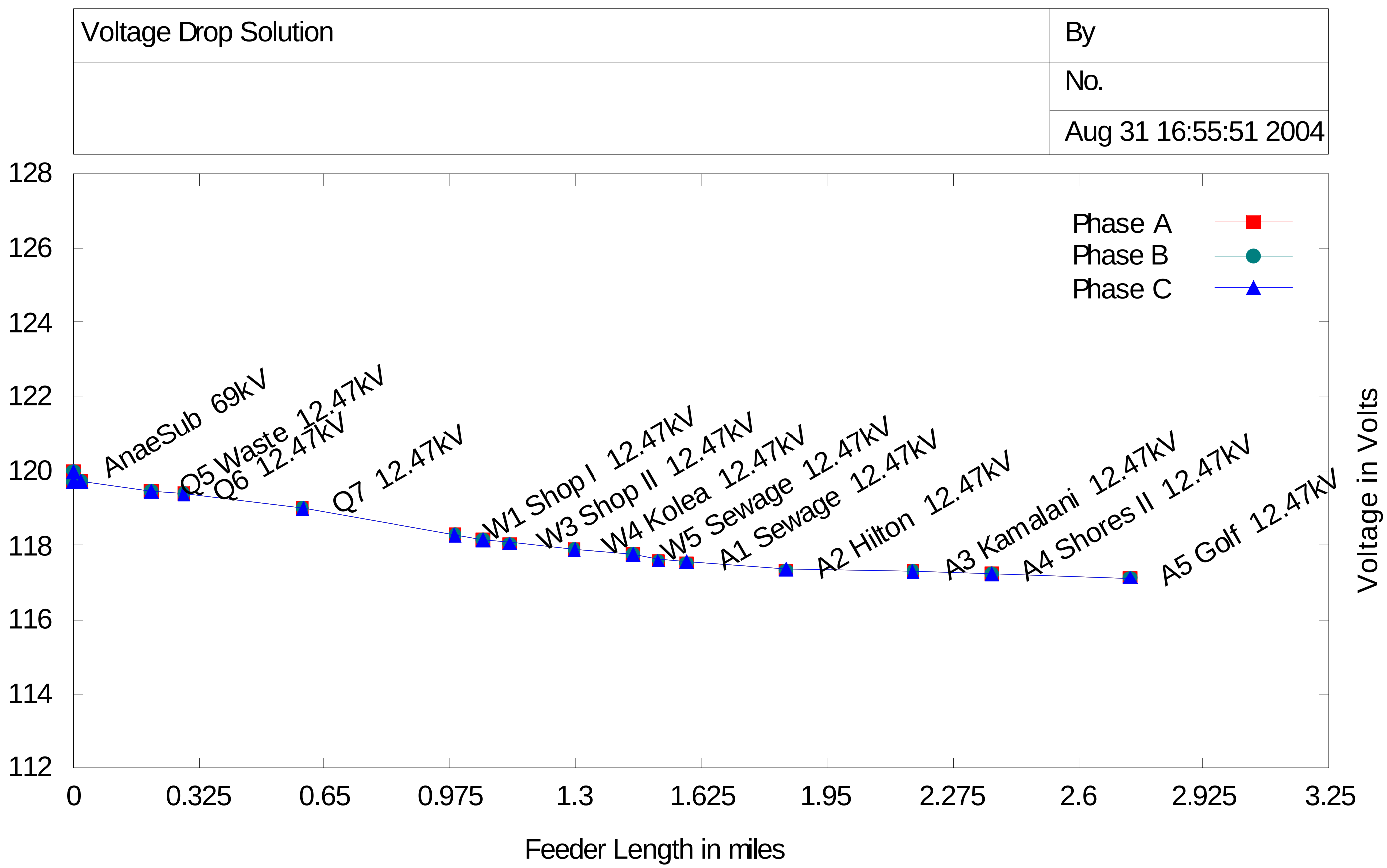


Figure 3. Anaehoomalu Max Ld 7MW SLD Add DG/CHP 2790 Kw

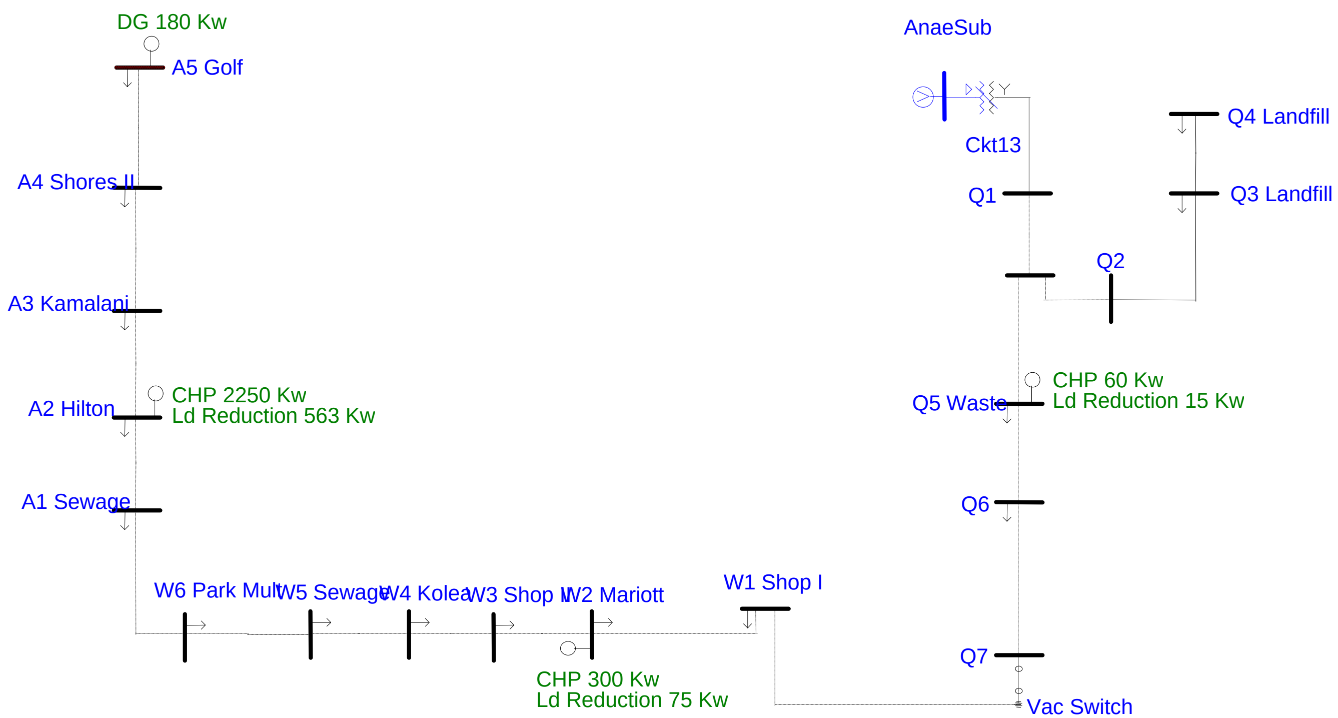


Figure 4. Anaehoomalu Max Ld 7MW Voltage Profile Add DG/CHP 2790 Kw

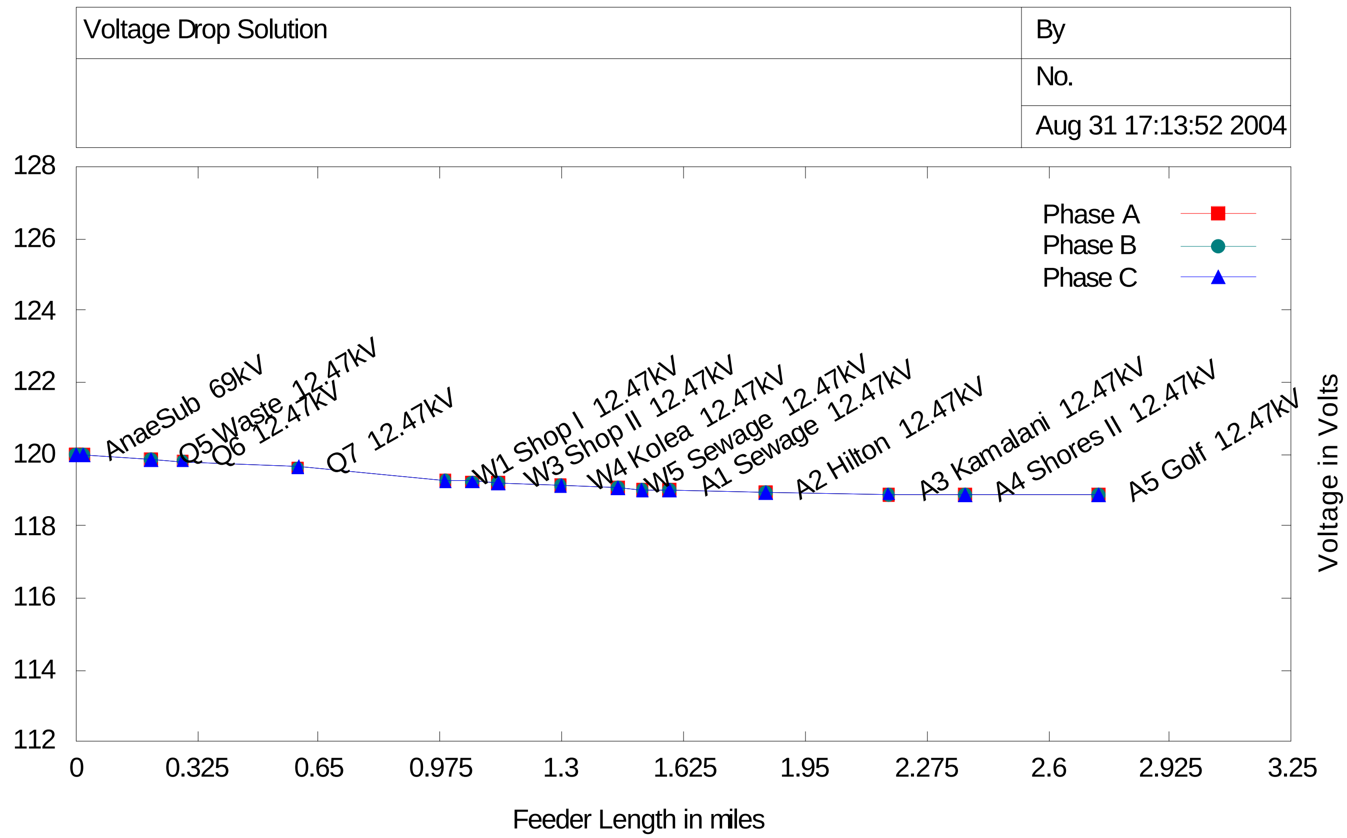


Figure 5. Anaehoomalu Max Ld 7MW SLD Add Capacitors

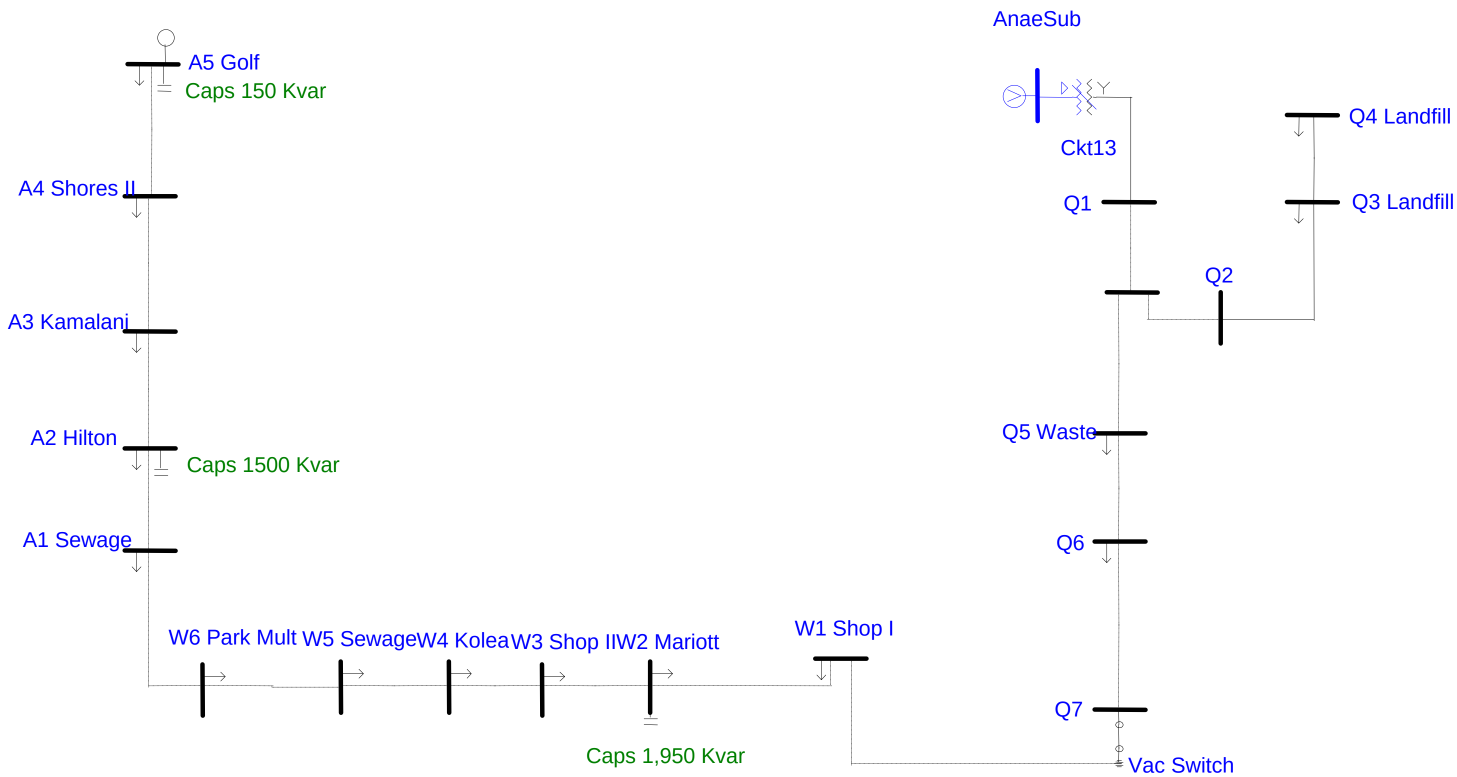


Figure 6. Anaehoomalu Max Ld 7MW Voltage Profile Add Capacitors

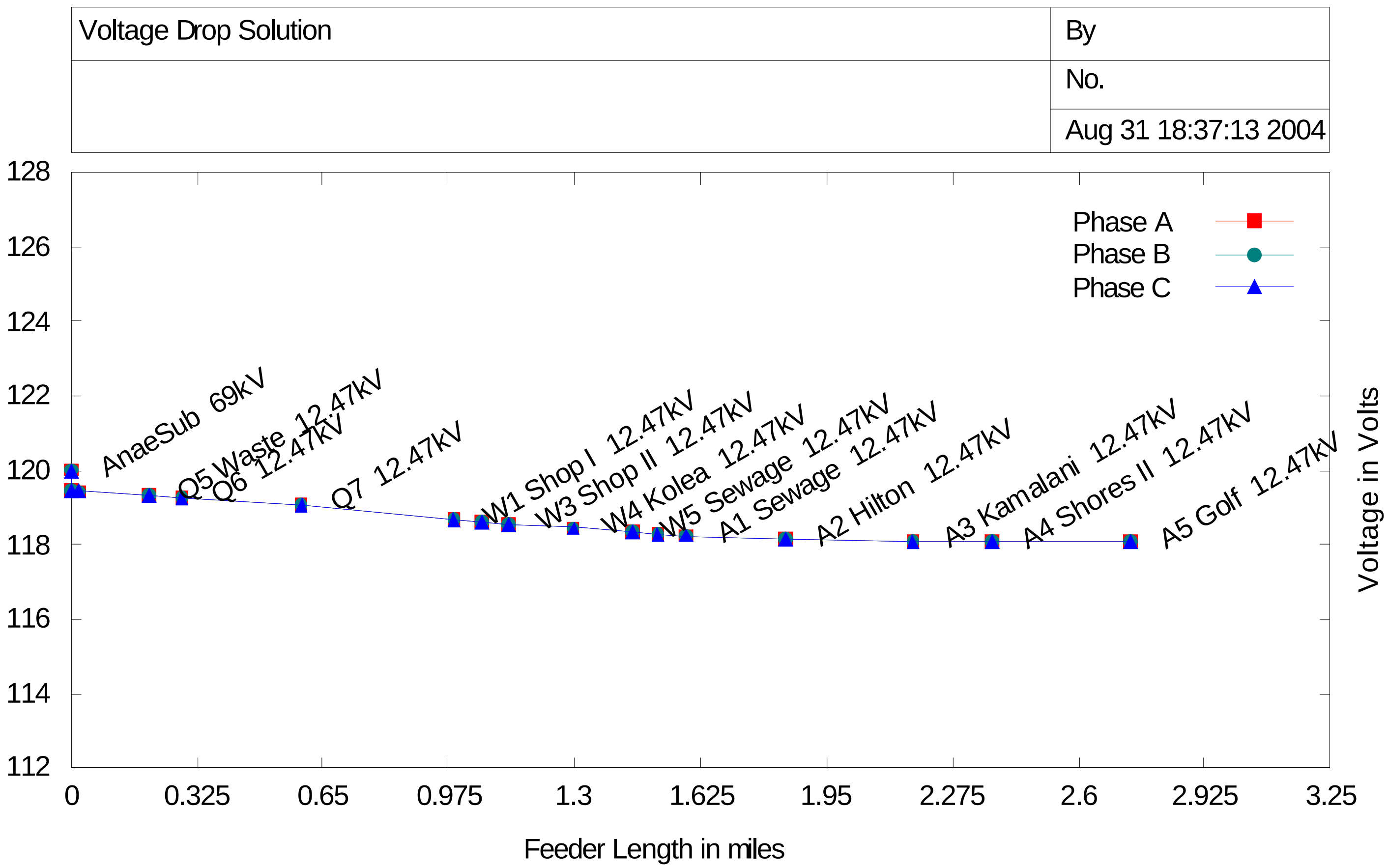


Figure 7. Anaehoomalu Max Ld 10MW SLD Base Case

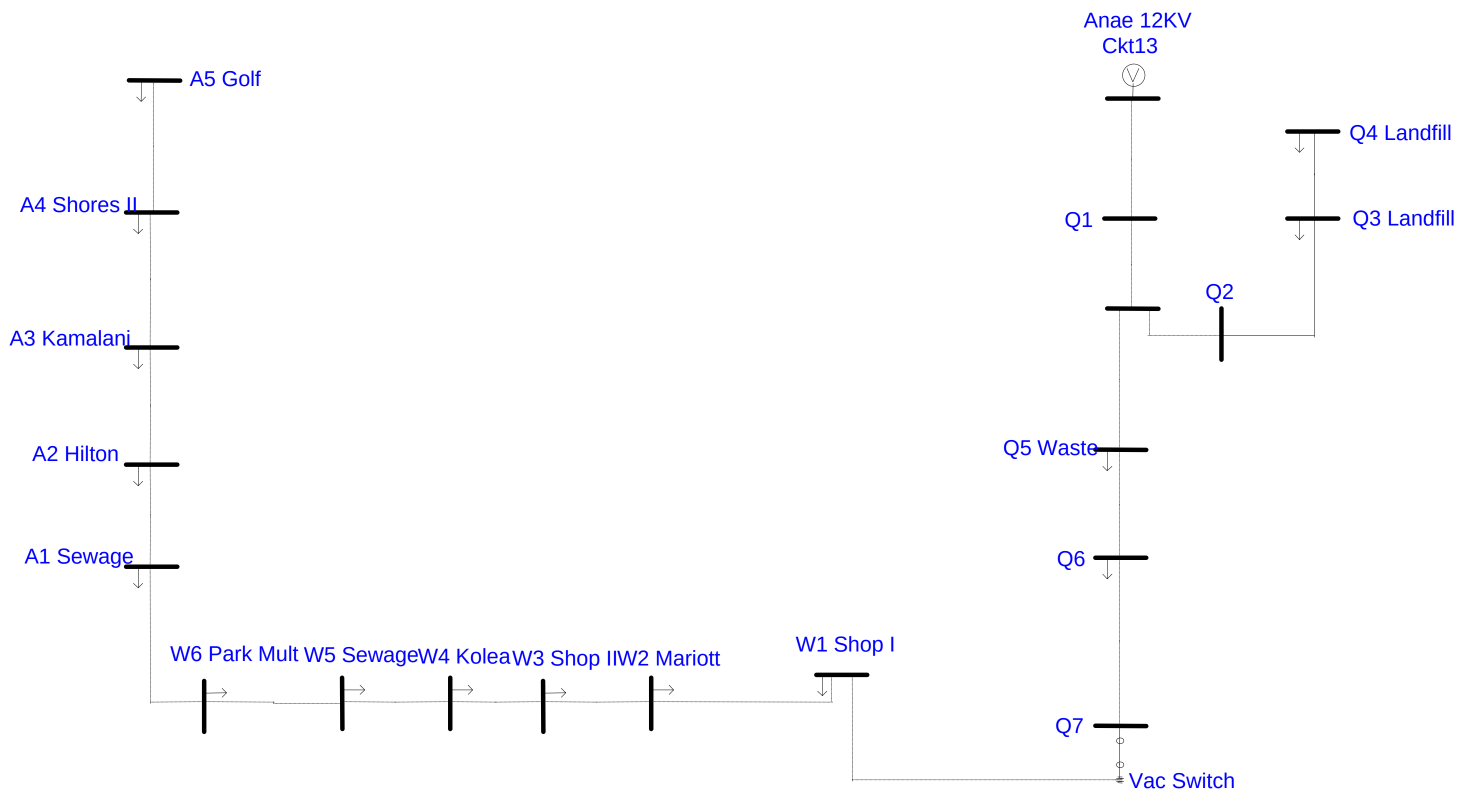


Figure 8. Anaehoomalu Max 10MW Voltage Profile Base Case

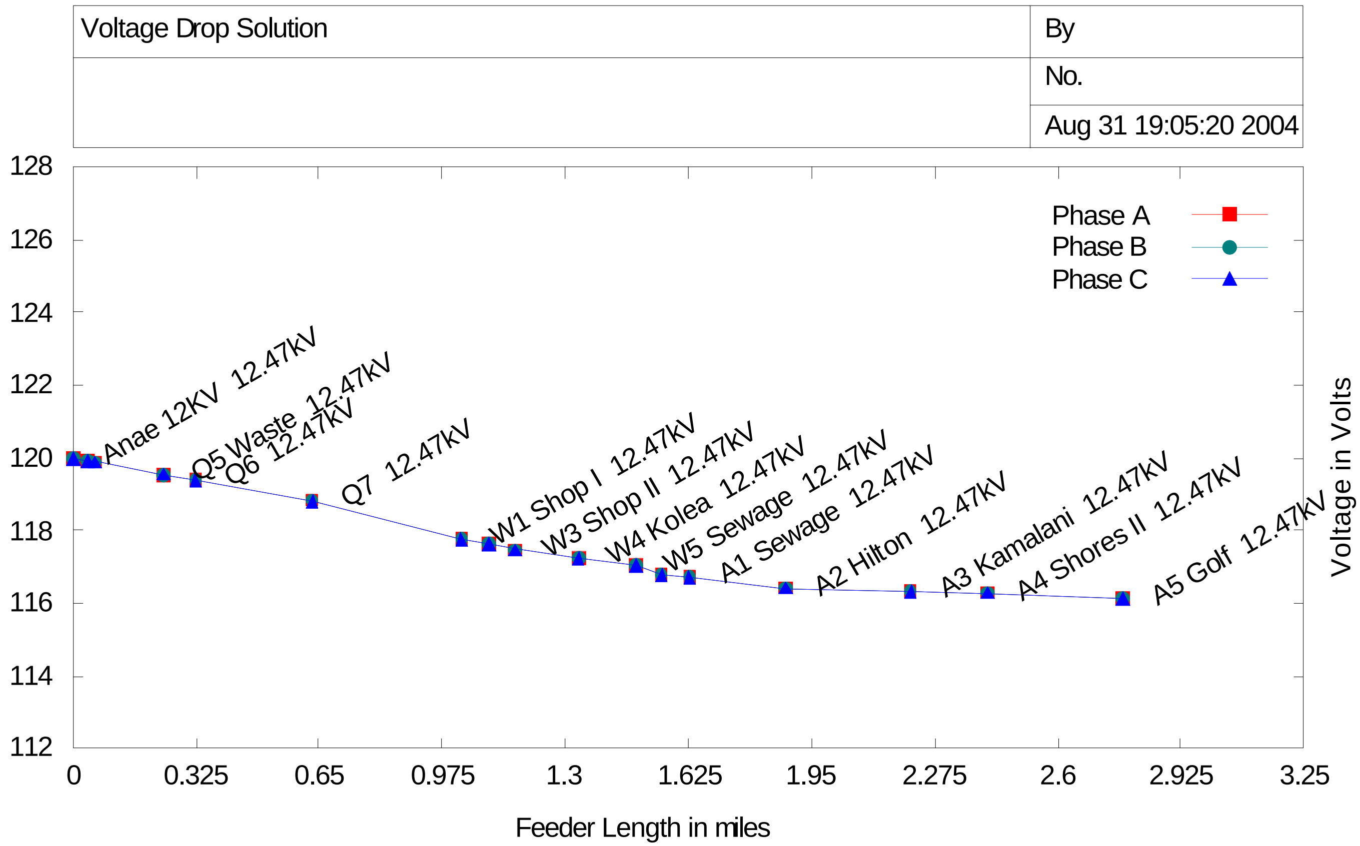


Figure 9. Anaehoomalu Max 10MW SLD Add DG/CHP 5,080 Kw

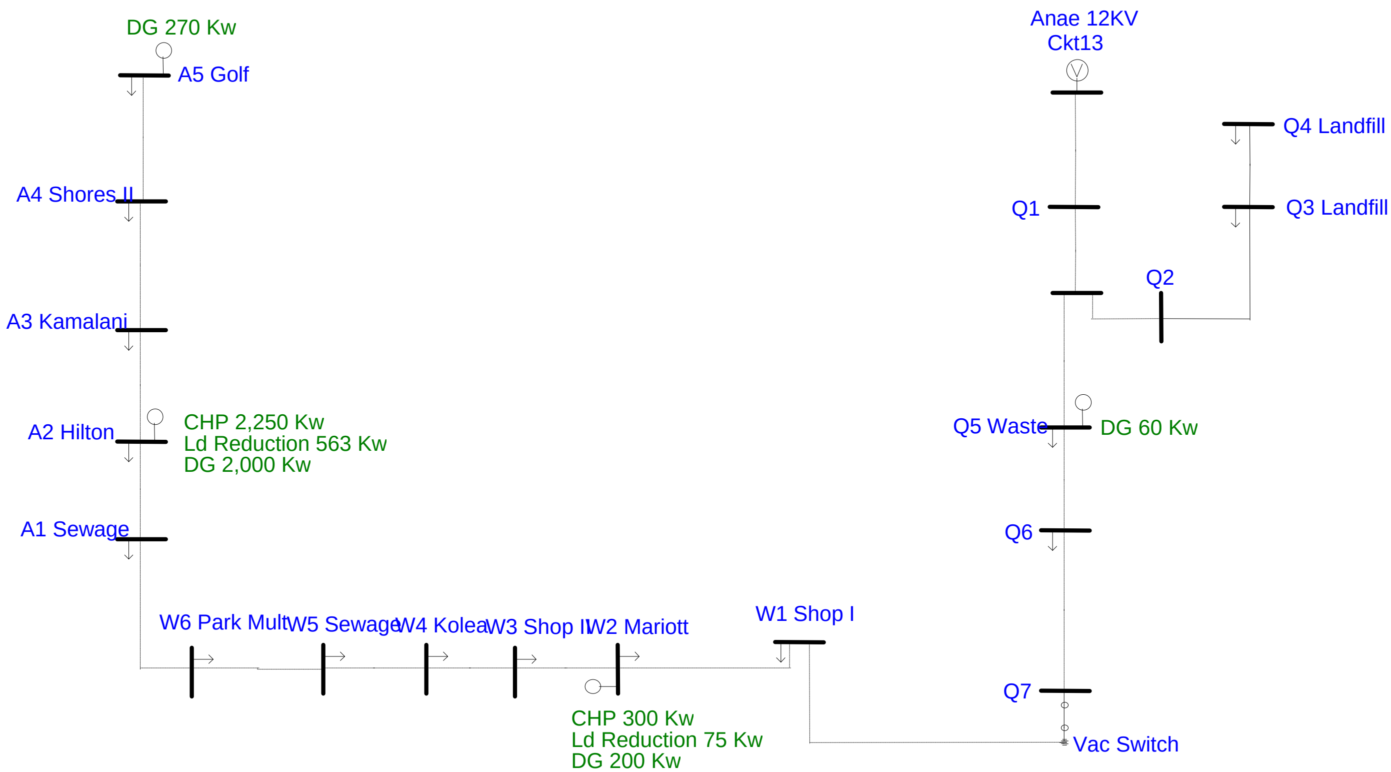


Figure 10. Anaehoomalu Max 10MW Voltage Profile, Add DG/CHP 5,080 Kw

Voltage Drop Solution	By
	No.
	Aug 31 19:33:36 2004

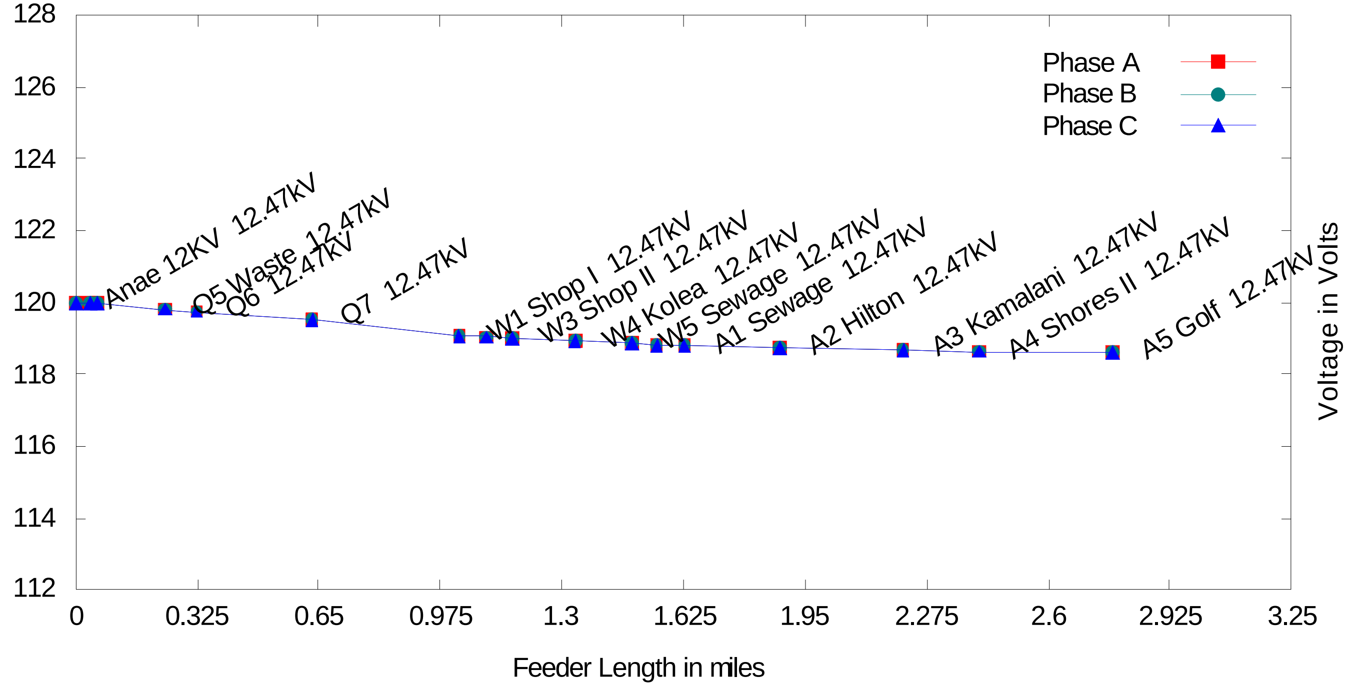


Figure 11. Anaehoomalu Max 10MW SLD, Add Capacitors

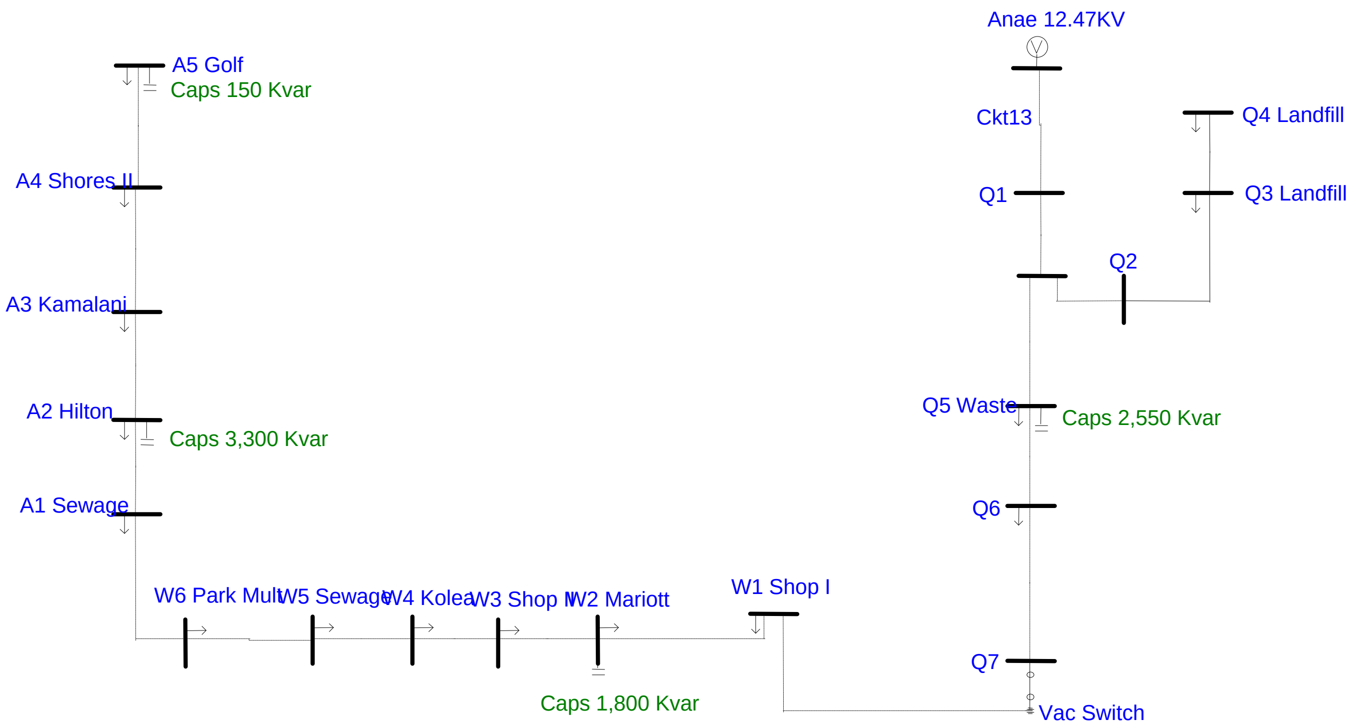
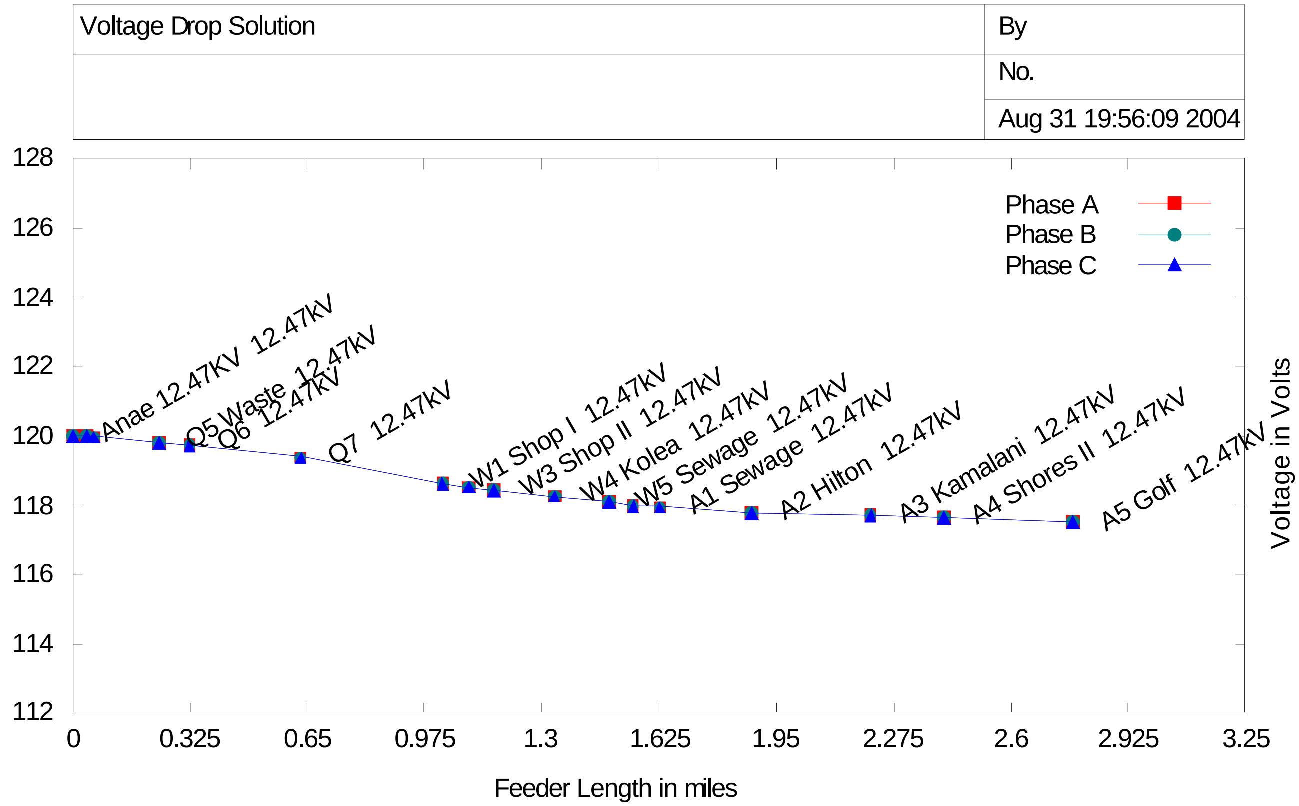


Figure 12. Anaehoomalu Max 10MW Voltage Profile Add Capacitors



APPENDIX D: HECO Response to CA-IR-13 of Docket No. 03-0371

CA-IR-13

Ref: HECO T-1, Page 19, Lines 24 through 25.

a. Mr. Seu indicates "the ability of the utility to directly control the operations and maintenance of a CHP system will improve its impacts on system reliability and power quality." Could the same impacts and benefits be derived from customer or third-party owned CHP systems if the utility has direct control over the operations and maintenance of the CHP system? Explain.

b. Please provide examples of how the operation and maintenance of a CHP facility not under the direct control of the utility would differ from that which is under the direct control of the utility.

c. Please identify the potential conflicts of interest of a customer or third-party owned CHP system under the direct control of the utility.

<u>HECO Response:</u>

a. If the system is designed and installed in a manner consistent with utility standards, then in general, the same impacts and benefits could be derived if the utility is directly in control of the operations and maintenance of the system. If the system is not consistent with utility standards, for example, sub-standard components are used causing more frequent breakdowns, there may still be adverse impacts on system reliability and power quality even if the utility is given control over operations and maintenance.

b. A third-party CHP system would be operated to maximize benefits to the customer and the CHP system owner. The utility-owned CHP system would be operated and maintained to balance the customer benefits with the overall utility operation with specific examples below:

   Having real-time dispatchability of the CHP units as described below differentiates the utility-owned and operated CHP systems:

   - Voltage support: the utility CHP system would standardize the use of synchronous generators. This would allow limited customer and regional voltage support benefits.
   - Control logic dispatch: the Companies are still finalizing their preferred CHP unit dispatch parameters, but is considering control system modifications to allow (4) control modes for utility CHP systems which are not currently used on any of the third party installed CHP systems in Hawaii:
     - <u>Normal:</u> the CHP power output would be balanced with the customer's thermal load to minimize the dumping of excess waste heat.

     - <u>Peaking:</u> on command, the CHP unit would maximize its power output without backfeed to the grid. This would provide system generation capacity support and/or support regional distribution system load in the event of a secondary feeder outage or temporary high loads.

- Minimum: on command, the CHP unit would minimize its power output. This mode is targeted to the neighbor island systems where on-line regulating units may already be at minimum load and backing off the CHP units would allow greater operating margin on the regulating units.

- Shutdown: utility system operators would be able to remotely shut-down each CHP system due to local network problems and lineman safety.

The maintenance of utility-owned and operated CHP systems would allow the scheduling of maintenance outages to minimize conflicts with distribution system maintenance work and other utility system considerations where regional distributed generation would support the local power quality and reliability.

c. If the customer or third party-owned CHP system is under the direct control of the utility, the customer or third party may question how the utility is dispatching or maintaining the CHP system. For example, the utility may decide, based on experience with similar units at other sites, that it needs to bring a customer-owned CHP system down for emergency maintenance. The customer may or may not agree with this determination, as they may be more concerned that the CHP system is not operating and is therefore not providing the CHP energy efficiencies to its facility. As another example, the customer or third party may decide to select a brand of CHP system equipment based primarily on near-term capital costs, whereas the utility would be more concerned about life-cycle costs including O&M and would have preferred to operate and maintain another brand of CHP equipment which is standardized with the utility's broader equipment inventory.

APPENDIX E: Proposed Utility CHP Program

PROPOSED UTILITY CHP PROGRAM

Hawaiian Electric Company, Inc.
Hawaii Electric Light Company, Inc.
Maui Electric Company, Ltd.

Cooling Tower | Absorption Chiller | CHP Units

Proposed Electric Utility CHP Program:

Hawaiian Electric Company, Hawaii Electric Light Company and Maui Electric Company believe that combined heat and power (CHP) systems can offer qualifying large power users another choice of options for potential cost savings. The utilities filed an application with Hawaii's Public Utility Commission (PUC) to establish a utility-owned CHP Program under Docket No. 03-0366 on October 10, 2003. The proposed utility CHP Program must be approved by the PUC. The application is currently suspended while the PUC considers policy issues concerning distributed generation in Hawaii, however the major elements of the proposed utility CHP Program are as follows:

1. Eligible CHP customers would be offered a conceptual CHP system design and estimated energy savings from the CHP system power and heat.
2. Potential CHP customers must meet minimum eligibility requirements (see other side) and would agree with the following key items:
   a. Provide the space for and access to CHP equipment
   b. Provide back-up heating and cooling equipment to allow for CHP system maintenance and outages
   c. Other items as described in the CHP Agreement
3. The utility would design, procure, install, own, operate, and maintain the CHP system.

HECO Contact: Scott Seu, Energy Projects Manager
Phone: 543-4805 e-mail: scott.seu@heco.com

APPENDIX F: Excerpts From HECO 7300 and 7200 Line Overload Study (Sections 6.4 and 6.5)

Final Draft Form
Prepared by the Planning & Engineering Department
Hawaiian Electric Company, Inc.
May 2004

6.4 INSTALLATION OF UTILITY-SPONSORED CHP ALONG THE KONA COAST OPTION

The results of the sensitivity analysis on the overloads on the 7300 and 7200 lines to the installation of utility-sponsored CHP along the Kona coast are discussed in this section. On October 10, 2003, HELCO filed an application with the PUC for approval of HELCO's CHP program (Docket 03-0336). This program is composed of 3rd party CHP/DG (distributed generation) and utility-sponsored CHP. The MW impacts from the utility-sponsored CHP and 3rd Party CHP programs are forecast on a system-wide basis and therefore are not specific to east or west sides of the HELCO system. The 3rd Party CHP/DG is contained in the load forecast shown in Figure 4-1. The utility-sponsored CHP, which is not part of the load forecast, assumes 9 MW of utility-sponsored CHP by the year 2008, increasing to approximately 23 MW by the year 2024.

As demonstrated in the load flow analysis, the worst loadings on the 7300 and 7200 lines will occur just prior to Keahole commitment. Depending on its location, utility-sponsored CHP can reduce the flows on these 69 kV lines by reducing the load at the customer load buses, which in turn reduces the flow on the 69 kV lines. As discussed previously, the projections for utility-sponsored CHP are on a system-wide basis and are not area specific. Utility-sponsored CHP in the Hilo area will not reduce the flows on either the 7300 or 7200 lines. In fact, utility-sponsored CHP on the east side of the HELCO system will tend to aggravate the overload problem on the 7300 and 7200 lines because some of the power generated by these units will flow on the 7300 and 7200 lines to loads on the west side of the HELCO system. Therefore, the utility-sponsored CHP will have to be located on the west side of the HELCO system, along the Kona coast, in an approximate area from Waika down to Kapua in order to be effective in reducing the overload problems on these lines.

The amount of utility-sponsored CHP required to reduce the loading on the 7300 or 7200 lines to the continuous rating is different in each case due to the fact that the configuration of the 69 kV system is different depending on whether the 7300 line is out-of-service or the 7200 line is out-of-service. Load flow analysis determined that the system configuration with the 7200 line out-of-service is the most severe condition in terms of quantity of utility-sponsored CHP needed to reduce the overload on the 7300 line when compared to the system configuration with the 7300 line out-of-service. Prior load flow results also showed that the worst overload occurs just prior to Keahole generation coming on-line. Under these conditions, and with the 7200 line out-of-service about 20 MW of utility-sponsored CHP on the west side of the HELCO system will be required in order to reduce the overload on the 7300 line to the continuous rating based on current system load conditions. The amount of utility-sponsored CHP needed to reduce the overload on the 7300 line will reduce to 0 MW by the year 2009 assuming the addition of the ST-7 unit at Keahole at that time. The level of utility-sponsored CHP is shown as the small dashed line on Figure 6-4. These results assume economic commitment of HELCO generation.

As the system load increases beyond the pre-Keahole level, Keahole generation will come on-line and tend to reduce the flows on the 7300 and 7200 lines as indicated previously. With utility-sponsored CHP, the situation is slightly different because the utility-sponsored CHP will be committed before Keahole and therefore the utility-sponsored CHP will raise the load level before which Keahole generation comes on-line, in a similar fashion to the situation with as-available generation or the HCPC contract. In order to define an upper limit to the amount of utility-sponsored CHP that will be required to back-off the overload on the 7300 line with the 7200 line out-of-service, the analysis looked at peak conditions with utility-sponsored CHP installed. Load flow studies determined that the amount of utility-sponsored CHP required to reduce the overload on the 7300 line with the 7200 line out-of-service will increase from about 52 MW in the year 2004 to about 59 MW by the year 2007. Under the assumption that the ST-7 unit comes on-line in the year 2009, the amount of utility-sponsored CHP required to reduce the overload on the 7300 line will drop to about 10 MW. The large dashed line on Figure 6-1 shows the upper bound of the amount of utility-sponsored CHP required to maintain the continuous rating on the 7300 line with the 7200 line out-of-service. For this analysis, west Hawaii is assumed to be the next generating plant after ST-7 is installed at Keahole with the first CT starting in the year 2017. The solid line shows the projected amount of utility-sponsored CHP based on HELCO's forecast.

One important result from this analysis is that there will not be sufficient utility-sponsored CHP early enough in time to reduce the overload on the 7300 line as a result of a 7200-line contingency based on current conditions. In addition, since only approximately 23 MW of utility-sponsored CHP is forecast by the year 2024, the projected amount of utility-sponsored CHP will not match the peak load utility-sponsored CHP requirement until the year 2016. At about $1,000/kW, the 20 MW of utility-sponsored CHP will cost approximately $21 million (2004 $), which is about 5 times the cost of reconductoring the two lines 69 kV lines depending on which of the two conductors is selected. At the high end of the required utility-sponsored CHP, 59 MW will cost about $61 million, which is about 13 times the cost of the reconductoring. Therefore, the installation of utility-sponsored CHP as an option to maintain the continuous rating on the 7300 line will cost between $21 and $61 million. There has been no utility-sponsored CHP installed to date because the program is still under consideration by the PUC. Similarly, the foregoing analysis assumes economic generation commitment conditions…

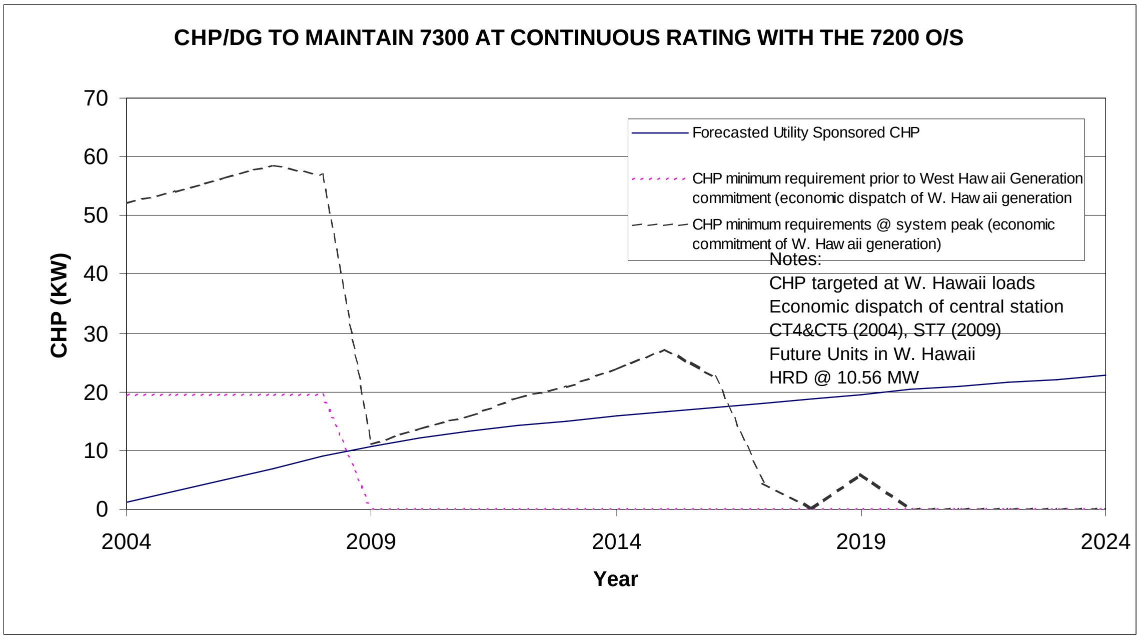


FIGURE 6-4: UTILITY-SPONSORED CHP TO MAINTAIN CONTINUOUS RATING ON 7300 LINE WITH 7200 LINE OUT-OF-SERVICE

6.5 INSTALLATION OF DG UNITS AT HELCO-OWNED SUBSTATIONS ALONG THE KONA COAST OPTION

The sensitivity of the overloads on the 7300 and 7200 lines to the installation of distributed generation (DG) at HELCO-owned substations along the Kona coast is evaluated in this section. In a similar fashion to the utility-sponsored CHP discussed previously, DG units located at HELCO-owned substations in the Hilo area will not be as effective in reducing the flows on either the 7200 or 7300 lines as will units on the west side since the west side units are electrically closed to the loads supplied by the 7300 and 7200 lines. Therefore, the DG units will have to be located on the west side of the HELCO system, along the Kona coast, in an approximate area from Waika down to Kapua in order to be effective in reducing the loading on these lines. These units are assumed to be installed at HELCO-owned substations subject to space availability.

As discussed previously, the worst loadings on the 7300 and 7200 lines will occur just prior to Keahole commitment. The DG units can reduce the flows on these 69 kV lines by reducing the load at the customer load buses, which in turn reduces the flow on the 69 kV lines. As indicated earlier in this discussion, load flow analysis determined that the system configuration with the 7200 line out-of-service is the most severe condition in terms of quantity of utility-sponsored CHP required to reduce the overload on the 7300 line when compared to the system configuration with the 7300 line out-of-service.

Two scenarios are possible with the installation of DG units at HELCO-owned substations along the Kona coast:

1) Assuming the 7200 line is out-of-service for an extended period of up to 5 months for reconductoring, the DG units at HELCO-owned substations will be required to commit with the rest of the generation on the HELCO system in order to reduce the overload on the 7300 or 7200 lines. This scenario is similar to the previous analysis in section 6.4 wherein utility-sponsored CHP units are installed at HELCO-owned substations along the Kona coast also to reduce the overload on the 7300 and 7200 lines. In that analysis, 20 – 59 MW of utility-sponsored CHP is required for the overload conditions. Similarly, 20 – 59 MW of DG generation will be required to cover the period from 2004 – 2024. At about $1,100/kW for a 1 MW DG unit, the 20 - 59 MW of DG units at HELCO-owned substations along the Kona coast will cost about $22.6 – $65.7 million, which is approximately 5 - 15 times the cost of reconductoring the two lines.

2) The second scenario that assumes that the DG units are installed at HELCO-owned substations along the Kona coast and designed to only run if there is a contingency to either one of the 7300 or 7200 lines was considered and rejected. A special protection scheme will be required to detect the tripping of either of the 7300 or 7200 lines. This scheme will then send a signal to the DG units to start and run up to full load using HELCO's Energy

Management System (EMS). Based on the results contained in table D-1 of Appendix D, and discussed in section 5.0, HELCO may have as little as about 100 seconds to react to a contingency involving the 7200 line and initiate a remedial action to reduce the overload. The typical starting time for a 1 MW diesel is about 90 seconds. Therefore, it is unrealistic to assume that 20 or more diesel units could be up and running within 100 seconds.

A separate evaluation determined that as few as 7 or as many as 41 additional containerized 1 MW diesel fuel-based generating units could be installed at HELCO-owned substation sites along the Kona coast subject to space and other requirements being met... Therefore, sites for a possible additional 15 - 49 1-MW units to make up the total of 59 MW of DG will be required in order to solve the overload problems on the 7300 and 7200 lines to the end of the study period. It appears unrealistic at this point to assume that HELCO will be able to site all these units at HELCO-owned substation sites within the area along the Kona coast.