Operational Flexibility Study
Phase 2 Report

Maui Electric Company, Inc.
Kahului, Hawaii

Final
December 12, 2012

Stanley Consultants INC.
A Stanley Group Company
Engineering, Environmental and Construction Services - Worldwide

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Executive Summary

PURPOSE

The State of Hawaii's clean energy policy strongly promotes the use of Hawaii's renewable energy resources, as evidenced by the Legislature's recognition in 2007 that "progressive energy policy-making at the state level is one of the most important issues on the current legislative agenda" (Act 177, Haw. Sess. L. 2007). In furtherance of this agenda, the 2009 Legislature passed a number of renewable energy bills, including Act 155, which among other things, mandates the electric utilities' 2015 Renewable Portfolio Standard (RPS) requirement of 15%, the 2020 RPS requirement increases from 20% to 25%, the 2025 RPS requirement of 30%, and adds a new 40% RPS requirement for the year 2030. A large component of these renewable resources (e.g., wind, solar, ocean currents, etc.) is non-firm, variable generation that must be integrated to the electrical system while maintaining current reliability standards. While the requirement for renewable energy generation is 40 percent of energy production by 2030, overall generation demand may also increase by this time, as consumption of gasoline for automobiles is displaced by the needs of electric vehicles.

To meet these new RPS requirements, Maui Electric Company (MECO) initiated several studies. They evaluated various strategies to integrate more renewable resources, and determined potential impacts on system reliability. One of the strategies identified early was modifications to MECO's operating units, identified as "must-run" units. The combined cycle and thermal units are considered must-run units because they provide essential grid services like system inertia, load following capability, reactive power capability, fault current for system protection, system reserves for contingency events, and for regulating reserves.

MECO's generating fleet consists of steam units load cycled daily, combined cycle units that swing with load requirements, and diesel generators that are started to meet peak demand. The MECO fleet provides the majority of the system operating reserves to manage contingency events and large load swings by non-firm renewable generation. The current reserve requirement is to carry a minimum of 6 MW of operating reserve and to provide up to 52 MW of up-reserve capacity when the full 72 MW of wind generation is being produced. At lower wind generation levels, operating reserve is between these two values.

MECO contracted Stanley Consultants to study the company's generating units for possible ways to enhance the acceptance of more intermittent resources. The first phase of the cycling study, referred to in this report as Phase 1, was conducted in January 2011. Results of the Phase 1 study presented several options to improve unit and system flexibility along with high level cost estimates and benefits. The study concluded that, with modification, increased wind energy can be accepted on the MECO system while maintaining adequate regulating reserves and system reliability.

Stanley Consultants was subsequently commissioned by MECO to conduct Phase 2 of the study, which further develops seven of these modifications. The scope of work for Phase 2 was to develop budgetary cost estimates for the seven recommendations listed in the table below and to test several of the units for the purpose of expanding the operating range.

Table E-1 – Primary Capital Recommendations

Section	Modification
3.1	Upgrade Burners for Kahului 3 & 4
3.2	Install Inlet Chilling on Combustion Turbines
3.3	Modify HRSGs for Cycling and Lower Loads
3.4	Install Engine Preheating (M10-M13)
3.5	Modify OTSGs for Lower Loads
3.6	Install a 10MW-90 minute BESS
3.7	Install Data Historian for Generating Units

Each of these modifications is discussed in detail in the sections listed. The primary objective of these recommendations is to enable additional renewable generation on the grid while maintaining personnel safety, grid stability, unit reliability, and by preserving equipment life.

The Stanley Consultants study team researched existing plant specifications, drawings, and reports. In-person interviews were conducted with MECO personnel during a site visit April 10th – 13th, 2012. With Stanley Consultants' support, MECO conducted low load testing on Kahului Units 3 and 4, Maalaea diesel generator Units 4 and 10, and both of the combined cycle blocks at Maalaea. The objective of this testing was to identify constraints and opportunities regarding lowering loads, starting faster, and improving ramp rates.

DESCRIPTION OF SELECTED PHASE 1 MODIFICATIONS

Below is a brief description of each of the seven Phase 1 modifications that are further developed in this Phase 2 Study.

<u>Upgrading the Burners</u> at Kahului Units 3 & 4 was further investigated in order to allow the units to operate at reduced loads. This will allow the two units to reduce minimum load from 7.5 MWs to 3 MW during off-peak periods. Budget estimates indicate this is an excellent value toward improving the RPS. It was suggested to install this modification in stages, starting with what is needed most to reliably achieve 3 MW low load operation. Included in the cost estimate

is first replacing the burner guns and steam atomizers, flame scanners, and new control valves for the fuel oil and steam. Not included in this report's cost estimate is the possibility of installing new automated air registers, automating valves at the burner front, and a burner management system.

Installing Inlet Chilling on the combustion turbines at Maalaea allows a total of 1.8 MW more peak power by reducing the air temperature entering the turbines. The net effect is the ability to count this 1.8 MW toward the necessary operating reserves. Options to install thermal energy storage through the use of chilled water tanks did not prove economical. This is the second highest priced modification.

Modifying the HRSGs on Maalaea Units 14 & 16 will enable these units to operate reliably at lower loads and be able to cycle one unit off at night in the future. It should be noted that currently, one unit cannot be cycled offline because of system needs for operating reserve. Test analysis indicates that the combustion turbines would be able to operate at a minimum load of 7 MW and still maintain backend temperatures above or near the acid dew point. This provides significant RPS benefits. These benefits can be realized most effectively by performing modifications that will help minimize additional maintenance costs. Enhancements include adding automation, improving metallurgy and providing coatings on backend surfaces. If the units are to be cycled off nightly, the additional thermal cycles could decrease equipment longevity.

Installing Engine Preheating on the Mitsubishi Diesel Generators at Maalaea will alleviate thermal expansion issues with the aluminum pistons and therefore will allow the engines to start quicker. Because of the aluminum pistons, these units start extremely slow by current industry standards. The modifications will keep the jacket water and oil hot which MHI indicates will allow the engines to start in 50 minutes rather than 90 minutes.

Modifying the OTSGs to enable lower loads has significant value if it can be confirmed that lower loads are not causing the M18 back end steam turbine erosion. This modification would involve re-tubing the top three rows of the OTSG with smaller diameter tubes that will maintain required flow velocities at lower loads. However, during the recent M18 outage, excessive water erosion was found on the last three rows of the steam turbine blades. There is concern that this damage may be occurring during the current 1X1 minimum load (14 MW on a single gas turbine and 3.5 MW on the steam turbine) and could worsen if loads were lowered further. Energy balance calculations indicate this would not be the case, but additional controlled unit testing should be conducted to eliminate low load conditions as the cause of the damage.

Another primary modification included in the Phase 1 Report was installing a Battery Energy Storage System (BESS) to provide 10 MW of up reserve power for a period of 90 minutes. This is by far the most costly modification but provides benefits to RPS and stability for the Maui grid. Ninety minutes was chosen to allow for the startup of one Mitsubishi diesel generator (12.5 MW). This modification effectively reduces the need to carry 10 MW of spinning operating reserve. Another benefit of the BESS option is that it will not require environmental air permitting.

Installing a Data Historian for the generating units is a minor cost for all the benefits it provides. This will enable engineers and operations personnel to easily trend performance and equipment condition. It is valuable in troubleshooting forced outages and equipment failure. This tool will allow for easy assembly of periodic or on-demand reports regarding plant operation.

The table below summarizes the estimated cost for each of the seven selected Phase 1 modifications and, where available, the RPS contribution. The RPS values listed were calculated with Generation Planning's simulation model using input parameters provided by Stanley Consultants. To allow a level comparison, the cost for each 1/10% RPS gain is provided in the last column and the modifications are ranked according to this parameter.

Table E-2 –Cost Estimates (Thousands of Dollars) and RPS

Modification	Unit Cost	Total Cost	Improved RPS (2020)	Cost per 1/10% RPS
Upgrade Burners for Kahului 3 & 4	$254	$508	0.9%	$56,400
Modify OTSGs for Lower Loads	$738	$1,475	2.1%*	$70,200
Modify HRSGs for Cycling and Lower Loads	$3,832	$7,664	3.5%	$219,000
Install Inlet Chilling on Combustion Turbines	-	$9,764	0.3%	$3,254,700
Install a 10MW-90 minute BESS	-	$39,005	1.1%	$3,546,000
Install Engine Preheating (M10-M13)	$2,222	$8,888	Unknown	N/A
Install Data Historian for Generating Units	-	$152	N/A	N/A

This table illustrates that those modifications that allow lower unit loads are the most affordable means of improving RPS. It also illustrates that the Inlet Chilling and BESS are a very expensive options for increasing RPS levels.

TESTING RESULTS

The following are the highlights of unit testing conducted during the two visits in May of 2012 on Kahului Units 3 and 4, both Maalaea combined cycle blocks, and two Maalaea diesel generators. Graphs and more detailed reports and summaries of this testing can be found in Appendices 1 and 2.

The results of the Kahului Unit 3 & 4 testing showed that with some modification these units should be able to achieve a 3 MW minimum load. Constraints identified and verified during the testing included requiring the removal of two (2) burners on each unit, limited automation capability, and deterioration in water quality. No indications of steam turbine backend moisture were observed but this should be monitored if 3 MW minimum load becomes a regular occurrence. The primary opportunities to mitigate the constraints include upgrading the burners for lower turndown, condensate polishing, and installing an alternate steam source for pegging the Unit 3 deaerator.

If Kahului Units 3 and 4 are to be AGC regulated, then it is necessary to install a hydraulic or electronic governor for Unit 3. With its manual governor, Unit 3 took 26 minutes to ramp from 7 MW to full load while Unit 4, with an electronic governor and more automation, performed this in 10 minutes.

The Maalaea combined cycle units were tested in order to identify specific constraints and limitations of the equipment. Each combined cycle block (CC1 & CC2) was tested to evaluate lower minimum load, maximum load, start times, and ramping capability. Due to the original design, these units exhibit much less flexibility than similar installations at other utilities. The full combined cycle startup takes 2 to 2.5 hours where industry norm is around 1 to 1.5 hours. On CC1, this lengthy start time resulted in 53 minutes where the HRSGs operated below acid dew point. Consideration should be given to standardizing startup operating procedures.

Other significant observations included the ability to turndown M14 and M16 as low as 9MW while keeping the HRSGs backend temperatures above the calculated dew point of 268 F. During startup, it was also noted that the unusual water fuel ratio restrictions in the Air Permit delays the startup, resulting in more overall emissions for the startup process. Once started, the units ramped fairly quickly, however the LP circuit on the M19 OTSG tripped during fast down ramping.

The combined cycle testing identified several opportunities for performance enhancement. The engines and combined cycle are operating below expected performance. There is an opportunity to optimize compressor water wash frequency that will improve heat rate and expand the usable operating range for regulation. Auxiliary load can be reduced and steam turbine back pressure could be optimized to further improve cycle efficiency.

For improved flexibility, automation should be added to the combined cycle. This includes automating the M14/16 inlet damper to improve start times.

The diesel generators, Maalaea Unit 4 and Unit 10, were also tested during May, 2012. Both units are constrained initially by temperature requirements on lube oil and jacket water. The larger MHI engines are unique because they have aluminum pistons and a steel block. This requires a very long heating schedule to ensure that the piston does not grow faster than the block. During testing, it took 2 hours 8 minutes to go from 3 MW to 12.5 MW. Both types of diesel units could start more quickly if they had improved oil and jacket water heating systems including instrumentation to monitor these temperatures. A quotation was provided by MHI to detail out and price this modification. Several other opportunities exist to reduce manual intervention and could eventually enable multiple units to be started at once.

RECOMMENDATIONS

As a result of this study, Stanley Consultants has refined recommendations and developed more detailed scopes and cost estimates for the primary modifications. These are summarized below as either equipment improvements or operational changes. Detailed descriptions of all suggested modifications can be found in Sections 3 and 4.

Capital Improvements

Of the seven Phase 1 modifications identified for further study, two modifications stand out as high value for improving RPS goals with a reasonable capital investment. These are installing new burners to allow lower minimum loads at Kahului Units 3 and 4; and performing HRSG modifications to allow lower minimum loads on Maalaea Units 14 and 16. OTSG modifications are also of high value, provided that concerns over back end erosion of the M18 steam turbine are overcome.

The other primary modifications provide less RPS value for the investment. The BESS installation is quite expensive for the RPS gains achieved, but it would provide other intangibles that could improve stability of the Maui grid. The inlet chilling benefits are minimal for the money invested and it is more difficult to justify at this point. Benefits of the inlet chilling modification were modeled differently by Generation Planning in the Phase 2 study which caused the value of this modification to decrease. It was not possible for Generation Planning to project benefits for engine heating modifications that improve the MHI diesel generator start times from 90 minutes to 50 minutes.

Installing a new user friendly data historian would be very valuable for tracking performance, evaluating equipment condition, retrieving past data, and trouble-shooting problems. The ability to measure and trend operational information, equipment condition, and plant performance is a first step toward improvement. This is of significant value in comparison to its relatively small cost.

Besides these primary modifications, additional changes should also be considered. For the larger Kahului units, a condensate polisher may eventually be required for operation down to 3 MW. Unit 3 would also require an additional steam source for the deaerator. Units from both plants would benefit from improved instrumentation to monitor equipment condition and performance. There are also many opportunities to improve automation in order to reduce operator intervention.

It is suggested to resurrect one Phase 1 recommendation for reconsideration. Enabling multiple EMD engines to start simultaneously will allow more emergency generation on the grid at once in situations where wind production has fallen suddenly. Recent battery system upgrades still do not allow for multiple EMD units to start at once. Two options are available: either additional batteries or conversion to air starting. In either case, black start capability will need to be retained.

Operational Improvements

During the course of this study a number of operational enhancements were noted. Below are some of the higher value observations. Further detailed discussion is provided in Section 4.

For Kahului Unit 4, testing indicates that the steam turbine governor could be programmed to ramp at a faster rate than the current "Fast Select" allows. It appears that this unit controls well enough that after tuning it could provide AGC regulation with a ramp limit of 0.5 MW/minute.

For Maalaea Units 14 and 16, consideration should be given to operational procedure changes that reduce start times. Current restrictions are very conservative and result in long periods that the HRSG remains below the acid dew point. Benefits of faster starts include reduced fuel consumption and reduced time needed to get these units up to AGC capability.

It is recommended to work with IST to enable the LP and HP circuits of the OTSG to start in parallel rather than in series. It would also be helpful to have DCS screens that specifically track progress in clearing the permissives for OTSG startups.

There are significant opportunities to improve thermal performance of the combined cycles. It was noted the combustion turbines are operating below expected performance. From our experience, most plants find that they can economically benefit from more frequent compressor washing. This can result in better heat rate, higher full load capacity, and a larger regulating range. Other performance opportunities include optimizing steam turbine back pressure and reducing auxiliary loads. The existing MicroNet screens have limited value for monitoring useful performance metrics to base decisions.

The MHI diesel generators could start a bit faster if the units are put on turning gear when it is anticipated a startup call is approaching.

OPERATION & MAINTENANCE IMPACTS

Most of the recommendations discussed have no significant impact to O&M costs. However, with more renewable generation, the units will start/stop more often and spend more time at lower loads. This will inevitably increase the generation cost due to higher overall system heat rate and increased maintenance. Specifically, running at lower loads can result in backend corrosion on the boilers and HRSGs. More startups will result in more thermal cycles for large machinery which can affect the remaining useful life for key equipment. Increasing automation will require some additional instrument tech time for calibration.

NEXT STEPS

As part of this study's scope Stanley Consultant's will develop procurement specifications for the HRSG Modifications and the Data Historian. This will be completed before the end of the year.

New Source Review (NSR) and New Source Performance Standards (NSPS) need to be evaluated for the Kahului Burner Upgrades, Maalaea Inlet Chilling, and MHI Engine Heating to determine any implications. In addition, emission rates need to be evaluated to ensure compliance with other regulations as well, including changing National Ambient Air Quality Standards (NAAQS) and Maximum Achievable Control Technology (MACT) regulations. Impacts due to the potential modifications are currently being evaluated by HECO Environmental.

At the time of this writing, the exact cause of backend water damage to the M18 steam turbine was still undetermined. Additional controlled unit testing is required to properly evaluate the levels of back end moisture at various conditions. The results of this testing could provide the most economical means of minimizing further turbine damage. In addition, testing should eliminate low loads as the cause of the damage, thus allowing continuation with the economically favorable OTSG modifications. Leaking attemperators and inadequate M18 backend draining should also be eliminated as a root cause by confirming proper operation. Efforts should continue to obtain answers from Mitsubishi Power System regarding the capabilities and limitations of their steam turbine. It should also be considered that even if limited steam turbine wear is allowed to continue on M18, the economic benefits of lower load operation are likely to far outweigh any increased maintenance costs.

There are a significant opportunities to optimize performance. This could result in heat rate improvement, increased capability and expanded operating ranges.

An alternate steam source for Kahului Unit 3 deaerator steam will be required for low load operation. If water quality remains an issue for lower loads, the scope and cost estimate for Condensate Polishers on Kahului Units 3 and 4 should also be further investigated. More steam and water analysis at low loads would help to clarify the water quality issues.

Section 1

Introduction

Phase 1 of the Operation Flexibility Study was conducted for MECO to identify equipment and operational modifications necessary to accommodate more as-available renewable energy. In addition to achieving operational flexibility, the study evaluated recommendations necessary to maintain unit reliability and availability, and to preserve equipment life. Modification of MECO's generating units is anticipated to enable additional wind energy to be delivered to the Maui system. Increased load ranges should enable these units to better provide the required regulating reserves necessary to counter the variability of the wind plants.

PURPOSE

The purpose of the Phase 2 study was to further develop selected modifications under consideration. Unit testing was conducted to better understand the capability of the units and identify constraints preventing a wider operating range. Previous Phase 1 modifications have been recommended to overcome constraints and enable MECO's fleet of generating units to operate effectively along with significant renewable generation. The more detailed scope and cost estimates for the selected modifications will be used in the project approval and budgeting process.

SCOPE

The scope of this study included the following deliverables:

- A trip report summarizing findings and decisions from the first kickoff and interview trip
- Test Procedures and Summary Results for unit testing at Kahului and Maalaea units
- A list of the necessary simulation runs by Generation Planning

- A list of additional modifications identified
- Draft scopes for the seven selected Phase 1 modifications
- Project Cost Estimates for the seven selected Phase 1 modifications
- Draft and Final Study Reports
- Procurement Specifications for primary equipment to be provided later

APPROACH

On site interviews with MECO personnel identified goals and specific areas that required more detailed investigation for each proposed modification. Discussions focused on the seven modifications identified in Phase 1, but additional points were brought to light as well. MECO personnel described future operational profiles and what benefits were expected from each modification. Ideas were generated in an effort to address constraints previously identified in the Phase 1 study. In addition, new constraints were identified as systems were better understood by Stanley.

These interviews also helped define how the unit testing would be performed. It was important that key plant personnel understood the test goals, timing and how known constraints would be dealt with, as well as what information would be collected during the tests. Detailed procedures were developed and reviewed prior to testing to ensure success. While the test was being conducted, operators were questioned so Stanley could better understand operational procedures.

After the tests, the results were analyzed and key constraints were identified and summarized. Additional operational constraints and potential modifications not originally identified were discovered as part of this analysis. In addition, test data was analyzed for performance degradation to demonstrate how maintenance activities can influence performance. Test reports and summaries were developed and are provided in Appendices 1 and 2.

After the basic constraints had been identified, design documentation was reviewed and vendors were contacted to assist in further developing the modifications that would address the problems. Equipment manufacturers assisted in determining costs, providing project details, and determining feasibility for each modification.

Once the modifications had been better defined, it was possible to estimate how the affected units would operate in the future. Scenarios and inputs for Generation Planning's Production Simulations were provided. These simulations determined how system costs and Renewable Portfolio Standard (RPS) would be affected by the new operating profiles. In the cases of the BESS and inlet chilling on the combustion turbines, several possible equipment sizes needed to be compared in order to determine the most optimal configurations. The Production Simulation outputs provide overall system operating costs over 20 years as well as the amount of renewable generation allowed on the system. The outputs helped define the value of each proposed modification.

It was also necessary to provide information to HECO and MECO environmental personnel to determine how proposed modifications might impact permitting. Once the environmental analysis is complete, it's possible that otherwise viable modifications will become impossible due to environmental considerations.

After the seven identified modifications were evaluated, a scope of work was created for each implementation. The scope of work includes a narrative with a description of the work, assumptions and budgetary cost estimates for engineering, labor, and materials.

Section 2

Discussion

BACKGROUND

Wind and solar powered electrical generation has become an increasingly popular method of supplying renewable energy to an ever growing market for green power. This is particularly true for remote and isolated areas, such as the Hawaiian Islands, that rely on petroleum fuels with significant transportation expense.

Wind and solar variability exposes electrical systems to the risk of sudden drops in generation, requiring the rapid replacement of the missing generation from conventional sources. Secondary to the variability of wind in the macro sense, is the micro variability of wind. Instantaneous variations in wind speed can directly affect the amount of power generated at any point in time. This results in erratic output from the wind facility, thus forcing other conventionally fueled units to continually adjust their output to meet current system demands. System operators must allow for macro and micro variations by maintaining higher levels of regulating reserve than would normally be called for.

The Phase 1 study identified several constraints that needed to be addressed to allow the MECO fleet to better follow the renewable generation. These constraints include slow unit starting times, high minimum loads, and sluggish load response.

Slow Unit Starting Times

In order to quickly respond to sudden losses of renewable generation, conventional units in the MECO fleet need to be able to start as quickly as possible. Improving the starting times of the more efficient units allows for faster replacement of inefficient generating assets, such as the EMD engines. This improves overall system efficiency.

High Minimum Loads

The MECO fleet was designed to run at or near baseload conditions. Because of this, the MECO units must run at relatively high minimum loads in order to protect the equipment from operating at ranges outside original design conditions. In addition, many units are required to run in order to satisfy the system up-reserve requirements. The combination of many units running at relatively high minimum loads reduces the amount of renewable generation that is allowed on the system. Thus, by reducing the allowable minimum loads of the larger units in the MECO fleet, more wind generation can be accommodated.

Sluggish Load Response

The ability of the large efficient generating units to quickly respond to system demand is important because it prevents other less efficient units from requiring a start. If the ramp rate of the combined cycle and thermal units can be increased, overall system efficiency and stability will improve.

As Maui moves forward with the eventual integration of additional renewable generation, it can be expected that these constraints will continue to limit the ability of the conventional generating assets to meet the increased variability of the electrical system in an effective and efficient way. As the constraints are addressed, more renewable generation can be allowed on the system and the conventional generating assets will be in a better position to respond to system demand.

The Phase 2 study approach to further identifying these constraints and opportunities included three main tasks. First, interviews were conducted to gather insight from key MECO individuals. Second, testing was performed to pinpoint constraints and identify operational shortcomings. Finally, investigative review of equipment design and operational information as well as interviews with equipment vendors helped develop the seven selected modification scopes.

INTERVIEWS AND EQUIPMENT DOCUMENTATION COLLECTION

At the beginning of the study, interviews of MECO personnel were conducted regarding the overall project and the proposed modifications to the MECO system and generating units.

The interviews were conducted with the following personnel and departments:

- Power Supply Manager
- Maalaea Station Manager
- Kahului Station Manager
- Staff Engineers
- Maalaea Operations Personnel
- Maalaea Maintenance Personnel
- HECO Boiler Specialist
- Combined Cycle O&M Personnel
- Diesel Generator Operation & Maintenance Personnel
- Control Maintenance Technicians

- Environmental Air Specialist
- Kahului Maintenance Personnel
- Kahului Operations Personnel
- Renewable Energy Services Vice President
- System Operations – Dispatch
- HECO Generation Planning

During each interview, plant systems of interest were discussed with the group and feedback was solicited for the potential capital modifications under consideration. Several issues were identified that helped define how testing would be conducted. In certain cases, new target minimum loads were identified as goals for the testing.

Additionally, the MECO equipment library was utilized to gather detailed design documents and operating and maintenance procedures in order to identify original equipment manufacturer specified constraints.

TESTING AND RESULTS

A test procedure was developed and finalized with Shift Supervisors, Engineers, and Plant Management. This was necessary to keep all involved parties informed of when and how the tests would be conducted. The following describes highlights of testing conducted during two trips in May 2012 on Kahului Units 3 and 4, both Maalaea combined cycle blocks, and two Maalaea diesel generators. Graphs and more detailed reports and summaries of this testing can be found in Appendices 1 and 2.

Kahului 3 Testing

Testing was conducted on May 1, 2012 to evaluate low load operation and ramping capabilities. A target low load of 3 MW was established prior to the test.

Significant Limitations

At higher loads, the deaerating steam source is a steam turbine extraction. At approximately 6 MW, this steam source was no longer available and the DA pressure went to zero. At lower loads, DA was on vacuum with exit water temperatures as low as 144 F.

A low fuel pressure alarm at 60 psi dictates that individual burners are to be pulled from service as load is dropped further. A 1999 report by EPT recommended a 40 psi alarm set point. Pulling burners is a manual task that is manpower intensive and time consuming. In order to achieve the 3 MW minimum load, two (2) burners had to be removed from service. These burners then had to be manually put in service to increase load.

The Boiler Master Control was a bit slow to respond to steam turbine load changes which slowed the rate the steam turbines load could be raised.

Significant Observations

Water quality deteriorated somewhat at lower loads and required additional chemicals. The steam turbine seemed to operate well at lower loads with vibrations, main steam pressure, and seal steam pressures within normal operating ranges. There were no indications of backend moisture problems. Combustion was monitored and excess air was erratic but opacity remained good throughout the low load test.

During the ramp test, the unit was able to raise load from 7 MW to 12.4 MW in 26 minutes. This is quite slow and limited by the manual steam turbine governor. It was also noted that boiler water conductivity increased from 3.2 to 3.9 µmhos, but this may clean up if allowed to run longer at low loads and with proper deaeration.

Opportunities

- Modify and tune the burners to allow all burners to remain in service at low loads
- Modify steam source for DA pegging to maintain water quality at low loads
- Perform steam and water quality analysis to determine the nature of the change in water quality
- Based upon the above analysis, it may be necessary to install a polisher to maintain proper water quality during load change events
- Tune boiler master and air flow control for quicker response
- Install an electronic governor to reduce manual intervention and improve response
- Reduce fuel oil pressure alarm to 40 psi if burners are not modified
- Shut off one circulating pump at low loads to reduce auxiliary load
- Measure O2 out of the DA to improve awareness of water quality
- Consider improving air flow control to stabilize excess air and improve opacity
- Automate several valves to reduce manual intervention
- Install an automatic recirculation valve for the condensate and boiler feed pumps
- Automate steam seal pressure regulator to reduce manual intervention at low loads

Kahului 4 Testing

Testing was conducted on May 2, 2012 to evaluate low load operation and ramping capabilities. Like Kahului 3, a target minimum load of 3 MW was established prior to the test.

Significant Limitations

In order to achieve the 3 MW minimum load, 2 burners had to be removed from service. These burners then had to be manually put back in service before increasing load. In addition, water quality deteriorated badly at 3 MW and required dumping of the hotwell. This may or may not clean up with more hours at the new low load point.

Significant Observations

Unit 4 was able to operate at 7.1 MW with all 4 burners in service and at 3 MW with 2 burners removed. No indications of backend moisture problems were observed on the steam turbine.

During ramping load increased from 7 MW to 13.5 MW in 10 minutes and the boiler master control was responsive and maintained steady pressure. Opacity spiked during fast ramping periods.

Opportunities

- Modify and tune the burners to allow all burners to remain in service at low loads
- Perform steam and water quality analysis to determine the nature of the change in water quality
- Based upon the above analysis, it may be necessary to install a polisher to maintain proper water quality at lower loads
- Replace the steam coil are heater (SCAH) to better protect backend equipment from acid dew point corrosion
- The steam turbine governor could be programmed to increase load at a higher % / min than the current "fast" settings allow
- Automate steam seal pressure and SCAH bypass valve to reduce manual intervention
- Add a steam seal pressure regulator to improve sealing pressure at low loads
- Station Steam Supply Valve is cutting and needs to be resized

The possibility of backend moisture does not appear to be a problem for Kahului 3 & 4 but needs further evaluation before extended operating hours at 3 MW. Also, if modified burners are installed, it will be important to verify steam temperatures can be maintained at 3 MW with four burners in service.

Combined Cycle Testing

The Maalaea combined cycle units were tested from May 23rd to May 25th. Each combined cycle block (CC1 & CC2) was tested in the following scenarios to determine constraints, limitations, and opportunities:

- Low load testing was conducted on CC1 to evaluate dew point corrosion concerns on the backend of the HRSGs and to identify any other constraints on a single train turndown
- Low load testing was conducted on CC2 to evaluate low load capability of the OTSGs and to identify any other constraints on a single train turndown
- Startup testing determined the time required to bring a second train online and ramp to full load operation when its partner train was initially in 1x1 AGC mode
- Ramping Capability was evaluated by manually ramping one train from maximum load to minimum load and back to maximum load
- Combined Cycle Capability was evaluated with both units in T54 temperature control mode

Significant Limitations

During startup testing, the hold points and start times were found to be extremely long for units of this size. M14 was held at 10 MW for 101 minutes and M19 was held at 12 MW for 78 minutes. The hold periods were to open dampers, clear permissives, and blend steam among other things and they present the best opportunity for reduced start time. Similar plants at other locations go through the entire hot startup, including the steam turbine, in 60 minutes.

During the lowest 1X1 loads, the M18 gland seal pressure dropped to 0.9 psi with the supply pressure control valve fully open.

The existing Air Permit averages MWs rather than weighting minutes in each MW range creating improper water/fuel ratio limitations. The illogical manner in which this permit wording was implemented leads to slower than necessary starting and ramping depending upon the clock time and current load level. At certain times, this resulted in less flexibility, increased fuel use, less availability for renewable generation and, ironically, an overall increase in Maalaea emissions.

Significant Observations

The estimated acid dew point range is 248-268 Deg F. During the startup of M14 it was noted that the HRSG spent 53 minutes with the stack temperature below 268°F. Corrosion and deposits may be occurring during this time.

The units ramped up and down very well with the exception of M19 down ramping, which twice tripped the LP circuit of the OTSG. The exact cause was never determined.

Condenser pressures were operated at values that may be costing cycle efficiency. This was more of a concern at low loads when a large portion of the air cooled condenser fans were on, thus reducing the steam turbine back pressure to unnecessarily low levels.

Opportunities and Further Evaluation

Low Loads

There are opportunities for achieving lower loads for both CC1 and CC2. For CC1, acid dew point does not appear to be a significant risk at CT loads above 8 or 9 MW. With modification this can be brought down to 7 MW. With improved data monitoring and additional operator intervention capability, M17/19 could run closer to the HP flow trip point of 38,000 lb/hr.

Performance

The engines are operating below expected performance. There is an opportunity to optimize water wash frequency in order to raise the capability of the units and improve heat rate. The inlet filtering O&M strategy can also be optimized to find the best trade-off between filter costs and engine performance.

For performance monitoring, the existing MicroNet system does have three built in performance monitoring screens, but they monitor Gas Turbine Shaft HP vs Engine Speed, Gas Turbine Engine Pressure Ratio vs Engine Speed, and Gas Turbine Compressor Pressure Ratio vs Engine Speed, which have limited value.

There are opportunities to reduce aux loads, especially while operating at lower loads. The set points for steam turbine back pressure can be optimized to find the right balance between aux load and steam turbine efficiency.

Startup and ramping

The most significant automation opportunity is with the M14/16 HRSG inlet dampers. This will allow faster startups and eliminate the need for frequent manual position observation. Additionally, consideration should be given to developing standard plant operating procedures for unit startup, shutdown, and loading.

Diesel Generator Units 4 and 10 Testing

Maalaea's Cooper Diesel Generator Unit 4 was tested on May 3, 2012.

Significant Limitations

Lube oil temperature into engine must achieve 140 Deg F before control is turned over to the main control room. This contributed 9 minutes to the start time. Similarly, jacket water temperature into engine must achieve 120 Deg F before control is turned over to main control room. This contributed 14 minutes to the start time.

Significant Observations

The engine took 53 minutes from the start of checks to full load. There is only one purifier/heater shared amongst the four Cooper engines. M4 was shut off the previous night at 10:00 and had the oil purifier operating through the night. If the oil purifier had been cleaning one of the other engines overnight, M4 would not have been as warm and would have taken even longer to start.

Opportunities

Install jacket water heaters and larger oil heaters for each unit (M4-M7). This will help keep the engines warm when offline and allow for faster starts. Additionally, investigate the procedure for running oil and jacket water pumps to allow for earlier preheating and shorter warm up times. If instrumentation were added to trend jacket water and lube oil temperatures, specific constraints could be identified easier. Finally, there are opportunities for automation to reduce manual intervention and possible allow two units to start simultaneously.

Maalaea's MHI Diesel Generator Unit 10 was tested on May 25, 2012.

Significant Limitations

The primary restriction that inhibits engine start time is the MHI ramp requirements. This in itself takes 2 hours and 8 minutes to go from 3 MW to 12.5 MW. Also of concern is the jacket water temperature constraint that dictates incoming water must achieve 140 Deg F before control is turned over to main control room. This contributed 10 minutes to the start time. Similarly, the lube oil temperature into this engine must achieve 123 Deg F before control is turned over to main control room.

Significant Observations

Startup time up to 8 MW was 95 minutes from the time startup checks were initiated.
The manufacturer startup times as listed in the "Startup Times" document state that it should take 85 minutes after lube oil and jacket water temps are achieved to go from 3 MW to 12.5 MW. During the test, it took 128 minutes to achieve this.

A 10 minute turning gear period that is required prior to start up could be anticipated by the operator to improve start time. Turning Gear is operated by resting a "weight" on top of a button and leaning the "weight" against the unit. The "weight" is susceptible to falling off the button and should be automated.

Opportunities

- Install jacket water heater and lube oil heating system
- Automate turning gear activation
- Adhere to the manufacturer startup times as stated in the "Startup Time" report which shows the unit can start faster than was observed
- Add instrumentation to trend lube oil and jacket water temperatures
- Start the turning gear in the morning approximately 15 minutes before the expected startup call time in order to eliminate 10 minutes of startup time

LITERATURE RESEARCH & APPROACH

After testing was conducted and major constraints and opportunities had been identified, vendor documents were reviewed to better define the constraints. In addition, equipment experts and original equipment manufacturers were consulted to get an understanding of how they viewed the proposed operational changes. Identifying modifications that would be required in order to accommodate faster start times, improved load response, and lower minimum loads were of greatest interest. Some of the vendors even visited the site in order to better understand the constraints and evaluate the equipment.

The opportunities and modifications previously identified were then used to develop operational scenarios. In some cases, there were multiple solutions for each constraint that needed to be evaluated side by side. These scenarios were provided to Generation Planning to be input to the Production Simulation model. The Production Simulation results identified the operational costs over 20 years associated with each proposal. These costs were compared to capital cost estimates to narrow the possible solutions. In addition, the model produced an RPS percentage figure that was later used to compare capital costs to relative impact each modification had on the amount of renewable generation allowed on the system.

With assistance from operations personnel and vendors, project scopes were developed and used to prepare more detailed cost estimates for each proposed modification.

MECO and HECO environmental personnel were consulted to determine what information was needed in order to assist in permit review. Cost estimates, emissions estimates, and scopes were also provided. It is important to understand any permit implications of the proposed modifications. Of most concern are the Kahului burners, the combustion turbine inlet chilling, and the MHI diesel generator preheating.

MODIFICATIONS

One of the tasks of this study was to evaluate and refine seven modifications recommended in the Phase 1 Final Report. The modifications have been reviewed to determine their applicability given the changes in the proposed operational philosophy since the final Phase 1 report was issued. In addition, detailed review brought to light equipment limitations and placed values on each modification in terms of operational costs and RPS benefit.

The following sections provide descriptions, scopes, cost estimates, and benefits of seven potential modifications. These modifications are as follows:

Table 2-1 – Primary Capital Recommendations

Section	Modification
3.1	Upgrade Burners for Kahului 3 & 4
3.2	Install Inlet Chilling on Combustion Turbines
3.3	Modify HRSGs for Cycling and Lower Loads
3.4	Install Engine Preheating (M10-M13)
3.5	Modify OTSGs for Lower Loads
3.6	Install a 10MW-90 minute BESS
3.7	Install Data Historian for Generating Units

Section 3

Key Modifications

INTRODUCTION

Several modifications have been identified as upgrades to the existing Kahului and Maalaea Units in order to improve turndown and cycling capability. The following sections describe each modification in more detail. There are additional modifications that were identified throughout the course of the Phase 2 study through interviews and testing. These are listed in Section 3.8 for consideration if they warrant further investigation in the future.

As part of scope and cost, each section will describe specific assumptions applicable to that modification. However, there are some general assumptions that were applied to all units during the development of the cost estimates.

- Owner's costs, such as in-house labor and warehousing fees, are better addressed by the owner and are not included. Each cost estimate includes engineering, contractor overhead, Hawaii Use Tax, contingency, and miscellaneous costs.
- Except where indicated otherwise, it is assumed that DCS configuration will be performed by MECO personnel and is not included in these cost estimates.
- Limited information was available about line sizes and valve types, so assumptions were made in order to estimate costs. It was assumed that if a control valve existed and needed replacement, the existing wiring could be reused.
- Where excavation was required, it was assumed that no underground utilities would need to be relocated, unless detailed otherwise.
- Where new piping and conduit needed to be provided, it was assumed that it could be run above ground and that existing structural racks could be used to provide support.

Section 3.1

Upgrade Kahului Burners & Combustion Controls

Kahului Units 3 and 4

BACKGROUND

Currently Kahului Units 3 & 4 are not well suited to operating effectively at lower loads. With all burners in service they were only designed to lower load to around 7 MW. There are significant benefits for improving RPS percentages if these units can operate on a regular basis at a new target load of 3MW. Testing revealed the new target minimum loads could only be achieved if two of the four burners were pulled manually on each unit in order to maintain proper flame and system stability. This is time consuming, inefficient, and can create thermal stress issues for the boilers. In order to eliminate this step, the burners should be modified to allow for 4:1 turndown to allow all four burners to remain in service at minimum load.

The following aspects of burner design were evaluated in this study.

Atomizer Upgrade

The current oil burners are steam atomized but were only designed for about a 2:1 turndown. Modern steam atomized burners normally have a turndown ratio of 4:1 or 5:1. After discussions with Coen, the burner supplier, it was determined that the burner guns and atomizing nozzles must be replaced to achieve the desired turndown level.

The new atomizers would operate with the steam pressure approximately 150 to 200 psig. The differential between the atomizing steam and fuel oil would remain the same at approximately 25-30 psid. These burners will be capable of firing No. 6 fuel oil, No. 2 diesel, bio-oil, and utilizing the current LO1 fuel additive.

New control valves may be required to allow for the new steam and oil operating pressures. Additionally, it may be desirable to incorporate flame scanners.

Combustion Control

New air registers were considered to assist in fine tuning the combustion air control. This includes new burner front plate assemblies, stationary registers, pneumatically operated air slide registers, swirlers, igniters, hoses, and gun retract assembly. In addition, depending upon the configuration of the boiler burner throats and the depth of the new register burners, new burner guns and atomizer tips may be required to accommodate the new geometry.

A Variable Speed Drive (VSD) on the FD fan motor was another option considered to improve combustion air control. This was discarded in favor of automating air registers.

Automation

In order to reduce the amount of manual intervention, fully automatic steam, fuel and purge valves were considered along with the required instrumentation.

Burner Management System

Finally, installing a BMS was considered. The BMS is a dedicated burner control system designed and operated in accordance with National Fire Protection Agency (NFPA) requirements to prevent furnace explosions. The BMS ensures proper operation of igniters and burners, controls burner cleaning and purging, controls furnace purge, and controls igniter and burner shutdowns under normal and emergency conditions. Installing a BMS will further modernize these units and improve safety as well as bring the units up to modern codes.

PROJECT DETAILS

It became apparent that the best approach would be to proceed with the new atomizers and burner guns, and if turndown operation isn't satisfactory, to then proceed with fuel and steam supply control valve replacement and possibly the addition of flame scanners.

Should additional control be required at that point, further modifications could also be installed. The following modifications are not included in the cost estimate: combustion control modifications, valve automation, and BMS.

The work involved in each phase of this project will consist of the following:

Phase 1 – Replace atomizers and burner guns.

- New oil burner gun assemblies
- New inside mixing atomizers
- New steam atomizers designed to fit into the existing registers
- New blowout devices to allow the steam to purge the oil from the gun prior to removal

Phase 2 – Replace Control Valves

- Replace the fuel oil and steam supply control valves (1 each per unit)

Phase 3 – Flame Scanners

- New flame scanners
- Control wiring from the plant control system to the flame scanners and electrical conduit

Not included in the cost estimate:

Phase 4 – Combustion Control

- Stationary Air Register Assembly
- Pneumatically operated air slide assembly
- Burner front plates
- Pneumatically operated gun retract assembly
- Swirlers
- High Energy Igniters (HEI)
- Oil and steam hoses
- Burner guns (possibly)
- Inside mixing atomizers and steam atomizers (possibly)

Phase 5 – Automation

- Fuel flow meter
- Fuel control valve
- SSO (Safety Shut Off) valve
- Pressure and temperature switches
- Pressure indicators
- Fuel oil return line with SSO valve
- SSO at each burner for oil, steam and scavenging.

Phase 6 – Burner Management System

- Fyr-Logix BMS
- PLC
- Interlocks and controls

COST ESTIMATE

The cost numbers below include money to implement Phase 1, 2, and 3 listed above. Additional details are provided in Appendix 3.1

Table 3.1-1 – Capital Cost to Upgrade Burners

Plant and Unit	Estimated Capital Cost
Kahului Unit 3	$254,000
Kahului Unit 4	$254,000

O&M IMPACTS

After installing these new burners, it is expected that flame length will decrease, atomization will improve, opacity will improve or stay the same, and changes in heat rate will be negligible. Unit output will remain the same. Steam consumption is expected to remain the same as is the Steam/Fuel ratio.

Given the likelihood that flame length will decrease reducing flame impingement, it is anticipated that tube maintenance will also decrease. Additionally, the new blowout devices will reduce the amount of manual burner cleaning required. In general, higher levels of automation will require additional routine calibration of instrumentation. However, this will be offset by reduced manual operator intervention during load changes.

The modifications described should easily allow for a 4:1 turndown with all burners in service compared to the existing 2:1 turndown capability. Results from Generation Planning Production Simulations indicate this will allow more renewable energy on the system, improving the RPS by 0.9% in the year 2020.

Section 3.2

Install Inlet Chilling on Combustion Turbines

Maalaea Units 14, 16, 17 and 19

BACKGROUND

The combined cycle units at Maalaea are the most efficient in the MECO fleet. However, due to system requirements, the units that make up these combined cycles need to operate at a reduced load in order to maintain certain levels of up reserve. This hurts system efficiency. Adding inlet chilling to the combustion turbines gives each machine an additional power boost when needed, allowing these units a larger operating range which has been shown to improve MECO's overall system efficiency. It achieves this by modestly boosting combustion turbine output thus keeping less efficient generator from an otherwise necessary start. This in turn allows renewable wind energy to stay on line which boosts MECO's RPS.

It is common practice in combustion turbine generation plants to utilize inlet cooling to increase the maximum output available from the unit. The reduction in compressor inlet temperature realized through the use of a chilled water system allows additional air mass to pass through the combustion turbine thus producing greater power output. The parasitic load associated with the chillers is more than offset by the power gains for the combustion and steam turbines.

Additionally, the parasitic load can be disassociated from the utilization of inlet cooling through the use of a thermal energy storage (TES) tank. This insulated water tank provides a means to store chilled water produced at night for use during the heat of the day. The perceived benefit of this system is that the parasitic load associated with the chiller could be consumed at night, reducing peak power auxiliary loads and allowing more wind energy on the grid at night.

This study considered two different sized direct chilling systems and two disassociated TES sized systems.

<u>Direct Chilling</u>

The first system considered was a small chiller that boosted the net output of each of the four combustion turbines by 450 kW when operational for a total of 1.8 MW net.

A larger direct chilling system was considered that increased the net output of each combustion turbine by 1075 kW for a total of 4.3 MW net.

Both systems consisted of air cooled chillers, pumps, coils in the combustion turbine inlets, and associated piping and electrical equipment.

<u>Chilling with TES</u>

A disassociated TES system was considered with 1150 kW per turbine or 4.6 MW of net power available during peak periods.

A larger disassociated TES system was also considered with 1900 kW per turbine or 7.6 MW of net power available during peak periods.

Both systems consisted of air cooled chillers, pumps, coils in the combustion turbine inlets, thermal storage tanks, and associated piping and electrical equipment.

PROJECT DETAILS

Generation Planning Production Simulations were used to determine the benefit of each system over 20 years. New assumptions for Phase 2 simulations reduced inlet cooling availability, considered additional fuel consumption, and included the cost of electricity associated with allowing additional wind onto the system. This reduced the benefits associated with TES and eventually eliminated it from consideration. MECO personnel used the results to determine that the smallest direct chilling system capable of producing 1.8MW net additional output for Maalaea was preferred.

The biggest constraint facing this modification is the lack of real estate available for additional equipment. After much discussion, it was determined that the best location for the new equipment would be on elevated foundations to the east of the existing eastern plant wall in the Pohakea drainage area. This still resides inside the plant property line.

The following equipment would be placed on foundations elevated by H piles. Platforms would be built as required to provide access to the equipment.

- Three (3) 500 Refrigeration Ton air cooled chillers would be placed on elevated foundations with access platforms surrounding them.
- Pump skid and control valves
- 480V Switchgear

The remainder of equipment and infrastructure is inside the existing plant wall and includes:

- 4160V/480V transformer with foundation
- 480V Non-Segregated bus
- Pre-insulated chilled water piping
- Additional 4160V Switch Gear located at the EMD medium voltage bus.
- 4160V Cabling
- Modifications to the existing 4160 V Switch Gear building
- Modifications to the combustion turbine inlet structures
- New combustion turbine inlet coils
- Optional condensate collection system
- Relocation of existing firewater and fuel oil lines so that the 4160V/480V transformer can be placed

COST ESTIMATE

The lack of real estate available represents a significant challenge to this modification. The elevated foundations and platforms are a significant capital cost that wasn't initially expected during the inception of this proposed modification. Additionally, the remote location of the chilling equipment relative to the combustion turbines requires significant quantities of expensive pre-insulated piping and 4160 V cable. Finally, the lack of spare 4160 V breakers and limited information about the location and configuration of the 4160 V bus connecting the EMD engines required some assumptions about modifications necessary to the electrical equipment and building that houses it.

The optional condensate collection system collects water condensed on the new inlet chilling coils and pumps it to a tank in the water treatment area for storage prior to the second pass RO system. It was assumed that the existing Degasifier Product Storage Tank could accommodate 5-10 gpm produced. It was also assumed that spare power is available to power the two (2) approximately 0.25 HP pumps located near M16 and M19. Information was not available about the cost of producing clean water prior to the second pass RO. Additional analysis could be performed to determine if the condensate collection system is economically beneficial.

The total cost to perform the work is estimated below. Additional details can be found in Appendix 3.2.

Table 3.2-1 – Capital Cost for Combustion Turbine Inlet Chilling

Plant and Unit	Estimated Capital Cost
Maalaea 14, 16, 17, and 19 combined	$9,764,000

O&M IMPACTS

The additional net power output provided by the chillers to the combustion turbines allows the combined cycles to generate more power and other less efficient MECO generating assets to remain offline during periods when system demands and regulating reserve requirements might otherwise require less efficient units run. Because of this, there is a fuel savings and more renewable energy is allowed on the system. The associated increase in RPS is 0.3% by the year 2020.

The additional chillers, pumps, valves, switchgear and transformer will increase maintenance requirements.

The chillers would only run when the combustion turbine were at full load during peak periods. Gross output is expected to increase 925 kW per combustion turbine. NO_x emissions are expected to increase by approximately 5 lb/hr per combustion turbine. Fuel consumption will increase slightly.

Section 3.3

Modify HRSGs for Cycling and Lower Loads

Maalaea 14 & 16

BACKGROUND

Presently, each combustion turbine/HRSG pair is turned down at night to allow wind energy onto the grid and to accommodate lower system demands. It would be beneficial to the system and RPS to be able to reduce the minimum load further and/or turn one of the combustion turbines off nightly. Concerns about HRSG backend corrosion due to cooler exhaust gas temperatures at low loads need to be addressed to allow more operating margin above the acid dew point. Additionally, if the HRSGs are to be turned off nightly, the units need more automation, durability, and the ability to retain heat.

Current combustion turbine minimum loads are 12.5 MW for M14 and M16. During testing in 1 x 1 combined cycle mode, the combustion turbine load was reduced to 7 MW with a corresponding steam turbine load of 2.5 MW. There were no indicators of operational problems. The upper estimate of dew point (268 F) was approached at 8 to 9 MW.

It is estimated that if left in 2 x 1 combined cycle mode with the combustion turbines at 7 MW, the steam turbine load would be approximately 6 to 7 MW.

Several industry experts, including the Original Equipment Manufacturer, were contacted in order to generate additional ideas about necessary modifications to accommodate cycling and lower loads. After numerous discussions with outside parties and MECO personnel, the list of modifications was finalized. In general, the modifications can be put into three categories: 1) Automation; 2) Heat Retention; and 3) Durability.

The current start-up and shut-down procedures require manual operation of many valves and dampers. If the units are to be cycled nightly, more automation is recommended in order to reduce manual intervention and decrease start time. These modifications include installing actuators on several HRSG vent and drain valves, automating the HRSG bypass dampers, as well as installing feedwater bypass control to allow for improved feedwater control at lower loads. The goal is to improve feedback to the operators and reduce or eliminate time required to manually operate equipment. Even without cycling at night, it is recommended to automate the bypass dampers to improve starting capability.

It is important to conserve as much of the heat energy as possible to allow for faster starts in the morning as well as to reduce the amount of thermal contraction and expansion. System boundaries need to be capable of sealing tight to reduce the amount of energy leakage.

Operating at low loads and cycling off frequently increases wear and tear on power generating equipment. Certain steps can be taken to increase unit flexibility and durability. In addition, the inevitable increased maintenance can be made easier by improving access for inspection and repair. All that said, the equipments' life cycle will decrease and replacement costs should be considered before choosing to change operating profiles.

PROJECT DETAILS

The following major equipment modifications and their associated installations are recommended:

- Automate HRSG bypass dampers
    - Expected modifications:
        - Add limit switches and position feedback sensors to the control loop
        - Develop control logic
- Add a pegging steam cross-tie between Maalaea units 14 and 16 to maintain temperatures and water chemistry in the off-line unit
    - Expected modifications:
        - Piping
        - Motorized and manual valves
- Upgrade HRSG exit dampers (1 per unit) to reduce amount of temperature loss
    - Expected modifications:
        - Replace the internals of the existing knife gate dampers, or replace entirely
        - Add access platforms for damper maintenance
- Inspect and Upgrade Vent and Drain valves
    - Expected modifications:
        - Inspect the following valves and replace those that leak
        - Where applicable, automate (including positioners and control logic) and upgrade the following valves:
            - Superheater Outlet Vent
            - HP Drum Continuous Blowdown
            - LP Drum Continuous Blowdown

        - Superheater Drain Valves: (Qty: 5)
        - HP Economizer Drain Valves: (Qty: 12)
        - Superheater Outlet Vent
        - Superheater Outlet Drain
        - Superheater Outlet Intermittent Blowdown
        - HP Evaporator Intermittent Blowdown: (Qty: 3)
        - LP Evaporator Intermittent Blowdown: (Qty: 2)
        - HP Drum Vent Valves: (Qty: 8)
        - LP Drum Vent Valves: (Qty: 3)
- Install HP boiler feedwater control bypass control valve to better control feedwater flow at lower loads and preserve the primary control valve
    - Expected modifications:
        - Add bypass leg with valves
        - Modify control logic to insure that BFP minimum flow is maintained
- Visually inspect steam line and add additional steam traps at low points to improve condensate capture during low load and cycling events
- Install automatic self-cleaning strainers on boiler feed pump suctions
- Replace lower superheater tube bends with a common header to alleviate thermal stress
- Change socket and fillet weld geometry on superheater drains to 2:1 (weld leg : throat size) to reduce fatigue stress
- Upgrade the HRSG flue gas inlet/outlet expansion joints
- To reduce corrosion:
    - Re-tube the LP section with T11 tubes
    - Add stainless steel liners on floors and the bottom two feet of duct walls
    - Add Epoxy coating on duct internals from the exit of the LP Evaporator to 10 feet up the stack
- Add 4 access manways per unit in outer casings to allow for better header inspections and repair.
    - Access provisions for the requested manways are currently sufficient so no additional platforms or provisions are required

COST ESTIMATE

It was assumed a mobilization cost in the case the gas side cleaning modification. The following table summarizes estimates for the capital cost for each HRSG. A more detailed breakout can be found in Appendix 3.3.

Table 3.3-1 – Capital Cost to Modify HRSGs

Plant and Unit	Estimated Capital Cost
Maalaea 14	$3,832,000
Maalaea 16	$3,832,000

O&M IMPACTS

Performing the aforementioned modifications to the HRSG will allow the units to reduce their minimum loads, shut off nightly, and improve start times. All of these outcomes will improve the amount of renewable generation allowed on the system. Generation Planning performed production simulations for reduced minimum loads. MECO's RPS will increase by 3.5% in the year 2020.

Due to difficulties in forecasting how the units would be cycled offline and schedule constraints of this study, production simulations were not performed for this operating scenario. If MECO wishes to pursue operating in this manner, further investigation would be required to determine when and how the units would be cycled in an effort to quantify economic impacts.

When operating in 2 x 1 combined cycle mode, the steam turbine is expected to perform in a manner consistent with current operating conditions. There are no indications of problems when in 1 x 1 mode with the combustion turbine at 7 MW and the steam turbine at 2.5 MW. However, if the steam turbine is expected to operate at 2.5 MW frequently, it should be monitored and inspected more thoroughly and frequently to insure that no back end moisture damage is occurring on the last stages. Inlet steam conditions should also be monitored carefully.

In general, frequent load changes and cycling increases the amount of maintenance. The inspection program will need to be adjusted to allow for more frequent inspections. It should be expected that components susceptible to thermal fatigue will need to be replaced more often. Boiler cycle chemistry will need to be monitored closely to ensure that chemical feed is adjusted as required by load changes. For nightly shutdowns, there could be a reduction in remaining useful life of the HRSGs due to the increase in thermal cycles.

Increased maintenance costs are somewhat offset by automation. Increased automation reduces the amount of manual operator labor but requires more I&C technician labor.

Overall fuel consumption is expected to go down because the units are operating at reduced loads but overall generation costs will go up due to higher costs for wind generation. In addition, since more renewables are allowed on the system, it's probable that less efficient generating assets can be left offline. There are no expected air permit impacts for cycling or low load operation.

Section 3.4

Install Engine Preheating

Maalaea 10 through 13

BACKGROUND

Currently, the Mitsubishi Diesel Generators take 90 minutes to go from a cold start to full load. Similarly sized modern reciprocating engines can be brought to full load in 10 minutes. There are two major constraints causing this slow start. First, these engines were designed to be base loaded and have aluminum piston skirts paired with steel cylinder liners. The different metal types expand at different rates and must be heated slowly so that the pistons don't seize inside the cylinder liners. Replacing the material of either component is not economically justifiable as it would be cheaper to replace the whole engine. Second, but related to the first constraint, are the hold points required to achieve lube oil and jacket water temperatures. The existing jacket water and oil preheating systems are small and do not maintain system temperatures such that the engine can be considered to be in a "Hot Start" condition.

If the engines are maintained in a hot state while offline, they're start times can be reduced. Mitsubishi Heavy Industries (MHI) was contacted to determine what engine modifications would be required to achieve this and how much start-time could be shortened.

PROJECT DETAILS

The MHI proposal is quite thorough including details regarding an improved start time and is provided in Appendix 4. If the system components are installed that will keep the jacket water and lube oil temperatures in a "hot start" condition (140 Deg F and 123 Deg F respectively), MHI expects that the start time will reduce from 90 minutes to 50 minutes.

As proposed by MHI, there are four major systems that require modification: 1) Engine Priming and Preheating; 2) Lube Oil Purification; 3) Lube Oil Filtering; and 4) Intake Air.

The Engine Priming and Preheating system requires replacement of the Jacket Water Circulating Water Pump as well as the heater. The current pump and heater are small and act on only a small portion of the Jacket Water loop. The new equipment would be sized for the entire system. New control valves are also required to incorporate the rest of the system. Finally, a new control panel is required to control the new equipment.

The Lube Oil Purification system requires replacement of the oil purifier with a new larger unit with a bigger pump and heater. It will accommodate additional contaminated oil captured by the upgraded Lube Oil Filtering equipment. The oil is transferred to the new purifier via a new Dirty Oil Tank.

The Lube Oil Filtering system will be modified to improve filtering capabilities. The existing Pre-Filter will be replaced with a Main Filter; the existing Main Filter will be replaced with an Indication Filter; and a Back Flushing Filter will be added.

The intake air system will be modified to include dust louvers to improve air quality into the engine.

COST ESTIMATE

The MHI proposal was very thorough and identified equipment and installation costs that were to be provided by MECO. The cost estimate in Appendix 3.4 breaks down the costs outside of MHI's scope and also details the MHI cost.

The following table provides the total estimated capital cost for each unit's Engine Preheating System.

Table 3.4-1 – Capital Cost to Install the Engine Preheating System

Plant and Unit	Estimated Capital Cost
Maalaea 10	$2,222,000
Maalaea 11	$2,222,000
Maalaea 12	$2,222,000
Maalaea 13	$2,222,000

O&M IMPACTS

Reduced start times will allow less efficient generating assets to shut down earlier than would otherwise be required or not be turned on at all, saving fuel and allowing more renewable energy on the system. Due to an inability for Production Simulations to incorporate the reduced start times, it was not possible to quantify how much the RPS and run time would be affected. Emissions and RPS are expected to improve.

Manual operator intervention will be reduced because of additional automation and the fact that the heating systems will be operating most of the time. The current engine preheating system is manually valved in and out when the units are stopped and started. This labor savings is more than offset by the additional electrical consumption necessary to keep the engines hot.

In addition, because the engines will be kept hot, the amplitude of the thermal cycles will be reduced which could reduce required equipment maintenance. The modifications will add equipment that will require maintenance including additional filters, but overall this should help protect the engine and reduce overall engine maintenance.

Section 3.5

Modify OTSGs for Lower Loads

Maalaea 17 & 19

BACKGROUND

The existing OTSGs are designed such that they trip when HP steam flow reduces below its set point of approximately 39,000 lbs/hr. The minimum flow requirement exists to ensure that the water flowing through the tubes is always in contact with the entire circumference of the inside of the tubes. Failure to maintain the minimum flow rate may result in "trough flow" in which the water is only in contact with a portion of the bottom half of the tube. If trough flow were to occur during operation, it would result in a severe temperature differential between the bottom of the tube and the top resulting in differential expansion and tube warping.

The original equipment manufacturer, IST was contacted to determine what would be required to lower this flow constraint. Reducing the diameter of the first few rows of high pressure tubes inside the OTSG will result in a significantly lower minimum required steam flow, and therefore lower allowable loads on both the combustion turbines and the steam turbine.

As constrained by the current OTSG low flow, the current combustion turbine minimum load is about 14 MW with an associated steam turbine load of 3.5MW in 1 x 1 combined cycle mode. At an assumed combustion turbine minimum load of 7 MW, the OTSG would produce an HP steam flow of approximately 30,000 lb/hr. This flow is far above the proposed new minimum flow constraint of approximately 14,000 lb/hr provided by IST.

PROJECT DETAILS

In order for this modification to be viable, the next low load constraint needed to be identified. Several attempts were made to contact MPS regarding the operating envelope for the steam turbine. Little information was gleaned from these communication attempts. However, MECO performed an overhaul of the M18 steam turbine and found indications of water erosion damage on the last three stages. Stanley Consultants used test data to perform an energy balance around the steam turbine in order to estimate the steam quality at the exhaust of the turbine for various loading conditions. It was noted that in all cases performed, the exhaust moisture content did not exceed normal or expected ranges. That said, results of this analysis indicate that increasing the incoming steam temperature reduces the moisture content at the exhaust of the steam turbine. The analysis also showed that lower loads actually decrease the amount of back end moisture. This is because decreased steam flow reduces steam turbine efficiency which allows more steam energy (as heat) to escape the turbine exhaust.

Still, the exact cause of the moisture damage should be determined before MECO can comfortably proceed with this modification. It is therefore recommended that MECO perform additional controlled unit testing to investigate the source of the back end erosion. Among other things, this testing would involve changing inlet steam and temperature pressure set points and closely monitoring how plant equipment and systems are affected.

If the steam turbine water erosion constraints can ever be eliminated, the project scope would include IST's proposal to replace the top three rows of 1" tubes with ¾" tubes.

COST ESTIMATE

The estimated cost is as follows. Further cost detail can be found in Appendix 3.5.

Table 3.5-1 – Capital Cost for OTSG Modifications

Plant and Unit	Estimated Capital Cost
Maalaea 17	$738,000
Maalaea 19	$738,000

O&M IMPACTS

These proposed modifications do provide an additional 2.1 % RPS value in the year 2020. Additionally, they allow for improved operational flexibility. It should be noted that there is also a small increase in feedwater pumping cost to overcome the additional head caused by the smaller tubes. Even if it is determined that low loads are causing the steam turbine damage, the economic benefits of operating the OTSGs at low loads will more than offset the increased steam turbine maintenance costs.

Section 3.6

Install a 10 MW – 90 Minute BESS

BACKGROUND

The large amount of wind generation on the Maui grid requires carrying up to 52 MW of operating reserve. A BESS system can provide a portion of these reserves as generation that is synchronized to MECO's system and ready to be increased or decreased in response to variations in system demand or generation just as a spinning generator would do.

However, a new BESS system has several advantages over a new spinning generator. First, no air permit is required for implementation, lowering risk. Once connected, no startup time need be accounted for since the system is always on. In addition, energy consumption is small when not discharging or charging. As secondary functions, the BESS can also provide grid frequency regulation, VAR, and voltage support.

One option considered was the idea of multiple smaller BESS systems rather than one large one. It was thought certain portions of the MECO grid would benefit from several specially located BESS' that could provide localized voltage support. However, this was rejected due to higher cost and the lack of room available at MECO's existing substations and plant sites. It was decided the best option would be to install a single BESS located at a new site on Pulehu Road.

An advantage of battery technology is its relatively high efficiency when compared to other energy storage options because the transformation from electrical to chemical energy is more direct with less heat and friction losses. For example, pumped energy storage has losses associated with mechanical pumps and fluid transport through pipes whereas battery storage has smaller losses associated with the inverters and the conversion to chemical energy. Thus, round trip energy loss is lower.

Despite many attractive benefits, a BESS is not as ideal an option as it initially appears. The primary disadvantage of a BESS is its high initial cost. Batteries also degrade over time and eventually must be replaced at a significant cost. Additionally, BESS vendors don't have much experience with systems as large as MECO requires and the technology has not been proven over time. Recent installations have come up short on expected performance and in one instance, suffered complete destruction due to fire. One of the initially preferred battery suppliers even declared bankruptcy during the time period this study was conducted.

For this study, Stanley Consultants solicited three companies to provide budgetary proposals along with technical details about each system. These were compared and clarified prior to deciding on the appropriate scope and prices to use in the cost estimate.

PROJECT DETAILS

It was decided a single BESS will be located on the 60 acres owned near Pulehu Road and will connect to the 69 kV line running between substations #2 and #17 across the front of the property. It will be sized to provide 10 MW of power at 0.8 power factor (leading or lagging) for 90 minutes. It will be designed around the premise that its primary function will be to provide 10 MW of up-reserve. As such, the batteries are expected to remain near fully charged the majority of the time with no down regulation available. It is anticipated that the BESS will be tied into AGC and would be queued to respond after all of the spinning generation options are exhausted. The BESS equipment's maximum output capability will be sized to provide a maximum of 10 MW discharge capability at 0.8 power factor.

As secondary functions, the BESS design will have a programmable control system that will allow for grid power factor correction (VAR support), line voltage support and grid frequency regulation. These secondary functions will allow the BESS to supply and absorb real and reactive power at selected levels. The BESS will monitor the internal conditions and external system levels. Operating the BESS in its secondary functions may negatively impact its primary function, but careful planning can allow for both primary and secondary functions to be utilized. Regardless, the size of the BESS energy storage capacity will not be increased to consider these secondary design points.

The BESS and its connection to the 69 kV line will consist of the following major components and their associated installation:

Provided by BESS supplier

- 20 banks of batteries installed in weatherproof housings (10" X 40' each)
- 5 AC/DC inverters(480 VAC/900 VDC nominal) installed in weatherproof housings (7' X 14.5' each)
- One Control House – Real time Embedded PLC Controller & Communications (10' X 20')
- NEMA 3R Enclosures
- Fire Suppression System
- 34.5 kV Switchgear
- 480 V to 34.5 kV harmonic mitigating transformers (inverter output to switchgear)
- 34.5kV to 480V station service transformer

- 69 kV CCVT's

Provided by Others
- Power Distribution Building
- Non-segregated bus duct
- 34.5 kV to 69 kV Step-up Transformer
- 69 kV Line Breaker
- Foundations and dead end structure
- Miscellaneous cable and raceway
- Scada Communications
- Site Construction

Interconnection and System Stability Studies should be completed before proceeding with final BESS engineering design and procurement. These studies will define many of the technical requirements needed to finalize procurement specifications.

COST ESTIMATE

The BESS vendors were unable to fully clarify the scope of what they would be providing. Thus, assumptions had to be made about costs associated with fire protection, equipment enclosures, and station service power.

The following table summarizes estimates for the capital cost for the BESS. For more detail, refer to Appendix 3.6.

Table 3.6-1 – Capital Cost of 10 MW – 90 Minute BESS

Modification	Estimated Capital Cost
10 MW BESS	$39,005,000

O&M IMPACTS

Per the production simulation study conducted by Generation Planning personnel the 10 MW BESS provides a 1.1% increase in MECO's RPS percentage.

There are no fuel costs, but there is significant cost to periodically replace the batteries. The battery system was quoted as being capable of 4500 cycles to 80% depth of discharge. If they are cycled in this manner once daily, the batteries would last about 12 years. Cost to replace the batteries was quoted as $18 million excluding freight and installation.

Section 3.7

Install Data Historian for Generating Units

BACKGROUND

Testing revealed that the existing ABB data collection system is slow, difficult to use, inconsistent in its ability to gather and retain information, and very inefficient in producing meaningful charts and reports. Multiple technicians were required to activate data collection and correct issues throughout the testing. It required significant time manipulating the test data to identify and illustrate key points.

For performance monitoring the existing MicroNet system does have three built in performance monitoring screens, but they monitor Gas Turbine Shaft HP vs Engine Speed, Gas Turbine Engine Pressure Ratio vs Engine Speed, and Gas Turbine Compressor Pressure Ratio vs Engine Speed, and have limited value.

A new higher quality historian would make data collection much easier and improve MECO's capabilities to track performance and equipment condition. It will also help with trouble shooting, root cause analysis, and report preparation by engineers, operators and clerks.

PROJECT DETAILS

The existing ABB system was designed as a temporary data collection system and operates on hardware that is out of date. ABB has a new product called SymphonyPLUS HMI or S+. This product has capabilities more in line with the historian industry benchmark called OSI- PI made by OSISoft, Inc. Under the current agreement with ABB, MECO is entitled to an upgrade to S+

and currently has a trial version that was recently installed this year after the testing mentioned above.

The trial system that is installed is a standalone system that can only be accessed from the Maalaea control room and only looks at data from Maalaea assets. In order to approach the capabilities of the OSI- PI system, additional hardware would need to be installed to allow units at both Maalaea and Kahului to be monitored and trended from workstations at Maalaea, Kahului, and the MECO main office in Kahului.

It appears that, because of the existing agreement with ABB, some initial costs would be reduced. However, there are additional costs that ABB was unable to quantify that would be necessary to match the capabilities of the OSI-PI system. The S+ software would cost less than $30,000. However, the following additional items are all unknown: hardware costs, installation costs, training costs, annual support costs, and system capabilities.

Product demonstrations revealed that the ABB S+ system is capable. However, even in the 2 hour presentation, some short-comings were seen as compared to the OSI-PI system. Without experience directly using the S+ software, it is difficult to arrive at a solid conclusion regarding its capabilities and user friendliness. In either case, more bandwidth may be required for internet transfer to remote locations.

Direct experience at other power generating facilities using the OSI-PI system and other industry historians has demonstrated that OSI-PI is the historian system that others are measured against. It allows users to easily create reports, trend data, and draw conclusions from system events. The user interface is intuitive and easy to use. Its design allows it to collect immense amounts of data efficiently without bogging down or using tremendous amounts of communication bandwidth. For the price and capability, the OSI is a very good value.

OSI PI is also the data historian used by HECO on their generating facilities. There may be some advantages to being on a common system and special pricing should be investigated considering HECO is already an OSI customer. The pricing below does not reflect any discounts.

COST ESTIMATE

Assumptions were made about what would be required to make the new historian system fully operational, fast, and up to industry standards. OSISoft included installation and training costs, but there would also be additional costs associated with upgrading hardware and system setup. These cost assumptions are captured in the OE & PM, Detailed Engineering, and Contingency line items as found in Appendix 3.7.

Because of all of the unknowns associated with the ABB S+ system, the OSI- PI system cost is used as the basis for a new historian.

Table 3.7-1 – Cost for New Historian

Total Installed Cost	Annual Support Costs
$152,000	$15,000

O&M IMPACTS

Installing a new user friendly HMI and data historian could prove invaluable for tracking performance, evaluating equipment condition, retrieving past data, and trouble-shooting problems. The ability to measure and trend operational information, equipment condition, and plant performance is a first step toward improvement and will undoubtedly be beneficial in operation and maintenance of the plant.

Data can be used to demonstrate how operation and maintenance events affect plant efficiency and performance; examples can be found in Appendix 1. These charts took hours to produce. An upgraded, user friendly data historian could produce these charts in minutes, not hours. This improves the ability to trend data over time which will improve decision making and allow for better analysis of key performance and efficiency parameters.

Section 3.8

Additional Equipment Modifications

All Units

BACKGROUND

Further interviews with MECO personnel and the unit testing conducted have identified numerous areas that could benefit from additional modifications beyond what was identified in Phase 1. This section lists those additional modifications with brief summaries of each. Many of these modifications require further investigation to determine if their investment would be a good value for MECO. A matrix presenting the benefits of each modification can be found in Appendix 5.

MODIFICATION DETAILS

Below are listed additional modifications identified during interviews and unit testing conducted during this Phase 2 study. They are broken out by plant and technology, and listed in approximate order of value.

Kahului

All of the modifications below refer to Units 3 and 4 at Kahului unless otherwise noted:

1. Install additional pegging steam source for the Unit 3 Deaerator to maintain pressure and improve water quality at lower loads. Tap into the station steam line at the steam drum or into the station steam cross over system to tie it in to all boilers. In either case most of the work can be done with the unit online and with a short shutdown to tie in. This is necessary for operation below 6 MW.

2. Both units saw water quality worsen at 3 MW. If further analysis of steam and water chemistry determines that additional steps are required to maintain proper quality at lower loads, the installation of Condensate Polishers will maintain the desired water quality. For this location a Powdex type system would be recommended that pre-coats a filter membrane with powdered deionization resins. Spent resins are then disposed of as other waste water.
3. Install Hydraulic or Electronic Governor on Unit 3 to reduce manual intervention and improve unit response. The existing manual hydraulic governor requires significant manual intervention and time to raise load. This is required if regulation is desired.
4. Replace the Steam Coil Air Heater (SCAH) on Unit 4 to better protect the backend of the boiler from reaching flue gas acid dew point. This is highly recommended for 3 MW operation.
5. Automate and replace valves if necessary for the following:
    a. Recirculation valve on condensate pumps at Unit 3
    b. Recirculation valve on boiler feed pumps at Unit 3
    c. Steam seal pressure regulator valves
    d. Unit 4 SCAH Station Steam supply valve for start-up (also add check valves)
6. Unit 4 Station Steam Supply Valve needs to be resized to avoid cutting.
7. Add atomizing steam flow measurement to quantify and optimize steam consumption to the burners.
8. Add instrumentation to measure dissolved O2 in the condensate and fuel flow. Better monitoring of O2 out of deaerator will improve water quality; improved fuel measurement allows for more accurate heat rate monitoring.

<u>Maalaea Combined Cycles</u>

The modifications below refer to both combined cycles at Maalaea:

1. Add electronic instrumentation for: Inlet pressure differential measurement for CTs, additional combustion air inlet temperature measurements for CTs, condenser air in-leakage measurement, seal steam pressure measurement. Better monitoring will potentially improve reliability, reduce maintenance, and could lead to improvements in heat rate.
2. Add electronic instrumentation on M14/15/16 for conductivity and O2 measurement of condensate.
3. Resize seal steam pressure control valve for M17/18/19 and repair O2 measurement of condensate.
4. Investigate adding Variable Frequency Drives (VFDs) or 2-speed fans for both ACCs. Additional fan speed control can allow for fine tuning of steam turbine back pressure over large load ranges. This leads to improvements in heat rate.
5. Add instrumentation to monitor amps, RTD, vibration, and run hours for critical motors including: BFPs, Fuel Oil pumps, NOx water injection pumps, Cooling fans, gear box motors.

Maalaea Diesel Generators

1. Enable multiple EMD engines to start simultaneously by either adding more batteries or converting to air start capability. This was resurrected from Phase 1 after multiple requests during interviews. Personnel confirmed that lack of battery capacity still limits starting multiple units. If air starting, retain black start capability by adding a small diesel generator driven air compressor.
2. The MHI engines are limited to solitary starts by starting air tank capacity. Increasing the tanks' size could allow for simultaneous starts.
3. Add the following instrumentation and DCS trending to MHI units: Digital Tachometer (indication only), Lube Oil and Jacket Water Temperatures, fuel flow, and vibrations. Trending key information can lead to improved start times, reduced maintenance, improved reliability, and better engine heat rate monitoring.
4. Integrate the Maalaea control systems so that one HMI controls all units.
5. Automate the following on MHI engines to improve start times: lube oil priming pump, turning gear, starting air valves, engine governor, jacket water heater pump, jacket water heater pump isolation valve, jacket water heater, lube oil/jacket water heat exchanger valves, jacket water radiator isolation valve.
6. Automate the following on the Cooper units 4 through 7 in order to improve start times: petcock valves (operator would still do visual inspection), governor control, and starting air valves.

New Generation Opportunity

From a strictly technical and economic viewpoint, one additional modification that would have significant impact on system operational flexibility is the possibility of replacing one MHI unit with a modern fast start 12 MW diesel engine. The existing MHI engine could be removed and used for spare parts. This idea would require a feasibility study to evaluate, but the basic concept would be to reuse the existing foundation and electrical infrastructure. It's possible that other ancillary support systems such as cooling water and oil could be reused as well.

This concept of a new modern reciprocating engine would provide many benefits. The engine can start in ten (10) minutes, turn down of 10 to 20%, and operate with improved efficiency and emissions as well as reduced maintenance. This engine can burn biofuel and the power generated can count towards the RPS requirements. The new unit would be subject to new environmental regulations which will likely require additional pollution control equipment such as SCR and CO catalysts. The high level cost estimate for such a conversion is about $25 million dollars. This would require a feasibility study to clarify scope and pin down costs.

While technically and economically attractive, this may not be possible due to environmental and competitive bidding requirements.

Section 4

Operation and Maintenance Observations

During the course of interviewing and unit testing, a number of potential operational enhancements were noted. Below are some of the higher value observations that could improve unit flexibility, performance, and operating costs.

GENERAL

With greater burdens being placed on the generating units, it may be appropriate to conduct more frequent inspections on fleet assets in certain cases. In addition, the plants would benefit from standardizing operating procedures.

KAHULUI THERMAL UNITS

1. With additional tuning Kahe 4 should be able to provide regulation at ½ MW/minute and be connected to AGC control.
2. It appears the K4 steam turbine governor could be programmed to ramp at a higher % / min than the current "fast" settings.
3. Shutting off one circulating pump at low loads will reduce aux load.
4. K3 boiler master and air flow control should be tuned for quicker response.
5. Reduce fuel oil pressure alarm to 40 psi on Unit 3.
6. Correct or re-tune minimum condensate recirculation flow on Unit 4.
7. In the long term, the amount of $CaNO_3$ could possibly be reduced during lower loads.

COMBINED CYCLE UNITS

Low Load Operation

1. Tune loops for better low load control. Specifically, M16 HRSG HP Flow control looks like it could be improved with tuning.
2. Improve responsiveness of the single element drum level control for the 10MW startup hold point on M14 and M16 by better tuning.
3. With improved data monitoring and additional operator intervention capability, M17/19 could run closer to the HP flow trip point of 38,000 lb/hr.
4. Consider developing a test plan for evaluating backend flue gas acid corrosion. This might include fuel and exhaust analysis, test ports for test coupons, and an inspection schedule.

Starting Operations

1. In general, improving start time will reduce the time and fuel needed to reach AGC capability. This means units can start later and still meet dispatch commitments.
2. For M14 and M16, improving start time will more quickly raise the HRSG exit temperatures above the acid dew point and reduce damage to the back end tubes and casing.
3. Opening the “34” blending control valve 3% per minute on M14 & M16 is likely overly conservative. Better steam temperature monitoring and control should enable this step to be completed much quicker.
4. Consideration should be given to developing standard plant operating procedures for unit startup, shutdown, and loading.
5. Discuss methods of reducing start time with IST. Our discussions indicate that the LP circuit should be able to start in parallel with the final stages of enabling the HP circuit.
6. For M17/19 OTSGs, develop better operator DCS screens to monitor clearing the HP & LP permissives.

Thermal Performance

1. The engines are operating below expected performance. There is an opportunity to optimize water wash frequency in order to raise the capability of the units and improve heat rate. This can be optimized to determine the most economical time to conduct compressor cleanings. Our experience is that after analysis, most plants find they can benefit from more frequent crank washes. Besides the heat rate benefits, this increases combined cycle capability which in MECO’s case provides greater regulating reserve and a wider range of operation.

   For performance monitoring, the existing MicroNet system does have three built in performance monitoring screens, but they monitor Gas Turbine Shaft HP vs Engine Speed, Gas Turbine Engine Pressure Ratio vs Engine Speed, and Gas Turbine Compressor Pressure Ratio vs Engine Speed, which have limited value in making operational decisions.

2. Controlled testing before and after a crank wash would better define the MW and heat rate gain. This will help to economically optimize when the ideal time is to conduct a water wash.
3. The set points for steam turbine back pressure can be optimized to find the right balance between auxiliary load and steam turbine efficiency.
4. The Inlet filtering O&M strategy can also be optimized to find the best trade-off between filter costs and engine performance. Low cost disposable pre-filters are often found to be a good investment.
5. There are opportunities to reduce auxiliary loads, especially while operating at lower loads. Specifically on CC2, consider removing one gland steam exhauster, one condensate pump and additional air cooled condenser fans from service to save electricity.
6. Monitor air in-leakage and conduct periodic air leakage testing of the ACC. On CC2 repair and possibly automate air in-leakage measurement.

<u>Other Plant Operations</u>

1. From the M19 ramp down test, determine the cause of the LP circuit trip by investigating logic set points and trip points. Possible reasons include HP steam temperature deviation from set point and LP steam pressure drop below set point.
2. For CC2, repair and calibrate dissolved oxygen measurements.

DIESEL GENERATOR UNITS

1. On MHI engines, consider starting the turning gear in the morning approximately 15 minutes before the expected start time. This would eliminate 10 minutes of start-up time.
2. On MHI engines, adhere to the manufacturer start-up times as stated in the “Start-up Time” report which could allow for faster start times.
3. On the Cooper engines, investigate procedure for running oil and jacket water pumps to allow for earlier preheating and shorter warm up times.

Section 5

Recommendations

Based on the research, interviews and test observations, Stanley Consultants offers the following recommendations. These recommendations will allow MECO units to achieve lower loads as well as start and change load quickly. They will also minimize the long term wear and damage to plant equipment.

EQUIPMENT MODIFICATIONS RECOMMENDATION

Upgrade Burners for Kahului Units 3 and 4

(Reference Section 3.1)

In order to improve turndown, upgrades to the burners are highly recommended and have a very good RPS value for the dollar investment. Modern steam atomized burners will enable the Kahului units to achieve new low loads of 3 MW with all burners in service while maintaining flame stability and proper emissions. Implementing this modification in phases will allow MECO to evaluate effectiveness of each individual modification before deciding if further modifications are necessary. It was decided with Kahului personnel to proceed in the following order:

- Install steam atomized oil burner guns that improve fuel atomization, turndown, combustion and stability
- If required, install new fuel oil and steam pressure control valves to accommodate the new atomizers

- If desired, install new flame scanners to improve safety and combustion surveillance

Before this modification is implemented, environmental constraints should be evaluated by HECO Environmental. This may involve low load emission testing to determine if this project should be pursued further. It is possible that new regulations would preclude this modification from consideration.

Install Inlet Chilling on Combustion Turbines

(Reference Section 3.2)

After many changes to inputs and assumptions for the Generation Planning Production Simulations and lack of available real estate, this modification now only has marginal value for the investment. Phase 1 Generation Planning Simulations didn't consider additional fuel consumed when the chillers were operational; nor did they include the cost of electricity associated with allowing additional wind onto the system. In addition, capital cost was much higher than expected due to space constraints for new equipment.

Input from MECO personnel helped determine that the smallest direct chilling system was the most beneficial. This system would boost output for all four combustion turbines a total of 1.8 MW. However, the amount of renewable generation this allows on the system is small compared to its high capital cost. There are definitely other modifications that offer a better value.

Modify HRSGs for Cycling and Lower Loads

(Reference Section 3.3)

Reducing the minimum load that Units 14-16 achieve each night shows the greatest RPS improvement by a wide margin. The modifications necessary to achieve this are highly recommended. The most important modifications are those that mitigate corrosion associated with relatively cool flue gas close to or below the acid dew point. These include retubing the LP evaporator section with T11 tubes, adding liners and coating on duct internals near the stack, and adding inspection doors.

Also, if after operating at low loads, it is determined that the boiler feedwater control valve is cutting due to severe throttling, a smaller bypass control valve should be considered.

Should MECO decide to cycle these units offline nightly, the remaining modifications should be considered. The most important are those that address thermal fatigue and help maintain boiler chemistry while offline. The pegging steam cross-tie, self-cleaning boiler feed pump strainers, HRSG exit dampers, insulation, and modification of tube geometry and weld types should be considered first.

Finally, regardless of the operational profile chosen, it is recommended that the HRSG bypass dampers be automated with position feedback to improve start times.

Install Engine Preheating - Maalaea Units 10 to 13

(Reference Section 3.4)

This is a fairly expensive option in order to reduce start times from 90 min to 50 min. The benefits associated with improved start times were not possible for Generation Planning to model and quantify. It is expected that there is some benefit but it is unclear if the high capital cost is justifiable.

Modify OTSGs for Lower Loads

(Reference Section 3.5)

Modifying the OTSGs, to allow them to achieve lower minimum loads, has significant impact on the RPS for a relatively small cost. However, backend moisture damage on the M18 steam turbine remains an obstacle that prevents giving a full recommendation at this time and the exact cause of this backend moisture requires further investigation.

MECO should perform controlled unit testing to verify calculations showing that backend moisture damage is not occurring while at low loads. If not, this modification becomes very attractive.

Install a 10MW - 90 Minute BESS

(Reference Section 3.6)

This is by far the most expensive modification and RPS gains are fairly meager. MECO preference and better definition of requirements dictated that the BESS be sized to reliably achieve 10 MW for 90 minutes which increased equipment size. Also, recent BESS industry fires hang a cloud of uncertainty over equipment reliability. That said, there are many intangible benefits associated with the BESS including grid power factor correction (VAR support), line voltage support and grid frequency regulation that may make this project attractive.

Install Data Historian for Generating Units

(Reference Section 3.7)

This modification is relatively inexpensive and would provide significant value to operations and engineering personnel. A new OSI-PI historian will allow MECO employees to use the workstations loaded on a typical PC to easily view performance, maintenance, and event data. MECO staff will be able to pull the data into Excel and manipulate it to create meaningful metrics that can more accurately define maintenance issues and overall system inefficiencies.

This is highly recommended.

Additional Modifications

(Reference Section 3.8)

Kahului

For Kahului units to achieve 3 MW, it is important that they have means to maintain water quality at low loads. It is recommended that an additional pegging steam source be installed for the Unit 3 Deaerator and if it proves necessary, condensate polishers be added at both Unit 3 and 4.

If Unit 3 is to be put onto AGC, it is necessary that a hydraulic or electronic governor be installed.

Finally, the Unit 4 SCAH needs to be replaced to better protect the backend of the boiler from acid corrosion associated with lower loads.

Maalaea Combined Cycles

It is recommended that electronic instrumentation be added for (additional) measurement of CT inlet temperature and differential pressure, condenser air in-leakage, and seal steam pressure. This will improve reliability, reduce maintenance, and possibly lead to heat rate improvements.

Maalaea Diesel Generators

Faster system response can be achieved by modifying the EMD engines to enable simultaneous starts using air or by adding batteries. Recent battery system upgrades still do not allow for multiple EMD units to start at once. Black start capability must be maintained in the case of any modification.

The MHI and Cooper units can be automated to allow for faster starts. Automation would include key pumps, valves, governors and turning gear as applicable.

Additional instrumentation and DCS trending capabilities on the MHI engines can identify problem areas and constraints and lead to faster start times, reduced maintenance, improved reliability and improved overall system heat rate. Also, it would be beneficial to integrate the Maalaea control systems so that one HMI controls all units. If after improved automation, it is desired to start multiple similar units at once, the air storage capacity will need increased for the air starting system.

OPERATION AND MAINTENANCE RECOMMENDATION

(Reference Section 4)

The following are recommendations of O&M activities that could be modified to improve low load capability and operational flexibility:

It is recommended that Kahului 4 be connected to AGC control and tuned to allow for a 0.5MW/minute ramp rate. This will improve operational flexibility.

For Maalaea Units 14 and 16, consideration should be given to implementing procedural changes that reduce start time, to reduce backend corrosion and reduce startup fuel consumption. An increase in the frequency of inspections is recommended to help keep tabs on how low loads are impacting tube and duct life.

Similarly, to reduce start times at Maalaea Units 17 and 19, it is recommended to work with IST to enable the LP and HP circuits to start in parallel rather than in series. It would also be helpful to have DCS screens that specifically track progress in clearing the permissives for OTSG startups.

At the time of the writing of this report, the exact cause of backend water damage to the M18 steam turbine was still undetermined. Additional controlled unit testing is required to evaluate the levels of back end moisture at various conditions and could point to the most economical method of reducing turbine damage. In addition, testing may eliminate low loads as the cause of the damage, thus allowing continuation with the economically favorable OTSG modifications. Even if it is determined that low loads are causing the steam turbine damage, the benefits of operating at lower loads will more than offset the increased steam turbine maintenance costs.

Regarding this back end moisture, MECO should investigate leaking attemperators and inadequate M18 backend draining. If possible, Mitsubishi Power System still needs to provide specific answers to the questions submitted regarding capabilities and limitations of their steam turbine.

In order to improve thermal performance on the combined cycles, it is recommended that MECO investigate the economics of more frequent compressor washing. This could result in better heat rate, higher full load capacity, and a larger regulating range. Thermal performance could also be improved by optimizing steam turbine back pressure and reducing aux loads.

Finally, the MHI diesel generators' start times could improve if the units are placed on turning gear when it is anticipated a startup call is approaching.

Section 6

Conclusions

BACKGROUND

During Phase 1, MECO units were studied as possible candidates for modification in order to increase the acceptance of renewable energy resources onto their grid. From this study, a list of potential modifications was developed. Phase 2 of the study has been intended to further develop seven of these modifications and also conduct several unit tests to further identify constraints and opportunities toward improving operational flexibility. Improved operational flexibility includes lower minimum loads, higher peak loads, faster starting or quicker ramping.

DISCUSSION

As mentioned, seven of the Phase 1 recommendations were selected for further study. The design effort in this study was intended to advance the work completed in Phase 1 to a point at which project details and cost estimates could be consolidated and submitted to MECO management and the PUC to begin the project approval process. While the preliminary design for each modification has been developed beyond the point at which Phase 1 left off, additional engineering is still required prior to implementing the proposed modifications. This work would include further optimization of the design (where applicable) and development of any required specifications, drawings and bid documents.

A summary of the cost and RPS improvement is provided in the table below.

Table 6-1 –Cost Estimates (Thousands of Dollars) and RPS

Modification	Unit Cost	Total Cost	Improved RPS (2020)	Cost per 1/10% RPS
Upgrade Burners for Kahului 3 & 4	$254	$508	0.9%	$56,400
Modify OTSGs for Lower Loads	$738	$1,475	2.1%*	$70,200
Modify HRSGs for Cycling and Lower Loads	$3,832	$7,664	3.5%	$219,000
Install Inlet Chilling on Combustion Turbines	-	$9,764	0.3%	$3,254,700
Install a 10MW-90 minute BESS	-	$39,005	1.1%	$3,546,000
Install Engine Preheating (M10-M13)	$2,222	$8,888	Unknown	N/A
Install Data Historian for Generating Units	-	$152	N/A	N/A

* The cause of the M18 steam turbine backend blade erosion needs to be determined.

Testing

At Stanley Consultants' request, MECO conducted testing on Kahului Units 3 and 4, both Maalaea combined cycle blocks, and two Maalaea diesel generators. This testing occurred during two site visits in May 2012. Stanley Consultants also interviewed several MECO staff members to gather additional information regarding operation and potential modification to the units.

These activities identified additional constraints reducing operational flexibility and also opportunities to mitigate these constraints. Lower load operation showed promise for Kahului Units 3/4 and Maalaea Units 14/16. With modifications, these are favorable options to remove off-peak generation from the Maui grid, while maintaining the necessary grid stability and operating reserves.

There is an opportunity to improve startup times for the combined cycles and, to a lesser degree, the diesel generators. Ramp rates can be improved and there are several opportunities to improve automation and monitoring.

Through the course of this testing and interviews several additional capital modifications were noted. These are listed in Appendix 5 and discussed in Section 3.8. Also a number of operational opportunities were identified and are discussed in Section 4.

RECOMMENDATIONS

Kahului Units 3 & 4 (Section 3.1)

It is desirable to enable these units to operate at a lower minimum load of 3 MW. It is also an advantage if these units can ramp more quickly in a stable and dependable manner throughout the full load range. Below are recommendations to maximize the flexibility of these units:

- The existing combustion system is not designed to operate as low as 3 MW with all burners in service. The burner modification is recommended to upgrade to new steam atomized burners. This would improve fuel atomization, flame stability, and turndown capability. If needed, additional modifications can be considered. Note that environmental considerations could make burner modifications unattractive.

- For operation at lower loads it will also be necessary to install condensate polishing. Given Maui's location, a Powdex type system is the most economical technology to accomplish this. This technology pre-coats a filter membrane with powdered deionization resins. Spent resins are eventually disposed of in the plant's waste water system.
- Low load operation can result in moisture formation on the backend of the boiler equipment thus promoting corrosion. These problems can be mitigated by the use of steam coil air heaters. This system exists on both units but is in poor condition needing replacement on Unit 4.
- A new pegging steam source will be required for the deaerator for loads below 6 MW for Unit 3 when the extraction pressure drops to zero.
- If it is desired for Unit 3 to operate on AGC, it will be necessary to install a hydraulic or electronic governor control system on the steam turbine. Unit 4, which has an electronic governor and additional automation, is able to ramp 2.5 times faster than Unit 3.
- It appears that Unit 4 is capable of providing regulation and with proper tuning could ramp at 0.5 MW/minute. In addition, it appears that with proper tuning, this unit's governor is capable of ramping faster than the current "Fast Select" rate.

Maalaea Combined Cycles - Flexibility

It is desirable to enable these units to operate at lower minimum loads that allow additional wind generation on the grid during off-peak times. It is also an advantage if these units can start more quickly and ramp faster in a stable and dependable manner. Below are recommendations to maximize the flexibility of these units:

- Installing HRSG Modifications (Section 3.3) for low load operation will mitigate corrosion from the moisture formation on the backend HRSG. These changes include improving metallurgy and providing coatings on backend surfaces. The RPS benefits for operating M14/16 at lower loads are substantial.
- Installing OTSG Modifications (Section 3.5) for low load operation would enable M17/19 to operate at lower loads providing significant RPS benefits for a low cost.
- Additional controlled unit testing is required to evaluate the levels of back end moisture at various conditions. This will help verify that low loads are not playing a part in the excessive wear recently discovered on the back end of the M18 steam turbine.
- Inlet Chilling (Section 3.2) benefits are marginal for the amount of investment. The business case for this modification produced poor results and it is no longer recommended.
- For Maalaea Units 14 and 16, consideration should be given to procedural changes that reduce start time. Some current restrictions are conservative and result in long periods that the HRSG exhaust remains below the acid dew point. Another benefit to faster starting is reduced fuel consumption and reduced time needed to get units up to AGC

capability. Written startup procedures would improve the efficiency and consistency of the startups.

- Test and inspection plans should be developed to monitor acid corrosion on the exits of the HRSGs.
- It is recommended to work with IST to enable the LP and HP circuits to start in parallel rather than in series. It would also be helpful to create DCS screens that specifically track progress in clearing the permissives for OTSG startups.

Maalaea Combined Cycles - Performance

There are significant opportunities to improve the thermal performance of the combined cycles. It was noted that the combustion turbines are currently operating at degraded performance levels up to 15% below design. Below are recommendations to improve the performance capability of these units:

- In our experience, most plants find economic benefits from more frequent compressor washing after they optimize the compressor cleaning schedule. This could result in better heat rate, higher full load capacity, and a larger regulating range.
- The set points for steam turbine back pressure can also be optimized to find the right balance between auxiliary load and steam turbine efficiency.
- There is opportunity to reduce auxiliary loads, especially when operating with the units turned down.

Maalaea Diesel Generators

It is desirable to enable these units to start quicker and in some cases enable multiple engines to start at the same time. Below are recommendations to maximize the flexibility of these units:

- Install Engine Preheating on MHI engines (Section 3.4). This will enable these engines to start in 50 minutes versus 90 minutes. This may mean the difference in whether or not to start one of the poorer efficiency Cooper or Colt units. Generation Planning was not able to quantify the expected benefits with their simulation modeling.
- Enable EMDs to start simultaneously by either installing additional batteries or converting to air starting.
- The MHI diesels generators could start a bit faster if the units are put on turning gear when it is anticipated a startup call is approaching.
- Improving automation and monitoring could enable similar engines to be started simultaneously. This can be a big benefit when renewable generation drops off quickly.

- Integrate the Maalaea control systems so that one HMI controls all units.

General

The suggestions below are recommendations that apply to all units:

- Nearly all units can benefit from improved instrumentation and monitoring. This will improve the monitoring of equipment performance and condition. As an example, many of the units do not have real time fuel metering, so heat rate is difficult to track.
- There are many opportunities on all units for increased automation to reduce operator intervention.
- With new operating profiles, certain pieces of equipment may need to be inspected more or less frequently.

O&M IMPACTS

The O&M cost impacts of the recommendations being considered should not be significant. However, with more renewable generation, the units may start/stop more often and spend more time at lower loads. This could increase the generation cost due to higher system heat rate and increased maintenance.

Running at lower loads can result in more water erosion to the last rows of blades on steam turbines and backend corrosion on the boilers and HRSGs. More startups will result in more thermal cycles for large machinery which would impact the remaining useful life. The added automation will require an increase in calibration and maintenance of the control equipment by I&C technicians.

NEXT STEPS

The following are recommended future actions beyond what was accomplished by the time of this Phase 2 report.

1) As part of this study's scope Stanley Consultants will develop procurement specifications for HRSG Modifications and the Data Historian. This will be completed before the end of the year.
2) Additional study by HECO Environmental group is in progress regarding the environmental regulation impacts regarding Kahului Burner Upgrades, Maalaea Inlet Chilling, and MHI Engine Preheating. This needs to be completed to understand what implications these modifications have regarding current and future regulations. This review will take place in November and December 2012.
3) Additional controlled unit testing is required to properly evaluate the levels of back end moisture at various conditions and what may be causing excessive erosion on M18 turbine blades. The results of this testing will allow proper decision making to resolve the issue. If calculations are correct, testing should eliminate low load operation as the cause of the damage, thus allowing continuation with the economically favorable OTSG modifications. Leaking attemperators and inadequate M18 backend draining could also be a root problem and should be ruled out by confirming proper operation. It is also recommended to continue

pursuing answers from Mitsubishi Power System regarding the capabilities and limitations of their steam turbine.

4) Compare maintenance costs to economic benefits on the M18 steam turbine during low load operation. Even if reasonable steam turbine wear is allowed to continue, the economic benefits of lower load operation are likely to far outweigh any increase in maintenance costs.
5) As mentioned, there is a significant opportunity to improve thermal performance for some units. Investigating this more thoroughly should result in heat rate improvements and higher output capability for some units.
6) The first step to improving equipment flexibility, operating range and performance is to measure and make transparent current operating data. The best way to do this is to significantly improve the data storing and retrieval with a quality data historian.
7) If it is desired to reduce minimum loads at Kahului Units 3 and 4 to 3 MW, steam and water sample analysis should be conducted to determine the nature of the water quality at low loads. If necessary, a scope and cost estimate can be developed for Condensate Polishers. Also, an alternate steam source for Unit 3 deaerator steam will be required to maintain proper deaerator operation.