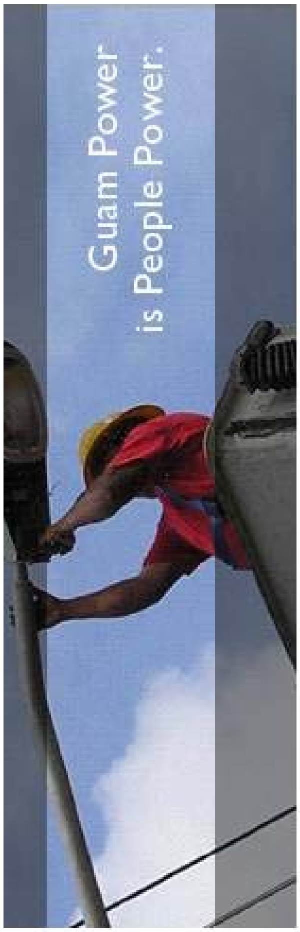


# Generation Resource Handbook
# FY 2008

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## 1. Introduction

The Guam Power Authority Generation Resource Handbook is a compendium of information related to the history, technology, utilization and performance of the Authority's installed generation base. The contents of this document are updated quarterly.

## 2. Guam Power Authority Governance

The Guam Power Authority Act of 1968 established Guam Power Authority (GPA or the Authority) in May 1968. Guam Code 12 Chapter 8 sets the legal definitions, empowerments and limitations for the Authority.

GPA is a public corporation and an enterprise fund of the Government of Guam. The Consolidated Commission on Utilities administers GPA. The Consolidated Commission on Utilities is a five member elected board of directors. Two of the directors are elected for four-year terms and the remaining three directors are elected for two-year terms. Additionally, GPA is regulated by the Guam Public Utilities Commission (PUC).

## 3. Island-Wide Power System

The Island-Wide Power System (IWPS) was jointly operated by the United States Department of the Navy (the Navy) and GPA until 1993. In 1993, the Navy became a customer of GPA and began the process of transferring Navy electric power assets to GPA. These assets included the Navy's Tanguisson #1 and Piti #2, #3, #4, and #5 generation units.

The bulk of installed generation capacity from the 1950s until 1975 was supplied by the Navy. Today, GPA supplies all on-grid electric energy. Table 1 shows the total installed generation capacity for FY 2007. Residual fuel oil (RFO) is less expensive than diesel distillate No. 2.

Table 1
FY 2007 Installed Generation Capacity

| Unit | Year Unit Installed | Nameplate Capacity Rating | Primary Fuel |
|---|---|---|---|
| Cabras #1 | 1974 | 66 | RFO |
| Cabras #2 | 1975 | 66 | RFO |
| Cabras #3 | 1995 | 39.3 | RFO |
| Cabras #4 | 1996 | 39.3 | RFO |
| MEC #8 | 1999 | 44.2 | RFO |
| MEC #9 | 1999 | 44.2 | RFO |
| Tanguisson #1 | 1971 | 26.5 | RFO |
| Tanguisson #2 | 1973 | 26.5 | RFO |

Table 1, cont.

| Unit | Year Unit Installed | Nameplate Capacity Rating | Primary Fuel |
|---|---|---|---|
| Dededo C.T. #1 | 1992 | 23 | Diesel |
| Dededo C.T. #2 | 1994 | 22 | Diesel |
| Macheche C.T. | 1993 | 22 | Diesel |
| Marbo C.T. | 1995 | 16 | Diesel |
| Yigo C.T. | 1993 | 22 | Diesel |
| Tenjo #1 | 1993 | 4.4 | Diesel |
| Tenjo #2 | 1993 | 4.4 | Diesel |
| Tenjo #3 | 1993 | 4.4 | Diesel |
| Tenjo #4 | 1993 | 4.4 | Diesel |
| Tenjo #5 | 1993 | 4.4 | Diesel |
| Tenjo #6 | 1993 | 4.4 | Diesel |
| Dededo Diesel #1 | 1971 | 2.5 | Diesel |
| Dededo Diesel #2 | 1971 | 2.5 | Diesel |
| Dededo Diesel #3 | 1971 | 2.5 | Diesel |
| Dededo Diesel #4 | 1971 | 2.5 | Diesel |
| Manenggon #1 (MDI) | 1994 | 5.3 | Diesel |
| Manenggon #2 (MDI) | 1994 | 5.3 | Diesel |
| Talofofo #1 | 1993 | 4.4 | Diesel |
| Talofofo #2 | 1993 | 4.4 | Diesel |
| TEMES | 1998 | 40 | Diesel |
| Total Installed Capacity (MW) | | 552.8 | |

## 4. Power Supply Development

Table 2 shows the addition and retirement of capacity to the IWPS system. Note that the period between 1970 and 1975 marked growth in the installed generation capacity. This new capacity totaled 205 MW of which 180 MW was installed by GPA and 25 MW by the Navy. Prior to this, GPA did not have a significant share in generation. It is interesting to note that no new capacity was installed until 1992.

From 1978 through 1986, system demand was fairly flat and it was not until 1986 that GPA matched its 1978 peak demand. GPA developed an Integrated Resource Plan to bring in new generation; however, there were disagreements on the magnitude and timing of future load increases and generation additions. As a result, GPA fell far behind the growth curve leading to a tumultuous period in the early and mid-1990s.

Table 2
Generation Capacity Addition and Retirement

| Commissioned | Installed Capacity | Nameplate Rating (MW) | | IWPS Total (MW) |
|---|---|---|---|---|
| | | Installed | Retired | |
| 1951 | Piti #2 Steam Unit | 11.5 | | 11.5 |
| 1953 | Piti #3 Steam Unit | 11.5 | | 23.0 |
| 1964 | Piti #4 Steam Unit | 22.0 | | 45.0 |
| 1965 | Piti #5 Steam Unit | 22.0 | | 67.0 |
| 1970 | Cabras Diesels #1 - 4 (@2.5 MW Each) | 10.0 | | 77.0 |
| 1971 | Tanguisson #1 Steam Unit | 26.5 | | 103.5 |
| 1971 | Dededo Diesel #1 - 4 (@ 2.5 MW Each) | 10.0 | | 113.5 |
| 1973 | Tanguisson #2 Steam Unit | 26.5 | | 140.0 |
| 1974 | Cabras #1 Steam Unit | 66.0 | | 206.0 |
| 1975 | Cabras #2 Steam Unit | 66.0 | | 272.0 |
| | | | | |
| 1992 | Dededo CT #1 | 23.0 | | 295.0 |
| | | | | |
| 1993 | Macheche CT | 22.0 | | 317.0 |
| 1993 | Yigo CT | 22.0 | | 339.0 |
| 1993 | Fast Track Diesel (8 Units @ 4.4 MW Each) | 35.2 | | 374.2 |
| 1993 | - Retired Cabras Diesels #1 & 3 | | -5 | 369.2 |
| | | | | |
| 1994 | Dededo CT #2 | 22.0 | | 391.2 |
| 1994 | Manenggon Diesel (2 Units @ 5.3 MW Each) | 10.6 | | 401.8 |
| 1994 | - Retired Cabras Diesels #2 & 4 | | -5 | 396.8 |
| | | | | |
| 1995 | Marbo CT | 16.0 | | 412.8 |
| 1995 | - Retired Piti #2 & 3 | | -23 | 389.8 |
| 1995 | Cabras #3 Slow Speed Diesel Unit | 39.3 | | 429.1 |
| | | | | |
| 1996 | Cabras #4 Slow Speed Diesel Unit | 39.3 | | 468.4 |
| | | | | |
| 1997 | Relocated Fast Track Diesels from Airport & Tumon to Tenjo | | | 468.4 |
| | | | | |
| 1998 | Piti #4 & 5 Decommissioning | | -44 | 424.4 |
| 1998 | IPP - TEMES CT | 40.0 | | 464.4 |
| | | | | |
| 1999 | IPP - ENRON Slow Speed Diesel (2 Units @ 44.2 MW Each) | 88.4 | | 552.8 |
| | | | | |
| 2000 | Relocated Fast Track Diesel from OGMH to Tenjo Vista Power Plant | | | 552.8 |

Figure 1 shows the growth of installed power capacity, the growth of electric power demand and power capacity considering N – 1 and N – 2 conditions. An N-1 condition reflects the capacity available when all generation units are available except for the largest unit. An N-2 condition reflects the capacity available when all generation units are available except for the two largest units. Currently, the two largest units on the GPA system are the 66-MW Cabras #1 & #2 steam power plants. An N -2 condition would be the unavailability of 132 MW of generation.

If the red line representing the peak system demand in Figure 1 rises above the N-1 or N-2 lines, then the system would be at risk for load shedding under capacity deficit scenarios.

From the mid-1970s through the 1980s, the GPA system was at risk primarily from N-2 events. However, this was not the case in the early and mid-1990s. A good example of this is the period 1990 through 1993. A maintenance outage of either Cabras steam unit resulted in load shedding. If a second Cabras steam unit experienced a forced outage while the other was under a maintenance outage, load shedding became severe. This period of time was known as the “Load Shedding Blues era.”

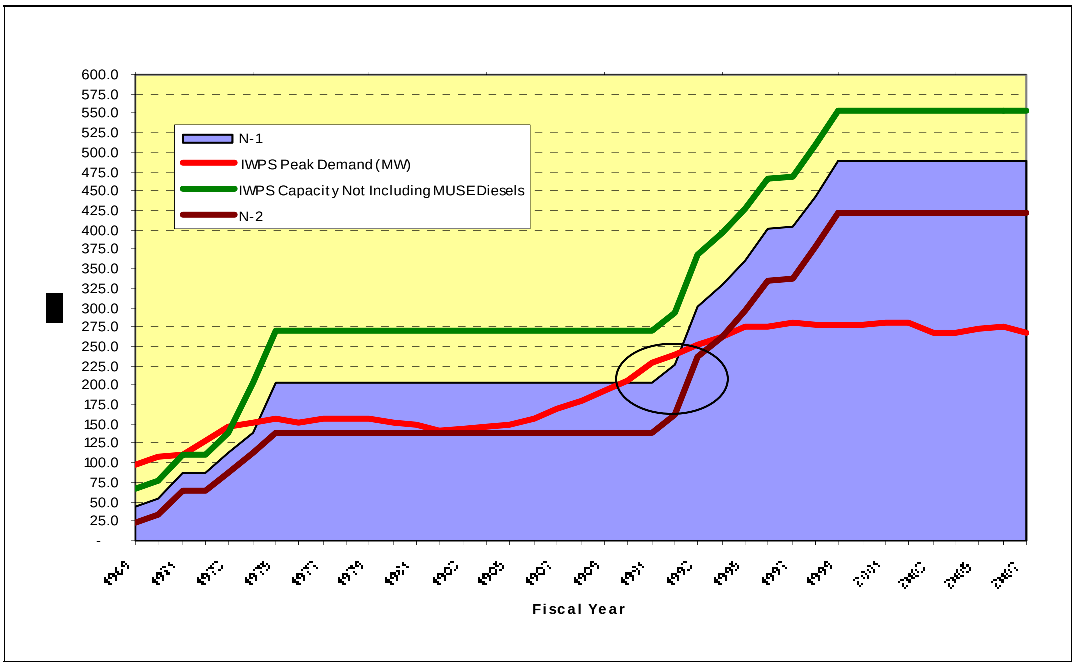


Figure 1: IWPS Historical Demand and Supply Capabilities

In 1995 and 1996, GPA commissioned Cabras #3 & #4. These units used a slow speed diesel technology and were the largest units available in this class. This technology converted fuel into electrical energy using about a 25% to 30% less fuel than Cabras #1 & #2. Cabras #3 & #4 experienced high forced outage rates over the next two years as could be expected for newly commissioned units. However, by 1997 GPA had reduced loss of load due to lack of generation from over 600 hours each in FYs 1995 and 1996 to about an hour.

Figure 2 shows forced outage rates over the life cycle of generation units. The units are subject to higher forced outages during the first years of operation than during the years in the mature phase. Generation units typically have a steady forced outage rate for most of their useful life and then will experience increasingly higher forced outage rates and more costly maintenance during the last phase of their useful life. This is called the “senile forced outage rate phase.”

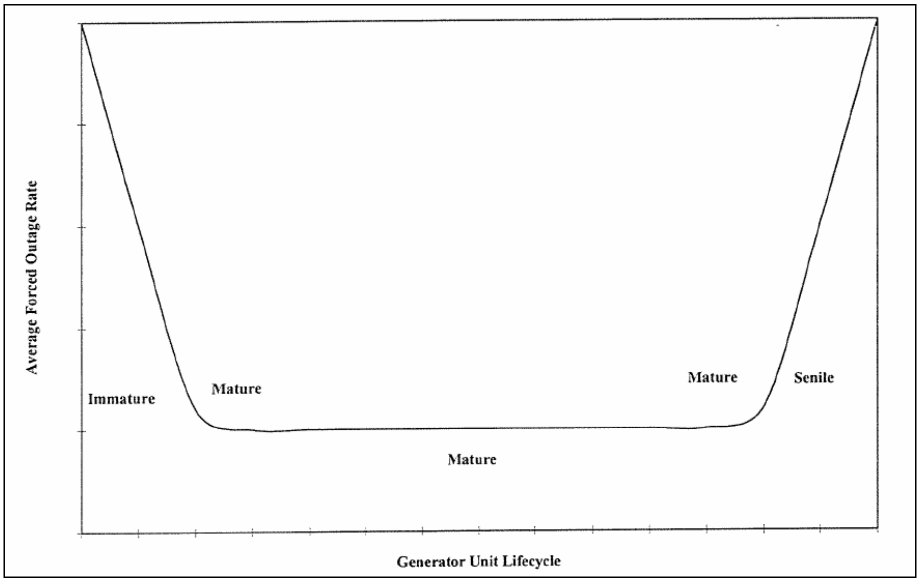


Figure 2: Life Cycle Generation Forced Outage Rates

In response to continuing generation reliability and reserve issues, in 1996 the Government of Guam pushed through an Emergency Generation Procurement Act that resulted in the introduction of three Independent Power Producers (IPP): ENRON (Marianas Electric Company), Taiwan Electric and Mechanical Engineering Services (TEMES), and Hawaiian Electric Industries, Inc. (HEI).

The Government’s move increased the Authority’s reserve margin to 96 percent. It also significantly increased costs. The IPPs’ fixed cost payments amounted to about 33 percent of total generation fixed costs. Additionally, capacity payments to IPPs approximately equaled the Authority’s debt service on its own generation units.

The setting of an appropriate reserve margin is a key driver in generation capacity planning. The Navy under a Customer Services Agreement and in recent discussions on capacity planning with NAVFAC has reiterated that reserve margins associated with a one day in ten years loss of load expectation is the planning criteria they believe appropriate for GPA to use. This has implications on how reliable the GPA power generation power supply would be as well as the total system cost in investments in reserve capacity.

# 5. Key System Constraints

GPA's existing operations are constrained by the environmental operating permits issued for each power plant.

## 5.1 Key System Constraints: Diesel-Fired Generation

Several GPA diesel burning generation units fall under the U.S. Environmental Protection Agency's (USEPA) "synthetic minor source" classification. The term "synthetic minor source" applies to a unit with operational hour limits imposed for the purpose of pollutant emissions reduction. GPA's synthetic minor source units operate under permits issued by the Guam Environmental Protection Agency (GEPA). GEPA issues these permits with courtesy inputs from USEPA Region IX. These permits include:

- Guam Environmental Protection Agency; September 10, 1997; Conditional Approval of Permit to Operate a 23 MW Combustion Turbine Generator, Model LM2500, General Electric, Located on Lot Nos. 5246-2 and 5246-3 in Macheche, Dededo, Guam (Macheche Combustion Turbine)
- Guam Environmental Protection Agency; June 10, 1997; Extension of Conditional Approval of Permit to Operate a 22 MW Combustion Turbine Generator at Temporary Site Location, on Lot No. 7054-R4, in Municipality of Yigo, Guam (Yigo Combustion Turbine)
- Guam Environmental Protection Agency; October 7, 1997; Renewal of Conditional Approval of Permit to Operate Two (2) identical 5.3 MW Stand-by Diesel Generators, Unit #1 and Unit #2, both Wartsila, Model 16V32, Located on Lot No. 5, Block 17, Tract No. 2511, Manenggon Hills, Yona, Guam (GPA's Manenggon Hills Diesel Units)
- Guam Environmental Protection Agency; September 25, 1997; Conditional Approval of Permit to Operate Two (2) Identical 5 MW Stand-by Diesel Generators, Unit #1 and Unit #2, both Caterpillar Model 3616, Located at Parcel 'A' Route 4, Talofofo, Guam (Talofofo Diesel Power Plant)
- Guam Environmental Protection Agency; April 30, 1997; Conditional Approval of Air Pollution Control Permit to Construct a 40 MW Combustion Turbine Generator within the Piti Power Plant Facility, Piti, Guam. (TEMES Combustion Turbine Piti Unit #7)
- Guam Environmental Protection Agency; June 15, 1995; Conditional Approval of Permit to Operate a 16 MW Standby Combustion Turbine Generator, Model FIAT TG-16, General Turbine Systems, Inc., Located at Marbo Substation, Yigo, Guam (Marbo Combustion Turbine)

Table 3 lists the permit limitations for diesel-fired generation other than those at Tenjo Vista Diesel Power Plant. In addition to the conditions of these permits, the USEPA requires GPA to use low sulfur diesel at its Tenjo Vista medium speed diesel plant. Specifically, Tenjo Vista Units #1 through #4 are required to use diesel fuel no greater than 0.5 percent sulfur by weight. Tenjo Vista Units #5 through #6 are required to use diesel fuel no greater than 0.3 percent sulfur by weight. However, since these units have a common fuel storage tank, all units are being supplied in compliance with the stricter limit of 0.3 percent sulfur by weight.

Table 3
Synthetic Minor Sources and Their Permit Limits

| Unit | 12-Month Rolling Average Fuel Burn (gal/year) | Full-load Hours |
|---|---|---|
| Macheche CT | 7,140,000 | 4,280 |
| Yigo CT | 7,140,000 | 4,280 |
| Manenggon | 1,305,543 | 4,640 |
| Talofofo | 1,480,851 | 4,640 |
| TEMES | 7,828,740 | 2,196 |
| Marbo CT | 4,760,000 | 2,654 |

## 5.2 Key System Constraints: Cabras-Piti Residual Fuel Oil-Fired Generation

The USEPA has granted GPA a 325 waiver from the Clean Air Act. As part of the requirements of this waiver, power plants within the Cabras/Piti area must comply with the Cabras/Piti Area Intermittent Control Strategy (CPAICS) as required by 69.11 (a)(3)(i) of 40 CFR Part 69 Subpart A, as amended, and any modification to the CPAICS approved by USEPA as defined in 69.11(a)(3)(ii).

Under the CPAICS, GPA is allowed to use high sulfur fuel (HSFO, 2 percent sulfur) at its Cabras-Piti facility whenever 15-minute average wind direction and wind speeds are within acceptable limits. Outside these acceptable limits, GPA must use low sulfur fuel (LSFO, 1.19 percent sulfur). This arrangement saves ratepayers approximately $2.25 million to $3 million annually. Tanguisson Power Plant has no restrictions on HSFO use.

## 5.3 Key System Constraints for Future Generation Addition

R. W. Beck, Inc., has conducted several development and siting studies for GPA over the last 10 to 20 years which have highlighted the challenges associated with developing new power generation resource options. Some of the primary challenges include siting (space and location), permitting (air and water), and fuel delivery issues. Siting on the western coast of the island is preferred; however, limited site options are available due to congestion around the existing port and proximity to various national parks and environmentally sensitive areas.

The environmental permitting process can also be constraining and take significant time to work through. For example, certain areas of Guam are currently designated as non-attainment areas for sulfur dioxide ($SO_2$) emissions. The Authority assumes that the power generation resource options sited at the Cabras-Piti area will utilize salt water cooling towers to minimize the use of both salt water and fresh water, along with the thermal effects on coastal biology.

Finally, any successful development of the resources utilizing coal or LNG will take significant effort due to the need for installation of new fuel receiving facilities. The Authority assumes that the existing port, which has piers with depths ranging from 34 to 70 feet and lengths of 370 to 2,000 feet, will not be available to accommodate fuel deliveries because of congestion and the lack of space to site a facility near the port. Therefore, new receiving facilities will need to be developed to support the resources utilizing coal and LNG. The design of receiving facilities will vary greatly depending on the coastal topography associated with the site being developed and the source of coal or LNG. To ensure flexibility in sources and vessels utilized for supply, receiving facilities should be able to accommodate vessels with capacity of up to 150 deadweight tons, which can be up to 1,000 feet in length and require 60 feet of draft.

## 5.4 Environmental Permitting Process[1]

### *5.4.1 Air Emissions[2]*

A proposed major new source or a modification to an existing major source of air pollution must undergo New Source Review (NSR) prior to commencement of construction. Implementation and enforcement of the federal NSR regulations for major sources have not been delegated to Guam, but have been retained by Region IX of the United States Environmental Protection Agency (USEPA). The areas around the existing Tanguisson and Cabras-Piti power plants have been designated as nonattainment areas for $SO_2$.

Permitting a new major source or a major modification in a nonattainment area can be difficult. It is likely that emission “offsets” will be required. Offsets are federally enforceable, permanent reductions in emissions that offset increases in emissions associated with the proposed project. The offsets are required as specified by the applicable regulations and may be in a ratio of 1.1:1. It is doubtful that any offsets are available in Guam at the present time.

The Governor of Guam can submit a petition to the USEPA under Section 325 of the Clean Air Act (CAA) for relief from many conditions of the CAA. USEPA issued a 325 exemption on August 2, 1993 in response to a Guam petition. That petition will allow addition of electric generating sources in the nonattainment area provided National Ambient Air Quality Standards (NAAQS) are maintained. Through ambient air monitoring studies and dispersion modeling, it is believed that the area no longer requires a “nonattainment” designation. Guam submitted a request to USEPA for redesignation of the area to “attainment.” This request was submitted in 1996 and has not been acted upon by USEPA. Therefore, for the purposes of air quality permitting, the area is considered “nonattainment” with respect to $SO_2$. It may be prudent to try to resolve this nonattainment issue as it would open up significant opportunities for plant sites.

For areas where the air quality meets the NAAQS, the USEPA has promulgated regulations to prevent further “significant” deterioration of the air quality in that area. Such areas are designated as either “attainment” or unclassifiable” and the program requirements for major source construction or modification is found in 40 CFR 52.21 and is known as the

1 Adapted from R. W. Beck, Inc., “Potential Supply-Side and Renewable Generation Options,” 1996.
2 Ibid.

Prevention of Significant Deterioration (PSD) program. The program establishes levels, or “increments,” beyond which existing air quality may not deteriorate.

A PSD permit application is required to include the following:

- Best Available Control Technology (BACT) Analysis
- Air Quality Analysis
- Additional Impacts Analysis
- A Class I Area Impact Analysis

Due to the availability of the Section 325 petition for Guam, it may be that some of the PSD requirements can be avoided. However, requirements concerning ambient air, and these include PSD increments, must be fulfilled. It may very well be that there is no available increment in the area proposed for development and, if that is in fact the case, development could not proceed.

### *5.4.2 Water Use and Discharge*[3]

Some of the alternatives under consideration would require process water for operation or non-contact cooling water for heat rejection. Supplying fresh water for process could be an issue as fresh water is limited and the primary sources are located on the northern end of the island. Providing salt water for cooling and discharging wastewater to the ocean would involve the National Pollutant Discharge Elimination System (NPDES) program for point source discharges and Sections 316(a) and 316(b) of the Clean Water Act, which regulate the intake of water for power plant cooling and the discharge of heated water. Furthermore, storm water discharges may also be regulated. The administration of water permitting on Guam is shared by Guam EPA and USEPA. Point source discharges and cooling water permitting would be addressed by USEPA. Storm water discharges to wetlands and construction in waterways are also permitted by the U.S. Army Corps of Engineers (USACOE).

Permitting requirements by federal agencies such as USEPA or USACOE would invoke compliance with the National Environmental Policy Act (NEPA). NEPA compliance can substantially affect the schedule and cost of any planned major project. Federal air permitting is specifically precluded from requiring NEPA compliance.

## 6. GPA Generation Routine Operations and Maintenance Cost Models

The Authority created a model of non-fuel routine operations and maintenance costs for each of its generation units. Many of the cost models are based on first-order regressions of historical cost and energy production. Some judgment was used in preparing the dataset used for the cost model. The cost model does not include extraordinary maintenance such as large overhauls. Additionally, it does not include any major capital improvement projects. Furthermore, it does not include any PMC fixed management fees.

[3] Ibid.

Annual non-fuel routine O&M costs are computed using the following formula:

Non-Fuel Routine O&M costs = Fixed Costs + Variable O&M * Unit Energy Production.

Table 15 lists the Fixed Costs and Variable O&M for this model. The figures for Variable O&M include values computed for the FY 1996 and FY 1999 Integrated Resource Plans. The independent calculations over time indicate consistency over time for this analysis. Different methodologies were used in FY 1996 and FY 1999 to compute Variable O&M.

Table 4
Routine Non-Fuel O&M Cost Model

| Generation Plant | Unit # | Fixed O&M Costs ($000) | Non-Fuel Variable O&M ($/MWh) | | |
|---|---|---|---|---|---|
| | | | FY 1997 | FY 1998 | FY 2007 |
| Cabras Steam | 1 | 2,867 | 1.63 | 1.63 | 1.11 |
| | 2 | 2,867 | 1.63 | 1.63 | 1.11 |
| Cabras Slow Speed Diesel | 3 | 1,144 | 4.08 | 4.08 | 5.08 |
| | 4 | 1,144 | 4.08 | 4.08 | 5.08 |
| Dededo CT | 1 | 2,168 | 4.91 | 4.91 | 5.44 |
| | 2 | 2,168 | 4.91 | 4.91 | 5.44 |
| Macheche CT | 1 | 2,180 | 5.75 | 5.75 | 6.24 |
| Yigo CT | 1 | 2,180 | 5.76 | 5.76 | 6.24 |
| Marbo CT | 1 | 2,730 | 8.34 | 8.34 | 7.80 |
| Dededo Diesel | 1 | 78 | 7.12 | 7.12 | 7.12 |
| | 2 | 78 | 7.12 | 7.12 | 7.12 |
| | 3 | 78 | 7.12 | 7.12 | 7.12 |
| | 4 | 78 | 7.12 | 7.12 | 7.12 |
| Pulantat Diesel | 1 | 149 | 4.00 | 4.00 | 4.06 |
| | 2 | 149 | 4.00 | 4.00 | 4.06 |
| Tenjo Diesel | 1 | 184 | 4.00 | 4.00 | 4.52 |
| | 2 | 184 | 4.00 | 4.00 | 4.52 |
| | 3 | 184 | 4.00 | 4.00 | 4.52 |
| | 4 | 184 | 4.00 | 4.00 | 4.52 |
| | 5 | 184 | 4.00 | 4.00 | 4.52 |
| | 6 | 184 | 4.00 | 4.00 | 4.52 |
| Talofofo Diesel | 1 | 61 | 4.00 | 4.00 | 4.52 |
| | 2 | 61 | 4.00 | 4.00 | 4.52 |

## 7. GPA Debt Service for Installed Generation

The Authority does not charge for energy conversion only; it is a full service electric utility. This means it provides all the services necessary to generate, transmit, distribute, sell, bill and provide internal ancillary business services in order to provide electric power to its customers. The Authority's charges for electric power service include amounts for debt service for bonds, operating and maintenance expenses, administrative expenses, capital improvement projects, reserve funds, debt service coverage and other strategic investments. As a regulated utility, the Authority is not allowed to make a profit. It is allowed only to cover expenses and the debt service and reserves that are determined to be prudent and necessary. Only a portion of the total amount the Authority charges for electric power service is for energy production.

The costs for energy production include fuel, operations and maintenance, capital improvement projects and debt service. Adding new capacity to serve existing loads does not eliminate the debt service for existing plants. Table 5 shows the debt service associated with existing power plants.

Table 5
Generation Plant Debt Service

| Generating Plant | Cost | Bond Issue Costs | Total Bond Size (Principal) | Term (Yrs.) | Average Coupon Bond Rate | Annual Debt Service | Series A Bond ID |
|---|---|---|---|---|---|---|---|
| Cabras 1 | 18,815,277 | 2,020,983 | 20,836,260 | 30 | 6.22638% | 1,550,579 | Ser A 1992 158M |
| Cabras 2 | 18,815,277 | 2,020,983 | 20,836,260 | 30 | 6.22638% | 1,550,579 | Ser A 1992 158M |
| Cabras 3 | 66,940,376 | 10,170,249 | 77,110,625 | 30 | 5.22329% | 5,144,551 | Ser A 1993 100M |
| Cabras 4 | 58,772,235 | 9,281,172 | 68,053,407 | 30 | 6.61504% | 5,273,651 | Ser A 1994 102.9M |
| Tenjo Diesel | 29,918,374 | 3,213,588 | 33,131,962 | 30 | 6.22638% | 2,465,592 | Ser A 1992 158M |
| Talofofo Diesel | 5,518,455 | 592,747 | 6,111,202 | 30 | 6.22638% | 454,779 | Ser A 1992 158M |
| Dededo CT #2 | 19,117,820 | 2,053,480 | 21,171,300 | 30 | 6.22638% | 1,575,512 | Ser A 1992 158M |
| Macheche CT | 18,086,814 | 1,942,738 | 20,029,552 | 30 | 6.22638% | 1,490,546 | Ser A 1992 158M |
| Yigo CT | 11,865,000 | 602,068 | 12,467,068 | 30 | 5.30965% | 839,850 | Ser A 1999 349M |

## 8. Energy Conversion Agreements (ECA)

This section provides background information on GPA’s Energy Conversion Agreements (ECAs) with Independent Power Producers (IPPs). GPA supplies all the fuel and the IPPs convert the fuel to electrical energy. The ECAs are between GPA and Pruvient, Taiwan Electrical and Mechanical Engineering Services (TEMES) and Enron Development Piti Corporation (ENRON). These ECAs are 20-year term contracts and the IPPs will transfer ownership of the generation plants to GPA upon contract expiration. The TEMES ECA provides for the construction, operation and maintenance of a 40-MW combustion turbine (CT) at the Cabras-Piti Complex. The plant has been in commercial operation since December 1997. The Pruvient ECA provides for the refurbishment, operation and maintenance of the Tanguisson Power Plant, which has been in commercial operation since September 1997. The ENRON ECA provides for the construction, operation and maintenance of an 88.4-MW slow speed diesel plant at the Cabras-Piti generation complex. The plant has been in commercial operation since January 1999.

Table 6 shows the model inputs for ECAs. The ECAs for TEMES and ENRON do not specify forced outage performance requirements. GPA bases the modeling of these ECA units on limits for annual unit downtime and unit availability.

## 8.1 Tanguisson Energy Conversion Agreement

On September 30, 1996, GPA entered into a 20-year contract with HEI Power Corp. Guam (HEI) for the refurbishment, operation and maintenance of the Tanguisson Power Plant. The plant has been in commercial operation since September 1997. Since then, HEI sold this contract to Mirant, and Mirant to Pruvient. Pruvient is the current incumbent IPP at Tanguisson.

## 8.2 Tanguisson ECA Unit Operating Parameters

GPA entered into this ECA to bring the Tanguisson plant to nameplate capacity and heat rate rating. Additionally, it contracted the operation and maintenance of this plant for the next 20 years. The ECA establishes guarantees for unit operation performance as described below.

The nameplate capacity of the plant is 53 MW at the generator terminals. The ECA stipulates that each unit must furnish a maximum capacity of 26.5 MW gross and 25 MW net. Additionally, the ECA provides a guaranteed plant minimum equivalent availability factor (EAF) of 87 percent with a maximum equivalent forced outage rate (EFOR) of 2 percent. Furthermore, the ECA guarantees a plant annual production capability for up to 328,500 MWh delivered to GPA at the high voltage side of the main power transformer. Finally, the ECA secures a minimum net plant heat rate at maximum capacity of 12,750 Btu/KWh on a higher heating value (HHV) basis. The plant will continue to use #6 residual fuel oil.

In addition to the mechanical and electrical performance guarantees, the plant must operate at all times within the limits provided by local and federal EPA permits.

The ECA refers to the Tanguisson Power Plant operation mode as baseload. The EPRI TAG manual defines baseload operation as 50 percent or greater capacity factor. Pruvient must provide the capability to continuously operate the plant at maximum rated output except during scheduled maintenance periods. However, GPA may operate the plant during emergency and/or abnormal system conditions with upon adequate notice to Pruvient. Additionally, Pruvient must control and operate the Tanguisson Power Plant consistent with GPA's system dispatch requirements.

Today, with greater Cabras Plant reliabilities, Tanguisson units operate as intermediate baseload or as reserve units.

## Table 6
## Energy Conversion Agreement Cost and Operations Model

| Item | Units | TEMES | Pruvient 1 | | | Pruvient 2 | | | MEC 8 | MEC 9 |
|---|---|---|---|---|---|---|---|---|---|---|
| | | FY 98-15 | FY 97 | FY 98 | FY 98-15 | FY 97 | FY 98 | FY 98-15 | FY 98-15 | FY 98-15 |
| | | | | | | | | | | |
| Average Heat Rate at Maximum Capacity | MBtu/MWh | 11.569 | 13.721 | 13.721 | 12.750 | 13.721 | 13.721 | 12.750 | 8.416 | 8.416 |
| Average Heat Rate at Minimum Capacity | MBtu/MWh | 11.969 | 17.410 | 17.410 | 16.177 | 17.410 | 17.410 | 16.177 | 8.760 | 8.760 |
| | | | | | | | | | | |
| Maximum Capacity | MW | 41.4 | 25.0 | 26.5 | 26.5 | 26.5 | 26.5 | 26.5 | 39.8 | 39.8 |
| Minimum Capacity | MW | 33.0 | 5.0 | 5.0 | 5.0 | 5.0 | 5.0 | 5.0 | 34.8 | 34.8 |
| | | | | | | | | | | |
| Fixed Annual Capacity Rate | $/kW/Year | - | 50 | 50 | 50 | 50 | 50 | 50 | 199 | 199 |
| Fixed Costs | $000/Year | 5,224 | 4,106 $ | 3,256 $ | 3,292 | 4,106 $ | 3,256 $ | 3,292 | 5,962 | 5,962 |
| | | | | | | | | | | |
| Variable O&M Costs | $/MWh | - | 1.08 | 1.08 | 1.11 | 1.08 | 1.08 | 1.11 | 2.61 | 2.61 |
| | | | | | | | | | | |
| Maintenance Requirement | Weeks | 4.1 | 5.7 | 5.7 | 5.7 | 5.7 | 5.7 | 5.7 | 4.1 | 4.1 |
| | | | | | | | | | | |
| Mature Forced Outage Rate | Percent | 2 | 2 | 2 | 2 | 2 | 2 | 2 | 2 | 2 |
| | | | | | | | | | | |
| Secondary Fuel Auxiliary Costs | $/MBtu | 2.423 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 |

## 8.3 Tanguisson ECA Contract Plant Performance

Table 7 summarizes the expected Tanguisson ECA plant contract performance.

## 8.4 Tanguisson ECA Contract Costs

Pruvient must refurbish, operate and maintain the Tanguisson Plant. Its responsibility includes fuel-to-electrical energy conversion and energy delivery to GPA based on dispatch requirements. GPA pays for the energy delivered. The ECA details the payment terms for capacity fees, energy conversion fees, fixed O&M fees, fee adjustments to the energy conversion fees and the fixed O&M fees, and bonus and penalty factors for heat rate, EAF and EFOR.

Table 7
Pruvient Plant Contract Performance Parameters

| Parameter | Guarantee |
|---|---|
| Plant Net Capacity | 50 MW |
| Minimum Plant EAF | 87% |
| Maximum EFOR | 2% |
| Maximum Plant Net Heat Rate | 12,750 Btu/kWh (HHV) |
| Frequency Limitation | 58.5 Hz to 61.5 Hz |
| Unit Voltage | 34.5 kV (+/-) 5% |
| Operation Mode | Baseload |

The ECA fixes the capacity fee at $4.180 per kilowatt per month based upon the contract capacity of the units. The energy conversion fees start at a rate of $0.001 per kilowatt-hour delivered to GPA. The ECA allows a fee adjustment (an increase or decrease) on the first day of every six-month period commencing from the completion date in accordance with the U.S. Gross Domestic Product Implicit Price Deflator (USGDPIPD). However, the energy conversion fees cannot exceed a rate equivalent to that of the initial rate escalated at 3.5 percent per year on a cumulative basis.

The fixed O&M fees start at a rate of $4.00 per kilowatt per month based upon the contracted capacity of the units.

The ECA allows a fixed O&M fee adjustment (an increase or decrease) on the first day of every six-month period commencing from the completion date in accordance with the USGDPIPD. However, the fixed O&M fees cannot exceed a rate equivalent to that of the initial rate escalated at 3.5 percent per year on a cumulative basis.

The ECA stipulates plant performance bonuses and penalties. The ECA provides a heat rate bonus and penalty. Heat rate bonuses or penalties can be applied periodically every six months. Following the last day of the six months following the completion date, the Adjusted Theoretical Energy Input will be summed for the preceding six-month period. GPA and Pruvient will compare this value to the actual energy input. If the Adjusted Theoretical Energy Input falls within (+/-) 1.0 percent of the Actual Energy Input, GPA will not apply any bonus or penalty payment. If the Actual Energy Input is greater than

101.0 percent of the Adjusted Theoretical Energy Input, GPA will receive a penalty payment from Pruvient. GPA will calculate the Penalty MBtu Base by subtracting 101 percent of the Adjusted Theoretical Energy Input from the Actual Energy Input. Pruvient will pay GPA an amount equal to half of the Penalty MBtu Base times the weighted average fuel cost for the period. If the Actual Energy Input is less than 99 percent of the Adjusted Theoretical Energy Input, GPA will pay a bonus to Pruvient.

GPA calculates the Bonus MBtu Base by subtracting the Actual Energy Input 99 percent of the Adjusted Theoretical Energy Input. GPA will pay Pruvient an amount equal to half of the Bonus MBtu Base times the weighted average fuel cost for the period.

Additionally, the ECA provides for an EAF bonus and penalty. The guaranteed minimum EAF of 87 percent is based upon a 3-year rolling average starting from the completion date. For any year in which the EAF falls below 85 percent, Pruvient will pay GPA $10,000 for each 1 percent below 85 percent. For any year in which the EAF exceeds 90 percent, GPA will pay Pruvient $7,500 for each 1 percent above 90 percent.

Finally, the ECA provides for an EFOR bonus and penalty. For any year in which the EFOR exceeds 2 percent, Pruvient will pay GPA $5,000 for each 0.1 percent above 2.5 percent. For any year in which the EFOR falls below 2 percent, GPA will pay Pruvient $7,500 for each 0.1 percent below 1.8 percent.

## 8.5 Taiwan Electrical and Mechanical Engineering Services (TEMES) ECA

On September 30, 1996, GPA entered into a 20-year Energy Conversion Agreement with TEMES for the construction, operation and maintenance of a 40-MW combustion turbine (CT) at the Cabras-Piti Complex. At the end of the 20-year period, TEMES will transfer the unit ownership to GPA. The plant has been in commercial operation since December 1997.

## 8.6 TEMES ECA Unit Operating Parameters

The ECA establishes TEMES plant operation parameters and performance guarantees. The following paragraphs describe these items.

> The maximum net plant capacity must be at least 40 MW at the high side of the main step up transformer. The plant must meet a minimum 95 percent EAF. TEMES guarantees the capability to deliver a minimum of 87,600 MWh of electricity yearly to GPA at the high voltage side of the main power transformer. The ECA stipulates that the plant must provide a net plant heat rate of 11,447 Btu/kWh at maximum capacity on a lower heating value (LHV) basis. The TEMES plant burns #2 diesel oil.
>
> The ECA stipulates other operating performance parameters including frequency and voltage. The plant must operate reliably at maximum continuous output between the range of 58.5 Hz to 61.5 Hz. The underfrequency protection is set at 58.5 Hz while the mechanical overspeed protection is set at 10 percent (+/-) 1 percent above rated speed. The plant must provide normal voltage of 34.5 kV (+/-) 5 percent at the transmission side of the generator step-up transformer.
>
> In addition to the mechanical and electrical parameter guarantees, the plant must operate at all times within EPA permit limits.

GPA contracted the TEMES plant for peaking and reserve capacity. GPA can operate the plant at 40 MW for six continuous hours per day. Outside these six hours, GPA may operate the plant at no more than 33 MW. GPA expects the plant to be available for dispatch except during scheduled maintenance. However, GPA may call the plant to operate during emergency and/or abnormal system conditions with adequate notice to TEMES.

TEMES will control and operate the CT consistent with GPA's system dispatch requirements.

## 8.7 TEMES ECA Contract Plant Performance

Table 8 summarizes the expected TEMES Plant contract performance.

Table 8
TEMES Plant Contract Performance Parameters

| Parameter | Guarantee |
|---|---|
| Plant Net Capacity | 40 MW |
| Minimum Plant EAF | 95% |
| Maximum Plant Net Heat Rate | 11,447 BTU/KWh (LHV) |
| Frequency Limitation | 59 Hz to 61 Hz |
| Unit Voltage | 34.5 kV (+/-)5% |
| Operation Mode | Peaking/Reserve Unit (daily: 40 MW six hours continuous 33 MW otherwise) |
| Start-up | Limited to 2 per day |

## 8.8 TEMES ECA Contract Costs

TEMES must design, construct, operate and maintain its plant. Additionally, TEMES must provide fuel-to-electrical energy conversion and energy delivery to GPA based on dispatch requirements. GPA pays for the energy delivered.

The ECA describes the capacity, energy conversion fees, fixed O&M fees, start up charges fees and heat rate bonus/penalty factors.

The ECA describes a tier structure for capacity payments. The capacity fees decline with plant capacity factor and are nested. If GPA operates the plant at 40 percent capacity factor, it will pay for the first 25 percent of that capacity factor at the 0 to 25 percent rate and the additional 15 percent at the 25 to 50 percent rate. Table 9 illustrates the tier structure.

Table 9
Capacity Fee Tier Pricing Structure

| Annual Capacity Factor (%) | Capacity Rate ($/kWh) |
|---|---|
| 0-25 | 0.02899 |
| 26-50 | 0.01323 |
| 51-75 | 0.01002 |
| 76-100 | 0.00834 |

The fixed O&M fees are also based on energy produced and are set up in a tier structure in a similar manner as the capacity fees. Table 10 illustrates the tier structure.

The ECA includes a minimum take provision. GPA is annually obligated to pay for 87,600 MWh. The start up charge is set at $7,650 per start for every start that exceeds 345 starts in each Contract Year.

The ECA provides for a heat rate bonus and penalty. Opportunities for a heat rate bonus or penalty factor arise on an annual basis commencing with the first anniversary of the completion date. GPA will evaluate the fuel efficiency by comparing the Guaranteed Net Plant Heat Rate to the Adjusted Actual Heat Rate. If the Adjusted Actual Heat Rate of the plant is greater than 100 percent of the Guaranteed Net Plant Heat Rate, TEMES will pay GPA for the additional fuel costs associated with the higher heat rate. If the Adjusted Actual Heat Rate of the plant is 1.5 percent or more below the Net Plant Heat Rate, GPA will pay TEMES an amount equal to half of the savings in fuel costs associated with the lower heat rate. Payment calculations will be based on the plant consumption of fuel and the average cost of fuel, as documented by GPA, for the period.

Table 10
Fixed O&M Fee Tier Pricing Structure

| Annual Capacity Factor (%) | Fixed O&M Rate ($/kWh) |
|---|---|
| 0-25 | 0.04031 |
| 26-50 | 0.01907 |
| 51-75 | 0.01390 |
| 76-100 | 0.01157 |

## 8.9 Marianas Electric Company (MEC) ECA

On September 30, 1996, GPA entered into a 20-year contract with Enron Development Piti Corporation (ENRON) for the construction, operation and maintenance of an 80-MW slow speed diesel plant at the Cabras-Piti generation complex. The plant had started commercial operation by January 1999. Since the collapse of its parent company, MEC has changed ownership several times. It is currently a wholly owned subsidiary of Osaka Gas, Japan.

## 8.10 MEC ECA Unit Operating Parameters

The ECA establishes plant operation parameters and performance guarantees. The following paragraphs describe these guarantees.

The MEC plant must provide a nominal net plant capacity of 79.6 MW at the high side of the main step up transformer. The ECA allows an aggregate downtime of 876 hours for both scheduled and forced outages per contract year. Additionally, MEC must provide a guaranteed net plant heat rate at maximum net output of 8,400 Btu/kWh. This heat rate is established on a higher heating value (HHV) basis at full load. The MEC plant uses #6 residual fuel oil.

The ECA stipulates other operating performance parameters including frequency and voltage. The plant must operate reliably at maximum continuous output between the range of 58.5 Hz to 61.5 Hz. The underfrequency protection is set at 58.2 Hz while the mechanical overspeed protection is set at 10 percent (+/-) 1 percent above rated speed. The plant must provide normal voltage of 115 kV (+/-) 5 percent at the transmission side of the generator step up transformer.

In addition to the mechanical and electrical operation parameters, the plant must operate within local and USEPA permit limits.

The ECA stipulates the MEC plant operation mode as baseload. MEC must provide the capability to operate continuously at rated output except during scheduled maintenance periods. However, the GPA may call the plant to operate during emergency and/or abnormal system conditions with adequate notice to MEC. Finally, MEC must control and operate the plant consistent with GPA’s system dispatch requirements.

## 8.11 MEC ECA Contract Plant Performance

Table 11 summarizes the Expected MEC Plant Contract Performance.

Table 11
MEC Plant Contract Performance Parameters

| Parameter | Guarantee |
|---|---|
| Plant Net Capacity | 79.6 MW |
| Downtime | 876 hours/year |
| Maximum Plant Net Heat Rate | 8,070 Btu/kWh (HHV) |
| Frequency Limitation | 58.5 Hz to 61.5 Hz |
| Unit Voltage | 115 kV (+/-)5% |
| Operation Mode | Baseload |

## 8.12 MEC Contract Costs

MEC must design, construct, operate and maintain its plant. Additionally, MEC must provide fuel-to-electrical energy conversion and energy delivery to GPA based on dispatch requirements. GPA pays for the energy delivered.

The following paragraphs describe the ECA capacity, energy conversion fees, fixed O&M fees, start up charges fees and heat rate bonus/penalty factors.

The capacity fee is fixed at $17.369 per kilowatt per month based upon the nominal capacity, contract capacity, and availability of the units.

The fixed O&M fees start at a rate of $6.372 per kilowatt per month based upon the nominal capacity, contracted capacity and availability of the units. The ECA provides a fee adjustment on the first day of every quarter commencing from the completion date in accordance with the U.S. Gross Domestic Product Implicit Price Deflator.

The variable O&M fees start at a rate of $0.0024 per kilowatt-hour delivered to GPA. The ECA secures the right for a fee adjustment on the first day of every quarter commencing from the completion date in accordance with the U.S. Gross Domestic Product Implicit Price Deflator.

The start up charge is set at $3,752 per start per engine for every start that exceeds fifteen starts in each contract year.

The ECA provides for a heat rate bonus and penalty. Opportunities for a heat rate bonus or penalty factor arise on an annual basis commencing with the first anniversary of the completion. GPA will evaluate fuel efficiency by comparing the Contractual Heat Rate to the Adjusted Actual Heat Rate. If the Adjusted Actual Heat Rate of the plant is greater than the Contractual Heat Rate, MEC will pay GPA for the additional fuel cost associated with the higher heat rate. There is no heat rate bonus. Payments are based on energy delivered to GPA during the contract year and the average cost of fuel for the period.

## 9. Performance Management Contracts

The Authority has Performance Management Contracts (PMC) at Cabras #1 & #2 steam power plant and at Cabras #3 & #4. PMCs provide the following:

- Top-tier plant management
- Outsourcing for goods and services related to power plant operations and maintenance
- Performance Improvement Projects
- Capital Improvement Projects

GPA staff came up with the idea for the PMCs. Contract details were developed collaboratively with the PUC.

Table 12
Performance Management Cost Summary: Cabras #1 & #2

| Fiscal Year | Fixed Management Fee | O&M | CIP / PIP | Total |
|---|---|---|---|---|
| 2003 | $1,046,667 | $312,199 | $105,611 | $1,464,477 |
| 2004 | $1,787,692 | $1,511,813 | $5,767,710 | $9,067,215 |
| 2005 | $1,617,048 | $604,706 | $4,958,484 | $7,180,238 |
| 2006 | $1,644,538 | $1,396,171 | $3,791,601 | $6,832,310 |
| 2007 | $1,672,495 | $1,949,624 | $4,132,000 | $7,754,119 |

Notes:
1. Costs under the Fixed Management Fee may include bonuses paid to vendors for performance incentives.
2. O&M costs include inventory replenishment reimbursement costs.
3. CIP/PIP costs include payments for projects under financing agreements.
4. All costs are provided in Fiscal Year, contract performance is based on Contract Year which begins on January 1.
5. All costs presented for FY 2007 are based on approved purchase order amounts (no actuals).

# 10. Fuels

GPA uses the following fuels: High Sulfur Fuel Oil (HSFO), Low Sulfur Fuel Oil (LSFO), Number 2 diesel fuel oil (DFO), and Low Sulfur Diesel.

High Sulfur and Low Sulfur fuel oils are residual fuel oils with maximum 2.0 percent and 1.0 percent sulfur content by weight, respectively. GPA uses Low Sulfur Diesel as the principal fuel at its Tenjo Vista, Manengon (MDI), Talofofo and TEMES CT power plants. It uses Low Sulfur Diesel for startup operations at the Cabras #1, #2, #3 & #4, MEC #8 & #9, and Tanguisson #1 & #2 power plants. The Authority uses Number 2 diesel fuel oil as the principal fuel at its combustion turbines and other medium speed diesel plants.

Historically, DFO is much more expensive than HSFO or LSFO. Figure 3 shows the Authority's historical fuel oil purchase prices. The Authority uses cylinder oil at Cabras #3 & #4 and MEC #8 & #9 slow speed diesel plants. For the purposes of the Levelized Energy Adjustment Clause (LEAC), this commodity is considered a fuel since it is consumed and contributed as part of the combustion process.

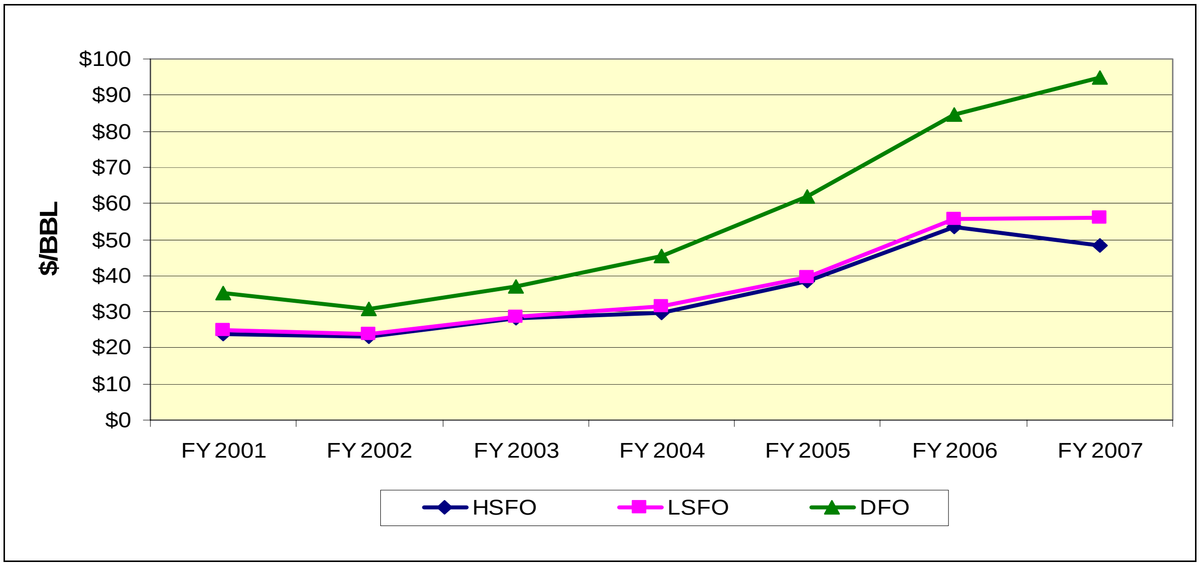


Figure 3: Historical Fuel Oil Purchase Prices

## 11. Long-Term Fuel Contracts

The Authority has long-term contracts with British Petroleum (BP Singapore Pte., Ltd.) and Shell Oil – Guam for residual fuel oil and diesel fuel, respectively. Table 13 summarizes existing GPA fuel contracts.

The Authority's contract for residual fuel oil is a three-year fuel supply contract with a two-year extension option with BP Singapore Pte., Ltd.. This supply contract commenced on February 1, 2007 and expires at midnight January 31, 2010.

The price for residual fuel oil from BP is set at the mean (arithmetic average) price for HSFO 180 cst posted in Platt's *Marketscan, Singapore Product Assessments* during the calendar month prior to the month in which the Bill of Lading date falls plus a fixed premium fee for either high or low sulfur fuel oil.

The Authority's contract for diesel fuel oil with Shell Oil – Guam commenced on December 1, 2006 and expires at midnight September 30, 2009. The fuel supply contract is for three years with the option to extend two additional one-year terms, renewable annually upon mutual agreement of both parties unless terminated earlier or cancelled due to unavailability of funds.

## 12. Fuel Diversification

The Authority's fuel diversification extends to the use of two main fuels: residual fuel oil and diesel distillate No. 2. However, the prices for these fuels are highly correlated because they are both petroleum products. Therefore, the Authority is considering several other fuels as a general policy for fuel diversification. These fuels include: coal, natural gas, and biodiesel.

## 12.1 Coal[4]

The Authority assumes that either Indonesian or Australian coal would be the fuel source. Both countries offer low-sulfur, high-quality coals. China, South Africa, Colombia, and the U.S. comprise the rest of the key coal exporting countries. Potential supply companies include BHP Billiton Limited, Xstrada Plc, Rio Tinto Plc, and Anglo American Plc. Each of these companies is active in Australia and most have operations in Indonesia.

Table 13
Long-Term Fuel Contract Summary

| Contract/PO # | Contractor | Fuel Type | Contract Period | Unit Price | Premium Adder ($/BBL) | Annual Contract Quantity | Units | Total Contract Cost Estimate ($) |
|---|---|---|---|---|---|---|---|---|
| GPA-007-03 Contract Summary | BP, Singapore | Low Sulfur Fuel | Aug 01, 2006 – Jan 31, 2007 | Average Spot market Price | 8.788 | 3,000,000 | BBLS | Varies with Market |
| | | High Sulfur Fuel | | Average Spot market Price | 5.303 | | | |
| PO #11544 | Shell Oil Guam | Diesel Distillate #2 | Dec 1, 2006 to Sep 30, 2009 | $2.504 | | 2,560,914 | Gallon | $ 6,412,529 |
| PO #11541 | | Low Sulfur Diesel | | $3.004 | | 100,839 | Gallon | $ 302,920 |
| PO #11542 | | Low Sulfur Diesel | | $2.595 | | 1,193,350 | Gallon | $ 3,096,743 |
| PO #11543 | | Low Sulfur Diesel | | $2.439 | | 2,257,626 | Gallon | $ 5,506,350 |
| PO #11545 | | Low Sulfur Diesel | | $2.964 | | 215,113 | Gallon | $ 637,595 |

The Australian Coal Association indicates that Australia exports 70 percent of the coal it produces and can blend coals of different characteristics to meet customer specifications.

World coal prices are reported to have increased from $36 per metric ton last year to $52 per metric ton as of September 2006. Xstrada reported in July that it had locked in a price for its Australian coal exports to Japan of approximately $52.50 per ton, delivered. Australian suppliers negotiate the prices for their coal exports directly with Japanese utilities on an annual basis. Approximately 60 percent of Australia's coal goes to Japan.

## 12.2 Natural Gas[5]

Natural gas excess to indigenous need is exported from both Australia and Indonesia in the form of LNG. LNG is natural gas chilled to -270 F, at which point it becomes a liquid and takes up 1/60 of the volume it did as a gas. Most LNG is transported in very large tankers and is delivered to destinations such as Japan on a baseload basis. Typical tanker size is 160,000 to 200,000 cubic meters, which equates to 3.5 to 4 billion cubic feet of natural gas. (Construction costs for the delivery-end terminal to "reheat" the LNG to its gaseous state for delivery to customers via standard pipeline can range up to $1 billion.) GPA's projected daily demand to support operation of a combined-cycle unit, in contrast, is 11,500 million cubic feet (MCF). Accordingly, a standard-sized LNG regasification terminal is not economically feasible for GPA.

Smaller LNG tankers and facilities are possible. Japan, for example, uses smaller tankers to "island-hop" deliveries of LNG to more remote locations. Knutsen OAS, a Norwegian shipbuilder, has designs to construct 1,100 cubic meter mini-tankers. The 1,100 cubic meter capacity is approximately 23,000 MCF, thus implying tanker deliveries every two or three days would be sufficient to supply a 60-MW nominal capacity combined-cycle unit.

4 Adapted from R. W. Beck, Inc., "Potential Supply-Side and Renewable Generation Options," 1996.
5 Ibid.

Another concept is compressed natural gas, or CNG. Trans-Ocean Gas is marketing a concept that converts container ships into tankers carrying CNG. These ships would be designed for short-haul trades such as from Malaysia to the Philippines. The off-loading terminals can cost up to $150 million.

Any of these technologies would involve purchasing natural gas from Australia or Indonesia. Indonesia has long been the world's largest exporter of natural gas as LNG, though political uncertainty and investment issues have pushed production below the level of contractual export commitments since 2005. PT Pertamina remains the sales agent for LNG sales to South Korea and Taiwan; these contracts expire in 2007 and 2009, respectively. In addition, BP Indonesia reports that its Tangguh project will begin service in 2008. The project initially consists of two trains with LNG output contracted to the Fujian LNG project in China, K-Power Co., Ltd. in Korea, POSCO in Korea and Sempra Energy LNG Marketing Corp., in Mexico. Tangguh is expandable to eight trains of capacity, which BP Indonesia says could occur if it has sufficient sales commitments for the gas. Tangguh's two cryogenic trains will initially export 340 BCF per year.

Australia produces approximately 1.3 trillion cubic feet (TCF) of natural gas per year and in 2005 exported 44 percent of that as LNG (with Japan the primary destination). Much of Australia's natural gas reserves are located in remote areas where it is more economic to convert the gas to LNG and export it than it would be to build a pipeline to carry the gas inland for domestic consumption. Besides the existing Northwest Shelf Venture currently exporting LNG, at least four other LNG export projects are under development with in-service dates ranging from 2006 to 2011. Some of the projects have already executed destination contracts; some merely have LNG sales agreements with an exporter who must still seek a delivery market for the gas. Leading LNG exporters include Woodside Petroleum, ChevronTexaco, Royal Dutch Shell, ExxonMobil and ConocoPhillips.

Pacific Basin LNG has traditionally been priced using a market-basket of world oil prices under an "S-Curve" methodology that moderated LNG prices as oil prices rose. Those contracts are expiring and LNG customers are demanding more flexible contract terms. With construction of LNG terminals in the U.S. and the existence of a highly liquid and transparent market, Henry Hub is expected to become the world LNG price benchmark; thus, buyers should see LNG contracts increasingly set prices using the Henry Hub price.

## 12.3 BioDiesel[6]

Several of the Authority's generators can use biodiesel with restrictions. A survey of the technical sales support for Caterpillar units which include Tenjo and Talofofo, Wartsila units (Manenggon), and GE LM2500 units (Macheche and Yigo) have indicated that biodiesel can be used as fuel for their units as long as it meets their recommended fuel standards (such as ASTM D-6751). Most unit manufacturers, however, do not warranty damages caused by fuel but they do have some technical information that will help customers if they plan to use the fuel. These include recommending 20 percent (15 percent for ethanol) or lower blending of biodiesel to diesel to prevent plugging, working with the fuel supplier to address microbial growth in storage with fuel additives, and including additional maintenance to

6 Adapted from U.S. Department of Energy Alternative Fuel Research, "21st Century Complete Guide to Biofuels and Bioenergy," 2003. ISBN 1-59248-279-1.

check condition of elastomeric seals as long-term effects are still being researched. Biodiesel typically is lower in heat content and it has about 5 to 10 percent loss in energy per gallon of biodiesel fuel.

Biodiesel (fatty acid alkyl esters) is a cleaner burning diesel replacement fuel made from natural, renewable sources such as new and used vegetable oils and animal fats. Just like petroleum diesel, biodiesel operates in compression-ignition engines. Blends of up to 20 percent biodiesel (mixed with petroleum diesel fuels) can be used in nearly all diesel equipment and are compatible with most storage and distribution equipment. These low level blends (20 percent and less) do not require any engine modifications and can provide the same payload capacity as diesel. Users should consult their engine warranty statement.

Higher blends, even pure biodiesel (100 percent biodiesel, or B100), can be used in many engines built since 1994 with little or no modification. Transportation and storage, however, require special management. Material compatibility and warrantee issues have not been resolved with higher blends.

Using biodiesel in a conventional diesel engine substantially reduces emissions of unburned hydrocarbons, carbon monoxide, sulfates, polycyclic aromatic hydrocarbons, nitrated polycyclic aromatic hydrocarbons, and particulate matter. These reductions increase as the amount of biodiesel blended into diesel fuel increases. The best emissions reductions are seen with B100.

The use of biodiesel decreases the solid carbon fraction of particulate matter (since the oxygen in biodiesel enables more complete combustion to $CO_2$) and reduces the sulfate fraction (biodiesel contains less than 24 ppm sulfur), while the soluble, or hydrocarbon, fraction stays the same or increases. Therefore, biodiesel works well with new technologies such as diesel oxidation catalysts (which reduce the soluble fraction of diesel particulate but not the solid carbon fraction).

Emissions of nitrogen oxides increase with the concentration of biodiesel in the fuel. Some biodiesel produces more nitrogen oxides than others, and some additives have shown promise in modifying the increases. More research and development is needed to resolve this issue.

Biodiesel has physical properties very similar to conventional diesel. Table 14 lists some of these physical properties.

Table 14
Biodiesel Physical Properties

| Biodiesel Physical Characteristics | Parameter Value Lower Limit | Parameter Value Upper Limit |
|---|---|---|
| Specific Gravity | 0.87 | 0.89 |
| KinematicViscosity @ 40°C | 3.70 | 5.80 |
| Cetane Number | 46.00 | 70.00 |
| Higher Heating Value (Btu/lb) | 16,928 | 17,996 |
| Sulfur, wt % | | 0.0024 |
| Cloud Point °C | -11 | 16 |
| Pour Point °C | -15 | 16 |
| Iodine Number | 60 | 135 |
| Lower Heating Value (Btu/lb) | 15,700 | 16,735 |

Biodiesel fuel can be made from new or used vegetable oils and animal fats, which are non-toxic, biodegradable, renewable resources. Fats and oils are chemically reacted with an alcohol (methanol is the usual choice) to produce chemical compounds known as fatty acid methyl esters. Biodiesel is the name given to these esters when they are intended for use as fuel. Glycerol (used in pharmaceuticals and cosmetics, among other markets) is produced as a co-product. Biodiesel can be produced by a variety of esterification technologies. The oils and fats are filtered and preprocessed to remove water and contaminants. If free fatty acids are present, they can be removed or transformed into biodiesel using special pretreatment technologies. The pretreated oils and fats are then mixed with an alcohol (usually methanol) and a catalyst (usually sodium or potassium hydroxide). The oil molecules (triglycerides) are broken apart and reformed into esters and glycerol, which are then separated from each other and purified.

Approximately 55 percent of the biodiesel industry can use any fat or oil feedstock, including recycled cooking grease. The other half of the industry is limited to vegetable oils, the least expensive of which is soy oil. The soy industry has been the driving force behind biodiesel commercialization because of excess production capacity, product surpluses, and declining prices. Similar issues apply to the recycled grease and animal fats industry, even though these feedstocks are less expensive than soy oils.

Based on the combined resources of both industries, there is sufficient feedstock to supply 1.9 billion gallons of biodiesel (under policies designed to encourage biodiesel use).

### 12.4 Biodiesel Prices

"The American Jobs Creation Act of 2004 (Public Law 108-357) created tax incentives for biodiesel fuels and extended the tax credit for fuel ethanol: Biodiesel and Ethanol (VEETC) Tax Credit. The biodiesel credit was available to blenders/retailers beginning in January 2005. Section 1344 of the Energy Policy Act of 2005 extended the tax credit for biodiesel producers through 2008. The credits are $.51 per gallon of ethanol at 190 proof or greater, $1.00 per gallon of agri-biodiesel, and $.50 per gallon of waste-grease biodiesel. If the fuel is used in a mixture, the credit amounts to $.0051 per percentage point ethanol or $.01 per percentage point of agri-biodiesel used or $.0050 per percentage point of waste-grease biodiesel (i.e., E100 is eligible for $.51 per gallon)."[7]

"It takes 7.35 pounds of degummed soybean oil to make 1 gallon of biodiesel," according to Vernon Eidman, a professor at the University of Minnesota. (Vegetable oil is measured in pounds at wholesale.) "and vegetable oil has been rising in price. Options on soybean oil futures, for instance, are selling for around 37 cents a pound. Thus, the raw material alone can cost more than $2.50 a gallon, above the wholesale price of refined, regular diesel. That now hovers around $2.40 per gallon. Without the federal subsidy … most biodiesel manufacturers would lose money."[8]

## 13. Energy Conversion Efficiency

Heat rates and heat input curves show a generating plant's efficiency of converting the heat energy in fuel to electrical energy. The units for heat rate are MBtu/MWh. The units for heat input are MBtu/hour. Table 15 provides the coefficients for the equations for the heat input curves of GPA's generation units.

Note that a certain generator may have a higher efficiency than another generator but actually be less economic in terms of energy conversion costs. Energy conversion costs are in units of $/MWh. A unit using a more expensive fuel may have higher energy conversion costs than a unit with a lower efficiency but using a less expensive fuel.

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[7] U.S. Department of Energy, "United States (Federal) Incentives and Laws: Biodiesel and Ethanol (VEETC) Tax Credit," 2007. [Internet] http://www.eere.energy.gov/afdc/progs/view_ind_fed.cgi?afdc/319/0 (Available October 10, 2007)

[8] Michael Kanellos. "Imperium says new plant slashes cost of biodiesel production," 2007. [Internet] http://www.news.com/Imperium-says-new-plant-slashes-cost-of-biodiesel-production/2100-11392_3-6202577.html (Available October 10, 2007.)

Table 15
Heat Input Coefficients

| Unit | Heat Input Curve Coefficients A | B | C |
|---|---|---|---|
| Cabras #1 | 0.04545 | 5.90513 | 109.67699 |
| Cabras #2 | 0.00247 | 8.97932 | 72.62941 |
| Cabras #3 | 0.13819 | (0.58671) | 134.13926 |
| Cabras #4 | 0.27996 | (9.54556) | 275.90910 |
| Tanguisson #1 | 0.10338 | 9.06312 | 33.86512 |
| Tanguisson #2 | 0.10338 | 9.06312 | 33.86512 |
| MEC #8 | 0.02949 | 5.83826 | 47.21844 |
| MEC #9 | 0.02949 | 5.83826 | 47.21844 |
| Dededo CT #1 | 0.22845 | 4.12644 | 136.41007 |
| Dededo CT #2 | 0.19459 | 3.51486 | 116.19256 |
| Macheche CT | 0.04103 | 7.85272 | 49.68998 |
| Marbo CT | - | 5.46854 | 137.94340 |
| Yigo CT | 0.12657 | 4.10896 | 57.75660 |
| TEMES CT | - | 11.62905 | 57.83442 |
| Dededo Diesel Units | - | 13.26825 | - |
| Manengon Diesel Units | - | 9.58650 | - |
| Talofofo Diesel Units | 0.47870 | 4.87200 | 6.80760 |
| Tenjo Vista Diesel Units | 0.47870 | 4.87200 | 6.80760 |

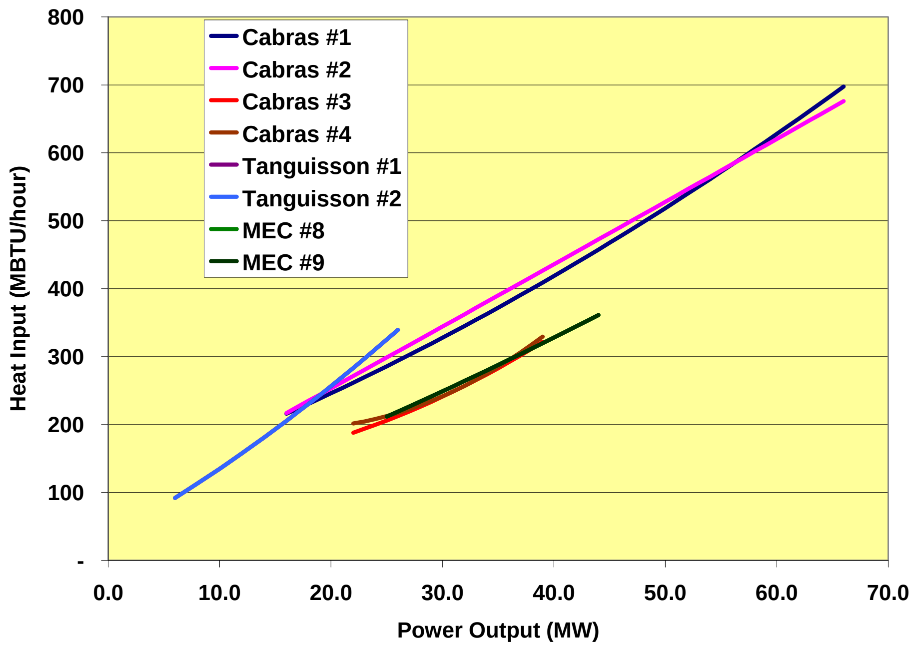



Figure 4, Heat Input Curves

# 14. Historical Production Costs

Table 16 shows the production costs per kilowatt-hour including debt service, fuel, and operating and maintenance costs for the GPA units. Note that if a unit is not producing much energy, the cost of production increases. This is because fixed costs are being allocated to fewer kilowatt-hours. For example, in FYs 2004 and 2005, the Talofofo diesel plant produced almost no energy because GPA did not need to operate. Therefore, the production numbers are significantly higher than the exact same type of units at the Tenjo Vista Diesel Power Plant.

Table 16
Historical Production Costs
Including Debt Service, Fuel, and O&M – FY 2004-2005

| | Total Costs (Cents per kWh) | | | | | |
|---|---|---|---|---|---|---|
| Power Plant | FY 2005 | FY 2004 | FY 2003 | FY 2002 | FY 2001 | FY 2000 |
| Cabras 1 & 2 | 7.827 | 6.324 | 5.294 | 4.777 | 6.466 | 6.478 |
| Cabras 3 & 4 | 7.611 | 7.964 | 17.062 | 8.459 | 8.766 | 10.019 |
| Dededo CT 1 | 19.381 | 19.092 | N/A | N/A | 11.705 | 9.238 |
| Dededo CT 2 | N/A | N/A | N/A | N/A | N/A | N/A |
| Macheche CT | 27.396 | 32.868 | N/A | N/A | 17.306 | 9.916 |
| Yigo CT | 31.503 | 36.788 | 13.143 | 11.919 | 11.160 | 9.913 |
| Marbo CT | N/A | N/A | N/A | N/A | N/A | N/A |
| Dededo Diesel | 21.020 | 27.403 | 19.156 | 9.692 | 12.283 | 9.061 |
| Mdi Diesel | 15.341 | 20.108 | 12.554 | 7.563 | 10.527 | 7.597 |
| Talofofo | 840.650 | 370.867 | 36.943 | 19.476 | 9.674 | 10.366 |
| Tenjo Vista | 23.395 | 17.120 | 14.951 | 15.896 | 14.319 | 13.922 |
| Tanguisson 1 & 2 | 10.019 | 9.264 | 7.697 | 6.592 | 6.714 | 5.955 |
| TEMES | 32.021 | 21.692 | 16.070 | 15.248 | 13.030 | 11.728 |
| MEC/ENRON (Piti 8 & 9) | 10.260 | 9.062 | 8.944 | 8.365 | 8.200 | 7.845 |

# 15. Generation Standards

The Authority must meet or exceed the following generation performance standards:

- 90 percent or greater of generation to come from baseload plants;
- 10 percent or less of generation to come from CT/Diesel generation;
- An average gross heat rate of 9,600 Btu/kWh for the baseload plants;
- An average gross heat rate for the CT/Diesel plants of 13,600 Btu/kWh;
- A system average gross heat rate of 10,000 Btu/kWh; and,
- Three-year rolling average Weighted Equivalent Availability Factor greater than or equal to those found in Table 17 for each baseload unit.

If the Authority does not meet the above standards, the PUC may penalize the Authority. These benchmarks were set in the March 31, 2005 stipulation between the Authority and Georgetown Consulting Group, Inc. (GCG). The Authority proposed its "Quality Management Plan for Prudent Fuel Use," and re-crafted the document in collaboration with GCG. Meeting these standards is prima facie prudence for fuel cost to be recovered in the LEAC.

The Authority has an availability standard for medium speed diesel generation units. These units will achieve a two-year rolling average of equivalent availability equal to or exceeding 87 percent at the end of fiscal year 2009 and for every fiscal year thereafter. With projected near-term annual capacity factors of less than 5 percent, the availability of medium speed diesels does not contribute in any substantial manner to the LEAC. Therefore, the Authority does not accept penalties or bonuses regarding the availabilities of medium speed diesel plants.

The Authority has an availability standard for combustion turbine generation units. These units will achieve a two-year rolling average of equivalent availability equal to or exceeding 87 percent at the end of fiscal year 2009 and for every fiscal year thereafter. With projected near-term annual capacity factors of less than 5 percent, the availability of combustion turbines does not contribute in any substantial manner to the LEAC. Therefore, GPA does not accept penalties or bonuses regarding the availabilities of combustion turbines.

Table 17
Baseload Generation
Equivalent Availability Factor Performance Factors

| Generation Unit | 2003 | 2004 | 2005 | 2006 | 2007 | 2008 | 2009 |
|---|---|---|---|---|---|---|---|
| Cabras Unit #1 | 78.1% | 65.0% | 75.0% | 82.5% | 85.0% | 85.0% | 87.0% |
| Cabras Unit #2 | 63.4% | 94.0% | 75.0% | 82.5% | 85.0% | 85.0% | 87.0% |
| Tanguisson Unit #1 | 96.4% | 89.0% | 85.0% | 87.0% | 87.0% | 87.0% | 87.0% |
| Tanguisson Unit #2 | 80.7% | 42.0% | 85.0% | 87.0% | 87.0% | 87.0% | 87.0% |
| Cabras Unit #3 | 0.0% | 56.0% | 62.0% | 76.0% | 90.0% | 90.0% | 90.0% |
| Cabras Unit #4 | 65.5% | 67.0% | 62.0% | 76.0% | 90.0% | 90.0% | 90.0% |
| MEC Unit #8 | 83.4% | 95.0% | 90.0% | 90.0% | 90.0% | 90.0% | 90.0% |
| MEC Unit #9 | 87.0% | 96.0% | 90.0% | 90.0% | 90.0% | 90.0% | 90.0% |
| Average Unit EAF Targets | 69.3% | 75.6% | 78.0% | 83.9% | 88.0% | 88.0% | 88.5% |
| Weighted Average EAF Targets | | 77.4% | 77.4% | 83.6% | 87.7% | 87.7% | 88.4% |

The Authority submits the following reports quarterly in accordance with the stipulation: (1) The performance indicators for availability factor and forced outage rates; (2) A 3-year rolling history and average for availability factor and forced outage rates (or as much history as is currently available); (3) Maintenance outage schedule for the next twelve months and summary of efficiency or availability enhancements to be undertaken during this period; (4) A statement of compliance with the Quality Management Plan filed with the PUC (QMP-002-2004), except as noted in Appendix A (Progress Status), and Quality Management Plan for Prudent Fuel Use, with LEAC Performance Charts attached as Exhibit A and the Economic Dispatch Performance Report attached as Exhibit B; and (5) Listing of Plants for which the maintenance is outsourced. These reports are posted at

http://www.guampowerauthority.com/operations/leac_performance/leac_performance.html.

## 16. Historical Equivalent Availability Factors

Figure 5 shows the Equivalent Availability Factor Performance Charts reported for April 2007 to the Guam Public Utilities Commission under the Authority's Prudent Fuel Management Plan. The Authority posts the performance measures for prudent fuel use at the URL:

http://www.guampowerauthority.com/operations/leac_performance/leac_performance.html.

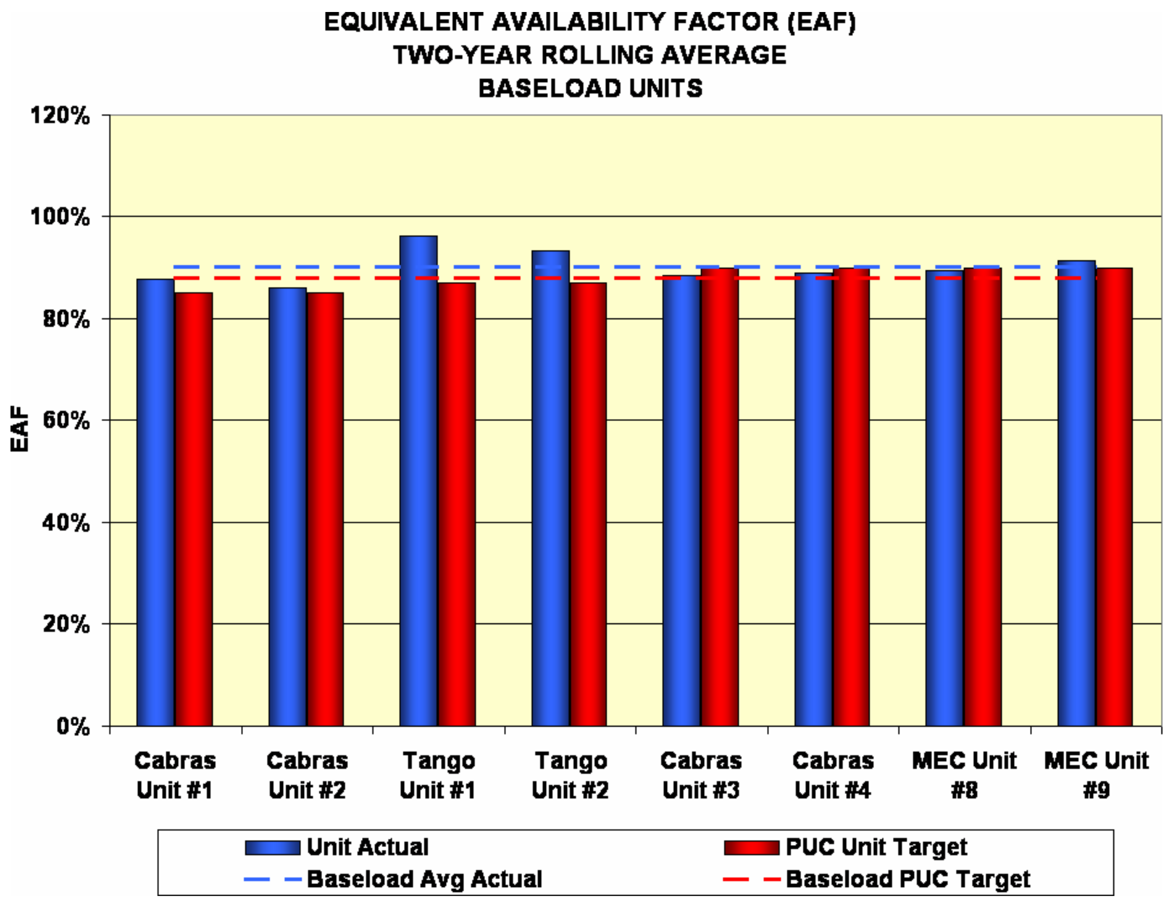



Figure 5, Two-Year Rolling Equivalent Availability Factor (EAF) for Baseload Units

# APPENDIX A: PLANT TECHNOLOGY SUMMARIES

Cabras #1 & #2 - Steam Units

This plant produces electricity for the power requirements on the island of Guam. The plant consists of two (2) 66 megawatt steam turbine generator units. The units are supplied by two (2) watertube, drum type, reheat boilers each capable of supplying 450,000 lbs/hr of superheated steam to the turbines. Each boiler supplies its own turbine/generator (Boiler 1 supplies T/G 1 and Boiler 2 supplies T/G 2). Both units are operated in base load service.

| | |
|---|---|
| BOILERS: | B&W; 450,000 lbs/hr; 2225 psi; 1005 º F; B.H.S. 10257 sq.ft; 550 psi (reheat); 1002º F; pressurized furnace; #6 residual fuel oil (RFO) and waste oil; built 1973- Unit #1 and 1974- Unit #2 |
| TURBINES: | GE; 66000 kW; 3600 RPM; 22 stages; 1800 psi; 1000 º F/ 1000 º F; exhaust 2.5" Hg absolute |
| GENERATORS: | GE; 77647 KVA; 0.85 pf; 13,800 volts; 3249 amps; hydrogen cooled; built 1973 - Unit #1 and 1974 - Unit #2 |
| TRANSFORMERS: | |
| Main (2): | Toshiba; 80000 KVA; class OA/FA; 13.2 kV/115 kV |
| Auxiliary (2): | Toshiba; 5000/7000 KVA; class OA/FA; 13.8 kV/4160 volts |
| Start-Up (1): | Toshiba; 5000/7000 KVA; class OA/FA; 13.8 kV/4160 volts |
| BOILER FEED PUMPS: | Ebara Byron Jackson; 12 stage HDB; horizontal barrel type; 1174 gpm; 2400 psig; GE; 2200 HP; 4000 volts; 3750 RPM |

Heat transfer media: Main steam (superheated) is supplied by the boilers to each unit. Each boiler operates at 1850-1900 psig. The boilers supply superheated and reheat steam at 1000º F to the turbines. Main steam enters the HP/IP turbine via the Main Stop Valves (MSV) and Control Valves (CV). Reheat steam enters the intermediate pressure (IP) section of the turbine via the Reheat Stop Valves (RHSV) and Intercept Valves (IV). The steam travels through the turbine and exhausts at low pressure and temperature into the condenser.

There are several steam extractions for the feedwater heaters (HP & IP) and gland seal steam.

An auxiliary steam line supplies steam to the DA tank and fuel atomizing system.

Seawater is used as the cooling medium in the main condensers of Cabras Units 1 & 2. It is al the jacket (engine) cooling medium for Cabras Units 3 & 4.

Each unit has one deaerator (DA); 2 forced draft (FD) fans; drum, superheater and reheat safety valves; and two high drum level alarms.

Electricity: The generators produce electricity at 13,800 volts. The voltage is then stepped up to 115,000 volts (115 kV) in the main transformers (2- 80 MVA and 2 - 50 MVA) for transmission and distribution.

The units' auxiliary transformers (5/7) MVA step the voltage down from 13,800 volts to 4160 volts for use in the plant

DC power for the Emergency Bearing Oil Pump (EBOP), critical relays and control equipment, and some station power is supplied by a bank of lead-acid batteries.

A station start-up transformer (5/7 MVA) supplies electric power to the plant when either one or both units are off line.

The largest motors in the plant are four (4) 2200 HP motors driving the boiler feed pumps (BFP). Each unit has two BFPs. Each BFP is capable of supplying 100 percent of its oiler's feedwater requirements at full load (450,000 lbs/hr)

Water and water treatment: Feedwater for the boilers is softened, passed through a cation/anion demineralizer system, then chemically treated to maintain the proper pH and oxygen levels for the boilers and condensers using a sulfite treatment.

Deionized water for the diesels (for NOX emissions control) is obtained by passing seawater through a desalination unit and a demineralizer system. The deionized water is then mixed with the fuel (#6 RFO) and stored in a storage tank for use in the engines.

Gas/fuel: Both boilers burn #6 RFO and waste oil (primarily used lube oil) from the diesels. Uses no. 2 diesel fuel for startup.

Cabras #3 & #4 - Slow Speed Diesel Units

This plant consists of two (2) 40 megawatt slow speed diesel engine generator units. This plant is used for baseload operations.

DIESELS: Hanjung-Man B&W; slow speed; type K80MC-S; 12 cylinder; in-line; 2 cycle; 55060 BHP; 102.9 RPM; fuel #6 RFO; built 1995

GENERATORS: ABB, SA; type W.950/95/70; 49280 KVA; 0.8 pf; 102.9 RPM; 13.8 kV; 2062 amps; 3 phase wye; 70 poles; air cooled

TRANSFORMERS:

Main (2): GE; 37.5/50 MVA; class OA/FA; 65 º C; 13.8 kV

Auxiliary (2): GE; 5000/6250 KVA; class OA/FA; 65º C; 13.8 kV/4760 volts
Uses no. 2 diesel fuel for startup. Primary fuel is residual fuel oil.

Tanguisson #1 & #2 - Steam Units

This plant produces electricity for the power requirements on the island of Guam. The plant consists of two (2) 26 megawatt steam turbine generator units. The units are supplied by two (2) watertube, drum type, reheat boilers each capable of supplying 247,000 lbs/hr of superheated steam to the turbines. Each boiler supplies its own turbine/generator (Boiler 1 supplies T/G 1 and Boiler 2 supplies T/G 2). Both units are operated in base load service.

BOILERS: CE; 247,000 lbs/hr; 1040 PSI - Unit 1 (1150 psi - Unit 2); B.H.S. 13730 sq. ft; WWHS 4400 sq. ft; #6 residual fuel oil (RFO)

TURBINES: GE; 26500 kW; 3600 RPM; 15 stages; 850 psig; 900 psi;exhaust 2.5" Hg absolute

GENERATORS: GE; 29412 KVA; 0.90 pf; 13,800 volts; 1179 amps; hydrogen cooled

TRANSFORMERS:
Main (2): GE; 30000 KVA; class OA/FA/FOA; 13.8 kv-delta/34.4 kV-wye;

Reserve Auxiliary: (1) Ward Transformer

Uses no. 2 diesel fuel for startup. Primary fuel is residual fuel oil.

Dededo Combustion Turbine #1 & #2

This plant consists of two (2) General Electric Frame 5 machines. Combustion Turbine No. 1 (CT1) is a Model MS 5001 PA (advanced version) rated at 23 megawatts. Combustion Turbine No. 2 (CT2) is a Model MS 5001 P (standard version) rated at 22 megawatts. The units are used for peaking and emergency operations.

| | |
|---|---|
| COMBUSTION TURBINES: | GE; Model MS5001PA (CT1) and MS5001P (CT 2); single shaft; 5100 RPM (turbine); 25,000 kW; #2 fuel (diesel ) oil. |
| GENERATORS: | GEC Ahlstom; 26,200 KVA; 3600 rpm; 13.8 kV; air cooled; rated outputs - 23 MW (CT1), 22 MW (CT2) |
| TRANSFORMERS | Magnatek; 18.24.30 MVA; class OA/FA/FA; 13.8 kV/34.5 kV Grd-Main (2) Y/ 19920 volts |

Heat Transfer Media: Air from the units' compressor section acts both as a cooling medium for the combustion cans and as the hot gas for the power turbine.

Electricity: The units' generators both produce electricity at 13,800 volts. The voltage is stepped up to 34,500 volts (34.5 kV) in main transformers (30 MVA maximum rating) for transmission and distribution.

Water and water treatment: Deionized water is used to control NOX emissions from the turbines. Water is passed through a system of softeners, cation/anion exchangers, and reverse osmosis (RO) equipment. The deionized water is stored in a tank for injection into the turbine during operation.

Gas/fuel: The diesels burn #2 diesel oil.

Dededo Diesels #1, #2, #3, & #4

The plant consists of four (4) General Motors -EMD diesel engine generators. Each diesel generator is rated at 2.5 megawatts. The plant's total generating capacity is 10 megawatts. The units are used for peaking and emergency service.

| | |
|---|---|
| DIESEL ENGINES: | GM-EMD; Model GM-20-645-E4; 3600 HP; 20 cylinder; V-type; turbo-charged; 900 RPM; #2 fuel (diesel ) oil. |
| GENERATORS: | GM-EMD; Model A20-C1; 3250 KVA; 0.8 pf; rated output 2.5 MW; 4160 volts; air cooled |
| TRANSFORMERS: | |
| Main (2): | Takaoka Electric (Brown-Boveri licensed); 5/7 MVA; class OA/FA; 4160 V/13.8 kV/23.9 kV |

Heat Transfer Media: An ethylene glycol and water mixture is used as the engine coolant (jacket water). Each engine is connected to a two cell cooling tower. The number of cells in operation depends on engine temperature. The engines can operate with just one fan in operation at a slightly reduced load (2.2 MW).

Electricity: The unit generators produce electricity at 4160 volts. The voltage is stepped up to 24,000 volts (24 kv) in the main transformers (7 MVA each) for transmission and distribution.

A small in-plant transformer supplies the plant's electrical requirements. It is air cooled.

Compressed Air: Compressed air is used to start the diesel engines. It is supplied by a small reciprocating compressor and stored in accumulation tanks at 200 psig.

Gas/fuel: The diesels burn #2 diesel oil.

Macheche & Yigo Combustion Turbine Plants

Each plant consists of one (1) General Electric LM2500 combustion turbine generator unit. The LM2500 is an aero derivative type combustion turbine. Each unit is rated at 22 megawatts. These units are used for peaking and emergency operations.

| | |
|---|---|
| COMBUSTION TURBINES: | GE; Model 7LM2500-PC-MD619; 3600 RPM (power turbine); two shaft; 16 stage compressor; 8 stage power turbine; 25,000 kw; #2 diesel fuel |
| GENERATORS: | Brush Electric; Model BDX7-167E; 3600 RPM; 13,800 volts; 25,000 kw; type HC/OP/OPLTR; class OA/FA/FA; 18/24/30 MVA; 13.8 .90 pf; air cooled; (rated output 22 MW) |
| TRANSFORMERS | Tatung; type HC/OP/OPLT; class OA/FA/FA; 13.8 kV (Yigo) kv/34.5 kV; no load tap changer |

Heat Transfer Media: Air from the units' compressor section acts both as a cooling medium for the combustion cans and as the hot gas for the power turbine.

Electricity: The units' generators both produce electricity at 13,800 volts. The voltage Is stepped up to 34,500 volts (34.5 kV) in main transformers (25 MVA and 30 MVA maximum rating) for transmission and distribution.

Water and water treatment: Deionized water is used to control NOX emissions from the turbines. Water is passed through a system of softeners, cation/anion exchangers, and reverse osmosis (RO) equipment. The deionized water is stored in a tank for injection into the turbine during operation.

Gas/fuel: The diesels burn #2 diesel oil.

Manenggon Diesel #1 & #2

The plant consists of two (2) Wartsila-ABB diesel engine generators. Each diesel generator is rated at 5.0 megawatts. The plant's total generating capacity is 10 megawatts. The units are used for peaking and emergency service.

| | |
|---|---|
| DIESEL ENGINES: | Wartsila; Model 16V32; 5522 kW; V-type; turbo charged; 720 RPM; #2 fuel (diesel ) oil. |
| GENERATORS: | ABB Stromberg; type HSG 900 LS10; 7250 KVA; 13.8 kV; 303 amps; air cooled. |
| TRANSFORMERS: | Tatung; OA/FA/FA; 18/24/30 MVA; 3.8 kV |

Heat Transfer Media: An ethylene glycol and water mixture is used as the engine coolant (jacket water). Each engine is connected to a six cell cooling tower. The number of cells in operation depends on engine temperature. Both units can operate at full load with only five (5) cells in operation.

Electricity: The unit generators produce electricity at 13,800 volts. The voltage is stepped up to 34,500 volts (34.5 kV) in the main step-up transformers (30 MVA each) for transmission and distribution.

A small in-plant transformer supplies the plant's electrical requirements.

Compressed Air: Compressed air is used to start the diesel engines. It is supplied by a small reciprocating compressor and stored in accumulation tank.

Gas/fuel: The diesels burn #2 diesel oil.

Marbo Combustion Turbine Plant

This plant consists of one (1) Fiat TG 16 combustion turbine generator unit. This engine is an aero derivative type combustion turbine. This unit is rated at 16 megawatts. These units are used for peaking and emergency operations.

| | |
|---|---|
| COMBUSTION TURBINES: | Fiat Avio-S.P.A.; 4914 RPM; 15 stage compressor; 5 stage power turbine; single shaft. |
| GENERATORS: | 1800 RPM; 19,000 KVA; 13.8 kV; 794.9 amps; 0.8 pf; air cooled. |
| TRANSFORMERS | Niagara; 12/16/20 MVA; class OA/FA/FOA; 13.8 kV; 34.5 kV |

Heat Transfer Media: Air from the units' compressor section acts both as a cooling medium for the combustion cans and as the hot gas for the power turbine.

Electricity: The units' generators both produce electricity at 13,800 volts. The voltage Is stepped up to 34,500 volts (34.5 kV) in main transformers (20 MVA maximum rating) for transmission and distribution.

Water and water treatment: Deionized water is used to control NOX emissions from the turbines. Water is passed through a system of softeners, cation/anion exchangers, and reverse osmosis (RO) equipment. The deionized water is stored in a tank for injection into the turbine during operation.

Gas/fuel: The diesels burn #2 diesel oil.

Tenjo Vista & Talofofo Diesel Plants

The Tenjo plant consists of six (6) Caterpilar -Kato diesel engine generators (two units are currently being overhauled). The Talofofo plant consists of two (2) Caterpillar-Kato diesel engine generators. Each unit is rated at 4.88 megawatts each. The units are used for peaking and emergency service.

| | |
|---|---|
| DIESEL ENGINES: | Catepillar; Model 3616; 6095 HP; 16 cylinder; V-type; turbo-charged; 900 RPM; #2 fuel (diesel ) oil. |
| GENERATORS: | Kato: Mod A256730000; 4880 kW; 6100 KVA; 0.8 pf; 13.8 kV; 255 amps; air cooled. |
| TRANSFORMERS: | |
| Talofofo | Westinghouse; 10/12.5 MVA; class OA/FA; load tap changer; 13.8 kV/34.4 kV; type SL |

Heat Transfer Media: An ethylene glycol and water mixture is used as the engine coolant (jacket water).

Talofofo - Each engine is connected to a four cell cooling tower. All four cells are required for full load operation.

Electricity:

Talofofo - The unit generators produce electricity at 13,800 volts. The voltage is stepped up to 34,500 volts (34.5 kv) in the main step-up transformers for transmission and distribution.

Compressed Air: Compressed air is used to start the diesel engines. It is supplied by a small reciprocating compressor and stored in accumulation tank.

Gas/fuel: The diesels burn #2 diesel oil.

# APPENDIX B: GUAM SEA WATER AIR CONDITIONING – EXECUTIVE SUMMARY

## EXECUTIVE SUMMARY

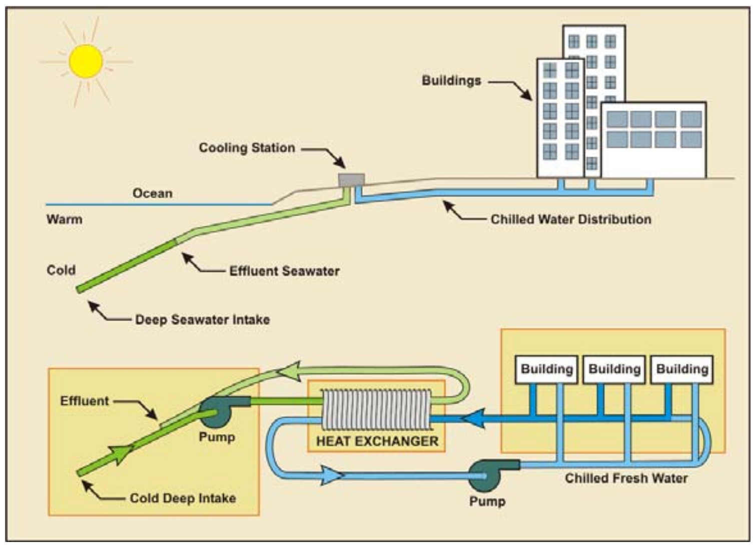
### 1.1 PURPOSE OF THIS STUDY

This document reports the results of a technical and economic assessment of the potential for using deep cold seawater to air condition hotels and other buildings at Tumon Bay, Guam. The purpose of the work is to determine whether or not there is technical and economic merit to proceed with implementing this system in Guam.

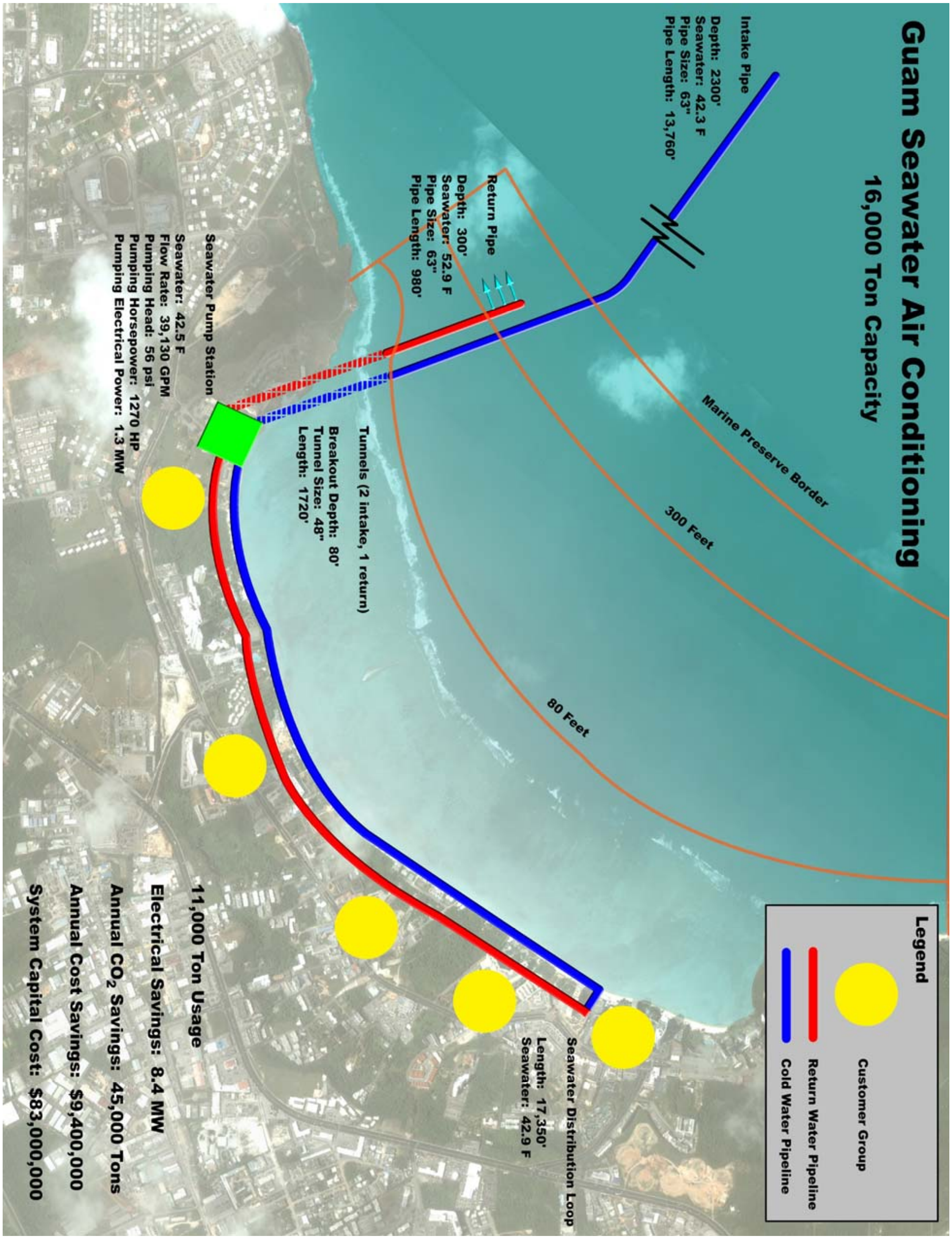
In this study, Makai and Market Street Energy have analyzed and sized the major components of the Guam Seawater Air Conditioning (GSWAC) system, determined the operational performance, estimated the probable costs and identified the economic and business advantages of the GSWAC system. The team has also defined the opportunities, risks and potential problems associated with such a cold water system for Tumon Bay.

### 1.2 BRIEF EXPLANATION OF GSWAC – HOW IT WORKS

The hotels along Tumon Bay are presently cooled with electric-powered refrigeration systems, or chillers, that cool chilled water which is circulated throughout the building. Seawater air conditioning is a means of bypassing the conventional chiller and using deep seawater and a heat exchanger to directly cool the building's chilled water. A schematic of a basic SWAC system is shown on the right.




For Tumon Bay, GSWAC would use a deep seawater intake pipeline going three miles offshore to a depth of 2200' and bringing 42.5º F seawater ashore. This water passes through a heat exchanger and chills a fresh water loop that is delivered to the customers. Each customer is provided cold fresh water at 44º F, the same as within most Tumon Hotels. Operation of the AC system within the hotel is unchanged. The next page shows the general features of the Guam SWAC system.


Guam Seawater Air Conditioning
16,000 Ton Capacity
Intake Pipe
Depth: 2300'
Seawater: 42.3 F
Pipe Size: 63"
Pipe Length: 13,760'
Return Pipe
Depth: 300'
Seawater: 52.9 F
Pipe Size: 63"
Pipe Length: 980'
Marine Preserve Border
300 Feet
80 Feet
Tunnels (2 intake, 1 return)
Breakout Depth: 80'
Tunnel Size: 48"
Length: 1720'
Seawater Pump Station
Seawater: 42.5 F
Flow Rate: 39,130 GPM
Pumping Head: 56 psi
Pumping Horsepower: 1270 HP
Pumping Electrical Power: 1.3 MW
Seawater Distribution Loop
Length: 17,350'
Seawater: 42.9 F
Legend
Customer Group
Return Water Pipeline
Cold Water Pipeline
11,000 Ton Usage
Electrical Savings: 8.4 MW
Annual CO2 Savings: 45,000 Tons
Annual Cost Savings: $9,400,000
System Capital Cost: $83,000,000

Cold seawater is drawn from 2300 feet deep at a temperature of 42.5 deg F. It follows a long pipeline that lies along the seabed, represented by the long blue line pointed out to sea. About 1700 feet from shore, the pipeline connects to a pair of underground tunnels, represented by the dashed blue line. The tunnels carry the water under the reef, across the shoreline, and into a pump station located near the Hilton, represented by the green square.

A pair of 600 hp pumps pushes the water into a cold water distribution pipe buried under the beach, represented by the blue line running along shore. The distribution pipeline has smaller branches that run to heat exchangers servicing the hotels along Tumon Bay. The yellow circles represent groups of hotels that may share a single large heat exchanger or single hotels that use a smaller individual heat exchanger. The heat exchangers allow the cold seawater to cool the hotels' chilled water to 44 deg F or cooler without contaminating it. Exiting the heat exchangers at about 54 deg F, seawater flows into a return water distribution pipeline, represented by the red line running along the shore, buried parallel to the cold water pipeline.

The warmed seawater follows the return distribution pipeline back to the pump station where it enters another tunnel, represented by the dashed red line, which carries it back under the reef. The tunnel takes the water to a return pipeline, represented by the red line pointing out to sea. At the end of the return pipeline, at a depth of 300 feet, the water is returned to the ocean via a 300 foot long diffuser. The diffuser serves to mix the return water with ambient seawater to minimize any environmental impacts.

Seawater air conditioning is particularly attractive on Guam because of the ease of access to the deep water, the concentration and quantity of AC users, the high utilization of AC on Guam, and the relatively high cost of electricity and water.

## 1.3 SUMMARY OF BENEFITS FOR USERS, OWNERS, GUAM

The GSWAC system can provide meaningful energy to a portion of Guam using a sustainable, non-polluting natural energy source. Among the benefits of this system are:

Energy Savings: By using the deep ocean for cooling, approximately 8 to 12 MW of power are conserved and the associated electrical power pollution will be reduced. The GSWAC system uses 1/6 the power of conventional AC chilling.

A Natural Resource: Guam's major natural energy resource is the thermal resource in the ocean. Guam has excellent access to this resource. GSWAC is an important step toward the expanded development of this resource in the future.

Economically Viable: GSWAC makes economic sense; it is an environmentally friendly and sustainable alternate energy that is financially attractive.

Environmentally Responsible: Guam's natural resource is readily available; it is environmentally responsible to use this renewable resource.

Environmentally Friendly: GSWAC conserves fossil fuels and reduces air and heat emissions. If properly designed, its local environmental impact during construction will be minimal.

Financial Independence: A locally available energy resource is substituted for energy from imported oil.

Greater Independence from Energy Price Escalation: In a world of rapidly increasing energy prices, GSWAC costs (which are capital dominated) are relatively flat compared to that of energy intensive conventional AC systems. Users will have a known and relatively flat future AC cost.

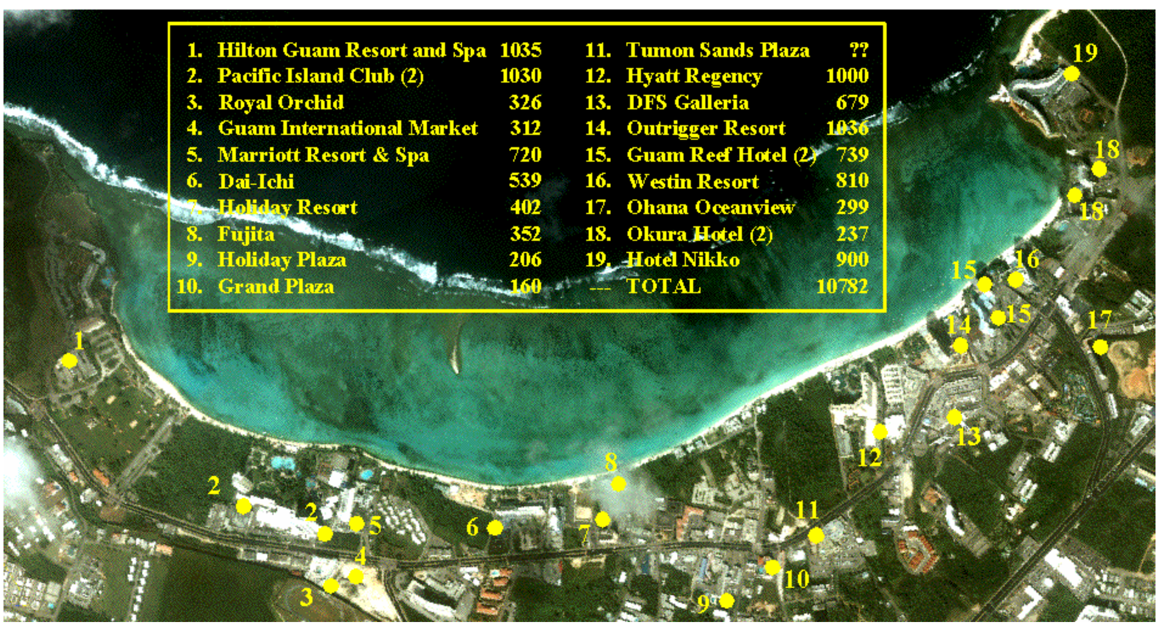
No Water Consumption by Cooling Towers: A significant cost of conventional AC is the consumption of fresh water by evaporative condensing units; GSWAC does not consume of fresh water.

Secondary Applications: Cold seawater is available for secondary applications such as production of healthy drinking water.

Proven Technology: Similar systems have been used at other locations; the technology is simple.

## 1.4 AC DEMAND

The likely customers for seawater AC are the large hotels near the beach or San Vitores Road in Tumon Bay. This study identified 19 potential users who currently have a total peak cooling demand of nearly 11,000 tons of refrigeration. The annual average AC load for these users is high due to the nature of their business (hotels) and the uniformly warm temperature and high humidity on Guam; the utilization factor is at least 70%, with an average demand of 7,700 tons.




## 1.5 GSWAC SCENARIOS ANALYZED

The team analyzed five GSWAC configurations for Tumon Bay. The baseline system is termed Scenario I. Primary variables considered within the four other scenarios involved changes to the onshore pipe routing, ocean pipe path, and the total size of the system. More specifically, the following designs were considered:

Onshore Distribution Loop along San Vitores Road or Along the Beach: Seawater distribution systems along the beach and fresh water distributions at higher elevations were modeled.

Offshore Pipe Route and Shoreline Landing: At the southwest end of the Tumon Bay shoreline near the Hilton (Route A), and in the middle of Tumon Bay (Route B)

Overall size: 16,000 tons and 11,000 tons.

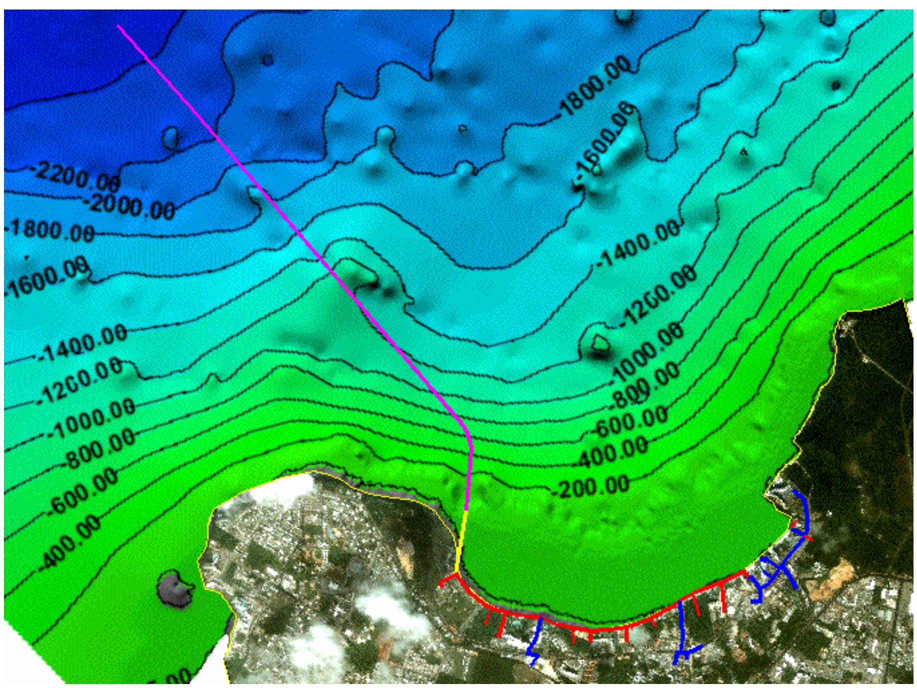
The following table summarizes these five scenarios.

**GSWAC Scenarios:**

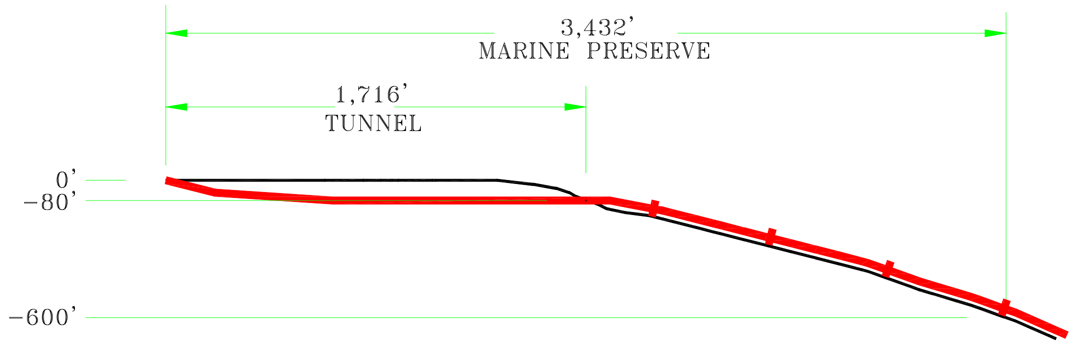
| | I | II | III | IV | V | |
|---|---|---|---|---|---|---|
| Max AC Load | 16,000 | 16,000 | 16,000 | 16,000 | 11,000 | Tons |
| Initial Load | 11,000 | 11,000 | 11,000 | 11,000 | 11000 | |
| User supply Temperature | 44 | 44 | 44 | 44 | 44 | Deg F. |
| Seawater Supply | Route A | Route B | Route A | Route B | Route A | |
| Seawater Distribution | yes | yes | no | no | yes | |
| Fresh Chilled water Distributi | 3 | 3 | 1 | 2 | 3 | number |
| Pump Location | Hilton end | Mid Bay | Hilton End | Mid Bay | Hilton end | |
| Main Distribution | Beach | Beach | San Vitores | San Vitores | Beach | |

## 1.6 GSWAC COMPONENTS, SCENARIO I

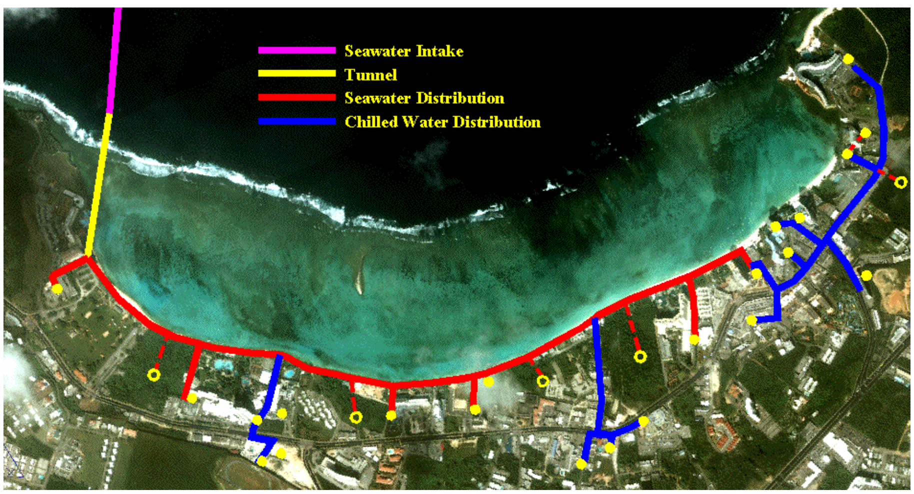
The overall layout of the piping for Scenario I is shown below. The deep water pipeline is a 63” diameter polyethylene pipe that is three miles long and brings in 42º F water from 2300’ depth. The pipeline lays on the seafloor.




The shoreline pipe crossing is tunneled below the reef to both protect the shoreline from construction damage and to protect the pipe from severe storms. The pipeline crosses the Tumon Bay Marine Preserve in this region, and the 1700’ long tunnel goes below the shallow portion of the preserve. The tunnel terminates at a seawater pump station located at the Hilton end of the beach. The pump station should include backup generators capable of maintaining the system at 2/3 of full capacity.

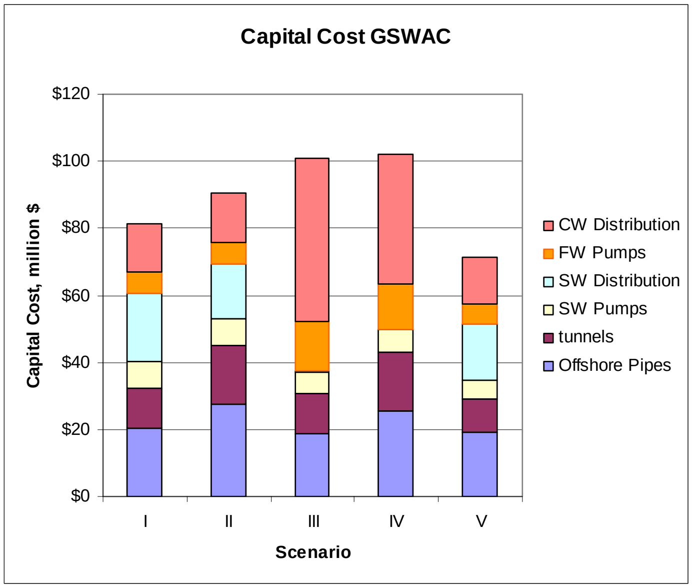



The more detailed view of the distribution system is shown below. The red line is a seawater distribution system buried below the beach. Several users are cooled through single-user heat exchangers along this route. Three chilled fresh water loops, cooled by a single heat exchanger, feed larger groups of clustered users. All users are provided with chilled fresh water that is colder than 44º F.




## 1.7 TOTAL SYSTEM COSTS

The total construction cost of each of the five scenarios was estimated. Capital costs range from $73 million for Scenario V to slightly over $100 million for Scenario IV as shown below. Scenarios III and IV costs are high because of the high cost of the San Vitores Road pipe installation. Scenarios II and IV have higher offshore costs associated with longer pipes and tunnels needed to land the offshore pipes at the middle of the bay. Overall, Scenario I is the most financially attractive of the four 16,000 ton systems. Scenario V is a smaller, 11,000 ton version of Scenario I that has the lowest cost.

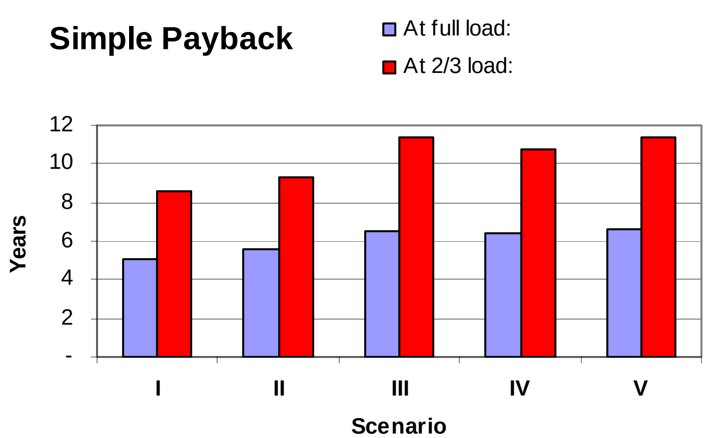



## 1.8 ECONOMIC FEASIBILITY ANALYSIS

The economic merit of the GSWAC was evaluated by using simple payback, a levelized cost comparison with conventional AC, and finally, a brief business plan was prepared for the most attractive GSWAC scenario.

### 1.8.1. Simple Payback

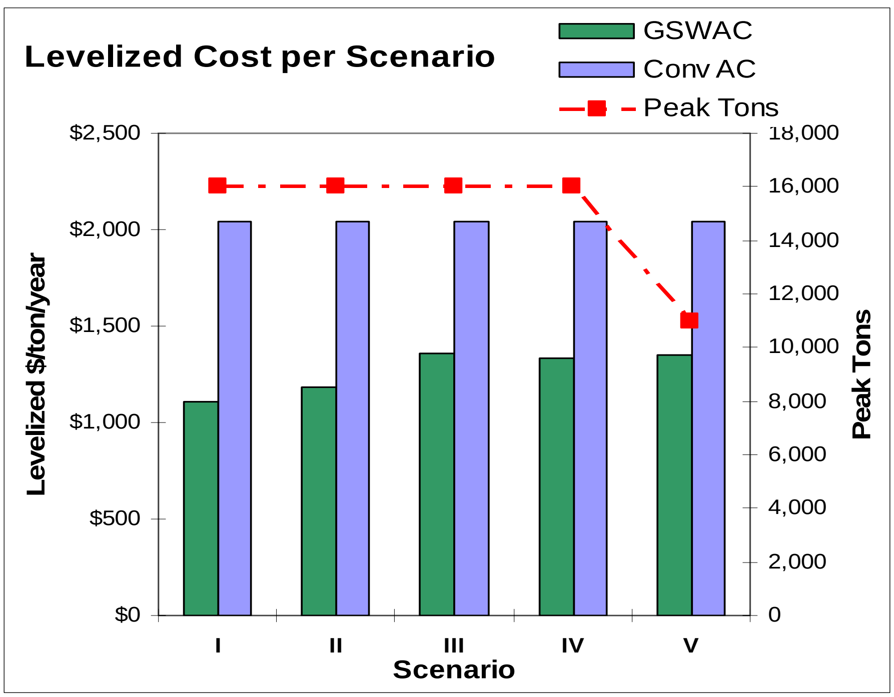
Simple payback was computed for the five scenarios based on the capital costs given above and net revenue. When fully loaded, the simple payback is between 5.1 and 6.7 years. If the system is partially loaded at only 2/3 capacity, the simple payback is between 8.5 and 11.4 years. Scenario I is the most financially attractive. The actual payback period is likely to be somewhere between these two ranges as the system starts out partially loaded and will expand its capacity over time. It should be noted that full load for Scenario V represents 11,000 tons, which is comparable to the other four scenarios' 2/3 load. Therefore, Scenario V has a shorter simple payback period for an 11,000 ton load than any other scenario.



### 1.8.2. Levelized Cost Comparison

A more rigorous financial comparison was performed between the five GSWAC scenarios and the conventional AC systems currently used at Tumon Bay. A Guam SWAC system will have a large capital cost and low operating costs. Conventional AC systems are already installed and have no installation cost but high operating and replacement costs. Considering a financing rate of 8% for payments during the 20-year book life of the system, Scenario I yields a 45% cost saving compared to conventional air conditioning.

The graph below shows the levelized cost difference between conventional AC and each of the five scenarios at full load. This analysis shows that GSWAC has a levelized cost ranging from $1,100/ton/year to $1,300/ton/year and conventional air conditioning's levelized cost is $2,020/ton/year. The wide difference between these costs suggests that GSWAC presents a viable business opportunity. Scenario I shows the widest gap between GSWAC and Conventional AC and is therefore the most financially attractive system if fully loaded. However, all GSWAC scenarios cost less than conventional AC at full load.




### 1.8.3. Business plan

An example conservative business plan was constructed using Scenario I. As opposed to the parametric analysis methods used in the bulk of this report, the business plan calculations focused on a cash flow analysis which yielded slightly different values. The following is a summary of the assumptions and results of the business model.

In addition to the $83 million in construction costs, the business plan allows for $15 million for incidental project initiation costs. Thus, the total cost to begin service is $98 million. It was assumed that 80% of this cost is financed with 6% bonds, and that GPA (or others) invests the remaining 20% with a minimum expected return of 10%.

In order to determine the current value of air conditioning, the avoided cost of using conventional air conditioning was determined. Included in the calculation is the conservative assumption that crude oil costs $50/barrel, which is 83% of the current value of $60/barrel. Given this assumption, the avoided cost of air conditioning is $0.202/ton-hr.

The business model showed that a minimum of 9000 tons of peak customer load is needed for the project to meet its financing commitments. It is conservatively assumed that only 9000 tons of peak AC is provided for the first 20 years; this is 9000 tons out of a total system has a capacity of 16,000 tons.

With this customer base, the project's first year revenue is $10.9 million, which approximately matches that of conventional air conditioning. However, since SWAC is less sensitive to increases in variable costs, the project's savings over conventional air conditioning increases with time. The model shows a positive cash flow for all but the first year, and yields a net savings over conventional air conditioning of $52 million.

Under this worst-case scenario, there is still a 10% return on equity. There are an additional 7000 tons of AC capacity to be sold with minimal additional cost. After 20 years when the capital loans are paid, revenue is high and expenses are very low.

A similar analysis was performed using a smaller 11,000 ton SWAC system, represented by Scenario V. The smaller system needed 8100 tons of peak customer load to meet its financing commitments.

## 1.9 ENVIRONMENTAL AND COMMUNITY ISSUES

GSWAC will be an environmentally responsible system that will reduce air pollution caused by burning fossil fuels and will cut greenhouse gas emissions. It is visually unobtrusive and uses little land, unlike other renewable technologies such as wind power or solar panels. However, the recently designated Tumon Bay Marine Preserve presents a regulatory challenge because the necessary GSWAC system pipelines will cross the Preserve; this will likely be a sensitive community issue.

To minimize impact on the preserve, the pipelines could be located along the southern side of the preserve, the pipelines would be tunneled below the more delicate coral regions, and the return seawater would be released deeper than 300' as suggested by Guam EPA representatives.

On land, the cold seawater is distributed via buried pipelines. Building the distribution pipelines will create some temporary disturbance. Three scenarios route the distribution pipes under the landward edge of the beach, which is within the Marine Preserve. An alternate, more expensive, route along San Vitores Road avoids the beach. More feedback is needed from the community on these potential routes.

## 1.10 OTHER WATER USES

Deep ocean seawater has potential applications other than air conditioning. Cold seawater applications include: improved power plant or cooling system efficiency, aquaculture, agriculture, desalination, health (drinking and bathing), and electrical power production. These side benefits of deep seawater have not been included in the economic assessment of a SWAC system.

The direct desalination of deep seawater for premium health-food drinking water has been rapidly expanding in Northeast Asia. Guam would have a ready market for its bottled water given its close proximity to Japanese and Taiwanese markets.

Cost estimates for deep water power plant cooling at Cabras and Tanguisson have been provided for further analysis by GPA.

Also, analysis has been presented for Ocean Thermal Energy Conversion (OTEC) and desalination at Cabras. OTEC and desalination are not cost effective today, but may be important to Guam in the future.

## 1.11 CONCLUSIONS

- GSWAC is a technically feasible means of providing up to 16,000 tons of air conditioning to the Tumon Bay area.
- GSWAC is financially feasible for loads that exceed 8100 tons of cooling. Simple payback periods are in the range of 5 to 8.5 years depending upon initial loading.
- Makai has performed similar SWAC studies at other locations in the Pacific Ocean and the Caribbean Sea. Comparison with these earlier studies indicates that Guam has a uniquely high potential for energy savings and profitability.
- 44 deg F chilled water can be provided to users without auxiliary chillers. If water below 44 deg F is required, auxiliary chillers would be more cost-effective.
- At full load, all five scenarios are cost-competitive with conventional air conditioning. Scenario V is the most cost-effective scenario to meet existing load. Scenario I is the most cost-effective scenario to meet the near-future expected load.
- A distribution system along San Vitores Boulevard is more costly than one along the beach.
- Energy usage would be reduced by 8.4 MW, and $CO_2$ emissions would be reduced by 45,000 tons per year.
- Potable water usage would be reduced by 184 million gallons per year.
- SWAC is a renewable and sustainable energy technology.
- All five scenarios involve construction within the Tumon Bay Marine Preserve.

## 1.12 RECOMMENDATIONS

- If GPA expects a final system load between 8000 tons and 11000 tons, Scenario V is recommended.
- If GPA expects a final system load between 13,500 tons and 16,000 tons, Scenario I is recommended.
- Based on this feasibility study, a GSWAC project should be conducted.
- GPA should hire a multi-disciplinary team to perform a conceptual design. In addition to Makai and Market Street, this team should consist of a civil engineer,

geotechnical engineer and electrical engineer, an architect and a firm specializing in environmental permitting.

# APPENDIX C: UNSOLICITED PROPOSALS FOR ELECTRIC POWER SUPPLY

The Authority has received many visits from Energy Providers. These include:

- Marianas Energy Company
- Osaka Gas
- Wartsila
- NAANOVO
- Marubeni
- h2ondemand
- OCEES
- International Group, Inc

# APPENDIX D: POTENTIAL SUPPLY-SIDE AND RENEWABLE GENERATION OPTIONS – R. W. BECK REPORT

October 17, 2006

Mr. John J. Cruz, Jr.
Manager, SPORD
Guam Power Authority
P.O. Box 2977
Hagatna, Guam 96932

Subject: **Guam Power Authority, Integrated Resource Plan – Development of Generation Resource Option Characteristics**

Dear Mr. Cruz:

R. W. Beck, Inc., working as a subconsultant to Winzler & Kelly, has been retained by Guam Power Authority (GPA) to characterize generation resource options for use as inputs to the GPA integrated resource plan (IRP) pursuant to Purchase Order No. 11033, dated July 12, 2006. This letter report summarizes the generation resource option characteristics and provides some general discussion on the options as well.

## Background

GPA is a government of Guam public corporation established in 1968, which is governed by the Consolidated Commission on Utilities (CCU). GPA, including its nearly 600 employees, is responsible for providing power to some 45,000 customers on the 210-square-mile island that is the United States territory of Guam. GPA serves the approximately 300-megawatt (MW) peak electric load with approximately 550 MW of installed generation capacity. The currently installed generation resources consist of 28 separate units ranging in capacity from 2.5 MW to 66 MW. The baseload units fire on residual fuel oil (RFO) (No. 6) while all other resources fire on diesel oil (No. 2). The generation resources currently available to serve load are described in more detail in Table 1 below. We note GPA is also responsible for over 650 miles of transmission and distribution assets and nearly 30 substations.

GPA currently has sufficient generation resources and reserve capacity to adequately serve its load. However, the current consumption level and volatility of oil prices have substantially increased the cost of generation to serve GPA's load. In addition, from a strategic standpoint, GPA has identified fuel diversity and environmental leadership as important factors in future generation additions or refurbishments. Therefore, through a coordinated effort, GPA and R. W. Beck identified several potential generation resource options to diversify the fuel mix of the GPA generation assets. Each of the options has the potential to lower system production costs (some pending negotiated fuel prices) and displace generation from higher cost units. The remainder of this letter report describes the costs, performance, emissions, general siting issues and other factors related to the six potential generation resource options selected for use by GPA in its IRP process.



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Table 1
Summary of Existing GPA Generation Resources

| Unit | Technology | Fuel | Capacity, MW | Service Date |
|---|---|---|---|---|
| Cabras 1 | Steam Turbine (ST) | RFO No. 6 | 66 | 1974 |
| Cabras 2 | ST | RFO No. 6 | 66 | 1975 |
| Cabras 3 | Slow Speed Diesel (SSD) | RFO No. 6 | 40 | 1996 |
| Cabras 4 | SSD | RFO No. 6 | 40 | 1996 |
| Piti 8 (MEC) | SSD | RFO No. 6 | 44 | 1999 |
| Piti 9 (MEC) | SSD | RFO No. 6 | 44 | 1999 |
| Tanguisson 1 (PRU) | ST | RFO No. 6 | 26.5 | 1976 |
| Tanguisson 2 (PRU) | ST | RFO No. 6 | 26.5 | 1976 |
| Dededo CT 1 | Combustion Turbine (CT) | Diesel No. 2 | 23 | 1992 |
| Dededo CT 2 | CT | Diesel No. 2 | 23 | 1994 |
| Machche CT | CT | Diesel No. 2 | 21 | 1993 |
| Marbo CT | CT | Diesel No. 2 | 16 | 1993 |
| Yigo CT | CT | Diesel No. 2 | 21 | 1993 |
| Piti 7 (TEM) | CT | Diesel No. 2 | 40 | 1997 |
| Dededo Diesel 1-4 | Medium Speed Diesel (MSD) | Diesel No. 2 | 2.5 ea/10 total | 1972 |
| Talofofo Diesel 1 and 2 | MSD | Diesel No. 2 | 5 ea/10 total | 1994 |
| Paluntat Diesel 1 and 2 | MSD | Diesel No. 2 | 4.4 ea/8.8 total | 1993 |
| Tenjo Diesel 1-6 | MSD | Diesel No. 2 | 4.4 ea/26.4 total | 1994 |

## Resource Options

The generation resource options selected for consideration by R. W. Beck include the following:

- Option 1 – Small Coal-Fueled Power Plant
- Option 2 – Small Combined-Cycle Power Plant With a Liquefied Natural Gas (LNG) Facility
- Option 3 – Wind Farm
- Option 4 – Repowering Piti 7 CT to a Combined-Cycle Power Plant
- Option 5 – Biomass Power Plant
- Option 6 – Reciprocating Engine Power Plant

## Resource Data and Operating Characteristics

The following information for each option is included in Attachment 1 to this letter.

- Technology
- Unit Model or Type
- Location
- Ownership Rate
- Size/Capacity
- Space Required
- Capital Cost
- Schedule
- Design Life
- Turn Down
- Baseload Heat Rate
- Outage Rates
- Primary Fuel(s)
- Fuel Characteristics
- Estimated Emissions Rates
- Start-Up Time
- Start-Up Fuel Burn
- Operating Ramp Rate
- Minimum Run Time
- Preferred Service Characteristic
- Water Consumption
- Fixed Operating and Maintenance (O&M) Costs
- Variable O&M Costs

Additionally, a short narrative has been developed and provided for each option to generally describe various market or project development related issues including the following.

- Status of technology
- Fuel price trends and availability
- Siting issues
- Operating constraints
- Heat Rate Curve
- Availability/Reliability issues
- Environmental issues
- Construction Drawdown Schedule

## Methodology and Assumptions

R. W. Beck developed the data and characteristics for the various resources utilizing our experience with other similar projects, our previous work with GPA, and our internal capital and O&M cost data bases. Various assumptions were made in development of the information provided herein. All costs are presented in 2006 dollars. Capital costs were estimated using non-union construction labor. The capital costs include a 20 percent allocation to account for owner costs associated with the development of the resource such as siting and contracting, but is not intended to include finance related costs such as bank fees or interest during construction. The O&M costs are not inclusive of emissions allowances as Guam is not currently required to participate in a cap and trade program. Further, the fixed O&M costs are inclusive of capital expenditures, but not inclusive of debt service, property taxes or insurance. The cost estimates developed are generic in nature and actual costs can be expected to be 20 percent higher or lower than presented herein, based on actual technology, fuel, siting, and timing of the resource being developed.

We have assumed that forced outage rates for a new power plant will be slightly higher in the first year of commercial operation than the long-term average. This assumption was intended to accommodate resolution of construction and O&M issues typically encountered with new facilities. The mature forced outage rates provided represent the long-term average expected for each resource.

R. W. Beck has conducted several development and siting studies for GPA over the last 10 to 20 years which have highlighted the challenges associated with developing new power generation resource options. Some of the primary challenges include siting (space and location), permitting (air and water), and fuel delivery issues. Siting on the western coast of the island is preferred; however, limited site options are available due to congestion around the existing port and near proximity to various national parks and environmentally sensitive areas. The environmental permitting process can also be constraining and will take significant time to work through. For example, certain areas of Guam are currently designated as non-attainment areas for sulfur dioxide ($SO_2$) emissions. We have assumed that the power generation resource options described herein will utilize salt water cooling towers to minimize the use of both salt water and fresh water, along with the thermal effects on coastal biology. Finally, successful development of the resources utilizing coal or LNG will take significant effort due to the need for installation of new fuel receiving facilities. We have assumed that the existing port, which has piers with depths ranging from 34 to 70 feet and lengths of 370 to 2,000 feet, will not be available to accommodate fuel deliveries because of congestion and the lack of space to site a facility near the port. Therefore, new receiving facilities will need to be developed to support the resources utilizing coal and LNG. The design of receiving facilities will vary greatly depending on the coastal topography associated with the site being developed and the source of coal or LNG. To ensure flexibility in sources and vessels utilized for supply, receiving facilities should be able to accommodate vessels with capacity of up to 150 deadweight tons, which can be up to 1,000 feet in length and require 60 feet of draft. Further investigation regarding fuel supply should be conducted to determine if the cost assumptions included herein are reasonable based on the final site and fuel supply plan.

In summary, the assumptions utilized in development of the data and characteristics of the subject resources, including siting, permitting, and fuel delivery should be considered thoroughly in the resource planning process.

# Environmental Process

## Air Emissions

A proposed major new source or a modification to an existing major source of air pollution must undergo New Source Review (NSR) prior to commencement of construction. Implementation and enforcement of the federal NSR regulations for major sources have not been delegated to Guam, but have been retained by Region IX of the United States Environmental Protection Agency (USEPA). The areas around the existing Tanguisson and Piti power plants have been designated as nonattainment areas for $SO_2$.

Permitting a new major source or a major modification in a nonattainment area can be difficult. It is likely that emission "offsets" will be required. Offsets are federally enforceable, permanent reductions in emissions that offset increases in emissions associated with the proposed project. The offsets are required as specified by the applicable regulations and may be in a ratio of 1.1:1. It is doubtful that any offsets are available in Guam at the present time.

The Governor of Guam can submit a petition to the USEPA under Section 325 of the Clean Air Act (CAA) for relief from many conditions of the CAA. USEPA issued a 325 exemption on August 2, 1993 in response to a Guam petition. That petition will allow addition of electric generating sources in the nonattainment area provided National Ambient Air Quality Standards (NAAQS) are maintained. Through ambient air monitoring studies and dispersion modeling, it is believed that the area no longer requires a "nonattainment" designation. Guam submitted a request to USEPA for redesignation of the area to "attainment." This request was submitted in 1996 and has not been acted upon by USEPA. Therefore, for the purposes of air quality permitting, the area is considered "nonattainment" with respect to $SO_2$. It may be prudent to try to resolve this nonattainment issue as it would open up significant opportunities for plant sites.

For areas where the air quality meets the NAAQS, the USEPA has promulgated regulations to prevent further "significant" deterioration of the air quality in that area. Such areas are designated as either "attainment" or unclassifiable" and the program requirements for major source construction or modification is found in 40 CFR 52.21 and is known as the Prevention of Significant Deterioration (PSD) program. The program establishes levels, or "increments," beyond which existing air quality may not deteriorate.

A PSD permit application is required to include the following:

- Best Available Control Technology (BACT) Analysis
- Air Quality Analysis
- Additional Impacts Analysis
- A Class I Area Impact Analysis

Due to the availability of the Section 325 petition for Guam, it may be that some of the PSD requirements can be avoided. However, requirements concerning ambient air, and these include PSD increments, must be fulfilled. It may very well be that there is no available increment in the area proposed for development and, if that is in fact the case, development could not proceed.

### Water Use and Discharge

Some of the alternatives under consideration would require process water for operation or non-contact cooling water for heat rejection. Supplying fresh water for process could be an issue as fresh water is limited and the primary sources are located on the northern end of the island. Providing salt water for cooling and discharging waste water to the ocean would involve the National Pollutant Discharge Elimination System (NPDES) program for point source discharges and Sections 316(a) and 316(b) of the Clean Water Act, which regulate the intake of water for power plant cooling and the discharge of heated water. Furthermore, storm water discharges may also be regulated. The administration of water permitting on Guam is shared by Guam EPA and USEPA. Point source discharges and cooling water permitting would be addressed by USEPA. Storm water discharges to wetlands and construction in waterways are also permitted by the U.S. Army Corps of Engineers (USACOE).

Permitting requirements by federal agencies such as USEPA or USACOE would invoke compliance with the National Environmental Policy Act (NEPA). NEPA compliance can substantially affect the schedule and cost of any planned major project. Federal air permitting is specifically precluded from requiring NEPA compliance.

## Option 1 – Small Coal

The characteristics for the small coal option were developed assuming that a coal jetty and bulk handling equipment to accommodate coal deliveries would be constructed along with the plant facilities. An allowance of $25 million was included in the capital cost estimate for this option to accommodate installation of the jetty and bulk handling equipment. Further, the characteristics were based on the facility having BACT to minimize emissions of nitrogen oxides ($NO_X$), $SO_2$, particulate matter (PM), carbon monoxide (CO), carbon dioxide ($CO_2$), and mercury. Additionally, the characteristics were developed assuming that a salt water cooling tower would be utilized for heat rejection.

### Status of Technology

Coal-fired power plants are the mainstay of most utilities throughout the U.S., and conventional coal-fired generation is a mature and proven technology. While very few new coal-fired generating units have been built since the late 1980s in the U.S., several new projects are being proposed to supply the ever-increasing need for additional generating capacity. Coal-fired generating units are best suited for baseload duty.

### Pulverized Coal Technology

Pulverized coal (PC) boilers were originally designed to accommodate larger boiler sizes with increased steam pressure and temperature, and are the most advanced type of solid-fuel boiler in use today. The PC-fired boiler improvements include higher boiler efficiencies and lower $NO_X$ emissions as compared to the older stoker and cyclone-fired boilers of the past.

The PC combustion process includes grinding the coal to a talcum powder consistency, mixing the coal powder with heated combustion air, and discharging the mixture into the boiler firebox through burners similar to conventional gas burners. Air emissions regulations require new coal-fired units to incorporate flue gas desulphurization (FGD) systems to control $SO_2$ emissions, selective or non-selective catalytic reduction (SCR/SNCR) to control $NO_X$ emissions, and either an electrostatic precipitators (ESP) or fabric filters to control PM emissions. Additional controls may soon be required for mercury, $CO_2$ and other emissions.

The PC-fired boiler can be either operated under subcritical (typically 2,600 pounds per square inch (psi), 1,000 degrees Fahrenheit (ºF) and lower) or supercritical (above 3,200 psi and 1,000ºF) steam conditions. Subcritical designs have been used extensively in the U.S. for decades, and are most predominant. They are available in sizes up to 1,200 MW in capacity, but have low fuel flexibility, since they are specifically designed for a certain quality and source of fuel.

### Circulating Fluidized Bed Technology

Circulating fluidized bed (CFB) boilers have been in widespread use in the U.S. and overseas since the mid-1980s for small independent power and utility applications. The boiler is similar to a PC-fired boiler in many characteristics, but is typically smaller (available in sizes up to 300 MW) and has always been a sub-critical design. CFB boiler designs involve injecting a portion of the combustion air through a bed of fuel, ash and limestone on the boiler floor. The upward flow of air fluidizes the material and allows the use of a diversity of possible solid fuel mixtures. However, a CFB boiler has much higher maintenance costs due to high material wear rates caused by erosion in the combustion zone and is also more difficult to operate and requires more operators than other comparably sized solid fuel boilers.

The most notable CFB achievements lie in the ability to burn less desirable fuels and satisfy current environmental emissions restrictions without the need for additional and costly $NO_X$ and $SO_2$ control systems through lower combustion temperatures and the ability to introduce limestone directly into the combustion area.

In recent years, the CFB boilers have included both atmospheric pressure CFB boilers, which are successfully operating in several commercial power plant locations, and pressurized CFB boilers, which operate at several atmospheres of pressure, and have higher thermal efficiencies. Pressurized CFB boilers are considered a developmental technology.

## Fuel Availability and Price Trends

The characteristics of the small coal option were developed assuming that either Indonesian or Australian coal would be the fuel source. Australia and Indonesia are among the world's six largest exporters of coal and are expected to remain so for the next 20 to 30 years, although Indonesia hopes to take over the top spot. Both countries offer low-sulfur, high-quality coals. China, South Africa, Colombia, and the U.S. comprise the rest of the key coal exporting countries. The U.S. Energy Information Administration expects China to switch from a net exporter to a net importer as coal use in China is projected to triple by 2030. Vietnam will step up to join the list of top exporters, owing in part to its resource availability and proximity to China. Potential supply companies include BHP Billiton Limited, Xstrada Plc, Rio Tinto Plc, and Anglo American Plc. Each of these companies is active in Australia and most have operations in Indonesia.

The Australian Coal Association indicates that Australia exports 70 percent of the coal it produces and can blend coals of different characteristics to meet customer specifications. R. W. Beck has a list of mines, operators and specifications as well as export brokers it can provide to GPA.

World coal prices are reported to have increased from $36 per metric ton last year to $52 per metric ton as of September 2006. Xstrada reported in July that it had locked in a price for its Australian coal exports to Japan of approximately $52.50 per ton, delivered. Australian suppliers negotiate the prices for their coal exports directly with Japanese utilities on an annual basis. Approximately 60 percent of Australia's coal goes to Japan.

## Siting Issues

Coal-fired power plants require considerable acreage, utilize a considerable amount of water, produce significant air and water pollutants, and generate significant amount of solid waste. With regard to solid waste, we estimate that a 60-MW coal-fired power plant would produce approximately 25,000 metric tons of ash per year that would need to be disposed of on the island or shipped to other locations. While there is a market for ash in the domestic U.S. for use in concrete and wall board, it is generally coordinated to save disposal expenses and does not result in a significant revenue stream to the plants. Further, depending on the type of emissions control technology utilized, the ash may not be usable for some byproduct applications. The primary issues in siting new coal capacity will be locating a coastal site with sufficient space to allow for construction and operation, ocean depths that support a deep water jetty for coal delivery, and a robust transmission interconnection point. In addition, environmental siting issues such as environmental impacts related to air emissions, avoidance of sensitive receptors, and locations for ash and scrubber sludge disposal will also arise.

## Operating Constraints

Coal-fired units are best operated as baseload units operating at full capacity as much as possible. Cycling and load following operations are typically detrimental to the economics of coal units, and increases maintenance costs considerably.

## Heat Rate Curve

Table 2 presents the heat rate curve for the small coal option. The curve has been generated to support potential turndown to 50 percent load, but actual turndown may be limited by the ability of the unit to maintain compliance with emissions limits, flame stability, and the like.

Table 2
Heat Rate Curve – Small Coal

| | Minimum Load | | | | | Baseload |
|---|---|---|---|---|---|---|
| % Load | 50 | 60 | 70 | 80 | 90 | 100 |
| Load, MW | 30 | 36 | 42 | 48 | 54 | 60 |
| % Baseload HR | 111 | 107 | 104 | 102 | 101 | 100 |
| Nominal HR, Btu/kWh | 11,655 | 11,235 | 10,920 | 10,710 | 10,605 | 10,500 |
| Nominal Burn, MMBtu | 349.650 | 404.460 | 458.640 | 514.080 | 572.670 | 630.000 |
| Incr Burn, MMBtu | | 54.810 | 54.180 | 55.440 | 58.590 | 57.330 |
| Incr HR, Btu/Wh | | 9,135 | 9,030 | 9,240 | 9,765 | 9,555 |

## Availability/Reliability Issues

Conventional coal-fired units have proven high availability and reliability. Typically, scheduled maintenance requirements include about five weeks per year of scheduled outage time for major equipment inspection and overhauls. Mature forced outage rates can be expected to be in the three to five percent range.

## Environmental Issues

The small coal option will likely be the most difficult of the options to permit due to potential impacts of installation and operation of a jetty for coal deliveries, coal handling and storage, air emissions, ash disposal, and heat rejection on the environment. Extensive controls will likely be required to obtain an air permit especially in light of the multitude of upcoming/proposed regulations. The small coal option emits much higher levels of $CO_2$ than an equivalent size gas-fired unit (there is currently a proposal in the U.S. Senate to regulate greenhouse gas emissions).

### Construction Drawdown Schedule

The construction drawdown schedule presented in the table below assumes the project is fully drawn at the end of construction.

Table 3
Construction Drawdown Schedule – Small Coal

| Month | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 | 11 | 12 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| % Complete | 6.1 | 7.0 | 8.5 | 9.6 | 12.0 | 13.0 | 14.1 | 16.6 | 18.0 | 19.5 | 21.0 | 23.5 |
| Month | 13 | 14 | 15 | 16 | 17 | 18 | 19 | 20 | 21 | 22 | 23 | 24 |
| % Complete | 27.0 | 31.0 | 36.5 | 42.5 | 48.0 | 54.0 | 61.0 | 67.5 | 74.5 | 79.9 | 85.0 | 90.0 |
| Month | 25 | 26 | 27 | 28 | 29 | 30 | 31 | 32 | 33 | 34 | 35 | 36 |
| % Complete | 93.0 | 94.0 | 95.0 | 96.0 | 96.5 | 97.0 | 97.5 | 98.0 | 98.5 | 99.0 | 99.5 | 100.0 |

## Option 2 – Small Combined-Cycle with LNG Facility

The characteristics for the small combined-cycle with LNG facility were developed assuming that a jetty, or pier, and associated piping systems to accommodate LNG deliveries would be constructed along with the plant facilities. An allowance of $25 million was included in the capital cost estimate for this option to accommodate installation of the jetty and piping facilities. Further, the characteristics included a LNG regasification facility including a two billion cubic feet (BCF) storage tank. We have also assumed that the facility would have BACT in the form of an SCR to minimize emissions of $NO_X$. Additionally, the characteristics were developed assuming that a chiller package would be included to provide CT inlet air cooling and a salt water cooling tower would be utilized for heat rejection.

### Status of Technology

Natural gas fired CTs are proven technology for power generation applications. The General Electric (GE) LM6000 has been in operation since 1990. The design is based on the GE CF6-80C2 jet aircraft engine and has undergone several performance enhancements since its original design to improve efficiency, availability, and emissions. Combined-cycle power generation has become more prevalent over the last 20 years and can also be considered proven technology. Regasification is a relatively simple process of heating the LNG to vaporize it back into gaseous form. Regasification is a proven technology with hundreds of regasification facilities in operation around the world.

## Fuel Availability and Price Trends

Natural gas excess to indigenous need is exported from both Australia and Indonesia in the form of LNG. LNG is natural gas chilled to -270 F, at which point it becomes a liquid and takes up 1/60 of the volume it did as a gas. Most LNG is transported in very large tankers and is delivered to destinations such as Japan on a baseload basis. Typical tanker size is 160,000 to 200,000 cubic meters, which equates to 3.5 to 4 billion cubic feet of natural gas. (Construction cost for the delivery-end terminal to "reheat" the LNG to its gaseous state for delivery to customers via standard pipeline can cost up to $1 billion.) GPA's projected daily demand to support operation of a combined-cycle unit, in contrast, is 11,500 million cubic feet (MCF). Accordingly, a standard-sized LNG regasification terminal is not economically feasible for GPA.

Smaller LNG tankers and facilities are possible. Japan, for example, uses smaller tankers to "island-hop" deliveries of LNG to more remote locations. Knutsen OAS, a Norwegian shipbuilder, has designs to construct 1,100 cubic meter mini-tankers. The 1,100 cubic meter capacity is approximately 23,000 MCF, thus implying tanker deliveries every 2 or 3 days would be sufficient to supply a 60-MW nominal capacity combined-cycle unit.

Another concept is compressed natural gas, or CNG. Trans-Ocean Gas is marketing a concept that converts container ships into tankers carrying CNG. These ships would be designed for short-haul trades such as from Malaysia to the Philippines. The off-loading terminals can cost up to $150 million.

Any of these technologies would involve purchasing natural gas from Australia or Indonesia. Indonesia has long been the world's largest exporter of natural gas as LNG, though political uncertainty and investment issues have pushed production below the level of contractual export commitments since 2005. PT Pertamina remains the sales agent for LNG sales to South Korea and Taiwan; these contracts expire in 2007 and 2009, respectively. In addition, BP Indonesia reports that its Tangguh project will begin service in 2008. The project initially consists of two trains with LNG output contracted to the Fujian LNG project in China, K-Power Co., Ltd. in Korea, POSCO in Korea and Sempra Energy LNG Marketing Corp., in Mexico. Tangguh is expandable to eight trains of capacity, which BP Indonesia says could occur if it has sufficient sales commitments for the gas. Tangguh's two cryogenic trains will initially export 340 BCF per year.

Australia produces approximately 1.3 trillion cubic feet (TCF) of natural gas per year and in 2005 exported 44 percent of that as LNG (with Japan the primary destination). Much of Australia's natural gas reserves are located in remote areas where it is more economic to convert the gas to LNG and export it than it would be to build a pipeline to carry the gas inland for domestic consumption. Besides the existing Northwest Shelf Venture currently exporting LNG, at least four other LNG export projects are under development with in service dates ranging from 2006 to 2011. Some of the projects have already executed destination contracts, some merely have LNG sales agreements with an exporter who must still seek a delivery market for the gas. Leading LNG exporters include Woodside Petroleum, ChevronTexaco, Royal Dutch Shell, ExxonMobil and ConocoPhillips.

Pacific Basin LNG has traditionally been priced using a market-basket of world oil prices under an "S-Curve" methodology that moderated LNG prices as oil prices rose. Those contracts are expiring and LNG customers are demanding more flexible contract terms. With construction of LNG terminals in the U.S. and the existence of a highly liquid and transparent market, Henry Hub is expected to become the world LNG price benchmark; thus, buyers should see LNG contracts increasingly set prices using the Henry Hub price.

## Siting Issues

The primary issues in siting new combined-cycle power plant with an LNG regasification facility will be locating a coastal site with sufficient space to allow for construction and operation, ocean depths that support a deep water jetty for LNG delivery, and a robust transmission interconnection point. In addition, environmental siting issues such as environmental impacts related to air emissions and avoidance of sensitive receptors will also arise.

## Operating Constraints

This unit can be operated as an intermediate unit to a baseloaded unit. Efficiency decreases at part load and turn down is limited to about 60 percent due to steam cycle equipment and emissions constraints. Maintenance intervals are affected by frequent start/stop cycles. Start up times can be up to six hours if the unit is cold and has not operated for several days. Boil-off from the LNG storage tank will need to be diverted for other use, recirculated, or flared in the event that the combined-cycle unit is shut down.

## Heat Rate Curve

Table 4 presents the heat rate curve for the combined-cycle option. The curve has been generated to support potential turndown to 66 percent load, which is based on 60 percent load on the CT to maintain emissions compliance and approximately 50 percent load on the ST to avoid condensation in the final stages of the turbine.

Table 4
Heat Rate Curve – Combined-Cycle with LNG Facility

| | Minimum Load | | | | | Baseload |
|---|---|---|---|---|---|---|
| % Load | | | 66 | 80 | 90 | 100 |
| Load, MW | 0 | 0 | 40 | 48 | 54 | 60 |
| % Baseload HR | 117 | 111 | 106 | 103 | 101 | 100 |
| Nominal HR, Btu/kWh | 9,386 | 8,919 | 8,557 | 8,275 | 8,131 | 8,050 |
| Nominal Burn, MMBtu | - | - | 338.863 | 397.219 | 439.047 | 483.000 |
| Incr Burn, MMBtu | - | - | - | 5.356 | 41.828 | 43.953 |
| Incr HR, Btu/kWh | - | - | - | 6,947 | 6,971 | 7,326 |

## Availability/Reliability Issues

Combined-cycle units have proven high availability and reliability. Typically, scheduled maintenance requirements include about three to four weeks per year of scheduled outage time for major equipment inspection and overhauls. Mature forced outage rates can be expected to be in the two to four percent range. While the combined-cycle and LNG facility can be designed with a certain level of redundancy, some risk is inherent with operations utilizing a single LNG storage tank.

## Environmental Issues

Combined-cycle units typically rely on dry low-$NO_X$ emission or water injection combustion plus post-combustion emission reduction equipment. Natural gas is considered a clean fuel. However, there are potential emission/impact issues with extensive oil firing, if it is included as a secondary fuel source. Also, there are additional permitting requirements/compliance issues associated with oil storage.

## Construction Drawdown Schedule

The construction drawdown schedule presented in the table below assumes the project is fully drawn at the end of construction.

Table 5
Construction Drawdown Schedule – Combined-Cycle with LNG Facility

| Month | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 | 11 | 12 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| % Complete | 6.5 | 7.2 | 8.9 | 9.8 | 12.0 | 15.0 | 17.0 | 19.0 | 21.0 | 23.4 | 28.0 | 34.0 |
| Month | 13 | 14 | 15 | 16 | 17 | 18 | 19 | 20 | 21 | 22 | 23 | 24 |
| % Complete | 40.0 | 50.0 | 59.0 | 70.0 | 80.6 | 89.0 | 95.0 | 97.6 | 98.1 | 98.6 | 99.0 | 99.3 |
| Month | 25 | 26 | 27 | 28 | 29 | 30 | 31 | 32 | 33 | 34 | 35 | 36 |
| % Complete | 99.5 | 99.6 | 99.7 | 100.0 | | | | | | | | |

## Option 3 – Wind Farm

The characteristics for the wind option were developed assuming that ten 2-MW units would be installed in an on-shore, ridgeline configuration. However, we note that the assumptions were not based on a specific location with correlating wind data. For the purposes of this study we have made the assumption that the hub height would be between 190 and 260 feet and the design would include consideration for high winds associated with typhoons.

### Status of Technology

Over the last decade wind turbine manufacturers have increased the size of utility service wind turbines to the two to three MW range. The manufacturers have based the design of the larger turbines on the design of smaller turbines that have been previously manufactured and placed into commercial service. While it is typical for industrial manufacturers to scale products up based on smaller designs, there are often design, construction, operations, or maintenance issues that arise that require additional attention or modification. While wind turbines assumed for this option have been manufactured with a design life of 30 years and placed into service, in recent years the fleet leader in operating hours still has limited experience. Without long-term operating data to confirm the integrity of the design and prove the support of the manufacturers to remedy potential issues, wind turbine technology of this size range cannot be considered proven and mature. However, wind turbines of the type proposed for this option are currently in commercial service and with continued application of resources to support O&M should continue to have refinements to improve operations, maintenance, and reliability.

### Fuel Availability and Price Trends

Not applicable.

### Siting Issues

The primary issues in siting a wind farm will be locating a site with adequate wind and sufficient space (between 75 and 125 acres) to allow for construction and operation, development of access roads, and access to a transmission interconnection point. It is important to note that significant study of the wind patterns at the specific site location selected is necessary to support development of the resource. As a frame of reference with regard to space required, the wind farm would likely stretch for approximately three to five miles. Multiple sites could be utilized, but costs may increase associated with the installation of additional access roads required, additional labor involved to move the construction crane(s), and the additional electrical interconnection equipment required to serve multiple sites. The frequency and strength of typhoons that hit Guam must also be considered. In the event of high winds, such as those associated with a typhoon, we have assumed typical mitigation techniques would be included in the design. These design features include blades that feather and application of a rotor brake in the event of high wind speeds. In addition, environmental siting issues such as environmental impacts related to construction, wake turbulence, and the like will also arise.

## Operating Constraints

The primary operating constraint is the lack of dispatch control of the wind turbines. Generation only occurs while the wind is blowing. The cut-in wind speed should be expected to be approximately 10 miles per hour (mph) with a cut-off wind speed of approximately 60 mph. It is also important to note that wind turbines do not normally operate at rated capacity for a significant number of hours each year, but instead something less. Therefore, to make reasonable assumptions for planning purposes related to the amount of annual generation that can be expected, wind data for the specific site location should be collected. Installation of a wind farm will likely displace higher cost power generation. In certain cases, a wind farm may result in the need to provide more spinning reserve or different control strategies to cover fluctuations in wind turbine generation.

## Heat Rate Curve

Not applicable.

## Availability/Reliability Issues

Typically, scheduled maintenance requirements include about one week per year of scheduled outage time for each turbine, which can be conducted simultaneously, but are typically taken in series. Mature forced outage rates can be expected to be in the three to five percent range.

## Environmental Issues

Primary environmental issues relate to siting and installation of both the access roads and the wind turbines themselves.

## Construction Drawdown Schedule

The construction drawdown schedule presented in the table below assumes the project is fully drawn at the end of construction.

Table 6
Construction Drawdown Schedule – Wind Farm

| Month | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 | 11 | 12 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| % Complete | 28.0 | 40.0 | 52.0 | 62.0 | 70.0 | 78.0 | 86.0 | 94.0 | 100.0 | | | |
| Month | 13 | 14 | 15 | 16 | 17 | 18 | 19 | 20 | 21 | 22 | 23 | 24 |
| % Complete | | | | | | | | | | | | |
| Month | 25 | 26 | 27 | 28 | 29 | 30 | 31 | 32 | 33 | 34 | 35 | 36 |
| % Complete | | | | | | | | | | | | |

## Option 4 – Repowering Piti 7 CT to Combined-Cycle

The characteristics for the repowering combined-cycle option were developed assuming that the Piti 7 CT, a GE Frame 6B, would be converted from a simple-cycle unit to a combined-cycle unit. We have assumed that installation would include an SCR to meet BACT requirements and a salt water cooling tower would be utilized for heat rejection.

### Status of Technology

No. 2 fuel oil-fired combustion turbines are proven technology for power generation applications. The GE Frame 6B has been in commercial operation for about twenty years and has undergone several performance enhancements during that time. Combine-cycle power generation has become more prevalent over the last 20 years and can also be considered proven technology.

### Fuel Availability and Price Trends

GPA currently sources and procures No. 2 fuel for use in its existing power generation resources. Diesel or No. 2 is widely available, although prices are subject to fluctuations.

### Siting Issues

Developing a plant configuration on the existing Piti site without encountering significant residual environmental issues or interfering with the other units is a primary consideration. Additionally, permitting this unit to run more hours annually in the nonattainment area presents some development challenges.

### Operating Constraints

This unit can be operated as an intermediate unit to a baseloaded unit. Efficiency decreases at part load and turn down is limited to about 60 percent due to steam cycle equipment and emissions constraints. Maintenance intervals are affected by frequent start/stop cycles. Start up times can be up to 6 hours if the unit is cold and has not operated for several days.

### Heat Rate Curve

Table 7 presents the heat rate curve for the repowering option. The curve has been generated to support potential turndown to 66 percent load, which is based on 60 percent load on the CT to maintain emissions compliance and approximately 50 percent load on the ST to avoid condensation in the final stages of the turbine

Table 7
Heat Rate Curve – Repowering Piti 7 CT to a Combined-Cycle

| | Minimum Load | | | | | Baseload |
|---|---|---|---|---|---|---|
| % Load | | | 66 | 80 | 90 | 100 |
| Load, MW | 0 | 0 | 40 | 48 | 54 | 60 |
| % BL HR | 109 | 106 | 105 | 103 | 102 | 100 |
| Nominal HR Btu/kWh | 8,829 | 8,586 | 8,465 | 8,343 | 8,222 | 8,100 |
| Nominal Burn, MMBtu | - | - | 335.194 | 400.464 | 443.961 | 486.000 |
| Incr Burn, MMBtu | - | - | - | 65.270 | 43.497 | 42.039 |
| Incr HR, Btu/kWh | - | - | - | 7,770 | 7,250 | 7,007 |

## Availability/Reliability Issues

Combined-cycle units have proven high availability and reliability. Typically, scheduled maintenance requirements include about three to four weeks per year of scheduled outage time for major equipment inspection and overhauls. Mature forced outage rates can be expected to be in the two to four percent range.

## Environmental Issues

As stated above, the primary issue for this option is utilizing the existing Piti site without encountering significant residual environmental issues. Additionally, permitting this unit to run more hours annually in the non-attainment area presents some development challenges.

## Construction Drawdown Schedule

The construction drawdown schedule presented in the table below assumes the project is fully drawn at the end of construction.

Table 8
Construction Drawdown Schedule – Repowering Piti 7 CT to a Combined-Cycle

| Month | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 | 11 | 12 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| % Complete | 9.8 | 12.2 | 14.5 | 16.7 | 20.4 | 25.0 | 31.0 | 38.0 | 56.4 | 71.5 | 78.5 | 85.0 |
| Month | 13 | 14 | 15 | 16 | 17 | 18 | 19 | 20 | 21 | 22 | 23 | 24 |
| % Complete | 90.1 | 93.5 | 96.5 | 98.0 | 99.1 | 100.0 | | | | | | |
| Month | 25 | 26 | 27 | 28 | 29 | 30 | 31 | 32 | 33 | 34 | 35 | 36 |
| % Complete | | | | | | | | | | | | |

## Option 5 – Biomass

The characteristics for the biomass option were developed assuming that sufficient biofuels and municipal solid waste, such as trash and woody waste, would be available. We have assumed that installation would include an SCR to meet BACT requirements and a salt water cooling tower would be utilized for heat rejection.

### Status of Technology

Mass burning technology is currently operating at numerous facilities worldwide. Common facilities utilize a field-erected, two-drum natural circulation watertube-type boiler. Common systems have traveling-grate spreader, stoker-fired, or CFB boilers with a single condensing steam turbine-generator. A 10-MW unit would be at the high end of the range of capacities for these types of units.

### Fuel Availability and Price Trends

A key to development of the biomass option is the coordination and development of fuel delivery to the facility at costs that are economically beneficial to the haulers and GPA. We note that there are currently environmental issues related to the existing Guam landfill involving the USEPA that could work either in favor of, or against the development of the project.

### Siting Issues

The primary issues in siting this option are locating a site near the waste resource with sufficient space to allow for construction and operation, sufficient water to support operations, and a robust transmission interconnection point. In addition, environmental siting issues such as environmental impacts related to air emissions and avoidance of sensitive receptors, etc., will also arise.

### Operating Constraints

Fuel volume and characteristics can limit baseload operations and potential turn down of the unit to approximately 80 percent load. Therefore, we have characterized this resource as a must-run facility due to the volume of fuel storage required during times of low-load operations or shutdown.

### Heat Rate Curve

Not applicable. We have assumed that this option would be a must-run unit due to the inherent desire to accommodate the volume of municipal solid waste generated in the area.

## Availability/Reliability Issues

Conventional boiler-steam turbine units have proven high availability and reliability. Typically, scheduled maintenance requirements include about five weeks per year of scheduled outage time for major equipment inspection and overhauls. Mature forced outage rates can be expected to be in the four to six percent range.

## Environmental Issues

The biomass option will be difficult to permit due to potential impacts of air emissions, ash and residual waste disposal, and heat rejection on the environment. Extensive controls will likely be required to obtain an air permit especially in light of the multitude of upcoming/proposed regulations (There is currently a proposal in the U.S. Senate to regulate greenhouse gas emissions.)

## Construction Drawdown Schedule

The construction drawdown schedule presented in the table below assumes the project is fully drawn at the end of construction.

Table 9
Construction Drawdown Schedule – Biomass

| Month | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 | 11 | 12 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| % Complete | 6.3 | 7.1 | 8.7 | 9.6 | 13.2 | 14.0 | 14.9 | 16.9 | 20.0 | 22.5 | 27.0 | 33.0 |
| Month | 13 | 14 | 15 | 16 | 17 | 18 | 19 | 20 | 21 | 22 | 23 | 24 |
| % Complete | 41.0 | 49.4 | 56.5 | 65.0 | 75.0 | 83.2 | 88.0 | 93.0 | 95.0 | 96.0 | 96.5 | 97.0 |
| Month | 25 | 26 | 27 | 28 | 29 | 30 | 31 | 32 | 33 | 34 | 35 | 36 |
| % Complete | 97.5 | 98.0 | 98.5 | 99.0 | 99.7 | 100.0 | | | | | | |

## Option 6 – Reciprocating Engine

The characteristics for the reciprocating engine option were developed assuming that two 20-MW units would be installed. Further, a salt water cooling tower was assumed to accommodate heat rejection and both an SCR and a FGD were included for emissions control.

### Status of Technology

Reciprocating engines are a proven technology for power generation applications.

### Fuel Availability and Price Trends

GPA currently sources and procures RFO for use in its baseload power generation resources. RFO is widely available, although prices are subject to fluctuations.

### Siting Issues

The primary issues in siting a new reciprocating engine plant are locating a coastal site with sufficient space to allow for construction and operation along with a robust transmission interconnection point. In addition, environmental siting issues such as environmental impacts related to air emissions and avoidance of sensitive receptors, etc., will also arise.

### Operating Constraints

There are no known operating constraints of any significance. The engines will typically be guaranteed to operate down to 50 percent of rated load and can be operated remotely.

### Heat Rate Curve

Table 10 presents the heat rate curve for the reciprocating engine option. The curve has been generated to support potential turndown to 50 percent load.

Table 10
Heat Rate Curve – Reciprocating Engine

| | Minimum Load | | | | | Baseload |
|---|---|---|---|---|---|---|
| % Load | 50 | 60 | 70 | 80 | 90 | 100 |
| Load, MW | 10 | 12 | 14 | 16 | 18 | 20 |
| % BL HR | 109 | 107 | 105 | 102 | 101 | 100 |
| Nominal HR, Btu/kWh | 9,223 | 9,053 | 8,904 | 8,691 | 8,585 | 8,500 |
| Nominal Burn, MMBtu | 92.225 | 108.630 | 124.653 | 139.060 | 154.530 | 170.000 |
| Incr Burn, MMBtu | - | 16.405 | 16.023 | 14.408 | 15.470 | 15.470 |
| Incr HR, Btu/kWh | - | 8,203 | 8,011 | 7,204 | 7,735 | 7,735 |

## Availability/Reliability Issues

There are no significant issues related to availability or reliability.

## Environmental Issues

Extensive controls will likely be required to obtain an air permit especially in light of the multitude of existing and upcoming/proposed regulations.

## Construction Drawdown Schedule

The construction drawdown schedule presented in the table below assumes the project is fully drawn at the end of construction.

Table 11
Construction Drawdown Schedule – Reciprocating Engine

| Month | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 | 11 | 12 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| % Complete | 9.8 | 12.2 | 14.5 | 16.7 | 20.4 | 25.0 | 31.0 | 38.0 | 56.4 | 71.5 | 78.5 | 85.0 |
| Month | 13 | 14 | 15 | 16 | 17 | 18 | 19 | 20 | 21 | 22 | 23 | 24 |
| % Complete | 90.1 | 93.5 | 96.5 | 98.0 | 99.1 | 100.0 | | | | | | |
| Month | 25 | 26 | 27 | 28 | 29 | 30 | 31 | 32 | 33 | 34 | 35 | 36 |
| % Complete | | | | | | | | | | | | |

Should you have questions or if you would like to discuss the proposed acquisition further please contact Rob Brune at (913) 768-0090 or Angelo Muzzin at (206) 695-4405.

Sincerely,

R. W. BECK, INC.

Robert A. Brune, P.E.
Senior Director

Angelo Muzzin
Principal

RAB/smm
Attachment

c: Bob Davis, R. W. Beck
Katie Elder, R. W. Beck
John McNurney, R. W. Beck

## Resource Assumptions

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| Date | Oct-06 | | | | | | |
| Project | Guam IRP | | | Resource Options | | | |
| Option/Exisiting Plant | | 1 | 2 | 3 | 4 | 5 | 6 |
| Plant Description | | Steam | CC w/ LNG | Wind | Retrofit | Biomass | Recip |
| Technology | | PC/CFB | LM6000 | 10x2MW On-shore | Piti 7 CC | Stoker/CFB | 2x20MW S/MSD |
| Location | | Guam | Guam | Guam | Guam | Guam | Guam |
| Ownership rate | % | 100 | 100 | 100 | 100 | 100 | 100 |
| Nominal Capacity | MW | 60 | 60 | 20 | 60 | 10 | 40 |
| Space Required | Acres | 200 to 300 | 15 to 30 | 75 to 125 | 5 to 15 | 10 to 25 | 10 to 25 |
| Plant Direct Costs | $000 | $ 150,000 | $ 40,000 | $ 23,000 | $ 21,500 | $ 52,000 | $ 38,000 |
| Interconnections Costs | $000 | $ 50,000 | $ 190,000 | $ 10,000 | $ 7,000 | $ 10,000 | $ 12,000 |
| Owner Costs | $000 | $ 40,000 | $ 45,000 | $ 7,000 | $ 5,500 | $ 13,000 | $ 10,000 |
| Capital Cost | $000 | $ 240,000 | $ 275,000 | $ 40,000 | $ 34,000 | $ 75,000 | $ 60,000 |
| Capital Cost | $/kW | $ 4,000 | $ 4,583 | $ 2,000 | NA | $ 7,500 | $ 1,500 |
| Constr Draw Schedule | | See tables in text of report | | | | | |
| Permitting | Months | 30 | 30 | 15 | 24 | 30 | 24 |
| Start of Eng to CO | Months | 36 | 28 | 9 | 18 | 30 | 18 |
| Total Duration | Months | 51 | 43 | 18 | 30 | 45 | 30 |
| COD | Date | Mar-11 | Jul-10 | Jul-08 | Jul-09 | Oct-10 | Jul-09 |
| Retirement | Date | Mar-41 | Jun-40 | Jul-38 | Jul-39 | Oct-40 | Jul-39 |
| Max Net Capacity | MW | 60 | 60 | 20 | 60 | 10 | 40 |
| Min Net Capacity | MW | 30 | 40 | 0 | 40 | NA | 10 |
| HR @ Max | MMBtu/MWh | 10.500 | 8.050 | N/A | 8.100 | 17.500 | 8.500 |
| HR @ Min | MMBtu/MWh | 11.655 | 8.557 | N/A | 8.465 | NA | 9.223 |
| HR curve | | See tables in text of report | | | | | |
| Mature FOR | % | 5.0% | 3.0% | 4.0% | 2.0% | 5.5% | 5.5% |
| New FOR for 1st yr | % | 8.0% | 6.0% | 6.0% | 3.0% | 9.6% | 9.6% |
| Scheduled Maintenance | Weeks | 5.21 | 3.65 | 1.04 | 3.65 | 5.21 | 5.21 |
| Scheduled Maintenance | % | 10.0% | 7.0% | 2.0% | 7.0% | 10.0% | 10.0% |
| Must-Run Flag | yes/no | no | yes | no | no | yes | no |
| Max Capacity Factor | % | 85.0% | 90.0% | 94.0% | 91.0% | 84.5% | 84.5% |
| Water Consumption | gpm | 850 | 225 | N/A | 300 | 140 | 20 |
| Primary Fuel | | Coal | LNG | Wind | No. 2 | MSW | No. 6 |
| Fuel Heating Value | Btu/lb | 8,920 | | | | 4,800 | |
| Fuel Heating Value | MMBtu/ton | 17.8 | | | | 9.6 | |
| Fuel Heating Value | Btu/CF | | 1,000 | | | | |
| Fuel Heating Value | MMBtu/MCF | | 1.0 | | | | |
| Fuel Heating Value | Btu/gal | | | | 148,000 | | 148,000 |
| Fuel Heating Value | Btu/lb | | | | 20,000 | | 20,000 |
| Fuel Sulfur Content | % | 0.15 | NA | | 0.05 | 0.1 | 2.5 |
| SO2 Emissions Rate | lb/MMBtu | 0.10 | 0.001 | | 0.06 | 0.21 | 0.28 |
| NOX Emissions Rate | lb/MMBtu | 0.06 | 0.01 | | 0.01 | 0.36 | 0.37 |
| Operating Ramp Rate | MW/min | 4.0 | 8.0 | | 8 | | |
| Cold Start Requirement | Hours | 8.0 | 6.0 | | 6.0 | | |
| Start-up Fuel - Cold Start | MMBtu | 315 | 240 | | 245 | | |
| Warm Start Requirement | Hours | 4.0 | 1.0 | | 1.0 | | |
| Start-up Fuel - Warm Start | MMBtu | 180 | 150 | | 160 | | |
| Min Run time | Hours | 24 | 8 | | 8 | | |
| Labor | $ | $ 3,150,000 | $ 2,550,000 | NA | $ 1,500,000 | $ 2,700,000 | $ 1,200,000 |
| G&A | $ | $ 315,000 | $ 255,000 | NA | $ 150,000 | $ 270,000 | $ 120,000 |
| Other | $ | $ 585,000 | $ 495,000 | NA | $ 325,000 | $ 430,000 | $ 340,000 |
| Cap Ex | $ | $ 750,000 | $ 600,000 | NA | $ 425,000 | $ 600,000 | $ 420,000 |
| FOM | $ | $ 4,800,000 | $ 3,900,000 | NA | $ 2,400,000 | $ 4,000,000 | $ 2,080,000 |
| FOM | $/kW-yr | $ 80.00 | $ 65.00 | NA | $ 40.00 | $ 400.00 | $ 52.00 |
| VOM | $ | $ 2,010,420 | $ 1,182,600 | NA | $ 2,152,332 | $ 5,551,650 | $ 1,628,484 |
| VOM | $/MWh | $ 4.50 | $ 2.50 | NA | $ 4.50 | $ 75.00 | $ 5.50 |
| Total Non-Fuel O&M | $ | $ 6,810,420 | $ 5,082,600 | $ 400,000 | $ 4,552,332 | $ 9,551,650 | $ 3,708,484 |
| Total Non-Fuel O&M | $/MWh | $ 15.24 | $ 10.74 | NA | $ 9.52 | $ 129.04 | $ 12.52 |

**Notes:**
All costs in 2006$
Non-union construction
Option 1 includes SCR, scrubber, ESP/baghouse, and mercury emissions control equipment
Capital costs for Options 1 and 2 each include $25 million of direct costs as an allowance for jetty design and construction and bulk handling equipment to on-shore fac
Capital costs include 20% owner costs
Capital costs exclude IDC and bank fees
FOM does NOT include property taxes, insurance, or debt service
FOM includes Cap Ex
FOR and maintenance schedule for options 3 and 6 are per unit and could overlap
Water consumption values represent average water needs based on annual operation at the maximum capacity factor