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.

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

Attachment 1

Resource Assumptions

Date Oct-06

Project Guam IRP

Option/Exisiting Plant		1	2	3	4	5	6
		Resource Options					
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