Guam Power Authority
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Guam Power Authority

Integrated Resource Plan

FY 2008

August 8, 2008

EXECUTIVE SUMMARY

The Authority's Integrated Resource Plan (IRP), in order to increase the well-being of customers and stakeholders, aims to provide:

♦ Lowest cost power in the long run for customers;

♦ Fuel Diversity; and

♦ Electric power supply in an environmentally responsible manner

Integrated Resource Planning is an exercise in strategic as well as capital planning. It is an ongoing activity that does not end with the submission of a report. The business situation is dynamic and uncertain. It is especially when rapid change is anticipated that continued planning and analysis becomes even more critical. Additionally, the IRP must be folded with other long-range and medium-range studies into a cost-of-service study.

The Strategic Issues behind this Integrated Resource Planning effort include:

- Fuel diversity that considers fuel supply risk, renewable energy, reduced environmental and greenhouse gas footprints, and energy conservation or Demand-Side Management (DSM);

- Supporting the electric power service requirements for the impending Department of Defense (DOD) build-up and its economic consequences; and

- Acquisition of new electric energy supply and its implication on human resource requirements and the Authority business model;

The primary recommendations of this IRP include:

- Award wind or other renewable energy projects by December 2009;

- Bring Liquefied Natural Gas (LNG) as a substitute fuel for Diesel Fuel Oil by 2012;

- Plan and permit for an additional gas-fired plant or non-petroleum-fired plant as a hedge for the uncertainty in the scope of the DOD buildup and related economic activity — Guam Power Authority (GPA) should construct this plant based upon high load growth triggers and work with the DOD to mitigate rate impacts to other customers; and,

- Find a business partner to develop the Guam Sea Water Air Conditioning (GSWAC) Project.

Other recommendations of this IRP include:

- Ensure that all generation plants meet the performance standards agreed with the Guam Public Utilities Commission (Guam PUC);

- Examine life extension of its existing plants in a comprehensive and integrated manner;

- Continue to evaluate renewable and energy efficiency technologies in order to obtain the lowest energy prices for its customers;

- Work collaboratively with the Guam PUC and stakeholders to improve the Authority's financial position relative to obtaining funding for these projects;

- Continue to investigate Geothermal, Ocean Thermal Energy Conversion (OTEC), Integrated Gasification Combined Cycle (IGCC), and other technologies;

- Work with Guam Waterworks Authority (GWA) on an interruptible load arrangement in order to hedge against the risk of higher than baseline load growth;

- Work with the Guam PUC to establish the rules of engagement and rates for net metering;

- Work with the Guam PUC on implementing economically and socially viable Demand-Side Management (DSM) Programs; and

- Add to its web site Enercom's packaged set of Internet energy tools called Energy Depot®[1] as part of an initial small DSM project and customer outreach.

Bringing LNG as a substitute fuel for diesel requires the Authority to:

- Work with the Department of Defense to support the paradigm change at the Japan Bank for International Cooperation's (JBIC) pledge for infrastructure funding for the DOD marine move from supplying electric energy to supplying LNG;

- Renegotiate the Taiwan Electrical and Mechanical Engineering Services (TEMES) Energy Conversion Agreement to include converting its plant to use natural or synthetic gas and combine cycle operation; and

- Examine supplying natural gas for industrial, commercial, and residential use as a utility under the Consolidated Commission on Utilities (CCU) and the Guam PUC.

Table 1 shows the capital requirements for the primary recommendations of this IRP. Note that the CLNG Project is contingent upon accelerated load growth.

[1] Online Energy Audits & Information. Accessed at http://www.hometownconnections.com/utility/enercom.html on May 27, 2008

Table 1, Recommended Capital Requirements (thru 2018)

Project	Description	Construction Schedule	Commission Year	Capital Requirement ($ 000)
WIND	Wind Farm - 20x2MW	18 Months	2011	97,076
WIND	Wind Farm - 20x2MW	18 Months	2012	97,076
TEML	TEMES Conversion to LNG - 40MW		2012	8,633
GSWAC	Guam Sea Water Air-conditioning	60 months	2013	100,000
CLNG	CC w/ LNG / LM6000	43 Months	2013 to 2021 Depending on Load Growth	334,000
SSD	Reciprocating Engine (Slow Speed Diesel) - 2x20MW	30 Months	2017	70,980
WIND	Wind Farm - 20x2MW	18 Months	2018	97,076
TOTAL				**804,841**

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1 Situation Analysis

1.1 Introduction

Guam Power Authority (GPA) is a public corporation and an enterprise fund of the Government of Guam. The Guam Power Authority Act of 1968 established GPA in May 1968. Guam Code 12 Chapter 8 sets the legal definitions, empowerments and limitations for the Authority.

The Consolidated Commission on Utilities (CCU), a five member elected board of directors, administers GPA. The directors are elected for staggered four-year terms. Additionally, the Authority is regulated by the Guam Public Utilities Commission (Guam PUC).

The Authority serves about 46,000 customers and has an annual budget of approximately $350 million dollars. GPA's highest peak system demand is 281.5 MW.

The Authority is a full service electric utility. It generates and wheels electric energy from power plant to individual users. GPA has an installed generation capacity of 552 MW gross including 181 MW from Independent Power Producers (IPPs). GPA has organized 210 MW of its baseload capacity under two Performance Management Contracts (PMCs). These contracts provide private management using public employees to operate and maintain the plants. These contracts contain performance-based incentives for reducing plant operating costs. Furthermore, the Authority has installed 663 miles of transmission and distribution lines and operates 29 substations throughout the island.

The Authority is budgeted for 592 Full-Time Employees (FTE's) but has 509 full time employees as of May 5, 2008. Additionally, GPA has an apprenticeship program recognized and licensed by the U.S. Bureau of Labor.

1.2 Historical Period since the Last Integrated Resource Plan

In its Fiscal Year 1999 Integrated Resource Plan, the Guam Power Authority foresaw limited near term-economic growth. Looking back since then, historical system peak demand fell, for the most part within the lower band between the Authority's low growth scenario and medium growth scenarios. Several systemic shocks such as the gulf war, SARs, major typhoons, and rising fuel prices occurred during this period adversely affecting the Guam economy. As a result, the demand for electric power contracted or remained flat relative to FY 1998.

1.2.1 Looking Forward

The Authority must plan for an economic boom driven by resurgence in tourism and the proposed massive build up of the United States military infrastructure. This IRP forms a significant part of the Authority's Business Plan. Most importantly, this Business Plan looks at near term strategic management decisions such as:

- The expectation of future loads, sales and revenues;
- New Public-Private Partnerships; and
- Near-term addition of generation plant to serve future loads including fuel diversity, generation retirement or life extension, financing, and demand-side management.

1.3 Load Forecast

GPA believes that Guam is leaving a period of flat economic growth. Guam is entering a period of high economic growth. The leading indicator of this view is the anticipated build-up of military infrastructure and presence as recorded in the Department of Defense Quadrennial report, anticipated load projections from the United States Navy, as well as speculative future projects and deployments beyond the timeframe of the quadrennial reports.

1.4 Energy Conversion Agreements

In FY 1997, GPA committed to Energy Conversion Agreements (ECA) with Hawaiian Electric Industries, Inc. (HEI), Marianas Electric Company (MEC), and Taiwan Electric and Mechanical Engineering Services (TEMES). HEI took over the Authority's Tanguisson Power Plant. MEC constructed the Piti 8&9 slow speed diesel plant. TEMES constructed Piti 7, a 40 MW combustion turbine. Ownership of the Tanguisson plant ECA has changed from HEI to Mirant and from Mirant to Pruvient. MEC ownership has changed from Tomen Bank and Enron to Osaka Gas and Arclight, and finally solely to Osaka Gas. TEMES ownership remains the same. These contracts are for twenty-year terms. Table 1-1 indicates nominal generation capacities, and the effective and termination dates for the ECA contracts.

GPA is in an era of "contracted competition." GPA must measure its generation system performance against the performance and cost achieved by the ECA contractors.

1.5 Performance Management Contracts

The Guam Power Authority staff came up with the idea of using PMCs to improve baseload plant reliability and efficiency. GPA staff recognized that GPA did not have sufficient plant management, technical, and plant operation acumen resident at GPA to run its baseload facilities well. Keeping many of these skill sets full-time at the Authority is economically prohibitive. Additionally, GPA already had difficulty recruiting to fill technical and professional positions. Also, GovGuam procurement does not support an operations environment well. GovGuam procurement issues often result in prolonged unit outages. Furthermore, the Authority recognized the need for better, consistent training of its plant staff. Finally, staff foresaw that performance-based compensation would best drive exemplary performance and better protect the ratepayer from poor performance.

Table 1-1, ECA Summary

Plant	IPP	Plant Capacity (MW)	Contract Effective Date	Contract Termination Date
Piti Unit 7 (Combustion Turbine)	TEMES	40	December 1997	December 2017
Piti Unit 8&9 (Slow Speed Diesel)	MEC	88	January 1999	January 2019
Tanguisson Unit 1&2* (Steam)	Pruvient[2]	53	August 1997	August 2017

Using these salient points, GPA staff engaged management about the opportunity to use a contracted management team to manage, maintain, and operate its baseload plants. The Authority worked with two consultants[3] to flesh out the details of applying staff concepts and entered into a collaborative development of a PMC for Cabras 1&2 with the Guam Public Utilities Commission. All Authority baseload plants are now under the management of PMCs. These contracts have resulted in increased plant efficiencies and availabilities.

1.6 Near-Term Generation Addition

The Authority must make prudent decisions for near-term generation additions in light of its expectation for increasing electric demand. DOD's proposed buildup of facilities and the movement of marine units from Okinawa will drive increasing electric demand in the next eight years. This is in contrast to growth driven by tourism expansion in the nineties. However, uncertainties in DOD planning and approval of funding by a new Congress and presidential administration provide an element of risk.

1.6.1 Long Term Generation Reliability

GPA is in the midst of a transformation towards long-term generation system reliability. Beyond FY 2007, GPA contends that it will improve and maintain generation plant reliability to place among the top quartile of units as part of its strategic vision. The Authority will embark on a program for continuous measurable improvement in

[2] Contract has been reassigned two times. HEI (Hawaii Electric Industries Inc.) was the first IPP then Mirant.

[3] Larry R. Noyes of New Energy Associates in Atlanta, Georgia and Dave L. Rogers of Information2Energy.

generation reliability to meet or exceed unit availability levels stipulated in its ECAs by fiscal year 2010.

1.6.2 Environmental Constraints

GPA faces major environmental constraints on adding baseload capacity. In the short-term, Cabras-Piti complex is the only developed site for baseload expansion. Expansion on this site is limited by air-emission permitting as well as ocean discharge permitting. Currently, the Orote Basin is designated a non-attainment area for SO_2. However, the Section 325 waiver granted to GPA works in its favor. This waiver allows GPA to use higher sulfur content fuel when the wind blows offshore.

The Authority submitted a petition for re-designation of the Cabras-Piti area during 1996 based on air quality modeling and ambient air monitoring. However, GovGuam and GPA did not follow through. Hence, the re-designation did not occur.

If GPA chooses to pursue re-designation after a 10-year hiatus, it will face a number of potential obstacles[4]:

- Although United States Environmental Protection Agency Region 9 (USEPA IX) retains some individuals familiar with the 1996 petition (including USEPA's lead attorney), some others will need to be familiarized with the project;
- USEPA IX policies and regulatory focus may have changed;
- USEPA will likely want to see additional ambient air quality monitoring data;
- USEPA will likely want to see evidence that fuel switching has been taking place as required;
- USEPA will likely also expect to see activities by Guam Environmental Protection Agency (GEPA) that GPA will not directly control, including SIP (State Implementation Plan) revision, updated regulations and new permit conditions on the Cabras-Piti power plants;
- USEPA will likely also expect to see GEPA create a sulfur dioxide maintenance plan; and
- Staff and administration at GEPA has changed.

It is also likely that unexpected issues will arise. This is not surprising when dealing with a 10-year-old petition as well as local and federal regulators. Furthermore, limits on thermal discharge into the ocean will likely require cooling towers for new plants. However, the Section 325 exemption available to GPA can be a powerful tool to manage those challenges.

[4] McNurney, John M. [JMcNurney@RWBeck.com] email

1.6.3 Generation Mix and Load Shape

The Authority has all its generation in oil-fired units. This presents a strategic problem that has arisen over the last few years. While it is a prudent choice in the past because oil was inexpensive, it is no longer the case.

Peaking unit technologies are relatively inexpensive and quick to install but expensive to operate. Therefore they are ideally operated only during system peak demand periods or as reserve units in the absence of reliable baseload capacity. Efficient baseload units require much longer permitting and construction lead times. However, they possess much higher capital requirements for installation but are less expensive to operate. Intermediate units have unit characteristics between peaking and baseload. Table 1-2 describes the characteristics of these unit operating modes and technologies.

GPA's current generation mix has substantial number of diesel-fired peaking plants stemming from the need to add capacity in the early 1990s. In the last few years, the Authority has not relied heavily on diesel-fired generation to produce electric energy.

Guam's year-round tropical climate and tourism-based economy results in a relatively flat load cycle with high load factor. Such characteristics tend to favor baseload technology additions since operation near the peak is the norm. As an example, Figure 1-1 shows the GPA average demand hourly load shape for the period April 29 – 30, 2008. Note that GPA requires peaking capacity for only four hours for about 15 to 19 MW incremental peak.

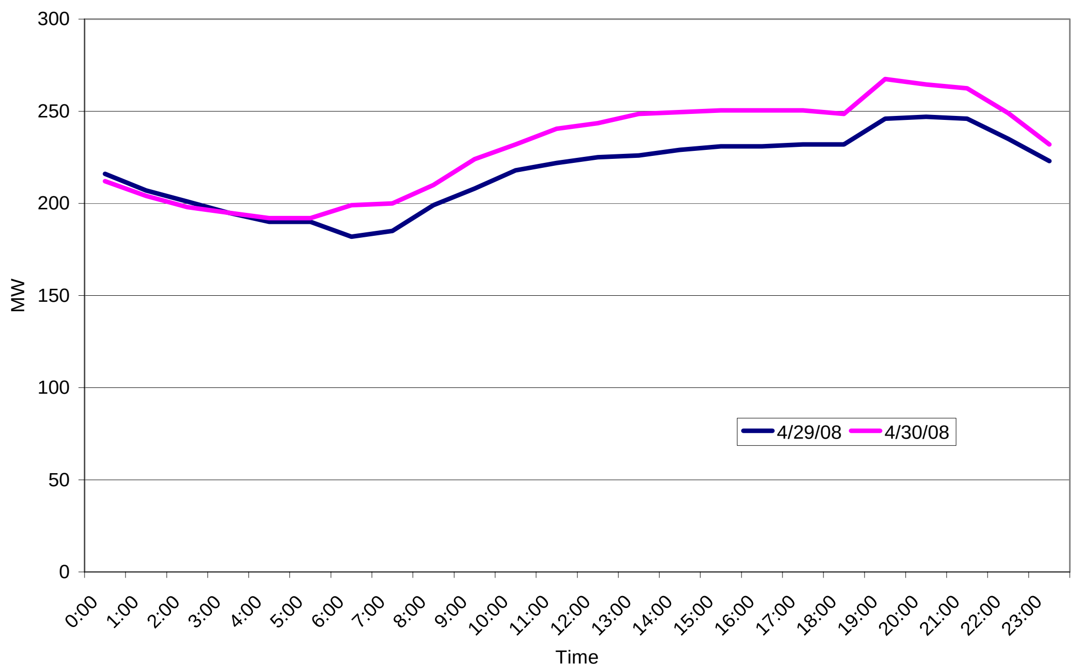


Figure 1-1, GPA Average Hourly Generation Requirements

Table 1-2, Duty Cycles and Capacity Factors[5]

Generating Unit Duty Cycle	Capacity Factor (%)		Generic Characteristics		
	Nominal	Range	Cost	Performance	Other
Baseload	65	50-85	High capital cost; low fuel cost; low maintenance cost	High Availability; high efficiency	Long Construction Lead Times
Intermediate	30	20 – 50	Intermediate-to-high capital cost; intermediate fuel cost	Increased output flexibility	Generally long construction lead times
Peaking	10	1-20	Low capital cost; high fuel cost; high maintenance cost	Increased output flexibility; quick starting	Short construction lead time

1.7 Fuel Issues

Fuel is a complicated issue. It now comprises over two-thirds of residential electric power rates. The issue is a global issue and affects all fuel types. Fuel issues include:

- Fuel price volatility;
- Risk of Fuel supply disruption;
- Fuel diversity;
- Environmental policies;
- Fuel hedging; and
- Prudent Fuel Use.

For the Guam Power Authority, fuel diversity will involve putting infrastructure in place to support other fuel types. This includes procurement, delivery, storage, and on-island transport. Figure 1-2 shows historical fuel prices for Diesel Fuel Oil No. 2, High-Sulfur Fuel Oil (HSFO), and Low-Sulfur Fuel Oil (LSFO).

[5] 1993 EPRI Technology Assessment Guide Volume 1: Electricity Supply. Table 2-1

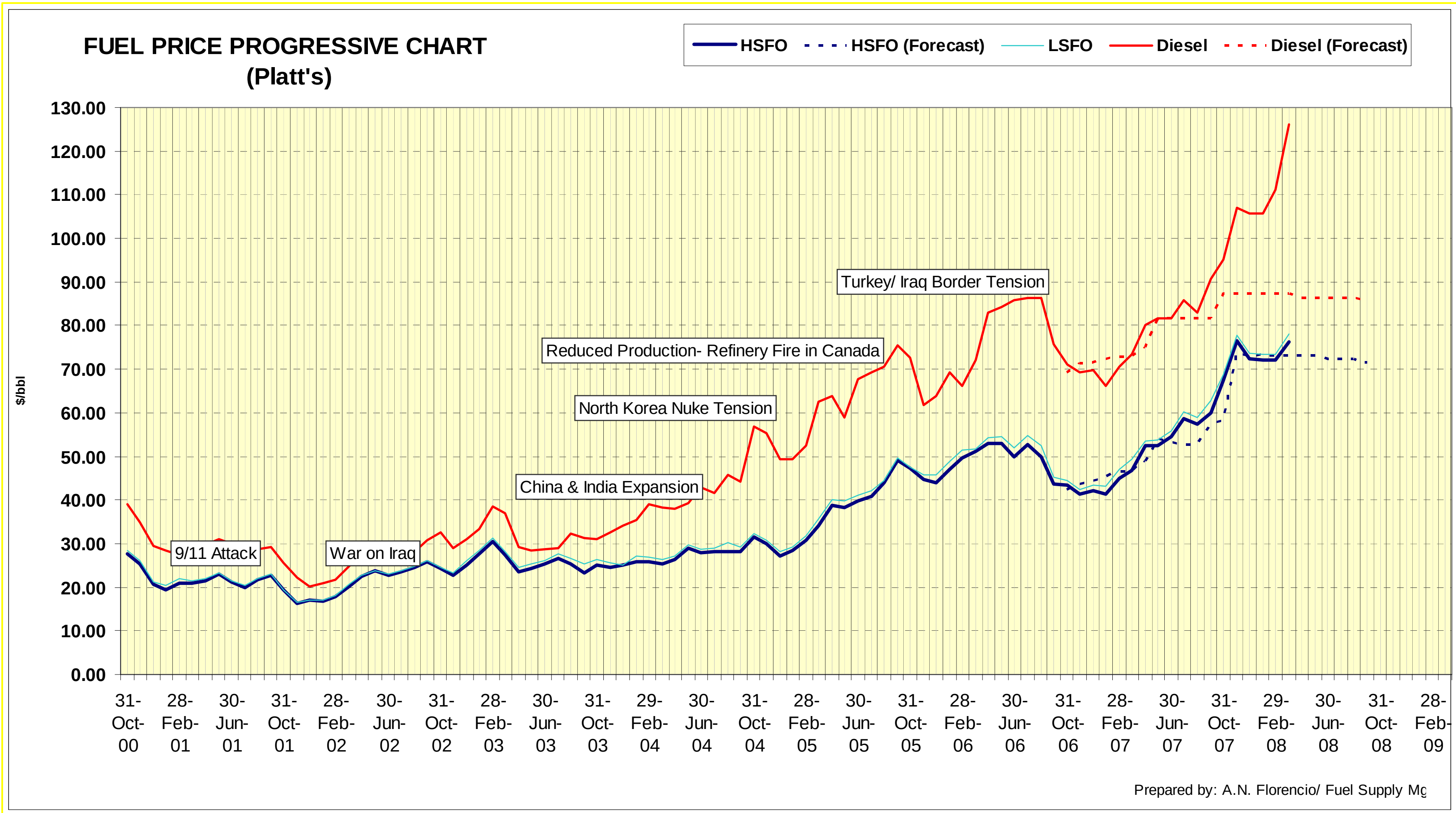


Figure 1-2, Historical Fuel Prices for Diesel No. 2, HSFO, and LSFO

1.7.1 Comprehensive Fuel Management Planning Requirement

GPA's Board of Directors has directed management to plan for fuel purchases. This directive has the following challenges:

- The availability of Major Baseloads impact fuel use dramatically;
- Generator failures are stochastic;
- Fuel Purchase Minimums must reflect expected unit dispatch but contain market and Fuel Management costs; and
- Fuel Purchase Maximum must reflect agreed upon contingencies.

The fuel purchase planning process must revisit the generation expansion plan. It must investigate fuel use under the assumption of expected or target operation modes as well as operation modes under various unit failure contingencies. GPA must plan for a bandwidth of operation and provide acceptable minimum and maximum fuel purchase limits.

This planning process must include a fuel purchase planning framework to provide the following:

- Fuel Purchase Minimums to satisfy expected use and inventory requirements; and
- Flexibility to accommodate baseload failures.

1.7.2 Change in Purchasing Practices Driven by Increased Baseload Reliability

With improvements to baseload reliability, GPA relies less on diesel fuel for energy production. Figure 1-3 shows the GPA's consumption by fuel type for FY 1991 through FY 2006. Figure 1-4 shows GPA production fuel expense by type for FY 1991 through FY 2006. Figure 1-5 shows the fuel savings to customers as a result of increased operational efficiencies.

The cost difference between Residual Fuel Oil (RFO) No. 6 and Diesel Fuel Oil (DFO) No. 2 on a per unit basis is a major system cost issue. Historically, DFO No. 2 is 1.5 times more expensive than HSFO No. 6.

The increase in diesel fuel use from FY 1992 until FY 1996 is due to fast track units serving loads. The drop in this fuel use from 1996 to 1999 is due to the operation of the Cabras 3&4. Despite the high unavailability of its own baseload units, the decline in diesel fuel use from FY 2000 to FY 2001 is due to the energy production from Independent Power Producers (IPP). The dip in fuel use from both RFO and diesel in FY 2002 is due to loss of loads because of typhoons. Recent historical decrease in the use of DFO No. 2 from FY 2003 stems from increased energy production from baseload units under the PMCs. Note that better baseload availabilities and better attention to economic dispatch have reduced both RFO and diesel consumption.

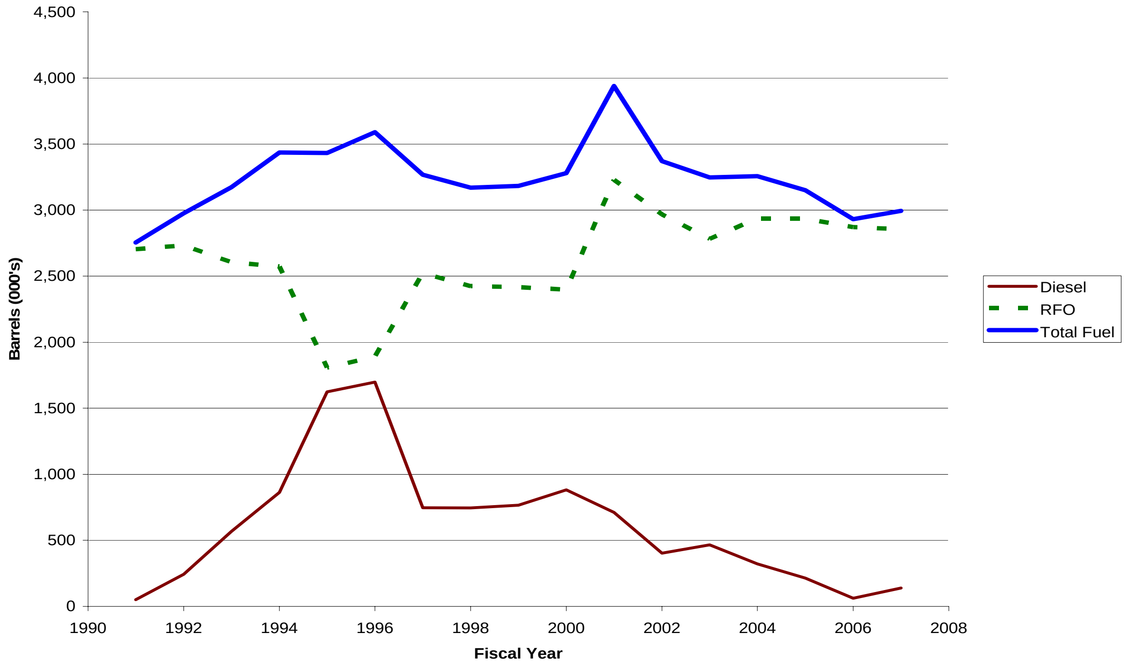


Figure 1-3, Production Fuel Consumption (000 Barrels) For FY 1991 Through FY 2007

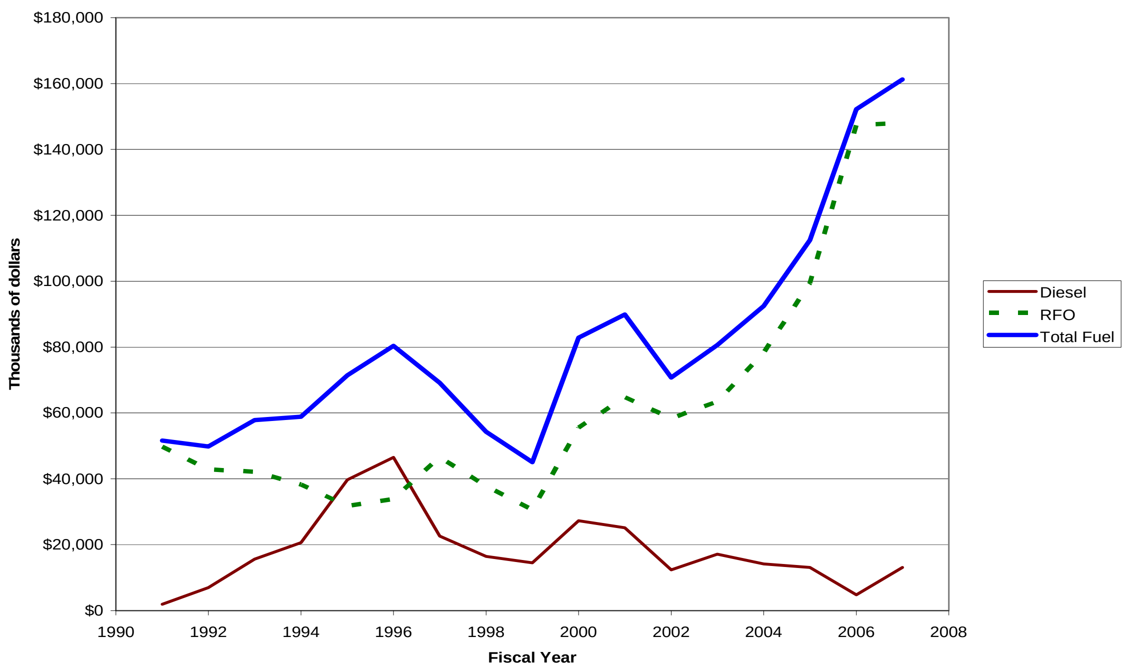


Figure 1-4, Production Fuel Expense ($000) For FY 1991 Through FY 2007

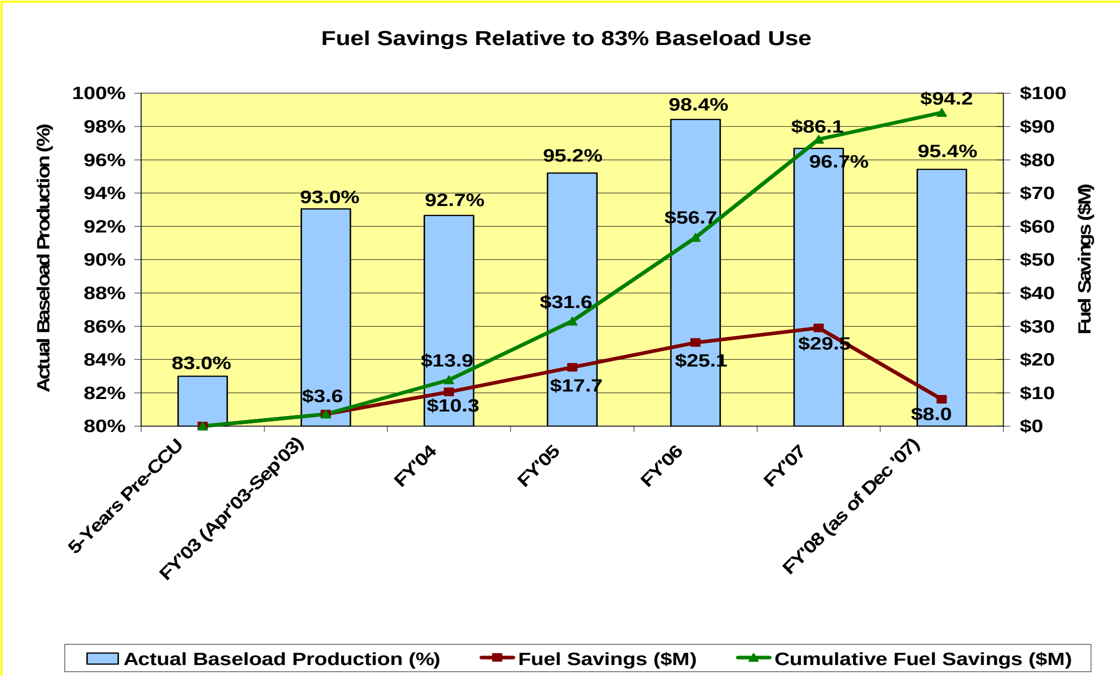


Figure 1-5, Fuel Savings Due to Increased Efficiency in Operations

1.8 Generation Retirement

GPA must prudently plan for generation unit retirements. Keeping units as back-up for poor operations is expensive. GPA must consider N-M scenarios, where N represent the number units installed and M represent the number of units on outage. Keeping assets because of equipment failures for large values of M is very expensive. However, GPA must also weigh the cost of unserved energy as part of the planning process.

1.8.1 Manpower Utilization Issues

Any retirement plan for generation must account for disposition of personnel. Thus, any generation retirement plan must assess the extent to which required personnel reductions may take place by retirement or retraining for reassignment within GPA and the Government of Guam.

1.8.2 Operational Value of Diesel-fired Assets

GPA must consider the operational value of units as strategic reserve by quantifying it in terms of net present value (NPV).   Additionally, the introduction of non-firm capacity renewable energy will require quick-start generation as a backup. The Authority would not need to add this backup capability. It already exists.

1.9 Risk

There are several risks that the Authority has exposure to in creating and executing upon the recommendations of the IRP. These include planning risk, financial risk, and regulatory risk. The Authority must institutionalize uncertainty and risk management throughout all its planning: operational, financial, medium-range, and long-range.

1.9.1 Planning Risk

Long-term electric power supply planning must consider risk. As part of the planning process, the utility needs to forecast loads, sales, economic variables, and revenues. Additionally, it must forecast the capital, fixed, and variable costs for various power supply candidates. The longer the forecast, the greater the risk for divergence from what may actually transpire.

In order to plan well, the Authority needs to consider scenario planning. "Scenario planning, which considers adaptive behavior under alternative futures, is uniquely suited for identifying and categorizing unknown utility risks."[6]

The magnitude and timing of DOD load growth is still very much uncertain. It may be prudent for the Authority to work with Guam Waterworks Authority (GWA) on an interruptible load arrangement in order to hedge against the risk of higher than baseline load growth;

In addition to forecast risk, the run-up of fuel prices and tightening of supply, especially in the last quarter of calendar year 2007, to $126/BBL for crude oil is of great concern and threatens the affordability of electricity on Guam. It is also having an enormous financial impact as free cash flows are being diverted to fuel inventory. This run-up on fuel price is pushing the drive to fuel diversity and the introduction of renewable energy.

1.9.2 Financial Risk

There are three finance issues affecting resource planning:

- Short-Term Debt;
- GPA's Growing Long Term Bond Debt; and
- Bond and Credit Rating.

[6] Karyl B. Leggio, David L. Bodde, and Marilyn L. Taylor. "Managing Enterprise Risk: What the Electric Industry Experience Implies for Contemporary Business." Oxford, U.K.: Elsevier Ltd. 2006. page 14.

1.9.2.1 Short Term Debt

The Guam Legislature granted GPA the authority to obtain Tax Exempt Commercial Paper (TECP). Commercial paper is unsecured capital market financing based on the financial strength of the organization. The paper has varying terms between 30 - 270 days. Interest is payable upon expiration of the notes. TECP benefits include the following:

- Lower Interest Rates;
- Flexible Terms; and
- Flexible Drawdown.

GPA and its regulators must consider the need to preserve GPA's access to such financing. TECP is short-term debt. It has the probability of being rolled-over, but contains an element of risk. TECP should be used prudently. GPA's continued drawdown of its letters of credit to their maximum limits with out a cycle of full payment within the year has negatively affected its relations with lending institutions. GPA cannot allow this to occur with TECP.

Recently GPA’s attempts to obtain TECP financing have failed due to market and credit issues.

1.9.2.2 GPA Long Term Debt Outlook

GPA has undergone an accelerated and massive capital improvement driven by the high load growth and economic boom of the late 1980s and 1990s. Table 1-3 shows the growth in GPA assets and long-term bond debt.

GPA's access and the terms of access to the municipal bond market is an important resource advantage over alternative financing provided by other means. GPA must prudently manage its financial position in order to maintain access to the investor-grade municipal bond market. Furthermore, GPA has improved its bond rating from non-investment grade (junk) to its current rating: Standard & Poor's (S&P) – BB+, Stable, Moody’s and Fitch – Ba1, Positive Outlook.

Table 1-3, GPA Total Assets and Total Bond Commitments

Year	Total Assets (000's)	Total Bond Debt (000's)
FY07	$ 756,114	$ 381,595
FY06	$ 779,963	$ 386,888
FY05	$ 769,855	$ 391,901
FY04	$ 781,395	$ 396,648
FY03	$ 810,326	$ 401,141

1.9.3 Regulatory Risk

Federal and local legislation regarding environmental and utility policy may have a large impact upon the choice of competing planning portfolios. Of concern is the institution of greenhouse gas legislation such as a carbon cap and trade program and renewable portfolio standards. The concerns are well founded and fundamentally affect the economics of the addition of coal-fired generation. On a global and domestic scale, carbon legislation and cap & trade programs are:

- Currently in place in the EU, Japan, Australia, etc;
- China is working on implementation;
- Mainland has a voluntary credit mechanism trading today;
- EEI and other major trade groups have announced their support of the upcoming legislation;
- Most trade groups and major utilities are activity involved in the shaping of the legislation;
- Expected to be passed in 2010 and in effect in 2012.

2 Strategic Issues

The Strategic Issues behind this Integrated Resource Planning (IRP) effort include:

- Fuel Diversity, fuel supply risk, and renewable energy;
- Supporting the electric power service requirements for the impending Department of Defense (DOD) build-up and its economic consequences; and
- Acquisition of new electric energy supply and its implication on human resource requirements and the Authority business model.

Fuel diversity is the top driving force behind this IRP effort. The rising cost of fuel oil impacts the affordability of electric energy and saps free cash flows from operations and capital investments into fuel inventory. Fuel price volatility is an increasing strategic issue with petroleum. Additionally, having a non-diversified fuel base places the Authority's customers at a higher risk for supply disruption. Furthermore, local dollars for fuel oils are almost entirely spent outside the local economy. This money does not multiply itself among the community. Renewable sources of energy may allow for some of these dollars to trickle into the local economy. Finally, as an island people, the results of greenhouse gases contributing to climate change are clearly evident in the shrinking coastlines of Guam and our island neighbors.

Tourism growth triggered the economic boom of the nineties. The Authority grew from a 156 MW to a 281.5 MW peaking utility in less than a decade. The engine for next decade of economic growth on Guam will be the DOD build-up and its economic consequences in the civilian community.

Acquisition of new diversified electric energy supply has implication on human resource requirements. The Authority is not familiar with many of these new technologies. The Authority must consider whether new electric supply assets will depend entirely on external labor sources or whether Guam needs to grow the labor pool necessary to support these human resource needs. Furthermore, the Authority's business models include its own generation with internal staffing, independent power producers with external staffing, and performance management contracts with mixed staffing. Additionally, there are private sector advantages in execution and tax credit eligibility. Public sector advantages include Federal Emergency Management Agency (FEMA) and government grant eligibility and lower costs of money. Using the business model to provide the greatest value for customers is a strategic concern.

3 Scope of Work

This study is part of a regular cycle in the process of overall utility and strategic planning. In this phase, GPA will investigate the following issues related to critical near-term and potential long range strategic decisions:

- The Need For Generation Capacity (Next Unit Addition);
- Retirement Of All Generation Units Singly And In Combination;
- Benefits and Costs of GPA's Demand-Side Management Program;
- Projected Effect of Implementing a Deep Sea Water Cooling Distribution System in Tumon Bay;
- Implementation of Renewable Portfolio Standards Policy; and
- An Optimized Near and Long-Term Generation Expansion Plan.

4 IRP Process

GPA combines an analytical process approach and a stakeholder approach in developing this IRP.

4.1 Analytical Process

GPA used the following steps below to develop this IRP.

- Review planning environment;
- Develop inputs and assumptions;
- Develop load and resource balance to identify annual capacity/energy positions;
- Define candidate resource list, including demand-side management and supply resources;
- Use the capacity expansion optimization tool STRATEGIST to determine the optimal portfolio that eliminates annual capacity deficits according to capacity reserve margin requirements;
- Use planning scenario results to help determine a diversified resource mix that is robust across the range of alternative futures;
- Create risk analysis portfolios based on alternative strategies for managing portfolio risks that can be differentiated; and
- Select a preferred portfolio using evaluation criteria: *Cost, risk, system reliability, emission.*

4.1.1 Review Planning Environment

GPA considers fuel diversification and renewable portfolio standards in this IRP including conventional and renewable candidate resources. Research efforts included fuel accessibility, price and storage. GPA focuses intensely on wind power primarily because of availability of data on capital and operational costs and maturity of technology. However, in the implementation of the recommendations GPA will consider wind power as a proxy for all renewables.

4.1.2 Develop Inputs & Assumptions

GPA uses a software application to determine optimal expansion plan based on lowest system costs. With that, critical information is inputted such as operational costs (fixed and variable costs, production efficiencies, etc.), anticipated load requirements, seasonal use, and availability/maintenance scheduling, to name a few. For new resources, construction timelines and capital/construction cost assumptions are applied.

In addition to this GPA must consider impacts of changes in capital costs, anticipated legislation (Carbon Cap & Trade or Renewable Production Tax Credits), uncertainties in Guam growth and uncertainties in fuel. Assumptions are typically made and new scenarios are developed in order to consider them.

4.1.3 Develop Load & Resource Balance

As the sole power utility on Guam, GPA must ensure power is available to its customers. System availability and reliability is a factor in determining when to bring in the next resource. System reserve margins ensure that the system is capable to serve its customers when a unit or several units are not operational due to maintenance or forced outages. R.W. Beck consultants recommended that a 50-60% reserve margin is appropriate for Guam.

4.1.4 Define Candidate List

The selection of potential resources can have a serious affect on an island grid. Units sized inappropriately will affect system reliability and may put the system at risk for system blackouts. Additional considerations include land requirements, local and federal regulation restrictions (environmental impact), accessibility to fuel resources, and fuel diversification. These are supply-side options.

GPA must also consider options for the customer-side. These are typically referred to Demand-Side Management (DSM) programs. They may be in the form of rebate program that promotes energy efficient appliances or displacing electricity use by an alternate source such as ocean water cooling for large hotel air conditioning systems.

4.1.5 Determine Optimal Portfolio

In order to determine an optimal portfolio a modeling software for resource expansion optimization is used. This software analyzes planning scenario costs which include load requirements, operational costs, and financing/bond requirements to determine the most economical plan for a study period. GPA licensed STRATEGIST to perform this task.

4.1.6 Determine Diversified Resource Mix

The STRATEGIST software will determine the most economical plans without constraints for fuel diversity. GPA should consider fuel diversification in addition to the most economic plans. However, GPA believes that the most economic plans will have substantial diversification.

4.1.7 Create Risk Analysis

Fuel market uncertainties and typhoons are risks that Guam is exposed to. Although fuel prices can be adjusted and analyzed through the expansion tool software, damages to wind turbines after a super typhoon and loss of production capacity and additional repair costs are not easily analyzed. Optimal plans identified through software modeling are further evaluated against such risks.

4.1.8 Select Preferred Portfolio

After all the models have been run and the risk analysis has been completed a preferred portfolio can now be selected that incorporates a least cost optimal plan and has considered risk factors.

4.2 Stakeholder Process

GPA uses a stakeholder process in an effort to involve the community in the development of the IRP. This process allowed GPA to provide the community progress in the plan and also initiated dialogue on assumptions and risk considerations being used for new resource candidates, fuel forecasts and availability, and local and federal regulations.

GPA selected representatives from different areas in the community and held four public meetings that presented progress information on the current state of GPA, anticipations of the IRP, information used in the IRP, and the modeling results. The meetings initiated in October 2007 and the last meeting was held in April 2008.

4.2.1 The Stakeholders

GPA initiated the stakeholder process by selecting and inviting people from the community which represent the following areas:

- Department of Defense (DOD);
- Hotel Industry (Guam Hotel & Restaurant Association);
- Construction Industry (Guam Contractors Association);
- Financial Institution (Bank of Guam);
- Legislature;
- Government Agencies (Guam Energy Office, Guam Chamber of Commerce, Port Authority of Guam, Civilian Military Task Force/DPW, EPA);
- Environmental;

- Other (Residential Customers);
- Public Utilities Commission of Guam (Guam PUC); and
- Consolidated Commission on Utilities (CCU).

4.2.2 Meetings

GPA completed four public meetings during the development of the IRP. The initial meeting provided an overview of the Authority and objective of the IRP as well as preliminary data acquired. The next meeting discussed the key assumptions being used. The third meeting provided preliminary results. Finally, the fourth and final meeting provided the updated assumptions and results.

GPA has tried to incorporate or address concerns generated during these work sessions by initiating additional research on other fuels and technologies as well as updating forecasts. All presentations, handouts and audio files were made available to the public on the GPA website at: www. guampowerauthority.com.

5 Future Electric Requirements of Guam

GPA contracted P.L. Mangilao Energy in FY 2006 to develop and update an econometric model to forecast GPA's sales and load. At the onset of this contract, there were four scenarios of probable load growth: No significant growth, Rapid tourism growth, Rapid infrastructure growth, and Rapid tourism and rapid infrastructure growth[7]. This was during the early discussion period of the Okinawa military base relocation and consideration of the Naval and Air Force base expansions. During the last several months however, it has become more evident that Department of Defense (DOD) growth will occur and that the baseline scenario should reflect this as infrastructure impact. Thus, the scenarios evaluated for this integrated resource plan are:

- Normal – "Business as Usual" (No DOD Buildup);
- Baseline – Moderate Tourism Growth and DOD Buildup; and
- High – Rapid Tourism and Rapid Infrastructure Growth.

These scenarios are based on local research on construction, labor, tourism, and anticipated DOD growth. The levels of growth due to DOD buildup present significant construction and employment opportunities. Ultimately, this affects Guam's economic outlook. Potential infrastructure spending due to primarily DOD contracts, amount to $8 billion as early as 2013 and totaling $16 billion by 2025 for a rapid infrastructure scenario. Growth in infrastructure will impact the GPA electrical system due to energy requirements necessary to support new load and the capability of the system to meet energy demand.[8]

5.1 The Econometric Model

There are several variables that go into an econometric model. Economic forecasts for Guam and Japan by Moody's are used to provide the basis for tourism and construction assumptions for Guam. Additional information that will affect construction activities, such as DOD buildup, is provided through the Department of Defense Quadrennial Report and meetings with DOD representatives. Historical weather and peak load data is also used to develop patterns for energy use (sales).

GPA uses the latest E-view program version to run its forecasting model. This is a Windows-based forecasting package developed by QMS (Quantitative Micro Software). Figure 5-1 identifies the variables used in the GPA model.

[7] GPA Peak Demand and Sales Forecast Documentation, PL Mangilao Energy, LLC, September 23, 2007.
[8] Forecasting GPA's Long Range Sales and Load, 2007 GPA Pacific Power Association Conference Paper

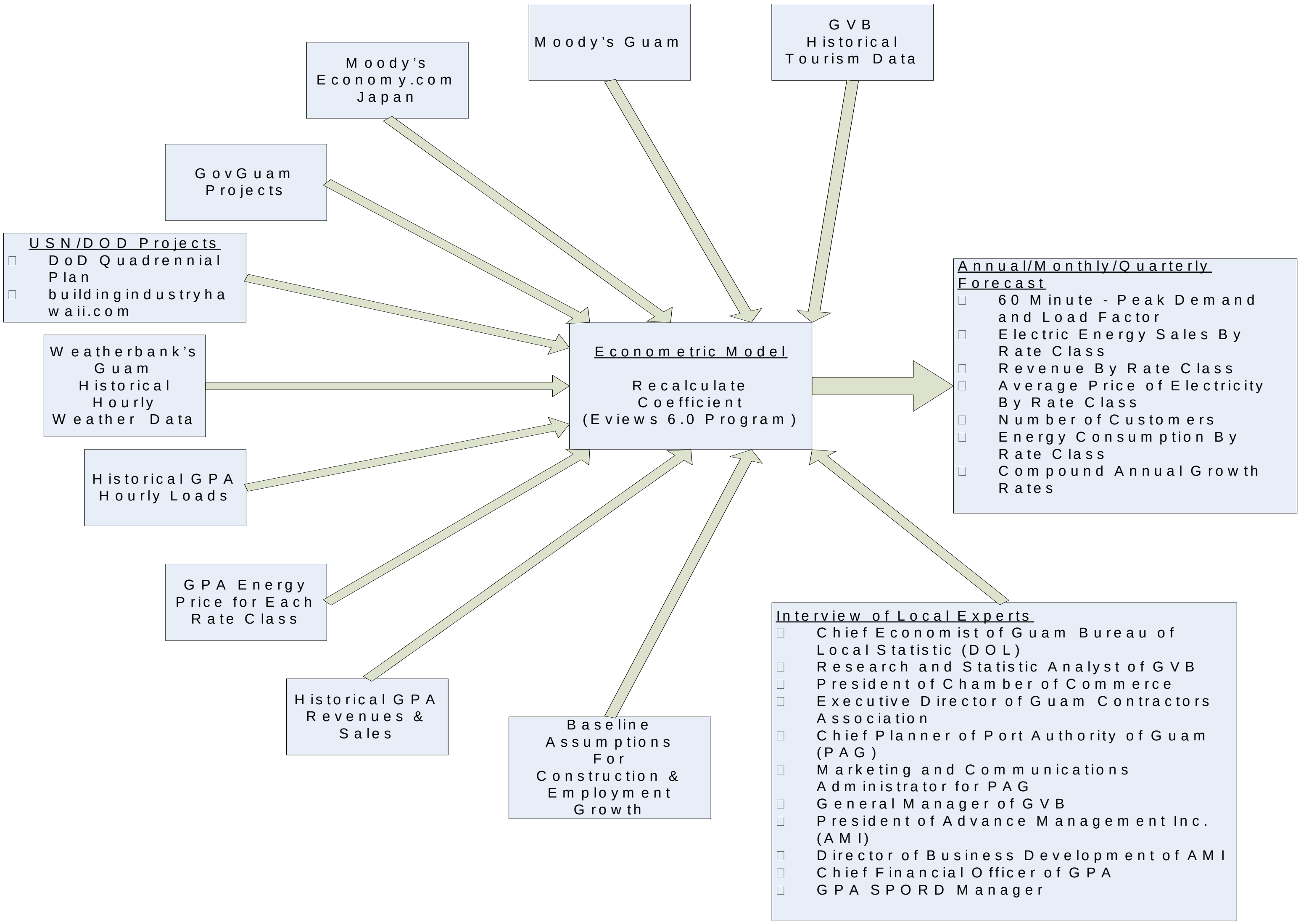


Figure 5-1, Econometric Model Input/Output Flow Diagram

5.2 Summary of Load Forecast Scenarios

The Normal ("Business as Usual") scenario does not consider significant tourism growth or appreciable DOD buildup. It does not consider the Okinawa base relocation.

The Baseline scenario is based on the Moody's forecast for Guam and Japan. It incorporates a 5.4% employment growth and anticipates a peak of 366 MW by 2017.

The High scenario considers a more expansive DOD buildup, inclusive of basing of aircraft carriers and attack submarines.

5.2.1 Forecast Assumptions

P.L. Mangilao made several assumptions in the forecast as shown in Table 5-1. These are based on their experiences and prior research over several decades forecasting in the electric power industry. This data is used for all scenarios.

Table 5-1, Forecast Assumptions

Assumptions	Assumed Value
Number of jobs created indirectly for every new infrastructure job	0.6
Construction employment effects are transitory	
Number of permanent operating or maintenance job is created for every $1 (2005 $) in construction spending:	1
A/E Firm's Average Overhead Rate:	30%
Guam Average Hourly Earnings In Construction (2005 $):	$11.50
Mainland Average Hourly Earnings In Construction (2005 $):	$37.00
Construction Expenditure per Construction Job (2005 $):	$189,150
% of Materials & Supplies in Construction Expenditure:	67%
% Labor Costs in Construction Expenditure:	33%
% of I-94 Labor:	50%
% of Mainland Labor:	50%
I-94 Workers, % of wages spent locally:	30%
Mainland Workers, % of wages spent locally:	50%
Indirect Employment Multiplier	0.60

In addition to the forecast assumptions, proposed construction projects for GovGuam and DOD were also considered. The projects are listed in Table 5-2 and the annual construction expenditures are graphed in Figure 5-2.

Table 5-2, Construction Projects

Project Description	Estimated Cost	Estimated Project Start	Estimated Project Completion
X-ray Wharf Upgrade by Sun Woo Corp	$ 2,000,000	2006	2006
Romeo Sierra Wharves Upgrade by Reliable Builders	$ 3,000,000	2006	2006
Dredging Naval Harbor	$ 8,000,000	2006	2006
Naval Waterworks and Wastewater Projects	$ 103,600,000	2008	2008
Naval Power System Hardening and Recapitalize	$ 400,000,000	2007	2017
Alpha Bravo Wharves Project	$ 55,000,000	2006	2007
Liguan Terrace Elementary School	$ 30,000,000	2006	2008
Astumbo Middle School	$ 30,000,000	2006	2008
Ukudu High School	$ 30,000,000	2006	2008
Adacao Elementary School	$ 30,000,000	2008	2010
New DoDEA Elementary/Middle School	$ 40,600,000	2006	2008
New DoDEA High School	$ 40,600,000	2006	2008
Housing construction and renovation at Naval Station	$ 512,000,000	2006	2025
Munitions storage facilities at AAFB	$ 15,000,000	2006	2006
Guam Army National Guard Facility Phase IV	$ 4,900,000	2006	2006
Replace AAFB Canine Facility	$ 3,500,000	2006	2007
GPA Underground Lines Upgrade	$ 200,000,000	2006	2013
GTA Modernization Investment	$ 100,000,000	2006	2010
Water System Upgrade	$ 360,000,000	2007	2009
P-780A, Upgrade NW Field, Ph I	$ 12,000,000	2007	2009
P-780B, Upgrade NW Field, Ph II	$ 12,000,000	2007	2009
Global Hawk Complex	$ 52,000,000	2007	2009
P-502, Kilo Wharf Extension, Ph I	$ 101,800,000	2008	2008
P-494, Harden Electrical System, Dist/Subs	$ 50,000,000	2007	2009
Naval Hospital Replacement	$ 145,000,000	2008	2011
8,000 Marines from Okinawa	$ 6,600,000,000	2008	2012
P-502A, Kilo Wharf Extension, Ph II	$ 25,000,000	2008	2008
Future Naval Construction	$ 3,168,000,000	2010	2025
High Growth Scenario:			
Aircraft Carrier Group	$ 3,150,000,000	2010	2015
Submarine 1	$ 189,000,000	2010	2014
Submarine 2	$ 189,000,000	2015	2019
Submarine 3	$ 189,000,000	2020	2024
Submarine 4	$ 189,000,000	2025	2029
Total	$16,040,000,000		

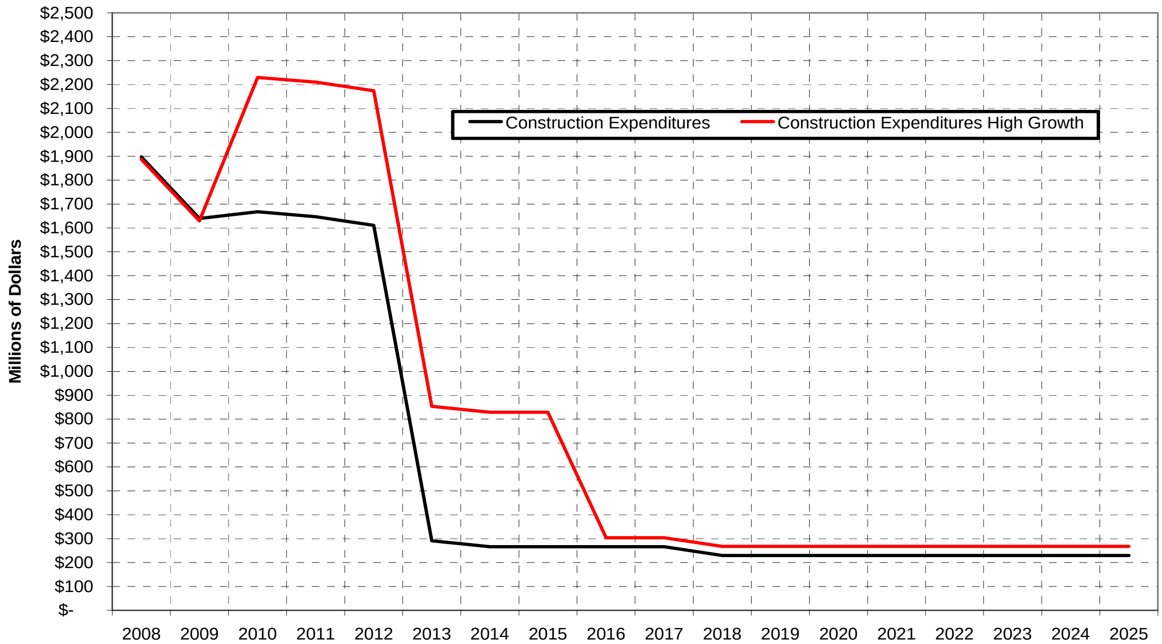


Figure 5-2, Total Construction Expenditures

5.2.2 Energy and Peak Demand Forecast

Figure 5-3 charts the forecast results for GPA energy sales. All three scenarios show significant growth rates with the High scenario taking off as early as 2008.

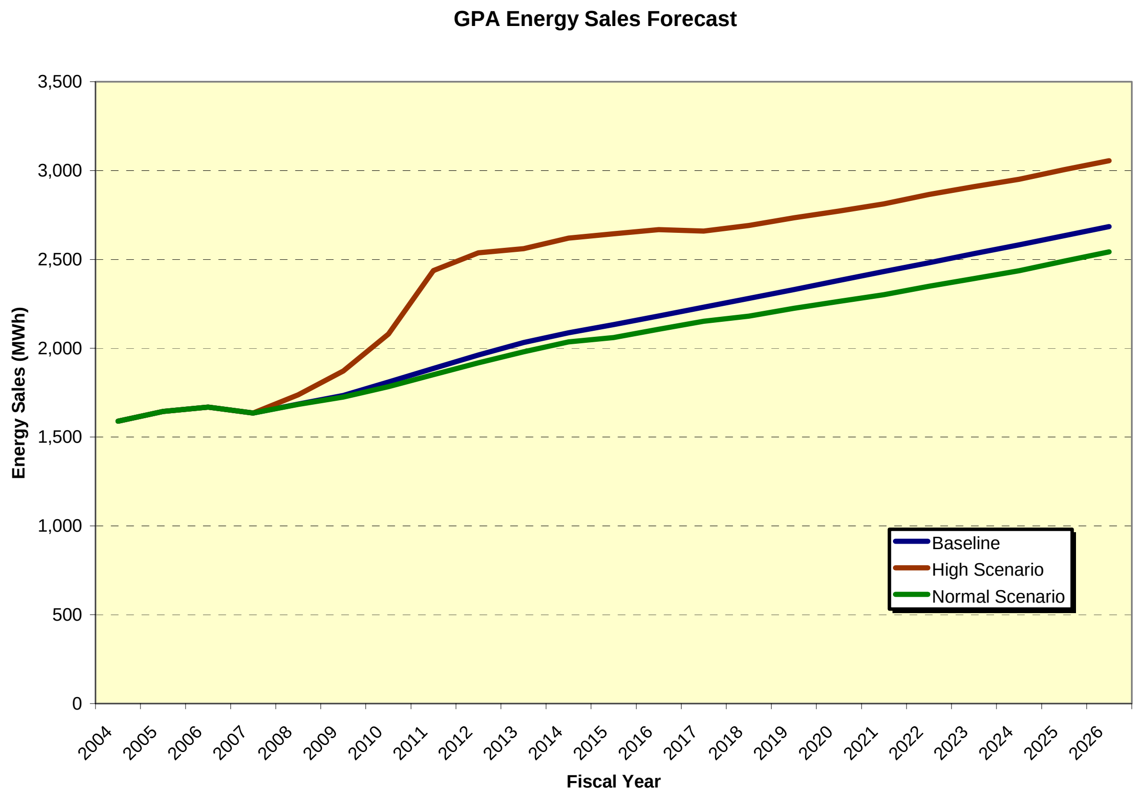


Figure 5-3, Energy Forecast

Figure 5-4 graphs the peak demand forecast. Based on a 60% reserve margin, the Baseline scenario shows new capacity is required in 2017. This is 5 years earlier than the scenario with minimum growth. Although GPA's currently installed capacity is sufficient to support a baseline scenario growth for the next several years GPA would need to start initiating the acquisition of the next unit due to procurement, engineering and construction schedules.

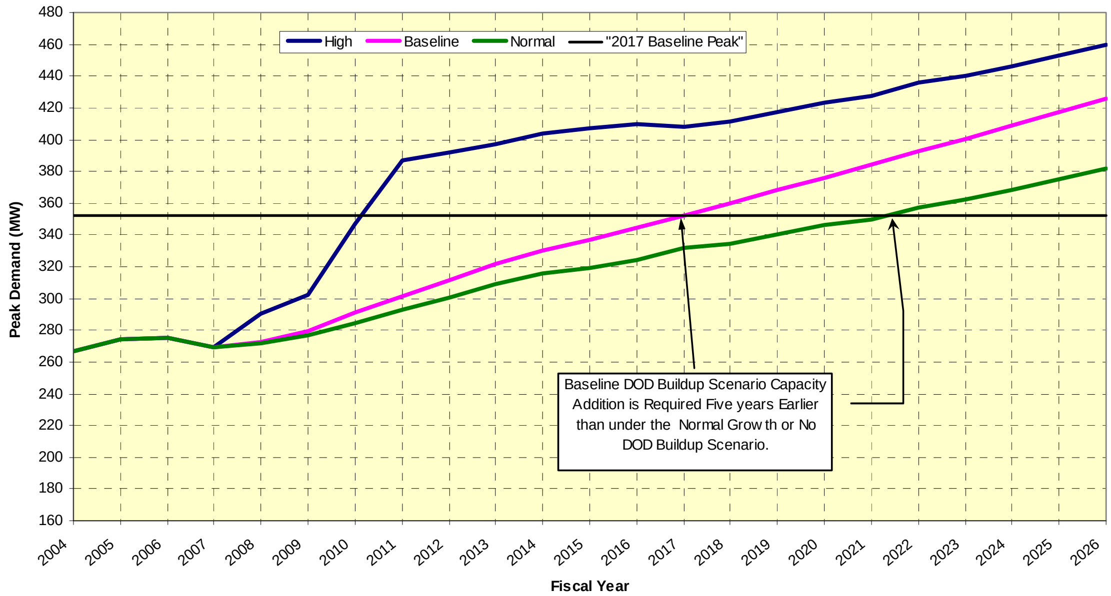


Figure 5-4, Peak Demand Forecast

6 Future Fuel Costs & Choices for GPA

GPA contracted P.L. Mangilao Energy in 2008 to develop the fuel price forecasts for Residual Fuel Oil (RFO), Diesel Oil (Diesel), Coal, and Liquefied Natural Gas (LNG). P.L. Mangilao Energy's fuel price forecast for RFO and Diesel are based on the forecasts of Singapore prices consistent with Strategic Energy and Economic Research's (SEER's) most recent "Global Petroleum SEER Monthly".[9] Similarly, the forecast for LNG is consistent with SEER's most recent outlook for natural gas, "Natural Gas SEER Monthly". The forecast for thermal coal is developed by JD Energy. These three forecasting organizations have been working closely together for more than a decade and their forecasts of energy prices are constructed to be rigorously consistent.

Figure 6-1 shows the forecast for high and low sulfur fuel oils, diesel, coal and LNG in heat energy unit price based on the long-term baseline scenario developed P.L. Mangilao Energy back in early 2008. However, current market conditions indicate higher than forecast prices for the near-term Prices are expected to rise even higher due to the weakening of the US dollar and the growing geopolitical tensions.

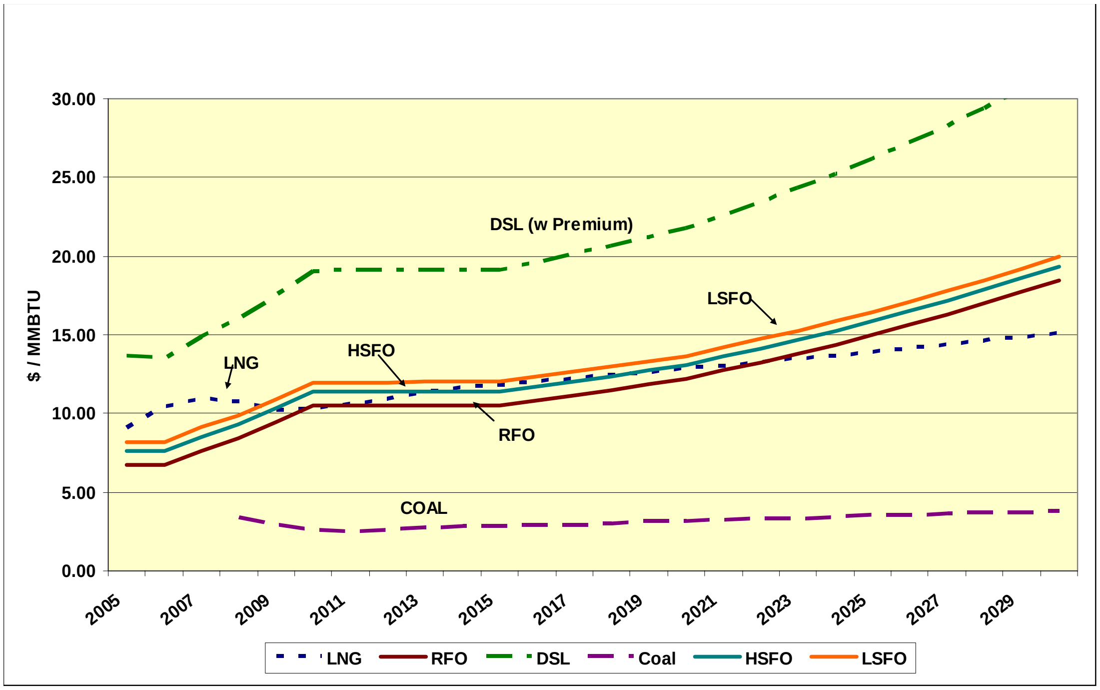


Figure 6-1, Forecast for Petroleum Products, Coal and LNG ($/MMBTU)

[9] GPA Peak Demand and Sales Forecast Documentation, PL Mangilao Energy, LLC, September 23, 2007.

The heat energy unit price forecasts are based on 5.7 million BTUs per barrel for Diesel, 6.0 million BTUs per barrel for High and Low Sulfur Fuel Oil.

The forecast fuel price for diesel is the SEER's forecast Singapore price for Gasoil plus the average markup in GPA's Diesel supply contracts, $14.2 per barrel. The forecasts for both High and Low Sulfur Fuel Oil recognizes that the price GPA pays is pegged to Singapore price for 180 cst Residual prices. An added markup of $5.30 per barrel is the markup over 180 cst Residual in GPA's supply contract and a special additional markup for the Low Sulfur variety of $3.49 per barrel is also from GPA's supply contract.

6.1 Price Forecast for Fuel Oil

P.L. Mangilao Energy developed three scenarios for the fuel oil price forecasts; a Low, a Base, and a High case. Prices given in the scenarios are shown for the following:

- West Texas Intermediate (WTI) in nominal or current year $/barrel;
- US Refiner's Acquisition Cost of Crude (a benchmark price in energy markets);
- Prices for RFO and No. 2 Fuel Oil CIF Singapore; and
- Prices for RFO and No. 2 Fuel oil CIF Guam.

The price of petroleum products in Asia, including Singapore and Guam is shape by the global market forces, such as product balances and shipping costs. Diesel Oil is historically 1.5 times more expensive than RFO, and shipping "clean" products such as Diesel fuel costs more. However, refinery economics do not vary significantly over the long term, and the outlook and forecasts over the next two decades result to eventual minimal differences between the RFO and Diesel forecasts prices.

6.1.1 Base Case

Table 6-1 illustrates P.L. Mangilao's base case outlook for petroleum products that will be purchased by GPA. This scenario shows approximately a 2% increase in worldwide oil production capacity, and by the end of 2008, the strong growth in oil productive capacity is expected to cause sharp downward pressures on oil and natural gas prices.

Table 6-1, Fuel Oil Forecast (Base Case)

	Current Year $ per BBL					
	US RAC	Singapore	Singapore	Guam	Guam	
	Imported Crude	Resid 180	Gasoil	Resid	Gasoil	WTI
2005	$46.53	$39.58	$62.09	$40.45	$63.35	$54.91
2006	$58.88	$39.41	$61.37	$40.31	$62.67	$66.05
2007	$60.94	$44.99	$69.22	$45.92	$70.55	$71.95
2008	$62.44	$49.63	$75.59	$50.55	$76.93	$71.92
2009	$65.53	$55.62	$84.01	$56.56	$85.38	$71.57
2010	$68.75	$61.87	$92.81	$62.84	$94.21	$71.98
2011	$68.88	$61.99	$92.99	$62.98	$94.42	$72.26
2012	$68.97	$62.08	$93.11	$63.09	$94.58	$72.56
2013	$69.03	$62.13	$93.19	$63.17	$94.70	$72.73
2014	$69.05	$62.14	$93.21	$63.21	$94.76	$72.75
2015	$69.02	$62.12	$93.18	$63.21	$94.76	$72.67
2016	$71.08	$63.98	$95.96	$65.10	$97.59	$72.47
2017	$73.21	$65.89	$98.83	$67.04	$100.49	$74.45
2018	$75.40	$67.86	$101.78	$69.04	$103.49	$77.53
2019	$77.64	$69.88	$104.82	$71.09	$106.57	$80.74
2020	$79.96	$71.96	$107.95	$73.20	$109.74	$84.09
2021	$83.39	$75.05	$112.57	$76.32	$114.41	$87.73
2022	$86.93	$78.24	$117.36	$79.54	$119.24	$91.47
2023	$90.61	$81.55	$122.32	$82.88	$124.25	$95.25
2024	$94.41	$84.97	$127.45	$86.34	$129.43	$99.11
2025	$98.35	$88.51	$132.77	$89.91	$134.79	$103.02
2026	$102.64	$92.38	$138.57	$93.82	$140.65	$107.21
2027	$107.10	$96.39	$144.58	$97.86	$146.71	$111.73
2028	$111.71	$100.54	$150.80	$102.05	$152.98	$116.50
2029	$116.48	$104.83	$157.25	$106.38	$159.48	$121.79
2030	$121.42	$109.28	$163.92	$110.87	$166.21	$126.71

6.1.2 High Price Case

P.L. Mangilao's high price case outlook is similar to the high price case contained in the US DOE/EIA 2007 Annual Energy Outlook. This can be found on US DOE's website - www.eia.doe.gov/oiaf/archive/aeo07/aeohighprice.html.

This takes into consideration global market uncertainties that can drive up the price of petroleum products, such as supply disruptions and strong demand growth. Table 6-2 illustrates the high case outlook for petroleum products delivered to Guam.

Table 6-2, Fuel Oil Forecast (High Case)

	Current Year $ per BBL					
	US RAC Imported Crude	Singapore Resid 180	Singapore Gasoil	Guam Resid	Guam Gasoil	WTI
2005	$46.53	$39.58	$62.09	$40.45	$63.35	$54.91
2006	$58.88	$52.99	$79.49	$53.89	$80.79	$66.05
2007	$60.94	$56.81	$85.21	$57.73	$86.54	$71.95
2008	$64.48	$59.34	$89.01	$60.26	$90.34	$72.17
2009	$69.73	$63.42	$95.14	$64.37	$96.50	$74.84
2010	$75.19	$67.67	$101.51	$68.64	$102.91	$78.42
2011	$79.48	$71.53	$107.30	$72.52	$108.73	$82.55
2012	$83.93	$75.54	$113.31	$76.56	$114.78	$86.48
2013	$88.56	$79.70	$119.55	$80.75	$121.06	$91.12
2014	$93.36	$84.03	$126.04	$85.10	$127.59	$96.54
2015	$98.35	$88.52	$132.78	$89.61	$134.36	$102.01
2016	$103.32	$92.99	$139.49	$94.12	$141.11	$107.64
2017	$108.48	$97.63	$146.45	$98.78	$148.11	$112.74
2018	$113.83	$102.45	$153.67	$103.63	$155.38	$117.97
2019	$119.38	$107.44	$161.17	$108.65	$162.91	$123.57
2020	$125.14	$112.63	$168.94	$113.87	$170.73	$129.27
2021	$129.84	$116.85	$175.28	$118.12	$177.12	$134.19
2022	$134.69	$121.22	$181.84	$122.53	$183.72	$138.64
2023	$139.71	$125.74	$188.61	$127.07	$190.54	$143.88
2024	$144.89	$130.40	$195.61	$131.77	$197.58	$149.30
2025	$150.25	$135.22	$202.84	$136.63	$204.86	$154.92
2026	$155.94	$140.34	$210.51	$141.78	$212.59	$160.72
2027	$161.81	$145.63	$218.45	$147.11	$220.58	$166.71
2028	$167.89	$151.10	$226.65	$152.61	$228.83	$172.90
2029	$174.16	$156.75	$235.12	$158.30	$237.36	$179.30
2030	$180.65	$162.59	$243.88	$164.17	$246.17	$185.94

6.1.3 Low Price Case

On the other hand, excess oil productive capacity can lead to sharp drops in oil prices. This would be the most likely case if the world economy can return to reasonable political stability and moderate economic growth. Table 6-3 shows the Low Price Case scenario constructed by SEER.

Table 6-3, Fuel Oil Forecast (Low Case)

	Current Year $ per BBL					
	US RAC Imported Crude	Singapore Resid 180	Singapore Gasoil	Guam Resid	Guam Gasoil	WTI
2005	$46.53	$39.58	$62.09	$40.45	$63.35	$54.91
2006	$58.88	$52.99	$79.49	$53.89	$80.79	$66.05
2007	$60.94	$54.06	$82.26	$54.98	$83.59	$71.95
2008	$61.19	$54.55	$82.61	$55.47	$83.94	$69.13
2009	$62.98	$56.42	$85.03	$57.36	$86.39	$69.28
2010	$64.83	$58.35	$87.52	$59.31	$88.92	$69.67
2011	$63.91	$57.52	$86.28	$58.51	$87.71	$68.38
2012	$62.91	$56.62	$84.93	$57.64	$86.40	$62.17
2013	$61.82	$55.64	$83.45	$56.68	$84.96	$63.15
2014	$60.63	$54.57	$81.85	$55.64	$83.40	$62.95
2015	$59.35	$53.41	$80.12	$54.51	$81.70	$63.61
2016	$61.34	$55.21	$82.81	$56.33	$84.43	$65.09
2017	$63.40	$57.06	$85.59	$58.21	$87.25	$67.24
2018	$65.52	$58.97	$88.46	$60.15	$90.16	$69.46
2019	$67.71	$60.94	$91.41	$62.15	$93.16	$71.74
2020	$69.97	$62.97	$94.46	$64.21	$96.25	$74.10
2021	$72.57	$65.31	$97.96	$66.58	$99.80	$76.80
2022	$75.25	$67.72	$101.58	$69.03	$103.47	$79.59
2023	$78.02	$70.22	$105.33	$71.55	$107.25	$82.47
2024	$80.88	$72.79	$109.19	$74.16	$111.17	$85.44
2025	$83.84	$75.45	$113.18	$76.86	$115.21	$88.51
2026	$86.89	$78.20	$117.31	$79.64	$119.38	$91.69
2027	$90.05	$81.04	$121.56	$82.52	$123.69	$94.96
2028	$93.31	$83.98	$125.96	$85.49	$128.14	$98.34
2029	$96.67	$87.00	$130.51	$88.55	$132.74	$101.83
2030	$100.15	$90.13	$135.20	$91.72	$137.49	$105.43

6.2 Price Forecast for LNG

P.L. Mangilao presented three cases for LNG price forecast, Base Case, High Case, and Low Case. This forecast is based on the Indonesia market (Tangguh) for LNG. It is considered the most likely source of LNG for Guam. Prices shown are for the commodity cost of LNG purchased at Tangguh, the cost of transport to Guam, the cost of regasification, and the delivered cost.

P.L. Mangilao points out that there are several challenges regarding the use of LNG as a substitute for Diesel and RFO. These are major challenges that GPA must seriously consider. The smallest sized LNG tankers require the corresponding required storage facilities be available on Guam. Increased costs are associated with purchasing a partial tanker load. Regasification requires a minimum throughput to be economic. To overcome these challenges, it was assumed that other applications for natural gas would be developed so that the overhead cost of storage and regasification could be spread over larger volumes.

The Tangguh LNG prices are shown in Tables 6-4, 6-5 and 6-6, the differences in the data being the adjustments for transportation costs and regasification of LNG.

6.2.1 Base Case Forecast

Table 6-4 is the base case outlook for LNG Prices for Guam. The delivered price of LNG is expected to gradually decrease over the forecast time horizon, from $10.91/mmbtu in 2007 (CIF Guam) to $13.90/mmbtu in 2025.

Table 6-4, LNG Forecast (Base Case)

Nominal $ per MMBTU

	Tangguh Indonesia	Transport	Regas	Guam Delivered Price
2005	5.15	1.30	2.65	9.09
2006	6.37	1.34	2.73	10.44
2007	6.74	1.37	2.80	10.91
2008	6.58	1.37	2.80	10.75
2009	5.95	1.41	2.87	10.22
2010	5.92	1.44	2.94	10.30
2011	6.13	1.48	3.01	10.62
2012	6.34	1.51	3.09	10.94
2013	6.57	1.55	3.16	11.28
2014	6.80	1.59	3.24	11.63
2015	6.86	1.63	3.32	11.82
2016	6.93	1.67	3.41	12.01
2017	7.00	1.71	3.49	12.20
2018	7.07	1.76	3.58	12.40
2019	7.13	1.80	3.67	12.60
2020	7.20	1.85	3.76	12.81
2021	7.27	1.89	3.85	13.02
2022	7.34	1.94	3.95	13.23
2023	7.42	1.99	4.05	13.45
2024	7.49	2.04	4.15	13.67
2025	7.56	2.09	4.25	13.90
2026	7.63	2.14	4.36	14.13
2027	7.71	2.19	4.47	14.37
2028	7.78	2.25	4.58	14.61
2029	7.86	2.30	4.70	14.86
2030	7.93	2.36	4.81	15.11

6.2.2 High Price Case

Table 6-5 shows the High Price Case forecast for LNG delivered to Guam, where LNG is expected to reach $16.43/mmBTU in 2025.

Table 6-5, LNG Forecast (High Case)

Nominal $ per MMBTU

	Tangguh Indonesia	**Transport**	**Regas**	**Guam Delivered Price**
2005	5.15	1.30	2.65	9.09
2006	6.37	1.34	2.73	10.44
2007	6.74	1.37	2.80	10.91
2008	7.16	1.37	2.80	11.33
2009	7.14	1.41	2.87	11.41
2010	7.46	1.44	2.94	11.84
2011	7.59	1.48	3.01	12.08
2012	7.80	1.51	3.09	12.40
2013	7.84	1.55	3.16	12.56
2014	7.78	1.59	3.24	12.61
2015	7.91	1.63	3.32	12.87
2016	8.17	1.67	3.41	13.25
2017	8.42	1.71	3.49	13.62
2018	8.67	1.76	3.58	14.01
2019	8.89	1.80	3.67	14.35
2020	9.11	1.85	3.76	14.71
2021	8.89	1.89	3.85	14.63
2022	9.15	1.94	3.95	15.04
2023	9.45	1.99	4.05	15.49
2024	9.76	2.04	4.15	15.95
2025	10.08	2.09	4.25	16.43
2026	10.41	2.14	4.36	16.92
2027	10.76	2.19	4.47	17.42
2028	11.11	2.25	4.58	17.94
2029	11.47	2.30	4.70	18.47
2030	11.85	2.36	4.81	19.02

6.2.3 Low Price Case

Table 6-6 shows the Low Price Case forecast for LNG delivered to Guam, where LNG is expected to reach $13.49/mmBTU in 2025.

Table 6-6, LNG Forecast (Low Case)

Nominal $ per MMBTU

	Tangguh Indonesia	Transport	Regas	Guam Delivered Price
2005	5.15	1.30	2.65	9.09
2006	6.37	1.34	2.73	10.44
2007	6.74	1.37	2.80	10.91
2008	6.14	1.37	2.80	10.31
2009	5.77	1.41	2.87	10.05
2010	5.60	1.44	2.94	9.97
2011	5.79	1.48	3.01	10.28
2012	6.00	1.51	3.09	10.60
2013	6.21	1.55	3.16	10.92
2014	6.43	1.59	3.24	11.26
2015	6.49	1.63	3.32	11.44
2016	6.55	1.67	3.41	11.63
2017	6.62	1.71	3.49	11.82
2018	6.68	1.76	3.58	12.02
2019	6.74	1.80	3.67	12.21
2020	6.81	1.85	3.76	12.42
2021	6.88	1.89	3.85	12.62
2022	6.94	1.94	3.95	12.83
2023	7.01	1.99	4.05	13.05
2024	7.08	2.04	4.15	13.27
2025	7.15	2.09	4.25	13.49
2026	7.22	2.14	4.36	13.72
2027	7.29	2.19	4.47	13.95
2028	7.36	2.25	4.58	14.19
2029	7.43	2.30	4.70	14.43
2030	6.17	2.36	4.81	13.35

6.3 Delivered Cost of Coal

Similarly, P.L. Mangilao developed two cases for the coal price forecast. This forecast is based on the assumption that coal will be delivered to Guam will most likely come from local Pacific Basin producers in Indonesia or Australia. The price adjustments are made to include transportation costs to Guam.

6.3.1 Base Case Forecast

Table 6-7 presents P.L. Mangilao's base case forecasts for Indonesian Coal delivered to Guam. It was assumed that Indonesian Coal would have had an average delivered price of $67.80.ton (CIF Guam) in 2008. It is expected to reach $69.50/ton in 2025.

Table 6-7, Coal Forecast (Base Case)

	Delivered Prices			
	2006$/t		Nominal $/t	
	Australia	Indonesia	Australia	Indonesia
2008	95.20	66.20	97.50	67.80
2009	79.20	55.80	83.14	58.58
2010	69.30	49.20	74.57	52.94
2011	63.40	45.50	69.92	50.18
2012	65.70	46.70	74.27	52.79
2013	66.90	47.40	77.52	54.92
2014	66.20	46.80	78.62	55.58
2015	65.90	46.80	80.22	56.97
2016	65.50	46.40	81.73	57.90
2017	65.10	46.20	83.26	59.09
2018	64.80	45.90	84.95	60.17
2019	64.40	45.60	86.54	61.28
2020	64.40	45.60	88.70	62.81
2021	64.00	45.50	90.35	64.24
2022	63.70	45.20	92.18	65.41
2023	63.30	44.90	93.89	66.60
2024	62.90	44.60	95.63	67.81
2025	62.90	44.60	98.02	69.50
2026	62.50	44.40	99.83	70.92
2027	62.10	44.10	101.67	72.20
2028	61.70	43.90	103.54	73.67
2029	61.40	43.60	105.62	75.00
2030	61.20	43.40	107.90	76.52

6.3.2 High Price Case

Table 6-8 presents P.L. Mangilao's High Price Case forecast for Indonesian Coal delivered to Guam. Indonesian Coal was expected to reach $93.94/ton in 2025.

Table 6-8, Coal Forecast (High Case)

	Delivered Prices			
	2006$/t		Nominal $/t	
	Australia	Indonesia	Australia	Indonesia
2008	95.20	66.20	97.50	67.80
2009	79.20	55.80	83.14	58.58
2010	85.00	60.28	91.46	64.86
2011	85.00	60.28	93.74	66.49
2012	85.00	60.28	96.09	68.15
2013	85.00	60.28	98.49	69.85
2014	85.00	60.28	100.95	71.60
2015	85.00	60.28	103.48	73.39
2016	85.00	60.28	106.06	75.22
2017	85.00	60.28	108.72	77.10
2018	85.00	60.28	111.43	79.03
2019	85.00	60.28	114.22	81.01
2020	85.00	60.28	117.07	83.03
2021	85.00	60.28	120.00	85.11
2022	85.00	60.28	123.00	87.24
2023	85.00	60.28	126.08	89.42
2024	85.00	60.28	129.23	91.65
2025	85.00	60.28	132.46	93.94
2026	85.00	60.28	135.77	96.29
2027	85.00	60.28	139.16	98.70
2028	85.00	60.28	142.64	101.17
2029	85.00	60.28	146.21	103.70
2030	85.00	60.28	149.87	106.29

7 Supply Side Options

The supply side options are identified to support an island grid system, provide fuel diversification, or support renewable energy standards.

7.1 Generation Resource Candidates

R.W. Beck, a subcontractor to local engineering firm Winzler & Kelly, support the research and development of this integrated research plan. R.W. Beck consultants researched viable and mature options for the GPA system which includes unit size, technology type, construction schedule, capital and operating costs, operating parameters (fuel efficiency, operating capacity, etc.), environmental issues (emissions, siting concerns, etc), fuel availability and price trends, and the availability and reliability of each technology.

The research results include six (6) options:

- Small Coal-Fired Power Plant – a pulverized coal (PC) boiler or circulating fluidized bed (CFB) boiler powering steam turbines;
- Small Combined-Cycle Power Plant W/ Liquefied Natural Gas (LNG) Facility – Combustion Turbines fueled by LNG;
- Wind Farm – On-shore, ridgeline configuration wind turbines, off- shore a possibility;
- Re-power Piti Power Plant - Retro-fitting Piti 7 Combustion Turbine (CT) into a Combined-Cycle plant by adding an Heat Recover Steam Generator (HRSG) and a Steam Turbine (ST);
- Biomass Power Generation Facility – Steam turbine generator plant fueled by biofuels and municipal solid waste; and
- Reciprocating Engine – Low or medium speed water cooled diesel units utilizing efficient reciprocating engine.

7.1.1 Capital & Operating Costs

A summary of costs are provided in Table 7-1.

Table 7-1, New Supply Side Options, Construction & Operation Costs[10]

Plant Description / Technology	Nominal Capacity MW	Primary Fuel	Capital Cost $000	Capital Cost $/kW	FOM $000	VOM $000	VOM $/MWH
Steam / PC/CFB	60	Coal	300,250	5,004	$ 4,928	$ 2,061	4.61
CC w/ LNG / LM6000	60	LNG	334,000	5,567	$ 4,004	$ 1,212	2.56
Wind / 10x2MW On-shore	40	Wind	97,076	2,427	NA	NA	19
Retrofit / Piti 7 CC	60	No. 2	71,601	NA	$ 2,464	$ 2,206	4.61
Biomass / Stoker/CFB	10	MSW	85,608	8,561	$ 4,107	$ 5,690	76.88
Recip / 2x20MW S/MSD	40	No. 6	70,980	1,775	$ 2,135	$ 1,669	5.64

7.1.2 Construction Schedules

GPA and R.W. Beck believe that overlapping of Permitting and Engineering work can occur most especially with low environmental risk options. Other options such as a coal plant would presumably require permitting to be completed before additional investments is put into plant construction.

A summary of permitting and construction timelines is provided in Table 7-2.

Table 7-2, New Supply Side Options, Construction Timelines[11]

Plant Description	Technology	Months		
		Permitting	Start of Eng to CO	Total Duration
Steam	PC/CFB	30	36	66
CC w/ LNG	LM6000	30	28	43
Wind	10x2MW Onshore	15	9	18
Retrofit	Piti 7 CC	24	18	30
Biomass	Stoker/CFB	30	30	45
Recip. Engine	2x20MW S/MSD	24	18	30

[10] Letter to GPA on Development of Resource Option Characteristics, R.W. Beck, November 16, 2007.
[11] Ibid.

7.2 Fuel Conversion Options

In addition to new power facilities, GPA researched fuel conversion of existing diesel fired-units to natural gas fuel. Natural gas can potentially provide GPA fuel diversification at a much lower cost than new supply options. GPA assumes that the fuel will be received as a gas (after regasification process) for fuel that has been shipped in liquefied form from Indonesia or Australia. The following was capital cost conversion for existing GPA facilities:

Table 7-3, Fuel Conversion Project Costs for Existing GPA Facilities

Existing Diesel-Fired Plants	LNG Conversion Costs ($000)*
Tenjo Plant	$39,608
TEMES CT	$8,633
Cabras 1&2 Plant	$17,667
Tanguisson Plant	$22,821
Macheche CT	$10,407
Dededo CT 1&2 Plant	$21,800
Yigo CT Plant	$14,020

Conversion costs include pipeline costs from the Cabras fuel farm area which is a potential area for gas storage.

7.3 Additional Options

During the course of the IRP development, GPA met with several companies that proposed, work with or supplied renewable energy alternatives. Several of these companies also participated in the stakeholder meetings and provided GPA with some information that are modeled in Strategist as options to the baseline models performed. The results are discussed later in the IRP. The companies and the power generation technologies discussed are:

- **Solar Thermal Plant,** *NAAVONO Energy USA, Inc* - Utilizes a liquid medium running parallel through parabolic solar trough which is heated vaporization to drive turbine;

- **Biogas (Methane) Extraction,** *Ship Supply, Logistic/Provisions* - Plant fueled with captured methane from decomposing waste at the Ordot dump;

- **Ocean Thermal Energy Conversion (OTEC),** *OCEES* - Using warm surface water to vaporize system fluid (ammonia) to drive turbine to produce electricity and cold deep water cools fluid to cycle the process; and

- **LNG + H2 Motor Generator,** *h2ondemand* - Fuel blend of natural gas and hydrogen with Deutz Hydrogen motors.

Next to hydro-power, wind power is the most mature of large renewable technologies to date. GPA uses wind power as a proxy for other renewable options.

However, GPA has initiated research on large solar photovoltaic plant, integrated gasification combined cycle (IGCC) plant, and geothermal plants as additional supply side renewable options.

The IGCC option is a coal conversion to synthetic gas process which is typically connected to a combined cycle plant for power production in industrial plants. Initial research has found they are high in capital costs, there is not reference plant design yet, there are few vendors or engineers for this technology, and it is hard to get favorable contract terms or risk sharing.

GPA has also initiated discussions of geothermal potential for Guam with a company in California but has not been able to complete research on this.

8 Demand Side Management

8.1 Introduction

Demand Side Management (DSM) activities and programs modify the shape and magnitude of customer loads in a way that is mutually beneficial to the customer and the Authority.

GPA filed a 20-year resource DSM plan with the PUC in 1993. The plan indicated a reduction of 27 MW in net capacity by 2000, and 39 MW by 2010, corresponding to estimated energy savings of 47,000 MWH and 118,000 MWH respectively, if the four most cost-effective programs were implemented. In August 1994, these four programs were initiated:

- Commercial Lighting;
- Commercial Air Conditioning;
- Residential Air Conditioning; and
- Residential Water Heating.[12]

However, personnel movement in FY 2000 required GPA to rebuild its DSM portfolio and reorganize the organization to be able to support the DSM program. Implementation was thus cut short.

For FY 2008, GPA decided to re-consider the implementation of DSM programs as a supplement for this period's IRP. A large-scale option and several small scale options were evaluated.

Guam Seawater Air Conditioning (GSWAC) is being considered as a major DSM program. Makai and Market Street Energy performed a technical and economic assessment of the major components of Guam Seawater Air Conditioning (GSWAC) system to determine operational performance, probable costs, economic and business advantages, risks and potential challenges.

For the small-scale options, a study was performed by R.W. Beck to evaluate the cost-effectiveness of residential and commercial DSM programs for potential implementation by GPA. Projections were based on the assumptions and circumstances described in the R.W. Beck Report.

[12] Demand Side Management Study, R.W. Beck, March 2008.

8.2 DSM Resource Alternatives

8.2.1 Large-Scale DSM Program

GSWAC explores the potential for using deep, cold seawater for air conditioning hotels and other buildings on Tumon Bay. Deep seawater at 42.5°F is brought to shore via an intake pipeline located three miles offshore at a depth of 2200’. Through a heat exchanger, the seawater will come in contact with a fresh water loop and bring down the temperature of fresh water. The cooled fresh water is then delivered to the customers.

8.2.2 Small-Scale DSM Programs

For the small-scale options, twenty-four DSM programs were suggested to GPA, and four were considered eligible for potential application:

- Energy Efficient Lighting Retrofit – Retrofit existing (60W) incandescent and fluorescent lamps with compact fluorescent and high-efficiency fluorescent lamps. Utility promotion through public information programs;

- Solar Photovoltaic – Install a 5-kW solar photovoltaic electric generation system in residential dwellings;

- Solar Thermal Water Heating – Install 40-gallon solar thermal water heating system in residential dwellings to replace electric water heating system; and

- Energy audit – Dwelling and business energy efficiency and infrared heat detection audits conducted by the utility.

Customers implement low-cost recommendations, providing 10% reduction in typical energy use.

8.3 Peak and Energy Impacts

8.3.1 Large-Scale DSM Program

The implementation of GSWAC as a large-scale DSM option will yield approximately 92 GWH energy savings per year. GSWAC uses one-sixth ($1/6^{th}$) the power of conventional air conditioning, with a capacity factor of over 70%.

8.3.2 Small-Scale DSM Programs

The impacts resulting from the small scale DSM programs are described in Table 8-1 as annual energy savings and peak reductions.

Table 8-1, Energy Savings from Small-Scale DSM Programs

	PENETRATION	MEASURE LIFE	ENERGY REDUCTION	NON-COINCIDENT DEMAND REDUCTION	PEAK DEMAND REDUCTION	COINCIDENT FACTOR	LOAD FACTOR
	# customers	years	kWh/year	kW	kW		
RESIDENTIAL PROGRAMS:							
Energy Efficient Lighting Retrofit	200	5	135,000	92.00	46.00	0.50	16.8%
Solar Photovoltaic (5 kW)	10	20	130,000	50.00	40.00	0.80	29.7%
Solar Thermal Water Heating	500	15	1,350	2.25	0.34	0.15	6.8%
Residential Energy Audit	1000	7	670,000	169.96	50.99	0.30	45.0%
COMMERCIAL PROGRAMS:							
Energy Efficient Lighting Retrofit	500	5	150,000	35.00	28.00	0.80	48.9%
Solar Photovoltaic (10 kW)	10	20	260,000	100.00	80.00	0.80	29.7%
Solar Thermal	200	15	540	0.90	0.27	0.30	6.8%
Residential Energy Audit	200	5	330,000	66.09	26.44	0.40	57.0%

8.4 Costs

8.4.1 Large-Scale DSM Program

The estimated capital cost for GSWAC ranges from $73 million to slightly over $100 million, depending on pipeline location and chilled water distribution. The best option costs approximately $100 million.

8.4.2 Small-Scale DSM Programs

Customers typically pay more for the DSM technology than the standard technology. DSM Program Measure or Program Costs include Equipment Costs per customer, Utility Program Costs and Tax Credits or Non-Utility Rebates. Included in the Equipment Costs per customer are installation and maintenance invested by participating customers. Table 8.2 provides the fixed DSM expense and variable incentives, in 2006 real dollars.

Table 8-2, DSM Program Costs

	PENETRATION	**MEASURE LIFE**	**EQUIPMENT Costs/customer**		**TAX CREDITS & REBATES**	**UTILITY COSTS**
	# unit	years	$/unit (Installed)	$/year (O&M)	$ per Customer	$ per Unit
RESIDENTIAL PROGRAMS:						
Energy Efficient Lighting Retrofit	200	5	3.0	-		5.0
Solar Photovoltaic (5 kW)	10	20	9,000.0	900.0	(5,000.0)	200.0
Solar Thermal Water Heating	500	15	3,500.0	5.0	(1,050.0)	40.0
Residential Energy Audit	1000	7	190.0	-		90.0
COMMERCIAL PROGRAMS:						
Energy Efficient Lighting Retrofit	500	5	2.0	-		50.0
Solar Photovoltaic (10 kW)	10	20	9,000.0	1,800.0	(5,000.0)	200.0
Solar Thermal	200	15	3,500.0	2.0	(1,050.0)	40.0
Residential Energy Audit	200	5	420.0	-	-	150.0

The costs do not include incentive payments. The incentive payments are one-time payments to GPA customers who have purchased and installed eligible DSM technologies.

8.5 Economic Evaluation

8.5.1 Large-Scale DSM Program

The Economic Evaluation of GSWAC utilized simple payback method, a levelized cost comparison with conventional air conditioning (AC).

Five GSWAC scenarios differing in onshore pipe routing, pipe path and system size were considered, all showing less costs compared with conventional air conditioning. The analysis showed that GSWAC levelized costs ranged from $1,100/ton/year to $1,300/ton/year, much lower than conventional AC's levelized cost of $2,020/ton/year.

A business plan was created for the best option among the five scenarios. Results showed that the project would cost approximately $100 million.

Economic Evaluation of the GSWAC program was completed by including it in the Strategist assumptions as an alternative for Demand Side Management.

8.5.2 Small-Scale DSM Programs

For the other DSM options, technical screening assessment was done by R.W. Beck. Each measure or program was rated for suitability to implementation, and ranked independently for residential and commercial classes and for utility facilities and services. The options that indicated at least an average potential for implementation were considered for further evaluation via the Economic Screening Analysis. To determine the economic viability of the eligible alternatives, several evaluations were completed:

- Utility Cost Test – measures whether the benefits of avoided utility costs are greater than the costs incurred to implement the DSM program;

- Rate Impact Measure (RIM) Test – measures whether utility ratepayers that do not participate in a DSM program would see an increase in retail rates as a result of other customers participating in a utility-sponsored DSM Program; and

- Total Resource Cost (TRC) Test – measures whether combined benefits of the utility and customers participating in the DSM program are greater than the combined costs to implement the DSM Program.

The results of the test are summarized in Table 8.3 Test Results.

Table 8-3, Test Results

BENEFIT/COST RATIO BY TEST METHOD			
RESIDENTIAL PROGRAMS:			
	Utility Cost	RIM	TRC
Energy Efficient Lighting Retrofit	29.353	0.730	4.193
Solar Photovoltaic (5 kW)	40.418	0.744	0.205
Solar Thermal Water Heating	21.508	0.679	0.416
Residential Energy Audit	2.094	0.592	0.722
COMMERCIAL PROGRAMS:			
	Utility Cost	RIM	TRC
Energy Efficient Lighting Retrofit	13.833	0.889	1.258
Solar Photovoltaic (10 kW)	40.418	0.888	0.258
Solar Thermal	21.508	0.809	0.416
Residential Energy Audit	2.636	0.568	0.694

A Benefit-to-Cost Ratio (Benefit/Cost Ratio) of greater than 1.0 for the Utility Cost and RIM Test indicated that the program would reduce GPA's operating costs at a level greater than GPA's cost of implementing the program. Additionally, the program would not cause an increase in the retail rates charged by GPA.

GPA has established that the DSM Programs passing both criteria for both Utility Cost Test and RIM Test are eligible for implementation. As can be seen in Table 8-3, none of the DSM measures evaluated were found to pass both tests. As such, GPA is not including any projections of the impacts of small-scale DSM programs in its IRP filing.

9 Policy Issues and External Factors

Since the last completed IRP in 1999, federal and local legislation have emerged regarding reduction in green-house gas emissions and establishing renewable portfolio standards. In the Integrated Resource Planning Process, the Authority examined several pieces of federal and local legislation.

The Public Utility Regulatory Policies Act of 1978 (PURPA) resulted as a response from U.S. Congress to address the energy crisis in 1973. This legislation was drafted to encourage energy conservation and use of renewable energy among other things. It opened up a market for power by requiring utilities to purchase power from non-utility electric power producers at an “avoided cost” rate. The Energy Policy Act of 2005 (EPAct of 2005) amended PURPA by introducing standards that that would specifically address conservation and promotion of renewable energy. These standards included (1) Net Metering, (2) Fuel Diversity, (3) Fossil Fuel Generation Efficiency, (4) Smart Metering, and (5) Interconnection. Electric utilities are required to consider each standard and make a determination whether or not it is appropriate to implement. Implementation is, however, discretionary.

Locally, bills have been introduced citing PURPA and EPAct of 2005. Two have passed into law. Public Law 27-132 requires the Authority to allow net metering to customers. This has not been implemented pending rate setup. Public Law 29-62 promotes renewable energy and requires the authority to meet renewable portfolio standards as early as 2015. The Authority supports both these laws.

There have also been some bills, citing PURPA, which would have some detrimental consequences for the Authority if passed. These bills try to establish retail access without performing the work necessary to protect the interests of customers and utilities. Retail competition for electric supply (also called retail access or retail choice) is defined as allowing retail customers of an electric utility the option to choose a supplier for generation service. Authority managements and several consultants retained by GPA have testified against these bills. The electric energy price increases due to increasing fuel prices motivate these efforts as they are wrongly seen as a quick way without much effort out of a difficult situation despite the evidence otherwise.

In testimony before the 29th Guam Legislature[13], Dr. Kenneth Rose summarized the following about the state of retail access:

- 20 states have retail access for either all customers or for only larger customers.
- However, 35 states have repealed, delayed, suspended, limited retail access to just large customers, or are now no longer considering retail access.

[13] Before The Guam Legislature: Proposed Bill No. 122 Testimony of Kenneth Rose, Ph.D. on Behalf of Guam Power Authority. January 9, 2008

- States that had not passed a restructuring law dropped further consideration after the California power crisis, the Enron collapse, revelations of market price manipulation, disclosures of accounting improprieties and data misreporting, the August 2003 blackout, and significant price increases in restructured states.

Rose explicated on a number of implementation issues that need to be considered before enacting retail competition, none of which these bills have considered:

- A "stranded cost" policy – Who pays for utility costs that are no longer paid for by customers that left the utility?;

- Rates have to be "unbundled" – that is, separate charges for generation, distribution/ transmission, and other services need to be determined; and

- "Cherry Picking" by alternative suppliers impose costs on remaining customers and a policy is needed to determine under what conditions customers can return to utility generation service.

Furthermore, Rose, who had been an early supporter of retail access, summarized his experiences about the unintended consequences of retail access. Rose posited that the United States experience in open retail access is different from what was expected when the laws were being passed. These expectations and experiences include:

- It was expected that prices would decrease for all customer groups – but prices are increasing faster in restructured states than in states that remain regulated.

- The cost to serve retail customers "full requirements" service is higher than expected and more complex.

- In additional to energy (generation), there are congestion charges, capacity costs, ancillary service requirements, transmission charges, transmission organization administrative charges, and costs of market risks faced by suppliers such as the loss of customers or a change in demand.

As the only power utility on Guam, GPA supplies local federal facilities, including military bases, their energy requirements. Federal facilities must provide 20% of their electric energy use from renewable sources by 2020. GPA's strategic vision for future supplying the energy needs of the impending military buildup on Guam includes establishing renewable portfolio standard goals that address the federal renewable energy mandates.

The Authority believes that federal legislation regarding greenhouse gases and carbon legislation in particular are simply a matter of time rather than speculation. All three presidential candidates – Obama, Clinton, and McCain - are in support of such legislation. Therefore, the Authority must ensure that its baseline planning scenario includes structures that account for this impending legislation. The Authority must also actively consider renewable energy as the focal point of this IRP. Guam law and Federal mandates for renewable energy demand it.

10 Capital Requirements

Table 10-1 and Table 10-2 list the capital requirements of the recommended expansion plan for the Base and High Scenarios respectively. Because the magnitude of this plan is very large, the Authority may need to partner up with the federal and private sectors.

Table 10-3 lists the Recommended Capital Requirements that incorporates both scenarios in which the Authority should prepare for in the event of accelerated load growth. The Authority will consider rate impacts and creative financing in its RFP for Renewable Energy and in its FY 2008/2009 Load Research and Cost of Service Study.

Table 10-1, Capital Requirements for Base Scenario (thru 2018)

Project	Description	Construction Schedule	Commission Year	Capital Requirement ($ 000)
WIND	Wind Farm - 20x2MW	18 Months	2011	97,076
WIND	Wind Farm - 20x2MW	18 Months	2012	97,076
TEML	TEMES Conversion to LNG - 40MW		2012	8,633
GSWAC	Guam Sea Water Air-conditioning	60 months	2013	100,000
SSD	Reciprocating Engine (Slow Speed Diesel) - 2x20MW	30 Months	2017	70,980
WIND	Wind Farm - 20x2MW	18 Months	2018	97,076

Table 10-2, Capital Requirements for High Scenario (thru 2018)

Project	Description	Construction Schedule	Commission Year	Capital Requirement ($ 000)
RETR	Retrofit / Piti 7 CC	30 Months	2010	71,601
WIND	Wind Farm - 20x2MW	18 Months	2011	97,076
WIND	Wind Farm - 20x2MW	18 Months	2012	97,076
GSWAC	Guam Sea Water Air-conditioning	60 months	2013	100,000
CLNG	CC w/ LNG / LM6000	43 Months	2013	334,000
WIND	Wind Farm - 20x2MW	18 Months	2013	97,076
SSD	Reciprocating Engine (Slow Speed Diesel) - 2x20MW	30 Months	2016	70,980

Table 10-3, Recommended Capital Requirements (thru 2018)

Project	Description	Construction Schedule	Commission Year	Capital Requirement ($ 000)
WIND	Wind Farm - 20x2MW	18 Months	2011	97,076
WIND	Wind Farm - 20x2MW	18 Months	2012	97,076
TEML	TEMES Conversion to LNG - 40MW		2012	8,633
GSWAC	Guam Sea Water Air-conditioning	60 months	2013	100,000
CLNG	CC w/ LNG / LM6000	43 Months	2013 to 2021 Depending on Load Growth	334,000
SSD	Reciprocating Engine (Slow Speed Diesel) - 2x20MW	30 Months	2017	70,980
WIND	Wind Farm - 20x2MW	18 Months	2018	97,076
TOTAL				**804,841**

11 Key Results

This section discusses the various investigations and findings completed for this IRP:

- Deferment of Base Load Unit and Intermediate Unit Retirements;
- Base Case Analysis; and
- Robustness analysis of supply-side options:
    - Effectiveness of supply-side options as a function of Capital Costs;
    - Effectiveness of Wind Farm as a function of Capital Costs, Capacity Factor, Carbon Cap & Trade and Production Tax Credits.

The Authority analyzed other emerging technologies including:

- Solar Thermal Power Conversion;
- Ocean Thermal Energy Conversion;
- Municipal Solid Waste Conversion;
- Initial Look at Integrated Gasification Combined-Cycle Plant Technology; and
- Initial Look at Geothermal Energy Technology.

11.1 Deferment of Base Load and Intermediate Unit Retirements

GPA evaluated the year-by-year deferment of Baseload and Intermediate unit retirements. The proto-base case was then modified according to the new retirement years resulting from the analysis. All subsequent analysis used this modified base case.

Deferment of existing unit retirements show significant utility costs savings differences from the base case. The implementation of this strategic initiative must ensure that such savings not be exceeded by the operating and refurbishment costs associated with extending the operating life of the units. Table 11-1 illustrates the new retirement years determined the most viable.

Table 11-1, Optimal Retirement Year Results

Unit	Type	Optimal Retirement Year
Cabras 1	Baseload	2026
Cabras 2	Baseload	2027
Cabras 3	Baseload	2035
Cabras 4	Baseload	2036
MEC 8 (Piti 8)	Baseload	2038
MEC 9 (Piti 9)	Baseload	2039
Tanguisson 1	Intermediate	2028
Tanguisson 2	Intermediate	2029

11.2 Optimal Resource Plan Analysis

The Authority used the software application, STRATEGIST, to investigate optimal resource expansion plans. The investigative scenarios assumed a planning period starting at year 2006 up to year 2035.

The investigative scenarios included a Normal, Baseline and High demand and energy forecast, a high low fuel forecast, and other variations of key assumptions,

Table 11-2 presents the results of the Optimal Resource Plan Analysis. To illustrate the additional costs associated with the increase in Load Forecast, the differences between the High and Normal scenarios and the Baseline and Normal scenarios were obtained. Details on the selection of the Wind option were noted to see how it is affected by load growth.

Table 11-2, Results of the Optimal Resource Plan Analysis

SCENARIO	Net Present Value Utility Costs ($000)	Difference from NORMAL Scenario Utility Costs ($ 000)	WIND DETAILS		
			Wind Farm before 2017?	No. of Wind Farms	Year Installed
NORMAL	$5,401,374.00	$0.00	**-**	0	-
BASE	$5,717,896.50	$316,522.50	**YES**	2	2011, 2012
HIGH	$6,672,279.50	$1,270,905.50	**YES**	3	2011, 2012, 2013

Table 11-3 enumerates the different supply-side options selected for the three scenarios. Wind, Slow Speed Diesel and LNG Conversion are the preferred alternatives for all scenarios, with the addition of TEMES LNG conversion for the Normal and Baseline Scenarios, and the Retro-fit option for the High Scenario.

Table 11-3, Comparison of Selected Options

YEAR	NORMAL	BASELINE	HIGH
2006			
2007			
2008			
2009			
2010			RETR
2011		WIND	WIND
2012		WIND TEML	WIND
2013			CLNG WIND
2014			
2015			
2016			SSD
2017	WIND TEML	SSD	
2018	WIND	WIND	
2019	WIND		
2020	WIND	WIND	SSD WIND
2021	CLNG	CLNG	WIND
2022			CLNG
2023	SSD CLNG	SSD CLNG	CLNG
2024	SSD	CLNG	CLNG
2025			
2026	CLNG	SSD CLNG	SSD CLNG
2027	SSD CLNG	SSD	SSD
2028	SSD	SSD	SSD
2029		CLNG	SSD
2030	SSD		SSD
2031		WIND	
2032		SSD	
2033			
2034	SSD		SSD
2035			

All supply-side options coming in before 2017 are added as a substitute to high oil-fired generation and not because of the need for capacity additions.

11.3 Robustness Analysis

The Authority evaluated the affect of varying the key assumptions to the above optimal resource expansion plans in order to substantiate the effectiveness of each option under a wide range of conditions. The Authority defines this set of investigations as robustness analysis. If an expansion plan is more robust than another, it means that it inherently has less risk associated with it.

11.3.1 Effectiveness of Supply-side Options as a Function of Capital Costs

The Authority investigated scenarios where capital costs for various candidate resources were increased and decreased by 10, 20 and 30%. Results for each scenario were compared to determine how decreasing capital costs affect the selection. Tables 11-4 and 11-5 summarize the results.

For the SSD option, decreases in Capital Cost make the option more viable; that is, more SSD options are selected as it gets more affordable. When capital cost is decreased 30%, a total of 8 SSD options are selected as compared to only 6 using the original cost. For the CLNG option, the decrease in Capital Cost has no effect on the selection of CLNG units. Results show that the number of CLNG units selected does not change even up to a 30% decrease in capital cost. Decreasing the capital cost has likewise no effect on both the Coal option and Retrofit option. Even when capital cost has been decreased by 30%, these two candidates are still not competitive enough to be chosen.

The Authority increased capital costs for Wind and SSD candidate resources by 10, 20 and 30% as part of it robustness analysis. For SSD, increasing capital cost does not affect the selection of SSD units. However, a 30% increase in capital cost decreases the selected number of Wind Farms. Table 11-5 presents the results.

Table 11-4, Effect of Decreasing Capital Cost to Alternative Option Selection

	No. of Units Selected				
CAPITAL COST ADJUSTMENT	**WIND**	**SSD**	**CLNG**	**CFB**	**RETR**
-30%	5	8	5	0	0
-20%	5	6	5	0	0
-10%	5	6	5	0	0
Base Case	5	6	5	0	0

Table 11-5, Effect of Increasing Capital Cost to Alternative Option Selection

	No. of Units Selected	
CAPITAL COST ADJUSTMENT	**WIND**	**SSD**
Base Case	5	6
10%	5	6
20%	5	6
30%	4	6

11.3.2 Effectiveness of Wind Farm

11.3.2.1 As a Function of Capital Cost

Results from the previous section show that the wind farm is a robust decision.

Additional analysis was done with the results from the test described in the previous section by inspecting Wind Farm selection prior to year 2017. Wind Farms are brought online prior to 2017 as a substitute for diesel-fired energy production. Table 11-6 indicates that regardless of an increase or decrease in capital cost of up to 30%, Wind Farms are always selected prior to 2017.

Table 11-6, Effect of Capital Cost to Wind Farm Selection

CAPITAL COST ADJUSTMENT	No. of Wind Farms coming in before 2017:	Total Wind Farms for study period:
-30%	2	5
-20%	2	5
-10%	2	5
Base Case	2	5
10%	2	5
20%	2	5
30%	2	4

11.3.2.2 As a Function of Capacity Factor, Carbon Cap & Trade and Production Tax Credits

The Capacity Factor assumed for Wind Farms for the study period is 30%, with considerations for the seasonality and strength of wind on the island. To test the robustness of any decision to employ Wind Farms, The Authority investigated several scenarios where the Capacity Factor of the Wind Option ranged from 15% to 35% in 5% increments. GPA compared the number of Wind Farms brought in before 2017 for each scenario to determine how changing the Capacity Factor affected the Wind Option.

Additionally, because of uncertainties in the Federal Legislation regarding, the Authority evaluated various scenarios for Carbon Cap & Trade (CT) and Production Tax Credits (PTC) to observe effects on Wind resource selection. These were tested along with different capacity factors in four scenarios:

- Scenario with CT and PTC for CF of 15% to 35%;
- Scenario with CT but no PTC for CF of 15% to 35%;
- Scenario with PTC but no CT for CF of 15% to 35%; and
- Scenario with no CT and no PTC for CF of 15% to 35%.

Results indicate that CT and PTC do not materially affect Wind Farm selection. If there is CT but no PTC, a 15% capacity factor will decrease the number of Wind Farms selected before 2017. For the scenario with PTC but no CT, Capacity Factors, no Wind Farms come in before 2017 for a CF of 15%. For the scenario where there is no PTC and no CT, the number of wind farms decrease at a CF of 20%, and at a CF of 15%, no Wind Farms come in before 2017. Table 11-7 shows the results for this analysis.

Table 11-7, Effect of Capacity Factor, Carbon Cap & Trade and Production Tax Credits To Wind Farm Viability

ANALYSIS CRITERIA	**Capacity (Wind Farm):**	**40 MW**	**40 MW**	**40 MW**	**40 MW**
	With Carbon Cap & Trade?	**Yes**	**-**	**-**	**Yes**
	With PTC?	**Yes**	**-**	**Yes**	**-**
RESULTS	CAPACITY FACTOR (%)	Wind Farms Selected Prior to 2017:			
	15	2	0	0	1
	20	2	1	2	2
	25	2	2	2	2
	30	2	2	2	2
	35	2	2	2	2

11.4 Other Investigations

Several proponents of emerging renewable sources of energy have provided GPA with information regarding their technologies. Using the data given by the suppliers, each new option was modeled into the base case and assessed as another supply-side candidate.

11.4.1 Solar Thermal Power Conversion

GPA recently received data regarding Solar Thermal Power Conversion. The Baseline scenario was modified to include a 25 MW Solar Thermal Power Conversion and executed in STRATEGIST. Results show that addition of this technology improves the Net Present Value Utility Cost for the study period, and a Solar Thermal Power Conversion plant is brought in at year 2016. Table 11-8 below illustrates the results.

11.4.2 Ocean Thermal Energy Conversion (OTEC)

The Authority investigated an OTEC option. After modifying the base case scenario to include OTEC technology, the Authority ran its simulations to determine whether OTEC would displace other supply candidates. Ocean Engineering and Energy Systems (OCEES) provided information on capital and operating costs.

Initial investigations showed that a 20 MW OTEC plant would need a subsidy of over $100 million in order to be competitive. GPA did not consider other uses of this technology such as potable water production, plant cooling, mariculture, or bottled gourmet water.

11.4.3 Municipal Solid Waste Conversion

The Authority investigated a Biomass or Municipal Solid Waste-to-Energy plant option. After modifying the base case scenario to include this technology, the Authority ran its simulations to determine whether it would displace other supply candidates.

Results indicate that this technology would require a subsidy of over $120 million in order to be economically viable for electric power production. This capital may be raised in the form of tipping fees or other such fees associated with Solid Waste management.

11.4.4 Integrated Gasification Combined Cycle Plant

The Integrated Gasification Combined Cycle Plant (IGCC) option refers to the conversion of coal to synthetic gas. The synthetic gas would fuel a gas-fired combined cycle plant. The IGCC technology allows for carbon capture, which is a significant advantage to coal plant.

Some challenges remain with this technology. The fuel price is tied to relatively inexpensive coal but, IGCC plants have very high capital costs. To date, there are very few vendors and engineers developing IGCC, and it is hard to get favorable contract terms. Apart from this, the reliable sequestration of carbon is still under development.

Table 11-8, Inclusion of Solar Thermal Power Conversion as a Supply-side Option

Year	Units
2006	
2007	
2008	
2009	
2010	
2011	WIND
2012	WIND, TEML
2013	WIND
2014	
2015	
2016	SOLAR
2017	
2018	
2019	SSD
2020	WIND
2021	WIND
2022	CLNG
2023	SSD, CLNG
2024	SSD
2025	
2026	CLNG
2027	
2028	SSD
2029	CLNG
2030	
2031	
2032	
2033	SSD
2034	
2035	

11.4.5 Geothermal Energy

GPA has initiated a conversation with Bottle Rock Power (BRP), and an exchange regarding the possibilities for electricity production via geothermal sources is ongoing. BRP believes there is geothermal potential on Guam.

BRP's principal asset is a 55-MW geothermal power plant at The Geysers Geothermal Field in northern California, and they expect the facility to produce approximately 200,000 MWH of electricity annually, to be sold to Pacific Gas & Electric Company.

11.5 Fuel Diversity Outlook

GPA is currently using mostly Residual Fuel Oil (RFO) for electricity production. A small percentage of energy production comes from Diesel Fuel Oil (DFO).

Through this IRP, GPA hopes to reduce the use of petroleum-based fuels through the implementation of Renewable Energy options (WIND), conversion to Liquefied Natural Gas and the use of the DSM program, GSWAC.

Figure 11-1 illustrates the Fuel Diversity Outlook for the study period.

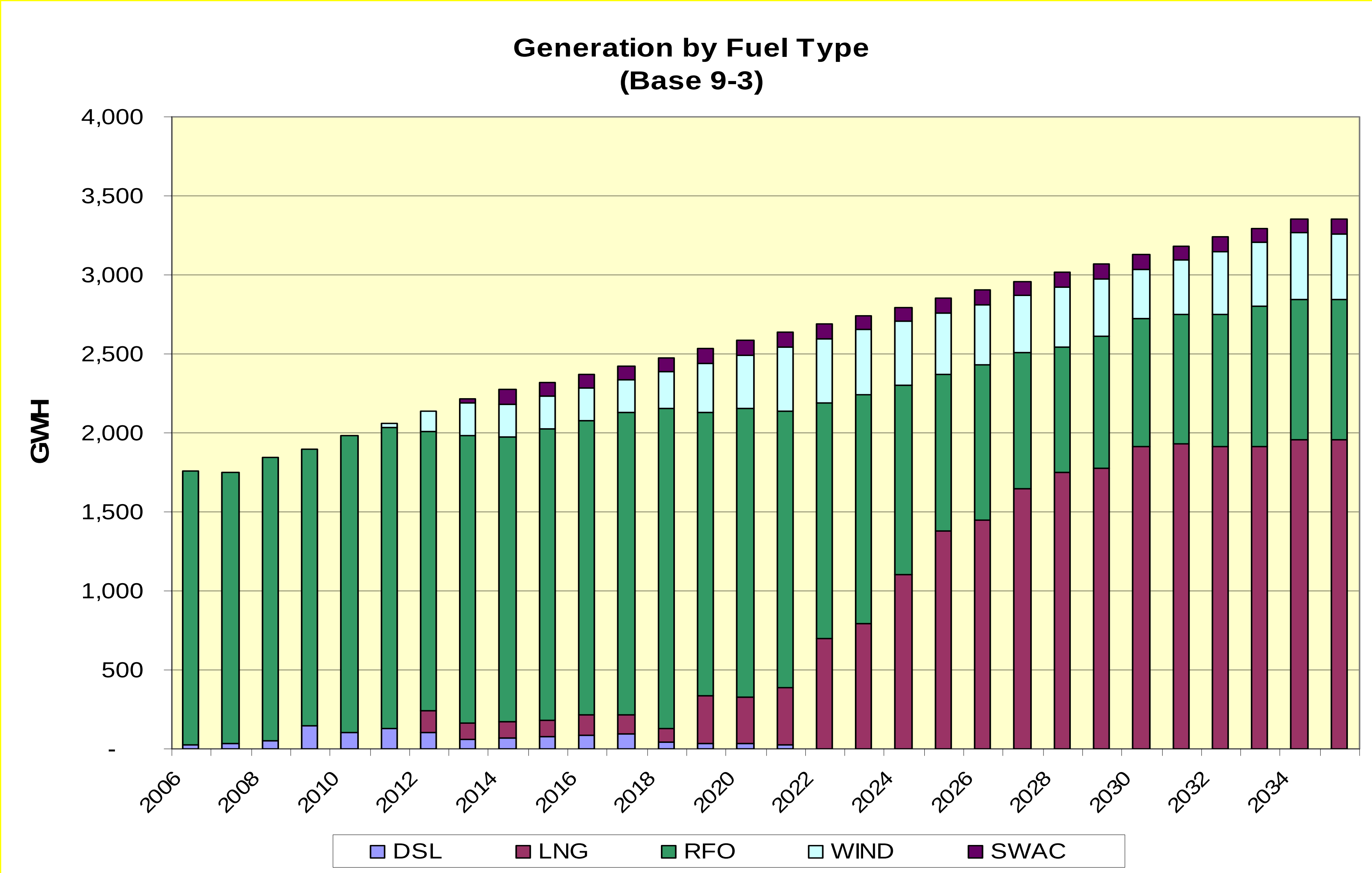


Figure 11-1, Fuel Diversity Outlook

12 Recommendations

The Integrated Resource Plan (IRP) report identifies three main alternative futures and an optimal resource plan for each.[14] The IRP report defines these three alternative futures as normal, baseline, and high. In the near-term GPA will base its decisions upon the baseline scenario which assumes significant DOD impacts. However, GPA planning and execution on its expansion plan must consider the high growth scenario. This is only prudent as the DOD has not completed its studies and there is great uncertainty surrounding the results presented to the Authority. Thus, GPA must recognize that DOD impacts could be more significant than those contained in the baseline scenario. Therefore, prudent management dictates that the Authority maintain vigilance and flexibility to respond accordingly. Under the normal and baseline scenarios GPA has sufficient capacity to meet customer demand. However, fuel diversification and the economic displacement of oil-fired generation presents the near-term resource challenge.

First, this IRP recommends that the Authority begin the procurement process to integrate renewable energy as quickly as practical following the renewable resource acquisition process outlined in Section 13. The Authority needs to act expeditiously to meet its aggressive target of awarding wind or other renewable energy projects by December 2009.

Second, this IRP recommends that the Authority begin the process to bring LNG as a substitute fuel for diesel fuel oil by 2012. This will include:

- Working with the Department of Defense to change the paradigm concerning the Japan Bank for International Cooperation’s (JBIC) pledge to support the infrastructure requirements for the DOD marine move from one of supplying electric energy to one supplying LNG;
- Renegotiation of the Taiwan Electrical and Mechanical Engineering Services (TEMES) Energy Conversion Agreement to include a conversion of the plant to use natural or synthetic gas and combine cycle operation; and
- Examination of supplying natural gas for industrial, commercial, and residential use as a utility under the Consolidated Utility Commission and the Guam Public Utility Commission.

Third, the Authority should plan and permit for an additional gas-fired plant or non-petroleum-fired plant as a matter of prudency regarding the uncertainty in the scope of the DOD buildup and related economic activity. GPA should construct this plant based upon load growth triggers.

Fourth, the Authority must ensure that all its plants meet or exceed the equivalent availability and other performance standards agreed with the PUC.

Fifth, the Authority must examine fully life extension of its existing plants.

[14] Portions of this section capitalize on our discussions with Larry R. Gawlik and may borrow liberally from the May 7, 2008 PUC Staff Update: Integrated Resource Planning (IRP) Process

Sixth, the Authority must continue to evaluate renewable and energy efficiency technologies in order to obtain the lowest energy prices for its customers.

Seventh, the Authority must work collaboratively with the Guam PUC and stakeholders to improve the Authority's financial position relative to obtaining funding for these projects.

Eighth, the Authority must continue to investigate geothermal, Ocean Thermal Energy Conversion (OTEC), Integrated Gasification Combined Cycle (IGCC), and other technologies since they will probably play a large role as these technologies become commercially available for Guam.

Ninth, the Authority must find a business partner to develop the Guam Sea Water Air Conditioning Project.

Tenth, the Authority must work with the Guam PUC to establish the rules of engagement for and rates for net metering.

Eleventh, the Authority must work with the Guam PUC on implementing small scale Demand-Side Management Programs. None of the projects evaluated by R.W. Beck pass the Rate Impact Measure (RIM) Test. Thus, they will impact customer rates. GPA will add to its web site Enercom's packaged set of Internet energy tools called Energy Depot®[15] as part of an initial small DSM project and customer outreach. The Authority will encourage the Guam Waterworks to add Enercom's Water Depot product to its web site.

Twelfth, the Authority must work with Guam Waterworks Authority (GWA) on an interruptible load arrangement in order to hedge against the risk of higher than baseline load growth.

[15] Online Energy Audits & Information. Accessed at http://www.hometownconnections.com/utility/enercom.html on May 27, 2008

13 Next Steps

In order to comply with local legislation and regulatory requirements, the Authority must take several steps in pursuit of new power production facilities construction and contracts for new demand side management programs.

A proven approach currently used in a number of states in the US Mainland is making the private sector compete for the development of a power plant. The process starts with the development of an Integrated Resource Plan (IRP) which shall serve as a "road map" to new generation acquisition. Objectives, targets and schedules shall also be defined at this point. Once this has been achieved, the next steps are:

- Submission to the Public Utilities Commission (Guam PUC) for review and approval;
- Development of Requests for Proposals (RFPs) to initiate the competitive process for resource development. This shall be an open and competitive process, wherein the best responsive offer is considered; and
- Awarding of Contracts for resource to chosen developers. May include the building and operation of plants, as well as fuel supply and management.

13.1 Role of the Public Utilities Commission

Before the development of the RFPs, the Guam PUC must review and approve the IRP. In addition, the procurement, rate filings, bond petitions or other processes will require oversight by the Guam PUC.

The Guam PUC, like many other commissions in the mainland, performs functions such as:

- Set rates for cost recovery;
- Evaluate utility's adequacy to serve the public;
- Examine environmental & location impacts for new resource siting;
- Set reserve margins to ensure sufficient power is available;
- May require utilities to evaluate different options for meeting and shaping projected future demand for electricity through an IRP process; and
- Enforce laws (Renewable Portfolio Standards).

With that, it is anticipated that Guam PUC will conduct a thorough review of the document to ensure it meets the objectives as set forth in prior issued Guam PUC orders regarding the development of this IRP document. This may include public hearings and review of the document by its technical consultant(s). GPA shall not commence new resource or demand side program acquisition without the Guam PUC's acceptance of the document and an authorization to proceed in the form of a Guam PUC order.

13.2 Acquisition Process

It is the authority's intention to acquire all new power resources (supply side) and demand-side programs (customer side) through an open invitation for bid procurement process.

There are several challenges regarding renewable resource acquisition. One of those challenges is that some resource development firms are unfamiliar with Guam and, and may lack knowledge or understanding of Guam's power needs. Another challenge is that Guam's power requirements may be viewed as small as compared to other public utilities. Thus, the process will include an outreach strategy. The Authority will develop information packages, provide a webpage and publish advertisements to promote interest for potential vendors to participate in any upcoming procurement solicitations. This will allow potential bidders to familiarize themselves with Guam prior to the formal announcement of any procurement invitations.

The renewable resource of choice in the near-term is wind.[16] Significant interest in wind exists. DOD has shared the fact that it is conducting wind studies at specific locations on its properties, and wishes to work collaboratively with the Authority. DOD has commissioned and completed wind studies designed to determine optimal sites for wind monitoring towers. In our conversations with DOD[17], it believes – and GPA concurs - that adequate wind monitoring data is critical to the siting and ultimate design of wind turbine installations on Guam. Having such information prior to procurement of these resources lowers risk and increases the likelihood of larger and more participants in the procurement process. Therefore, the Authority's immediate conduct of wind studies is critical.

The reduction of risk from the developer's perspective is a paramount concern since:

- Most established renewable resource development firms are busy;
- Most established renewable resource development firms are not familiar with Guam;
- GPA's requirements may be viewed as "small"; and
- Lack of understanding of Guam power issues.

Upon the Guam PUC's approval of the IRP and authorization to proceed, the Authority will embark on a new power acquisition process. GPA has developed a preliminary schedule for new renewable power acquisition in Figure 13-1. GPA believes the IRP-driven competitive

[16] Portions of this section capitalize on our discussions with Larry R. Gawlik and may borrow liberally from the May 7, 2008 Guam PUC Staff Update: Integrated Resource Planning (IRP) Process
[17] These discussions occurred during the weekly Joint Guam Program Office (JGPO) and Guam Utilities teleconference. Additionally, CMDR Matthew Suess and DOD's Jack Brown have been instrumental in this dialog.

acquisition process will create a more competitive generation environment and most importantly provide least cost energy for our customers. GPA intends to use the competitive RFP process for acquisition of proposals for the turn-key development of one or more wind farms. The Authority will heavily borrow from the "White Creek" development model described in Stakeholder Meeting No. 3. This business model combines the advantages of a public/private undertaking[18].

Moving towards fuel diversity, the introduction of LNG into the fuel mix coupled with the conversion of the TEMES CT plant to use this fuel will provide an economic displacement of diesel fuel oil as system demand increases.

The challenge regarding the introduction of LNG as a replacement for diesel fuel includes:

- Changing the paradigm concerning the Japan Bank for International Cooperation's (JBIC) pledge to support the infrastructure requirements for the DOD marine move from one of supplying electric energy to one supplying LNG;
- Renegotiation of the Taiwan Electrical and Mechanical Engineering Services (TEMES) Energy Conversion Agreement to include a conversion of the plant to use natural or synthetic gas; and
- Examination of supplying natural gas for industrial, commercial, and residential use as a utility under the Consolidated Utility Commission and the Guam Public Utility Commission.

[18] Session 3—IRP Stakeholder Meeting—STRATEGIES FOR ACQUIRING NEW RESOURCES (http://www.guampowerauthority.com/operations/strategicplanning/GPAIRP.html) White Creek public/private development model.

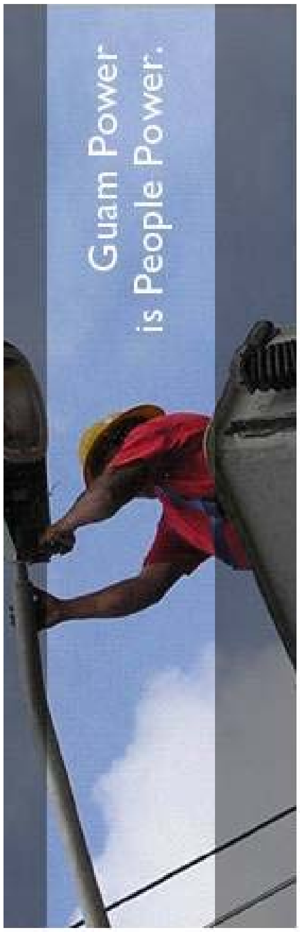
Draft as of 5/5/2008

	Renewable Resource Acquisition	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
		2008							2009											2009
1	GPUC Review of IRP - Review to endorse GPA's selection of renewables																			
2	Wind Monitoring & Best Sites - information to be made available to potential vendors - should have data posted on website - Note, need to include solar data																			
3	GPA test turbine																			
4	Vendor Outreach & First Level Information - make vendors aware of wind data and process - information of physical risk vs. financial risk, etc. - helps screen for those firms that should get greater follow up attention																			
5	2nd Vendor Information Sessions - more wind data and responses to question and issues.																			
6	RFP - Prepare document and evaluation criteria. The RFP should describe possible contract models, risk issues, option to purchase, etc. for GPA																			
7	Issue RFP																			
8	Evaluate RFP																			
9	Award RFP																			

Figure 13-1, Renewable Resource Acquisition Proposed Schedule

APPENDICES

A Generation Resource Handbook



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.”

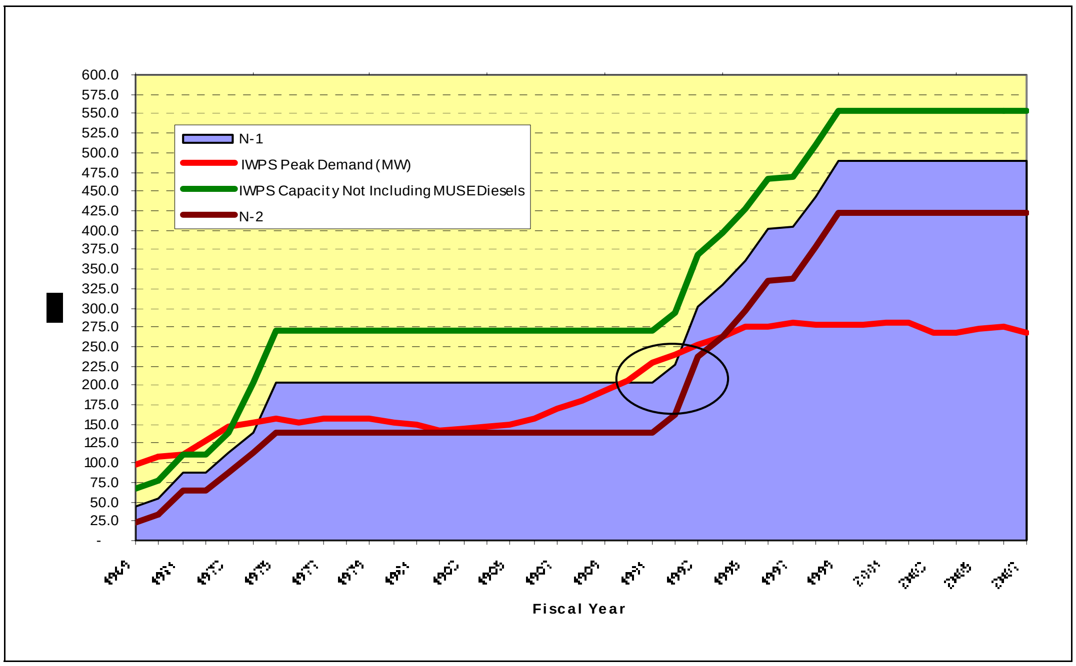

Figure 1: IWPS Historical Demand and Supply Capabilities

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."

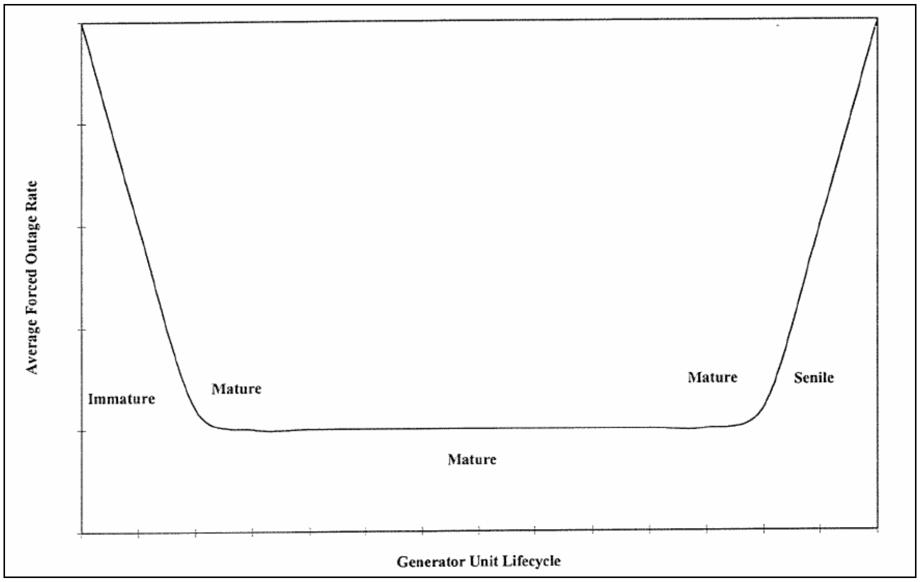

Figure 2: Life Cycle Generation Forced Outage Rates

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

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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.

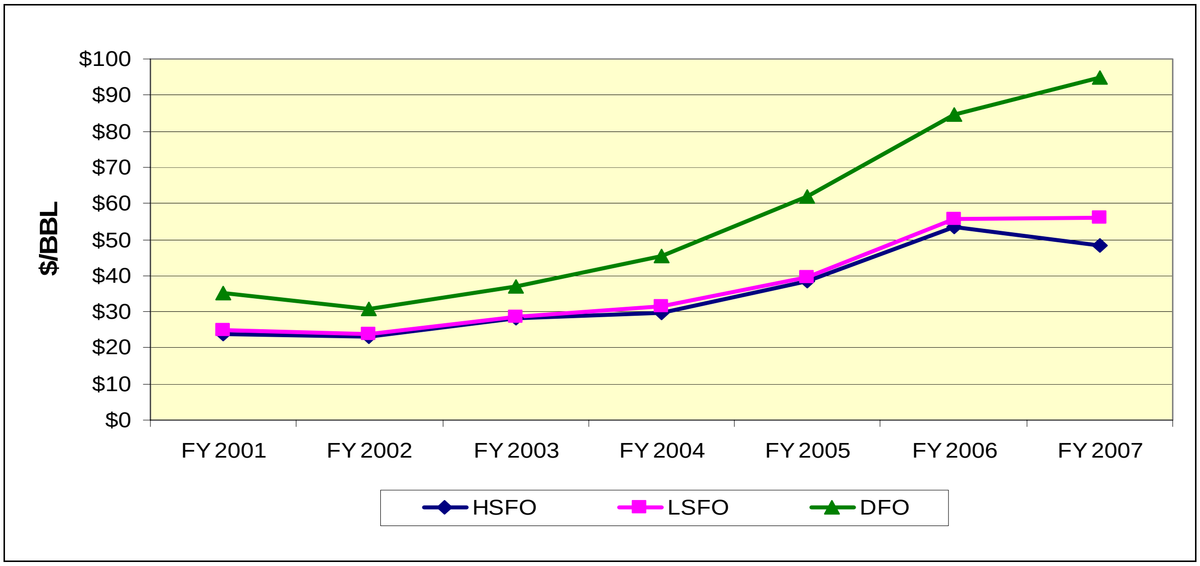

Figure 3: Historical Fuel Oil Purchase Prices

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

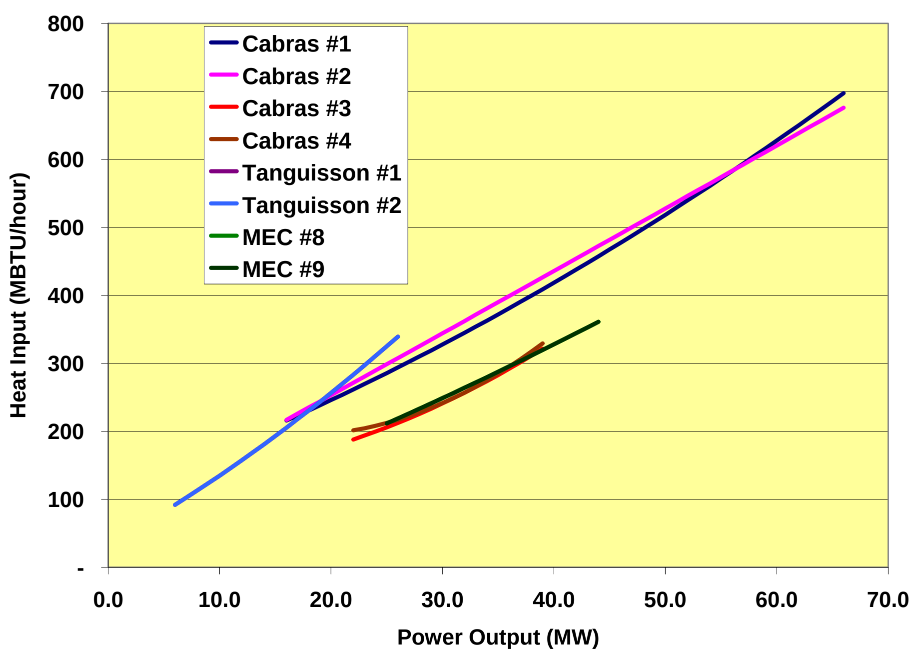


Figure 4, Heat Input Curves

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.

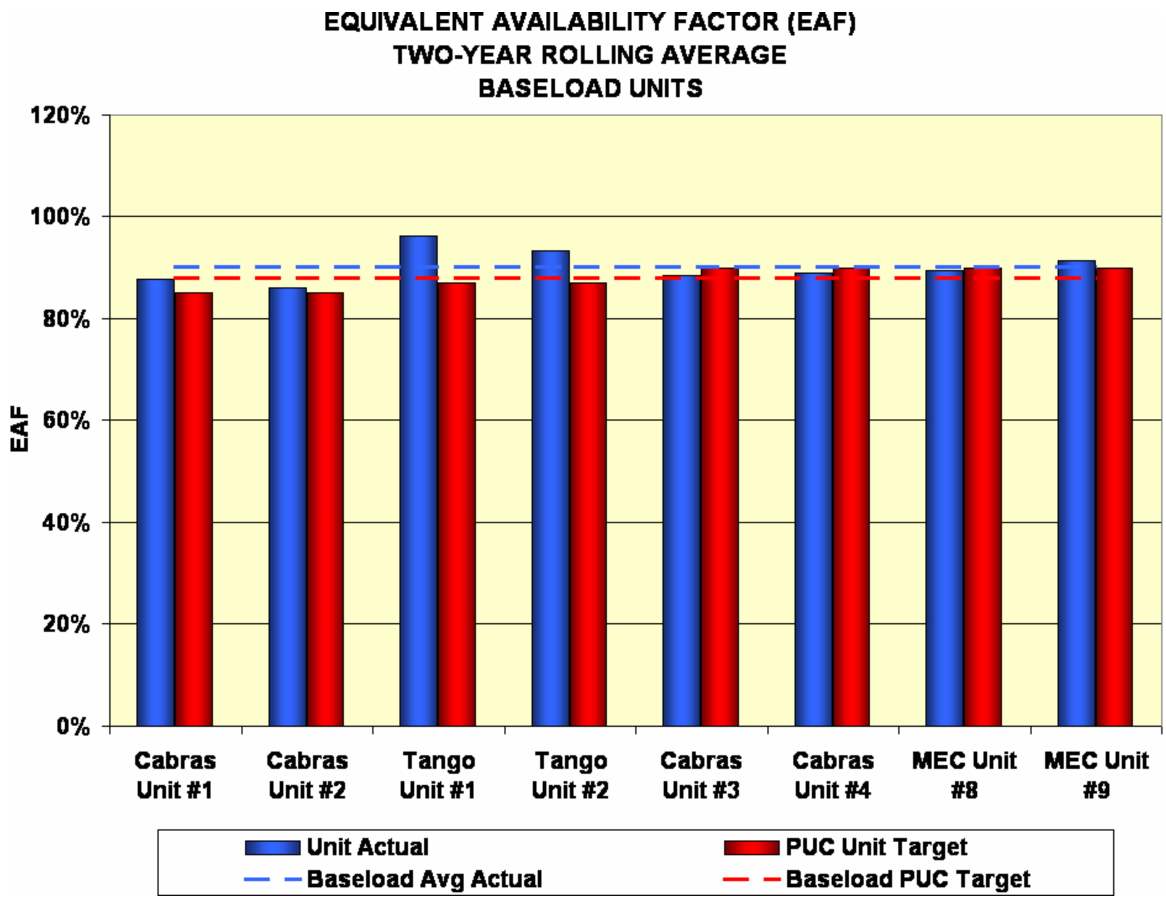


Figure 5, Two-Year Rolling Equivalent Availability Factor (EAF) for Baseload Units

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

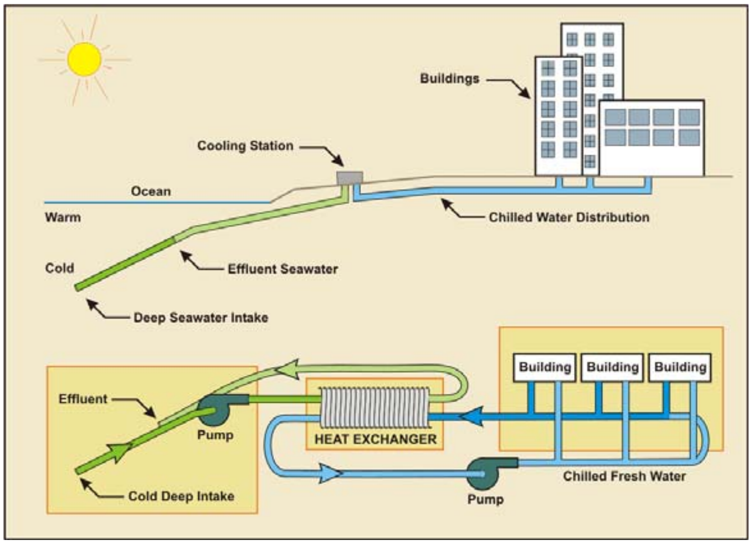
1.1 PURPOSE OF THIS STUDY

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.

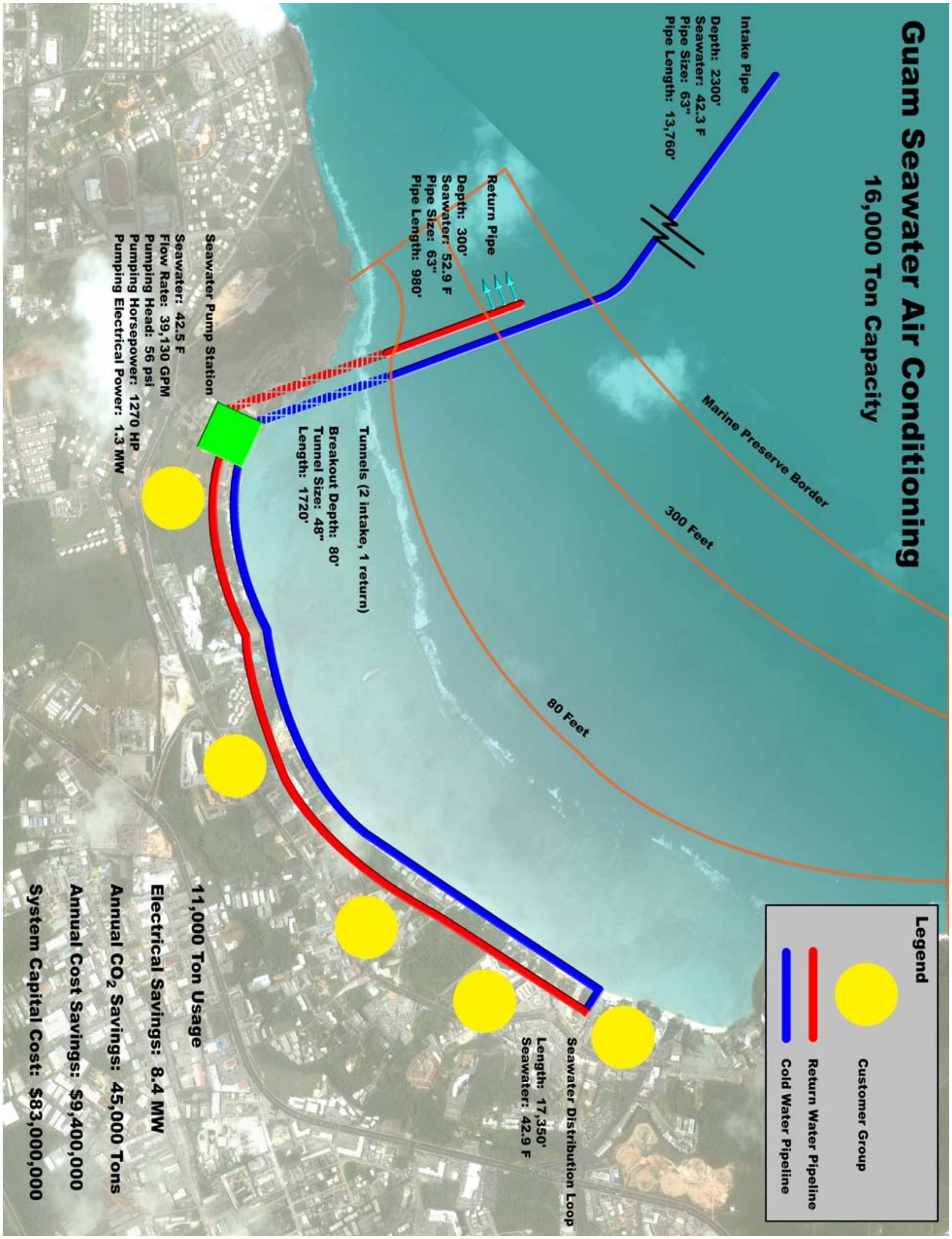
In this study, Makai and Market Street Energy have analyzed and sized the major components of the Guam Seawater Air Conditioning (GSWAC) system, determined the operational performance, estimated the probable costs and identified the economic and business advantages of the GSWAC system. The team has also 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
Legend
Customer Group
Return Water Pipeline
Cold Water Pipeline
Seawater Distribution Loop
Length: 17,350'
Seawater: 42.9 F
11,000 Ton Usage
Electrical Savings: 8.4 MW
Annual CO_2 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.

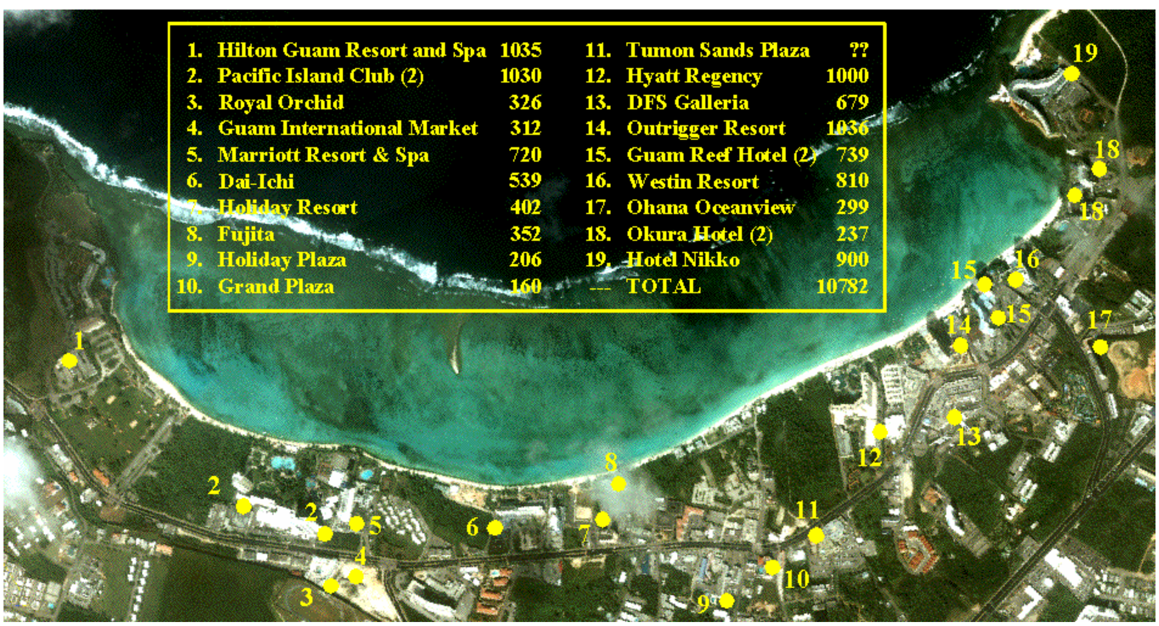
No Water Consumption by Cooling Towers: A significant cost of conventional AC is the consumption of fresh water by evaporative condensing units; GSWAC does not consume of fresh water.

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.

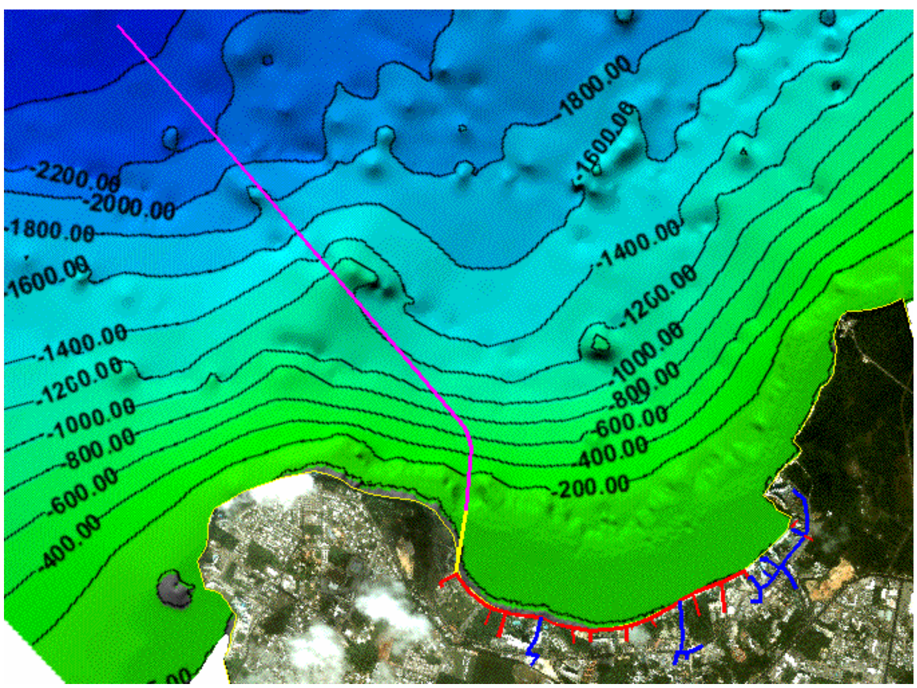
The following table summarizes these five scenarios.

GSWAC Scenarios:

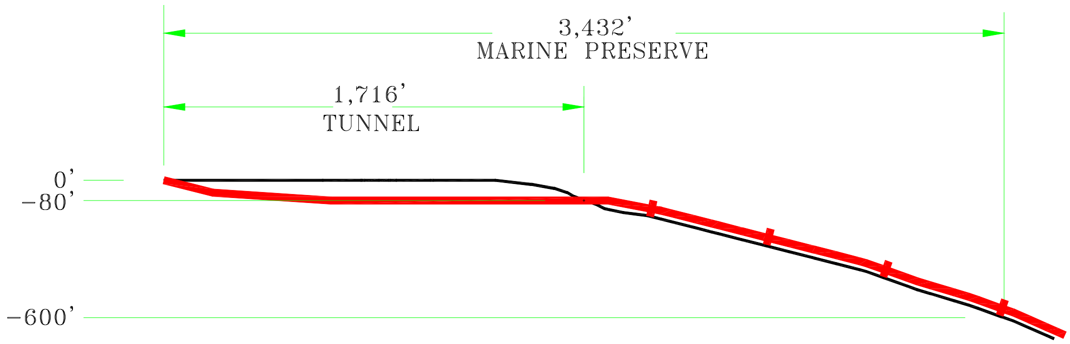
	I	II	III	IV	V	
Max AC Load	16,000	16,000	16,000	16,000	11,000	Tons
Initial Load	11,000	11,000	11,000	11,000	11000	
User supply Temperature	44	44	44	44	44	Deg F.
Seawater Supply	Route A	Route B	Route A	Route B	Route A	
Seawater Distribution	yes	yes	no	no	yes	
Fresh Chilled water Distributi	3	3	1	2	3	number
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

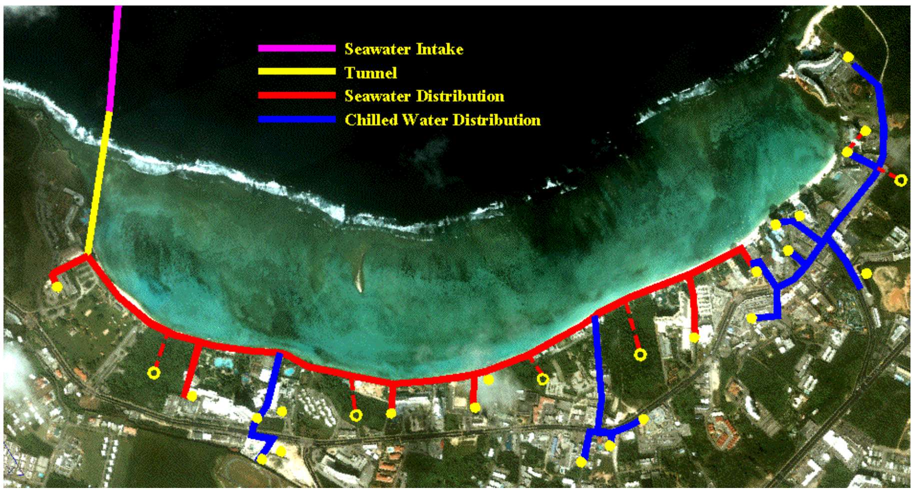
The overall layout of the piping for Scenario I is shown below. The deep water pipeline is a 63" diameter polyethylene pipe that is three miles long and brings in 42º F water from 2300' depth. The pipeline lays on the seafloor.



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.

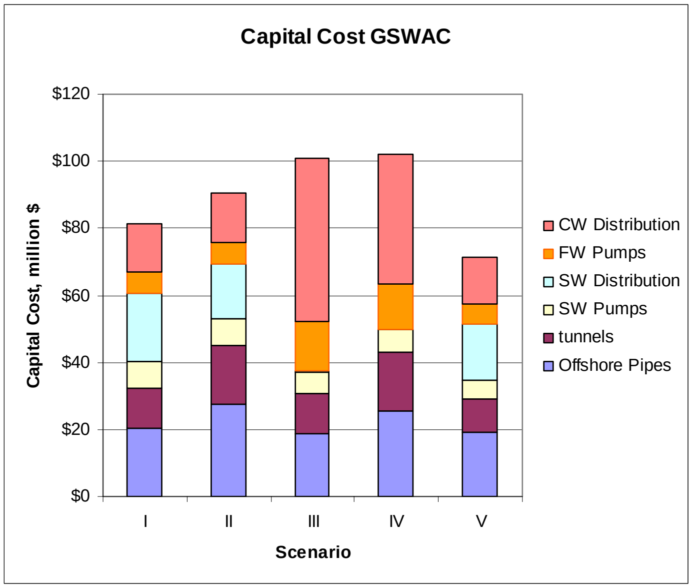


The more detailed view of the distribution system is shown below. The red line is a seawater distribution system buried below the beach. Several users are cooled through single-user heat exchangers along this route. Three chilled fresh water loops, cooled by a single heat exchanger, feed larger groups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

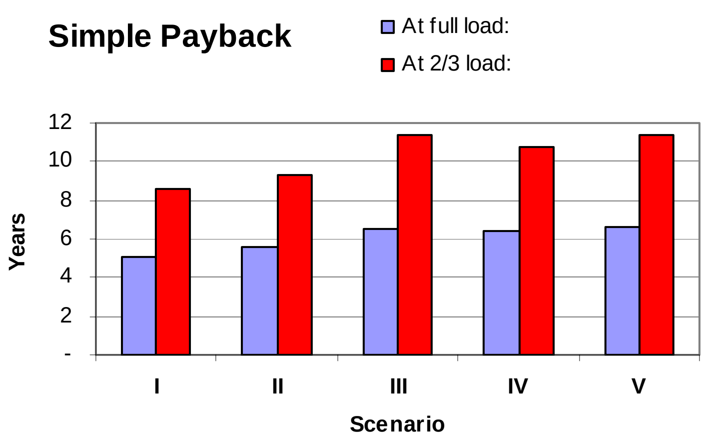


1.8 ECONOMIC FEASIBILITY ANALYSIS

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

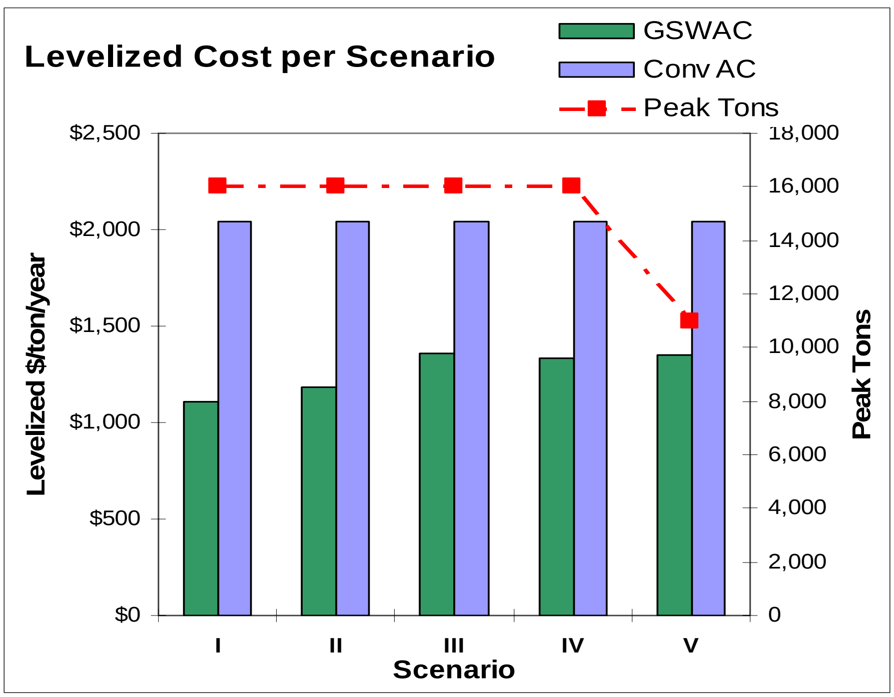
Simple payback was computed for the five scenarios based on the capital costs given above and net revenue. When fully loaded, the simple payback is between 5.1 and 6.7 years. If the system is partially loaded at only 2/3 capacity, the simple payback is between 8.5 and 11.4 years. Scenario I is the most 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

B Renewable Portfolio Standards

pu

Office of the Governor of Guam

P.O. Box 2950 Hagåtña, Guam 96932

TEL: (671) 472-8931 • FAX: (671) 477-4826 • EMAIL: governor@mail.gov.gu

2008 APR 10 AM 10: 54

Felix P. Camacho
Governor

Michael W. Cruz, M.D.
Lieutenant Governor

09 APR 2008

for

The Honorable Judith T. Won Pat
Speaker
Mina' Bente Nuebi Na Liheslaturan Guåhan
155 Hessler Street
Hagåtña, Guam 96910

Dear Speaker Won Pat:

Transmitted herewith is Bill No. 166(EC), "AN ACT TO PROMOTE THE DEVELOPMENT OF RENEWABLE ENERGY; TO REQUIRE THE GUAM POWER AUTHORITY TO ESTABLISH RENEWABLE PORTFOLIO STANDARD GOALS AND TO REQUEST THE PUBLIC UTILITY COMMISSION TO STUDY THE FEASIBILITY OF IMPLEMENTING A RATE STRUCTURE TO ENCOURAGE THE USE OF RENEWABLE ENERGY BY *ADDING* NEW §§8311, 8312, 8506 AND 12028, TO TITLE 12, GUAM CODE ANNOTATED" which I signed into law on April 4, 2008 as **Public Law 29-62.**

Sinseru yan Magåhet,

FELIX P. CAMACHO
I Maga'låhen Guåhan
Governor of Guam

Attachment: copy of Bill

cc: The Honorable Tina Rose Muña Barnes,
Senator and Legislative Secretary

29-08-0264
Office of the Speaker
Judith T. Won Pat, Ed.D.
Date 4/09/08
Time 4/12
Received by

1442

I MINA'BENTE NUEBI NA LIHESLATURAN GUÅHAN
2008 (SECOND) Regular Session

CERTIFICATION OF PASSAGE OF AN ACT TO *I MAGA'LAHEN GUÅHAN*

This is to certify that **Bill No. 166 (EC), "AN ACT TO PROMOTE THE DEVELOPMENT OF RENEWABLE ENERGY; TO REQUIRE THE GUAM POWER AUTHORITY TO ESTABLISH RENEWABLE PORTFOLIO STANDARD GOALS AND TO REQUEST THE PUBLIC UTILITY COMMISSION TO STUDY THE FEASIBILITY OF IMPLEMENTING A RATE STRUCTURE TO ENCOURAGE THE USE OF RENEWABLE ENERGY BY *ADDING* NEW §§8311, 8312, 8506, AND 12028, TO TITLE 12, GUAM CODE ANNOTATED,"** was on the 21st day of March, 2008, duly and regularly passed.

JUDITH T. WON PAT, Ed.D
Speaker

Attested:

TINA ROSE MUÑA BARNES
Senator and Secretary of the Legislature

This Act was received by *I Maga'lahen Guåhan* this 25 day of March, 2008, at 10:50 o'clock A .M.

Assistant Staff Officer
Maga'lahi's Office

APPROVED:

FELIX P. CAMACHO
I Maga'lahen Guåhan

Date: 4 APRIL 2008

Public Law No. 29-62

I MINA'BENTE NUEBI NA LIHESLATURAN GUÅHAN
2007 (FIRST) Regular Session

Bill No. 166 (EC)
As amended by the Author
and further amended on the Floor.

Introduced by:

v. c. pangelinan
James V. Espaldon
B. J.F. Cruz
Tina Rose Muña Barnes
Frank F. Blas, Jr.
Edward J.B. Calvo
Mark Forbes
Judith Paulette Guthertz
Frank T. Ishizaki
J. A. Lujan
A. B. Palacios, Sr.
R. J. Respicio
David L.G. Shimizu
Ray Tenorio
J. T. Won Pat, Ed.D.

AN ACT TO PROMOTE THE DEVELOPMENT OF RENEWABLE ENERGY; TO REQUIRE THE GUAM POWER AUTHORITY TO ESTABLISH RENEWABLE PORTFOLIO STANDARD GOALS AND TO REQUEST THE PUBLIC UTILITY COMMISSION TO STUDY THE FEASIBILITY OF IMPLEMENTING A RATE STRUCTURE TO ENCOURAGE THE USE OF RENEWABLE ENERGY BY *ADDING* NEW §§8311, 8312, 8506, AND 12028, TO TITLE 12, GUAM CODE ANNOTATED.

BE IT ENACTED BY THE PEOPLE OF GUAM:

Section 1. Legislative Findings and Intent. *I Liheslaturan Guåhan* finds that the Guam Power Authority (GPA) is totally dependent on oil for the production of electricity for consumers. Such dependence has resulted in rate increases in the form of increased fuel surcharges. The Levelized Energy Adjustment Clause, a provision in law, initially set rate adjustments on a monthly basis. Subsequently, the Guam Power Authority requested to change the cycle to a calendar year and reviewed every six (6) months. The fact that oil is the *sole* source of our power production does not give GPA any opportunity to diversify and hedge cost savings in the fuel component of its cost structure.

The diversification of fuel type used for production may help offset costs and may be achieved by implementing technology which uses renewable energy resources already found on Guam such as wind, solar, ocean thermal, wave and biomass resources in new production facilities.

It is the intent of *I Liheslatura* to require the development of renewable energy production and decrease our total reliance on oil for electricity production.

Section 2. A new §8311 is hereby *added* to Article 3 of Chapter 8 of Title 12, Guam Code Annotated, to read as follows:

"**§8311. Renewable Portfolio Standards.** The Guam Power Authority *shall* establish a preliminary renewables portfolio standard goal of:

(a) five per cent (5%) of its net electricity sales by December 31, 2015;

(b) eight per cent (8%) of its net electricity sales by December 31, 2020;

(c) ten per cent (10%) of its net electricity sales by December 31, 2025;

(d) fifteen per cent (15%) of its net electricity sales by December 31, 2030; and

(e) twenty-five percent (25%) of its net electricity sales by December 31, 2035.

The amount of renewable capacity may be subject to engineering and economic analysis by the Guam Power Authority."

Section 3. A new §8312 is hereby *added* to Article 3 of Chapter 8 of Title 12, Guam Code Annotated, to read as follows:

> "**§8312.** The Guam Power Authority *shall* undertake all necessary investments *or* outsourcing agreements, including, automatic generation control, so as to provide for the maximum feasible ability to add renewable resources to the Island-wide Power System. The Public Utilities Commission is directed to deem such renewable resource as prudent costs for purposes of rate setting to ensure such investments do *not* hinder the Guam Power Authority's financial stability to support the capital activities associated with the intent of this Public Law."

Section 4. New Construction of Electrical Power Generation Plants. The Guam Power Authority, whether constructing conventional base load power capacity on its own *or* through a private entity, *shall* be required to add additional renewable capacity with each construction of a conventional base load unit. This additional renewable capacity *shall* be at least ten percent (10%) of the new conventional capacity, and must be in place *no later than* eighteen (18) months of the new conventional base load plant commissioning. Additional renewable capacity may be commissioned prior to the commissioning of conventional base load units.

Section 5. A new §12028 is hereby *added* to Article 1 of Chapter 12 of Title 12, Guam Code Annotated, to read as follows:

> "**§12028. Rate Structure Implementation; Renewable Portfolio Standard Incentives; Report.** The Guam Public Utilities Commission and the Consolidated Commission on Utilities are the governing bodies for electric utility rate and policy. The Guam Power Authority *shall* file with

the Guam Public Utilities Commission as part of its cost of service study:

(a) recommendations for the implementation of a utility rate structure designed to reward and encourage consumers to use renewable energy sources found on Guam;

(b) the extent that this proposed utility rate structure would impact Guam Power Authority coverage ratios, and to ensure that these coverage ratios *do not* decrease for a period of five (5) years following the implementation of this rate structure;

(c) findings and recommendations concerning the types of incentives offered through the Guam Power Authority that the Public Utilities Commission could authorize for GPA customers in meeting the renewable portfolio standards established in Title 12 GCA §8311; and

(d) report findings and recommendations, including proposed legislation, to *I Liheslatura no later than* one (1) year after enactment."

Section 6. A new §8506 is hereby *added* to Article 5 of Chapter 8 of Title 12, Guam Code Annotated, to read:

"**§8506. Interim Metering.** GPA is authorized to immediately implement an interim, emergency net metering rate structure wherein Customer generators *shall* be entitled to receive immediate credit for one hundred percent (100%) of the power generation capacity based on the specifications of the generation equipment installed times the rate the Guam Power Authority currently charges the customer until such time that GPA submits a rate structure to the PUC for the net metering program and it is approved by the PUC. This interim rate *shall* be subject to PUC revocation at any time."

Section 7. Severability. *If* any of the provisions of this Act or the application thereof to any person or circumstance is held invalid, such invalidity shall *not* affect any other provision or application of this Act which can be given effect without the invalid provision or application, and to this end the provisions of this Act are severable.

C Load Forecast

GPA Peak Demand and Sales Forecast Documentation
September 23, 2007
PL Mangilao Energy, LLC

The GPA Peak Demand and Sales Forecast

A 20-year forecast of system peak hour demand and energy sales by revenue class has been prepared for GPA by PL Mangilao Energy, LLC (Mangilao). The forecast is based upon an econometric/end-use model of the demand for electricity on Guam that was constructed in 2006 and 2007. The forecast contains four scenarios that are characterized by different expectations for future development of the tourism industry and for infrastructure/military spending on the island. These scenarios are:

- Case I: The Base Case or Business as Usual Case
- Case II: A Rapid Tourism Development Case
- Case III: A Rapid Infrastructure/Military Spending Case
- Case IV: The Rapid Development Case

Case I, the business as usual case, is based upon the April 2007 Moodys Economy.com outlook for the Guam economy. While this forecast calls for dramatic 4.5%-5.5% growth in total civilian non-agricultural employment during the first decade of the forecast, Mangilao is of the opinion that Case I is a lower bound for the GPA sales outlook. There is known tourism development and infrastructure/military development on Guam (which Mangilao has discussed in detail elsewhere) that is simply not included in the Moodys forecast – or indeed, in the forecasts of any of the Mainland publishers of economic forecasts for Guam.

Case IV, the rapid development case is based upon Case I supplemented with additions to the economic outlook that have been prepared by Mangilao as part of this effort. In the case of tourism, Mangilao has prepared an independent assessment of the opportunities for the growth in tourism visitation and the construction of new hotel rooms – and hotel jobs. In the case of infrastructure/military development, Mangilao has prepared a careful inventory of the construction projects that either have been included in the constructor's capital budget, or that have similar cause to inspire confidence that the project will be built. This inventory of projects was then converted into an estimate of annual construction spending, resulting temporary construction jobs and permanent jobs necessary to operating and maintaining the new facilities.

This documentation begins with a discussion of the forecast's Business As Usual case. Following that is a discussion of the estimated price elasticities by revenue class that result from this analysis. Appendix I reports the linear regression estimates of the stochastic equations used in the GPA Peak Demand and Sales Forecast Model. Appendix II provides procedures for a user to operate and maintain the model. Appendix III contains the EViews program used to estimate the model and prepare the forecast.

The GPA Load and Sales Forecast

Guam is an island economy that has spent the last decade in an economic doldrums. Economic growth has been stagnant, employment growth has been almost non-existent, and electricity demand has been stagnant.

All of that is changing now, with the primary driver of growth being the more than $10 billion in new infrastructure and military construction projects that are slated for the next few years. The onset of this growth burst has been almost unexpected. Two years ago the prospect was just a rumor – and the Moodys Economy.com economic forecast called for 0.5% growth in employment going forward. Today, the rumored construction funds are documented in budgets and published financial plans – and the forecast is for 5.4% employment growth. The difference is like night and day.

This rapid upward revision in expectations for economic growth translates into expectations for rapid growth in electricity demand. Figure 1 and Table 1, below, illustrate the outlook for growth in electricity demand.

The need for new generating capacity is measured in MW, the level of instantaneous demand caused by the electricity consuming appliances and capital goods connected to the system. As can be seen in Table 1, the peak demand on the system amounted to 269 MW, a level that is essentially unchanged from recent years.

With the current economic outlook for Guam, however, we are on the cusp of a period of extremely rapid growth. Over the next decade – between now and 2107 – we expect the peak demand to grow to 366 MW, or 3.1%

annually. Most important for GPA's planning, we expect peak demand to exceed 300 MW by 2011 – just 4 years from now.

Figure 1

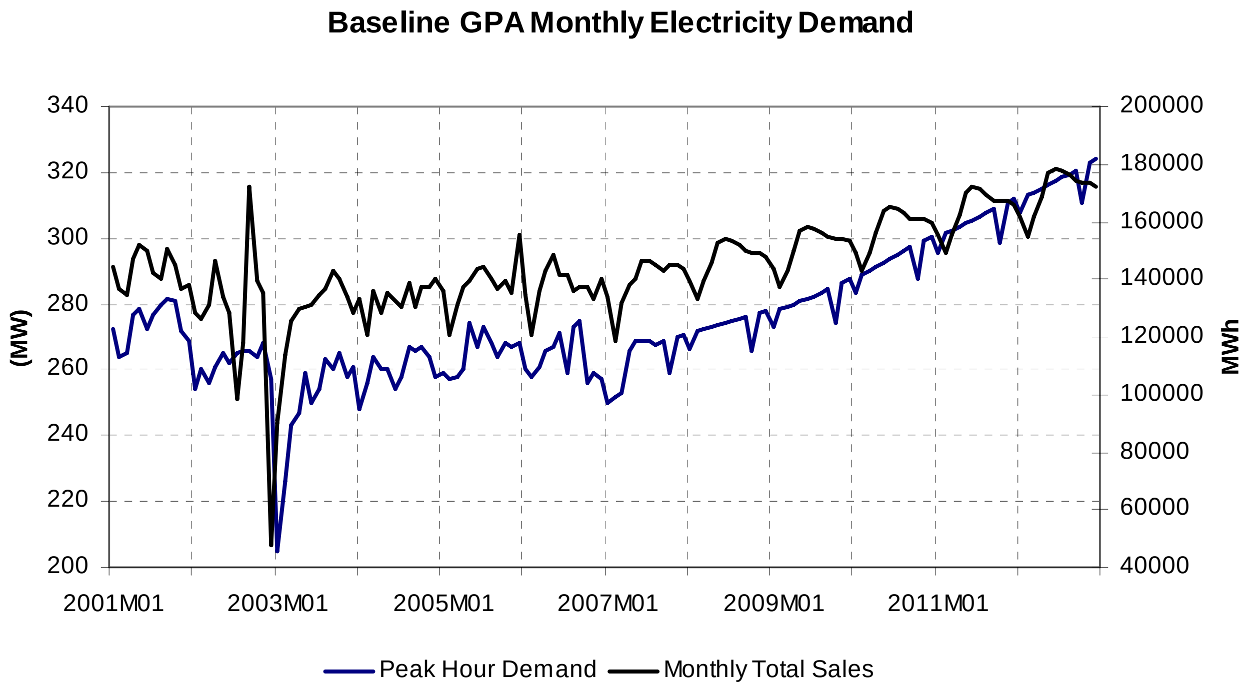

Table 1
GPA Peak Hour Demand (MW), Total Sales (MWh) and Implied Load Factor (%)

	Peak Demand	Sales	Implicit Load Factor
2004	267	1,588,851	67.75%
2005	274	1,644,540	68.52%
2006	275	1,669,001	69.28%
2007	269	1,653,526	70.17%
2008	276	1,752,568	72.27%
2009	284	1,803,099	72.39%
2010	297	1,878,396	72.11%
2011	309	1,955,140	72.27%
2012	321	2,031,027	72.12%
2013	332	2,117,566	72.86%
2014	341	2,169,209	72.67%
2015	349	2,215,596	72.51%
2016	357	2,264,802	72.14%
2017	366	2,314,458	71.96%

GPA's total sales are expected to grow at a comparably fast rate. In 2007, Total Sales is expected to amount to 1.65 tWh (teraWatt-hours, or billion kWh). Total Sales are expected to grow to 2.31 tWh by 2017, a growth rate of 3.4% annually.

The GPA Price Elasticity

Price elasticities are a commonly used method of measuring consumer's response to changing prices. A price elasticity is defined as the percentage change in the consumption of an item resulting from a one percent (1%) change in the price of that same commodity. For example, a price elasticity of -0.1 indicates that a one percent increase in the price of a commodity will lead to a 0.1% reduction in the consumption of that commodity.

In the course of constructing the GPA load and sales forecasting model, Mangilao prepared estimates of the price elasticity of consumers for the different electricity products that GPA sells. These estimated elasticities are presented in Table 1 (below).

The elasticities presented in Table 1 were estimated with data that was current as of August 29, 2007. Using data from a different time period would lead to slightly different results. The first column begins with the elasticity of system peak demand, measured in megawatts (MW), followed by each of GPA's revenue classes. Column two reports the estimated coefficient on the price term in the equation for that revenue class (the equations themselves are reported in Appendix I to this document. This coefficient should be interpreted as the nominal change in consumption (measured in MW or MWh) resulting from a $1 change in the underlying price, measured in 2006 dollars. The most recently observed nominal price is reported in column 2. Since economic theory teaches that consumers respond to real prices (inflation adjusted prices), the nominal price is converted into a real price (2006 $) in column four. The amount of electricity consumed is reported in column five. The resulting calculated elasticity is reported in column six, the right-most column.

Table 1

Guam Price Elasticities as of August 29, 2007

	Price Coefficient	Nominal Price	Real Price	Quantity	Elasticity
MW	-161.95084	0.187	0.177	269	-0.107
RES	-105,753,548	0.187	0.177	42,000,753	-0.446
SGND	-7,951,701	0.233	0.221	4,679,019	-0.376
SGD	-34,431,946	0.221	0.210	17,391,447	-0.416
Large	-102,227,590	0.194	0.184	30,100,641	-0.625
POL	-57,003	0.384	0.364	46,838	-0.443
GSGND	-1,145,879	0.230	0.218	862,742	-0.289
GSGD	-23,631,648	0.213	0.202	8,893,524	-0.536
Glarge	-17,763,260	0.202	0.192	7,134,543	-0.477
GSL	-52,252	0.464	0.440	819,836	-0.028
Navy	-23,048,877	0.145	0.138	28,100,485	-0.113

These estimated elasticities are of a magnitude that is consistent with results that Mangilao has obtained in other jurisdictions. They indicate that consumers are very responsive to increases in the price of electricity. For example, an increase in GPA rates that would result in a 1%increase in residential prices is estimated to lead to a 0.11% decrease in system peak demand (MW). Similarly, a 1% increase in prices to residential customers will result in a 0.45% decrease in residential consumption (kWh).

Appendix I

GPA Sales and Peak Demand Regression Equation Listing

September 7, 2007

Definitions

APR03 – Categorical variable for April 2003
APR04 – Categorical variable for April 2004
APR96 – Categorical variable for April 1996
APR98 – Categorical variable for April 1998
AUG – Categorical variable for the month of August
AUG01 – Categorical variable for the month of August 2001
BILLCDD68 – Billing month adjusted cooling degree-days, calculated on a comfort threshold of 68 degrees Fahrenheit
CDD68 – Calendar month cooling degree-days, calculated on a comfort threshold of 68 degrees Fahrenheit
CHATAAN1, CHATAAN 2, CHATAAN 3 – Categorical variables for the 1st, 2nd and 3rd month following typhoon Chataan
Earthquake3 – Categorical variable for earthquake number 3
EMP – Guam Total Non-Agricultural Civilian Employment
FEB01 – Categorical variable for February 2001
FEB02 – Categorical variable for February 2002
FEB04 – Categorical variable for February 2004
FEB96 – Categorical variable for February 1996
CPI – Guam Consumer Price Index
GSLCUS – Government Street Light customers
GSLKWH – Government Street Light sales
GSLPRI – Government Street Light average revenue per kWh
GSSDCUS – Government Small Demand customers
GSSDKWH – Government Small Demand sales
GSSDPRI – Government Small Demand average revenue per kWh
GSSLCUS – XXXXX customers
GSSLKWH – XXXXX sales
GSSLPRI – XXXXX average revenue per kWh
GSSNDCUS – Government Small Non-Demand customers
GSSNDKWH – Government Small Non-Demand sales
GSSNDPRI – Government Small Non-Demand average revenue per kWh
JAN – Categorical variable for January
JAN96 – Categorical variable for January 1996

JAN97 – Categorical variable for January 1997
JAN01 – Categorical variable for January 2001
JUL96 – Categorical variable for July 1996
JUL99 – Categorical variable for July 1999
JUN – Categorical variable for June
JUN00 – Categorical variable for June 2000
JUN03 – Categorical variable for June 2003
JUN05 – Categorical variable for June 2005
JUN06 – Categorical variable for June 2006
JUN07 – Categorical variable for June 2007
JUN96 – Categorical variable for June 1996
JUN97 – Categorical variable for June 1997
JUN98 – Categorical variable for June 1998
JUN99 – Categorical variable for June 1999
LGCUS – Large general customers
LGDKWH – Large General Demand sales
LGDPRI - Large General Demand average revenue per kWh
MAY00 – Categorical variable for May 2000
MAY01 – Categorical variable for May 2001
MAY02 – Categorical variable for May 2002
MAY04 – Categorical variable for May 2004
MAY96 – Categorical variable for May 1996
MWGPA – Monthly peak hour demand
NOV00 – Categorical variable for November 2000
OCT00 – Categorical variable for October 2000
OCT06 – Categorical variable for October 2006
OCT03 – Categorical variable for October 2003
OCT98 – Categorical variable for October 1998
OCT99 – Categorical variable for October 1999
NOV98 – Categorical variable for November 1998
PAKA1, PAKA2, PAKA3 – Categorical variables for the 1^{st}, 2^{nd} and 3^{rd} month following typhoon Paka
POLCUS – Outdoor light customers
POLKWH – Outdoor light sales
POLPRI – Outdoor light average revenue per kWh
PONGSONA1, PONGSONA 2, PONGSONA 3 – Categorical variables for the 1^{st}, 2^{nd} and 3^{rd} month following typhoon Pongsona
POPULATION – Guam civilian population
RESCUS – Residential Customers
RESKWH – Residential sales

RESPRI – Residential average revenue per kWh
SEP00 – Categorical variable for September 2000
SEP01 – Categorical variable for September 2001
SEP96 – Categorical variable for September 1996
SEP97 – Categorical variable for September 1997
SEP99 – Categorical variable for September 1999
SGDCUS – Small General Demand customers
SGDKWH – Small General Service Demand sales
SGDPRI – Small General Service Demand average revenue per kWh
SGNDCUS – Small General Service Non-Demand customers
SGNDKWH – Small General Service Non-Demand sales
SGNDPRI – Small General Service Non-Demand average revenue per kWh
STR06 -

Regression Results

```
========================================================================
Dependent Variable: RESCUS
Method: Least Squares
Date: 09/06/07   Time: 21:32
Sample (adjusted): 1993M05 2007M06
Included observations: 170 after adjustments
Convergence achieved after 7 iterations
========================================================================
            Variable            CoefficienStd. Errort-Statistic  Prob.
========================================================================
               C                 18270.69   3477.968   5.253265   0.0000
.5*POPULATION+.5*POPULATION(-1)  118.2144   22.07978   5.353964   0.0000
             PAKA1              -15690.89   351.8195  -44.59926   0.0000
             PAKA2              -36457.00   404.8972  -90.04013   0.0000
             PAKA3               14606.86   351.8153   41.51855   0.0000
             OCT99               11576.99   289.5409   39.98397   0.0000
            CHATAAN1             3407.874   351.7949   9.687104   0.0000
            CHATAAN2             768.0030   404.8584   1.896967   0.0597
            CHATAAN3             3144.125   351.7911   8.937477   0.0000
           PONGSONA2            -637.9548   332.7564  -1.917183   0.0570
           PONGSONA3            -887.7237   332.7551  -2.667799   0.0084
             AR(1)               0.865137   0.032991   26.22346   0.0000
========================================================================
R-squared                        0.990302    Mean dependent var 36407.10
Adjusted R-squared               0.989627    S.D. dependent var 3753.713
S.E. of regression               382.3023    Akaike info criteri14.79827
Sum squared resid                23092502    Schwarz criterion  15.01962
Log likelihood                  -1245.853    F-statistic        1466.797
Durbin-Watson stat               2.295434    Prob(F-statistic)  0.000000
========================================================================
Inverted AR Roots                     .87
========================================================================
```

```
============================================================
Dependent Variable: SGNDCUS
Method: Least Squares
Date: 09/06/07   Time: 21:32
Sample (adjusted): 1992M11 2007M06
Included observations: 176 after adjustments
Convergence achieved after 6 iterations
============================================================
     Variable      CoefficienStd. Errort-Statistic  Prob.
============================================================
         C          3096.981   1241.412   2.494725   0.0136
        AUG         20.86102   10.04682   2.076381   0.0394
       PAKA1       -1560.962   45.20694  -34.52925   0.0000
       PAKA2       -3817.949   52.20019  -73.14053   0.0000
       PAKA3        1409.038   45.20694   31.16863   0.0000
       OCT99        1264.006   36.91761   34.23856   0.0000
     CHATAAN1       227.4370   37.25211   6.105347   0.0000
     CHATAAN3       242.4368   37.25203   6.508015   0.0000
     PONGSONA2     -110.6564   42.62415  -2.596096   0.0103
     PONGSONA3     -154.3235   42.62414  -3.620565   0.0004
       APR03       -61.99581   36.91173  -1.679569   0.0949
       AR(1)        0.994084   0.013554   73.34322   0.0000
============================================================
R-squared           0.986683    Mean dependent var 3539.449
Adjusted R-squared  0.985790    S.D. dependent var 436.6154
S.E. of regression  52.04685    Akaike info criteri10.80791
Sum squared resid   444255.5    Schwarz criterion  11.02408
Log likelihood     -939.0962    F-statistic        1104.669
Durbin-Watson stat  2.371604    Prob(F-statistic)  0.000000
============================================================
Inverted AR Roots        .99
============================================================
```

```
=========================================================================
Dependent Variable: SGDCUS
Method: Least Squares
Date: 09/06/07   Time: 21:32
Sample (adjusted): 1993M05 2007M06
Included observations: 170 after adjustments
Convergence achieved after 7 iterations
=========================================================================
            Variable           CoefficienStd. Errort-Statistic  Prob.
=========================================================================
               C               -1558.578   214.3981  -7.269551   0.0000
.5*POPULATION+.5*POPULATION(-1)  17.72953   1.365699   12.98202   0.0000
             PAKA1             -462.3476   29.54994  -15.64631   0.0000
             PAKA2             -1128.910   33.92431  -33.27733   0.0000
             PAKA3              456.7016   29.53714   15.46194   0.0000
             OCT99              366.6780   24.44072   15.00275   0.0000
            CHATAAN1           -319.9703   24.39078  -13.11849   0.0000
            CHATAAN3           -346.1039   24.37071  -14.20164   0.0000
           PONGSONA2           -151.3817   27.96895  -5.412490   0.0000
           PONGSONA3           -149.1160   27.96867  -5.331536   0.0000
             AR(1)              0.820265   0.039655   20.68524   0.0000
=========================================================================
R-squared                       0.981271    Mean dependent var 1184.100
Adjusted R-squared              0.980093    S.D. dependent var 223.3795
S.E. of regression              31.51728    Akaike info criteri9.801467
Sum squared resid               157940.9    Schwarz criterion  10.00437
Log likelihood                 -822.1247    F-statistic        833.0374
Durbin-Watson stat              2.217179    Prob(F-statistic)  0.000000
=========================================================================
Inverted AR Roots                    .82
=========================================================================
```

```
============================================================
Dependent Variable: LGCUS
Method: Least Squares
Date: 09/06/07   Time: 21:32
Sample (adjusted): 1993M04 2007M06
Included observations: 171 after adjustments
Convergence achieved after 5 iterations
============================================================
     Variable      CoefficienStd. Errort-Statistic  Prob.
============================================================
         C         -283.7206   34.88418  -8.133217   0.0000
    POPULATION      2.663060   0.223281   11.92694   0.0000
       PAKA1       -108.6802   12.05836  -9.012848   0.0000
       PAKA2       -110.7348   13.39262  -8.268347   0.0000
       PAKA3        108.1030   12.05706   8.965950   0.0000
       FEB02        482.6336   10.55628   45.72004   0.0000
     PONGSONA3      91.41861   10.57124   8.647863   0.0000
       AR(1)        0.578300   0.063893   9.051075   0.0000
============================================================
R-squared           0.947308    Mean dependent var 133.3918
Adjusted R-squared  0.945046    S.D. dependent var 51.95794
S.E. of regression  12.18017    Akaike info criteri7.883150
Sum squared resid   24182.13    Schwarz criterion  8.030128
Log likelihood     -666.0093    F-statistic        418.6386
Durbin-Watson stat  2.446659    Prob(F-statistic)  0.000000
============================================================
Inverted AR Roots        .58
============================================================
```

```
============================================================
Dependent Variable: POLCUS
Method: Least Squares
Date: 09/06/07   Time: 21:32
Sample (adjusted): 1993M04 2007M06
Included observations: 171 after adjustments
Convergence achieved after 11 iterations
============================================================
     Variable      CoefficienStd. Errort-Statistic  Prob.
============================================================
         C          360.9391   148.4214   2.431854   0.0161
        EMP         3.912023   2.415141   1.619791   0.1072
       PAKA1       -231.3643   23.13980  -9.998544   0.0000
       PAKA2       -622.9726   26.56414  -23.45164   0.0000
       PAKA3        197.3901   23.12748   8.534875   0.0000
       SEP99       -185.5706   22.03635  -8.421111   0.0000
       OCT99        113.8911   22.02153   5.171806   0.0000
     CHATAAN1       88.47144   19.07984   4.636907   0.0000
     CHATAAN3       89.90675   19.09817   4.707612   0.0000
       JUN07       -59.04206   24.91065  -2.370153   0.0190
       AR(1)        0.831421   0.044497   18.68468   0.0000
============================================================
R-squared           0.885324    Mean dependent var 597.2222
Adjusted R-squared  0.878157    S.D. dependent var 71.07401
S.E. of regression  24.80915    Akaike info criteri9.322468
Sum squared resid   98479.07    Schwarz criterion  9.524563
Log likelihood     -786.0710    F-statistic        123.5233
Durbin-Watson stat  2.399592    Prob(F-statistic)  0.000000
============================================================
Inverted AR Roots        .83
============================================================
```

```
============================================================
Dependent Variable: GSSNDCUS
Method: Least Squares
Date: 09/06/07   Time: 21:32
Sample (adjusted): 1993M10 2007M06
Included observations: 165 after adjustments
Convergence achieved after 13 iterations
============================================================
     Variable      CoefficienStd. Errort-Statistic  Prob.
============================================================
        C           367.2213   307.5170   1.194149   0.2342
   @MOVAV(EMP,7)    5.884979   5.045050   1.166486   0.2452
      PAKA1        -819.3136   24.43990  -33.52360   0.0000
      PAKA2        -821.1537   28.17776  -29.14191   0.0000
      PAKA3         320.9402   24.43778   13.13296   0.0000
      OCT99         656.0223   20.01048   32.78393   0.0000
      SEP00        -722.5332   20.01696  -36.09605   0.0000
      FEB01         786.4215   20.01037   39.30070   0.0000
    EARTHQUAKE3    -342.4820   20.01098  -17.11470   0.0000
      AR(1)         0.906976   0.034261   26.47227   0.0000
============================================================
R-squared           0.968934    Mean dependent var 720.5818
Adjusted R-squared  0.967130    S.D. dependent var 149.0001
S.E. of regression  27.01393    Akaike info criteri9.489274
Sum squared resid   113111.6    Schwarz criterion  9.677513
Log likelihood     -772.8651    F-statistic        537.1468
Durbin-Watson stat  2.235222    Prob(F-statistic)  0.000000
============================================================
Inverted AR Roots        .91
============================================================
```

```
=========================================================================
Dependent Variable: GSSDCUS
Method: Least Squares
Date: 09/06/07   Time: 21:32
Sample (adjusted): 1993M05 2007M06
Included observations: 170 after adjustments
Convergence achieved after 7 iterations
=========================================================================
            Variable            CoefficienStd. Errort-Statistic  Prob.
=========================================================================
              C                -357.8681   148.0559  -2.417115   0.0168
.5*POPULATION+.5*POPULATION(-1)  4.903566   0.934951   5.244731   0.0000
             PAKA1             -361.6968   9.144655  -39.55281   0.0000
             PAKA2             -365.4365   10.54490  -34.65529   0.0000
             PAKA3              152.7764   9.144560   16.70681   0.0000
             OCT99              325.0790   7.486630   43.42128   0.0000
             SEP00             -408.8429   7.488130  -54.59880   0.0000
             FEB01              431.1235   7.486579   57.58618   0.0000
             MAY01              43.21852   7.492422   5.768298   0.0000
             MAY02              59.52909   7.488019   7.949911   0.0000
             FEB04              62.04510   7.487947   8.285997   0.0000
             JUN05              73.98256   7.486823   9.881703   0.0000
             JUL06             -177.0754   7.486739  -23.65187   0.0000
             AR(1)              0.911544   0.030616   29.77323   0.0000
=========================================================================
R-squared                       0.989574    Mean dependent var 400.5412
Adjusted R-squared              0.988705    S.D. dependent var 95.31729
S.E. of regression              10.13005    Akaike info criteri7.547652
Sum squared resid               16008.38    Schwarz criterion  7.805895
Log likelihood                 -627.5504    F-statistic        1138.970
Durbin-Watson stat              2.328467    Prob(F-statistic)  0.000000
=========================================================================
Inverted AR Roots                    .91
=========================================================================
```

```
============================================================
Dependent Variable: GSLCUS
Method: Least Squares
Date: 09/06/07   Time: 21:32
Sample (adjusted): 1993M04 2007M06
Included observations: 171 after adjustments
Convergence achieved after 7 iterations
============================================================
     Variable      CoefficienStd. Errort-Statistic  Prob.
============================================================
         C         -51.57105   44.37406  -1.162189   0.2469
    POPULATION      0.662374   0.282285   2.346471   0.0202
       PAKA1       -56.87234   4.640380  -12.25597   0.0000
       PAKA2       -57.99035   5.339999  -10.85962   0.0000
       PAKA3        45.64235   4.640223   9.836240   0.0000
       FEB01        57.58670   3.813877   15.09926   0.0000
       SEP00        43.61062   3.813883   11.43470   0.0000
       AR(1)        0.863412   0.038610   22.36222   0.0000
============================================================
R-squared           0.904332    Mean dependent var 51.18129
Adjusted R-squared  0.900223    S.D. dependent var 15.95128
S.E. of regression  5.038606    Akaike info criteri6.117790
Sum squared resid   4138.171    Schwarz criterion  6.264768
Log likelihood     -515.0710    F-statistic        220.1147
Durbin-Watson stat  2.560460    Prob(F-statistic)  0.000000
============================================================
Inverted AR Roots        .86
============================================================
```

```
============================================================
Dependent Variable: GSSLCUS
Method: Least Squares
Date: 09/06/07   Time: 21:32
Sample: 1997M01 2007M05
Included observations: 125
Convergence achieved after 10 iterations
============================================================
     Variable      CoefficienStd. Errort-Statistic  Prob.
============================================================
         C         -2637.201   1988.669  -1.326113   0.1874
   @MOVAV(EMP,3)    47.11059   34.21495   1.376901   0.1712
       JAN97        219.8089   75.69878   2.903732   0.0044
       PAKA1       -971.0580   75.74616  -12.81990   0.0000
       OCT00        779.9509   87.72640   8.890721   0.0000
       NOV00        390.4546   87.71666   4.451316   0.0000
       FEB01        1198.900   75.64983   15.84802   0.0000
       STR06        1168.268   105.7544   11.04700   0.0000
       AR(1)        0.964277   0.019631   49.11934   0.0000
============================================================
R-squared           0.958355    Mean dependent var 942.6960
Adjusted R-squared  0.955483    S.D. dependent var 497.9881
S.E. of regression  105.0706    Akaike info criteri12.21642
Sum squared resid   1280619.    Schwarz criterion  12.42006
Log likelihood     -754.5261    F-statistic        333.6830
Durbin-Watson stat  1.458820    Prob(F-statistic)  0.000000
============================================================
Inverted AR Roots        .96
============================================================
```

```
=====================================================================
Dependent Variable: RESKWH
Method: Least Squares
Date: 09/06/07   Time: 21:32
Sample (adjusted): 1995M12 2007M06
Included observations: 139 after adjustments
=====================================================================
          Variable           CoefficienStd. Errort-Statistic  Prob.
=====================================================================
              C               17743602   8236115.   2.154365   0.0331
  RESPRI/(CPI/126.90230833)  -1.06E+08   25989848  -4.074040   0.0001
      BILLCDD68*RESCUS        2.206854   0.169469   13.02217   0.0000
 @MOVAV(.5*EMP+.5*EMP(-1),6)  100562.8   83468.23   1.204803   0.2305
            PAKA1            -9173018.   3557984.  -2.578150   0.0111
            OCT99            -9968195.   3510242.  -2.839746   0.0052
          CHATAAN1           -11136960   3435504.  -3.241725   0.0015
          CHATAAN2           -10492436   3419872.  -3.068079   0.0026
          PONGSONA1          -29071912   3402008.  -8.545516   0.0000
          PONGSONA2          -20647815   3482225.  -5.929489   0.0000
=====================================================================
R-squared                     0.731817    Mean dependent var 42095033
Adjusted R-squared            0.713106    S.D. dependent var 6259979.
S.E. of regression            3352998.    Akaike info criteri32.95783
Sum squared resid             1.45E+15    Schwarz criterion  33.16894
Log likelihood               -2280.569    F-statistic        39.11274
Durbin-Watson stat            2.071552    Prob(F-statistic)  0.000000
=====================================================================
```

```
===========================================================================
Dependent Variable: SGNDKWH
Method: Least Squares
Date: 09/06/07   Time: 21:32
Sample (adjusted): 1996M01 2007M06
Included observations: 138 after adjustments
===========================================================================
             Variable              CoefficienStd. Errort-Statistic  Prob.
===========================================================================
                C                   225194.9   782561.2   0.287767   0.7740
@MOVAV(SGNDPRI,2)/(CPI/126.90230833-7958708.   1393742.  -5.710318   0.0000
         BILLCDD68*SGNDCUS          2.664764   0.546023   4.880312   0.0000
         @MOVAV(SGNDCUS,2)          912.8716   317.4970   2.875213   0.0047
               JAN96               -4275184.   887179.2  -4.818851   0.0000
               FEB96                19851746   901169.4   22.02887   0.0000
               APR96               -23663385   903007.4  -26.20508   0.0000
               OCT96                4560936.   883880.2   5.160129   0.0000
            EARTHQUAKE2             9829999.   1177461.   8.348471   0.0000
             PONGSONA1             -3707600.   876987.8  -4.227652   0.0000
===========================================================================
R-squared                           0.919035    Mean dependent var 5642389.
Adjusted R-squared                  0.913342    S.D. dependent var 2967660.
S.E. of regression                  873609.2    Akaike info criteri30.26836
Sum squared resid                   9.77E+13    Schwarz criterion  30.48048
Log likelihood                     -2078.517    F-statistic        161.4374
Durbin-Watson stat                  1.753675    Prob(F-statistic)  0.000000
===========================================================================
```

Dependent Variable: SGDKWH
Method: Least Squares
Date: 09/06/07 Time: 21:32
Sample (adjusted): 1997M01 2007M06
Included observations: 126 after adjustments

Variable	Coefficient	Std. Error	t-Statistic	Prob.
C	1603998.	4540953.	0.353229	0.7246
SGDPRI/(CPI/126.90230833	-34659629	9746291.	-3.556186	0.0005
BILLCDD65*SGDCUS	9.216218	2.038017	4.522150	0.0000
@MOVAV(EMP,6)	255012.5	47142.15	5.409437	0.0000
PAKA1	-7274630.	1624235.	-4.478804	0.0000
PAKA2	-8409906.	1992698.	-4.220362	0.0000
PAKA4	3495529.	1553271.	2.250432	0.0263
OCT00	8408351.	1640171.	5.126508	0.0000
CHATAAN1	-4354634.	1595194.	-2.729845	0.0073
CHATAAN3	6285560.	1627948.	3.861032	0.0002
PONGSONA1	-10518715	1542785.	-6.818003	0.0000
PONGSONA2	-7113876.	1586348.	-4.484436	0.0000

R-squared	0.745812	Mean dependent var	16578628
Adjusted R-squared	0.721285	S.D. dependent var	2867136.
S.E. of regression	1513661.	Akaike info criteri	31.38835
Sum squared resid	2.61E+14	Schwarz criterion	31.65847
Log likelihood	-1965.466	F-statistic	30.40790
Durbin-Watson stat	2.139262	Prob(F-statistic)	0.000000

Dependent Variable: LGKWH
Method: Least Squares
Date: 09/06/07 Time: 21:32
Sample (adjusted): 1995M12 2007M06
Included observations: 139 after adjustments

Variable	Coefficient	Std. Error	t-Statistic	Prob.
C	-9170267.	7737424.	-1.185184	0.2381
LGPRI/(CPI/126.90230833	-1.02E+08	22275405	-4.583136	0.0000
CDD65	33449.65	9666.858	3.460240	0.0007
POPULATION	228611.7	43887.18	5.209078	0.0000
SEP96	-73162217	7287225.	-10.03979	0.0000
PAKA1	-23659342	4040038.	-5.856217	0.0000
PAKA2	17265164	3978751.	4.339343	0.0000
PONGSONA1	-18835899	3963303.	-4.752576	0.0000

R-squared	0.680488	Mean dependent var	27106588
Adjusted R-squared	0.663415	S.D. dependent var	6785751.
S.E. of regression	3936819.	Akaike info criteri	33.26548
Sum squared resid	2.03E+15	Schwarz criterion	33.43437
Log likelihood	-2303.951	F-statistic	39.85717
Durbin-Watson stat	1.704048	Prob(F-statistic)	0.000000

Dependent Variable: POLKWH
Method: Least Squares
Date: 09/06/07 Time: 21:32
Sample (adjusted): 1996M01 2007M06
Included observations: 138 after adjustments
Convergence achieved after 9 iterations

Variable	Coefficien	Std. Error	t-Statistic	Prob.
C	34631.13	20251.31	1.710069	0.0897
POLPRI/(CPI/126.90230833	-58631.93	12382.91	-4.734907	0.0000
POLCUS	97.89843	31.45664	3.112171	0.0023
EARTHQUAKE3	-216370.3	15134.82	-14.29619	0.0000
PAKA2	-52479.65	24536.64	-2.138828	0.0344
APR98	-93377.05	15410.32	-6.059385	0.0000
JUN98	71728.89	15086.29	4.754573	0.0000
JUN99	105637.4	15200.02	6.949819	0.0000
CHATAAN2	39058.10	15313.58	2.550553	0.0119
PONGSONA2	75587.61	15092.58	5.008262	0.0000
AR(1)	0.628494	0.071255	8.820371	0.0000

R-squared	0.709149	Mean dependent var	68917.36
Adjusted R-squared	0.686248	S.D. dependent var	31648.89
S.E. of regression	17727.68	Akaike info criteri	22.48000
Sum squared resid	3.99E+10	Schwarz criterion	22.71333
Log likelihood	-1540.120	F-statistic	30.96502
Durbin-Watson stat	2.413205	Prob(F-statistic)	0.000000
Inverted AR Roots	.63		

Dependent Variable: GSSNDKWH
Method: Least Squares
Date: 09/06/07 Time: 21:32
Sample (adjusted): 1995M12 2007M06
Included observations: 139 after adjustments

Variable	Coefficien	Std. Error	t-Statistic	Prob.
C	-964506.4	549403.1	-1.755553	0.0815
GSSNDPRI/(CPI/126.90230833)	-821455.1	263474.2	-3.117782	0.0022
CDD80*GSSNDCUS	5.327641	1.889248	2.819979	0.0056
@MOVAV(EMP,6)	37287.48	8921.529	4.179495	0.0001
MAY96	8369742.	438040.5	19.10723	0.0000
JUN96	10493297	440798.9	23.80518	0.0000
SEP97	-1898326.	433349.6	-4.380587	0.0000
PAKA1	-2398554.	439066.0	-5.462855	0.0000
JUN99	1750896.	429971.5	4.072121	0.0001
OCT99	1259704.	440819.5	2.857641	0.0050

R-squared	0.903225	Mean dependent var	1449529.
Adjusted R-squared	0.896473	S.D. dependent var	1329362.
S.E. of regression	427730.0	Akaike info criteri	28.83960
Sum squared resid	2.36E+13	Schwarz criterion	29.05071
Log likelihood	-1994.352	F-statistic	133.7764
Durbin-Watson stat	2.176900	Prob(F-statistic)	0.000000

Dependent Variable: GSSDKWH
Method: Least Squares
Date: 09/06/07 Time: 21:32
Sample (adjusted): 1999M01 2007M06
Included observations: 102 after adjustments
Convergence achieved after 16 iterations

Variable	Coefficient	Std. Error	t-Statistic	Prob.
C	6908760.	5467579.	1.263587	0.2096
GSSDPRI/(CPI/126.90230833)	-23633841	4226246.	-5.592159	0.0000
BILLCDD80*GSSDCUS	30.30615	13.78908	2.197836	0.0305
@MOVAV(.5*EMP+.5*EMP(-1),6)	93344.78	92073.93	1.013802	0.3133
JUL99	-3102305.	1070205.	-2.898794	0.0047
SEP99	-2011139.	1077256.	-1.866909	0.0651
PONGSONA1	-5362167.	1141143.	-4.698946	0.0000
PONGSONA2	-844982.1	1230455.	-0.686723	0.4940
OCT03	3739034.	1057804.	3.534715	0.0006
AR(1)	0.415943	0.093997	4.425085	0.0000

R-squared	0.550531	Mean dependent var	8616153.
Adjusted R-squared	0.506562	S.D. dependent var	1626525.
S.E. of regression	1142555.	Akaike info criteri	30.82833
Sum squared resid	1.20E+14	Schwarz criterion	31.08568
Log likelihood	-1562.245	F-statistic	12.52068
Durbin-Watson stat	2.187945	Prob(F-statistic)	0.000000
Inverted AR Roots	.42		

Dependent Variable: GSLKWH
Method: Least Squares
Date: 09/06/07 Time: 21:32
Sample (adjusted): 1995M12 2007M06
Included observations: 139 after adjustments

Variable	Coefficient	Std. Error	t-Statistic	Prob.
C	3973055.	2075806.	1.913982	0.0579
GSLPRI/(CPI/126.90230833	-17032730	3125270.	-5.450003	0.0000
CDD80*GSLCUS	296.1357	80.38943	3.683764	0.0003
@MOVAV(EMP,1)	87708.06	30125.10	2.911461	0.0043
JUL96	21857196	1467689.	14.89226	0.0000
SEP96	-30630851	1596447.	-19.18689	0.0000
JUN97	-7521065.	1394066.	-5.395056	0.0000
PAKA1	-7697206.	1402035.	-5.490024	0.0000
AUG01	-6429574.	1408555.	-4.564660	0.0000
SEP01	8008536.	1411813.	5.672519	0.0000
OCT98	4684078.	1403734.	3.336870	0.0011
NOV98	5415117.	1390807.	3.893508	0.0002

R-squared	0.876960	Mean dependent var	6987667.
Adjusted R-squared	0.866303	S.D. dependent var	3745342.
S.E. of regression	1369469.	Akaike info criteri	31.18012
Sum squared resid	2.38E+14	Schwarz criterion	31.43346
Log likelihood	-2155.018	F-statistic	82.28953
Durbin-Watson stat	1.816899	Prob(F-statistic)	0.000000

```
=================================================================
Dependent Variable: GSSLKWH
Method: Least Squares
Date: 09/06/07   Time: 21:32
Sample (adjusted): 1996M01 2007M06
Included observations: 138 after adjustments
Convergence achieved after 10 iterations
=================================================================
        Variable         CoefficienStd. Errort-Statistic  Prob.
=================================================================
            C             587398.1   69622.79   8.436865   0.0000
GSSLPRI/(CPI/126.90230833-52807.91   15532.93  -3.399740   0.0009
         GSSLCUS          284.7876   61.81019   4.607453   0.0000
          MAY00           6107624.   248491.5   24.57880   0.0000
          APR04          -2139900.   234253.8  -9.134961   0.0000
          JAN96           1032601.   247113.9   4.178645   0.0001
          PAKA1          -775072.9   253193.5  -3.061188   0.0027
          PAKA2           581728.8   257043.2   2.263156   0.0254
          JUN00           838347.0   257194.8   3.259580   0.0014
          SEP00          -848033.8   241619.4  -3.509793   0.0006
          JAN01           619323.2   246495.7   2.512511   0.0133
           JAN            144118.7   79043.01   1.823295   0.0707
           JUN            140104.8   72154.81   1.941725   0.0544
          AR(1)           0.333613   0.085923   3.882696   0.0002
=================================================================
R-squared                 0.867797    Mean dependent var 860251.4
Adjusted R-squared        0.853937    S.D. dependent var 643824.8
S.E. of regression        246057.9    Akaike info criteri27.76045
Sum squared resid         7.51E+12    Schwarz criterion  28.05742
Log likelihood           -1901.471    F-statistic        62.61184
Durbin-Watson stat        2.202664    Prob(F-statistic)  0.000000
=================================================================
Inverted AR Roots              .33
=================================================================
```

```
=================================================================
Dependent Variable: NAVYKWH
Method: Least Squares
Date: 09/06/07   Time: 21:32
Sample (adjusted): 1996M01 2007M06
Included observations: 138 after adjustments
Convergence achieved after 17 iterations
=================================================================
        Variable         CoefficienStd. Errort-Statistic  Prob.
=================================================================
            C             11521229   5588903.   2.061447   0.0413
NAVYPRI/(CPI/126.90230833-22589857   13249937  -1.704903   0.0907
        CDD65*EMP         423.9179   66.04053   6.419056   0.0000
      @MOVAV(EMP,3)       98849.38   85282.42   1.159083   0.2486
          PAKA1          -8075375.   1500748.  -5.380901   0.0000
        CHATAAN1         -11982492   1330658.  -9.004938   0.0000
        CHATAAN3          24135000   1467489.   16.44646   0.0000
        PONGSONA1        -10075268   1342512.  -7.504786   0.0000
          JUN03          -8734679.   1343715.  -6.500397   0.0000
          MAY04          -5026568.   1376677.  -3.651234   0.0004
          AR(1)           0.589040   0.073195   8.047556   0.0000
=================================================================
R-squared                 0.839381    Mean dependent var 27451888
Adjusted R-squared        0.826734    S.D. dependent var 3684243.
S.E. of regression        1533573.    Akaike info criteri31.40045
Sum squared resid         2.99E+14    Schwarz criterion  31.63378
Log likelihood           -2155.631    F-statistic        66.36933
Durbin-Watson stat        2.331149    Prob(F-statistic)  0.000000
=================================================================
Inverted AR Roots              .59
=================================================================
```

```
============================================================================
Dependent Variable: MWGPA
Method: Least Squares
Date: 09/06/07   Time: 21:32
Sample (adjusted): 2000M01 2007M06
Included observations: 90 after adjustments
Convergence achieved after 11 iterations
============================================================================
             Variable             CoefficienStd. Errort-Statistic  Prob.
============================================================================
                 C                 107.6200   62.46327   1.722933   0.0887
@MOVAV(RESPRI(-3)/(CPI(-3)/126.9023-161.9508  149.9655  -1.079920   0.2833
           @MOVAV(EMP,6)           3.137635   1.117040   2.808883   0.0062
             PONGSONA2            -42.91271   5.634364  -7.616247   0.0000
             PONGSONA3            -22.46078   5.377649  -4.176690   0.0001
               OCT06              -11.09215   4.799867  -2.310929   0.0233
                JAN               -5.083417   1.798510  -2.826460   0.0059
               AR(1)               0.624129   0.088559   7.047628   0.0000
============================================================================
R-squared                          0.762739    Mean dependent var 263.3989
Adjusted R-squared                 0.742485    S.D. dependent var 10.98032
S.E. of regression                 5.572071    Akaike info criteri6.358098
Sum squared resid                  2545.934    Schwarz criterion  6.580303
Log likelihood                    -278.1144    F-statistic        37.65866
Durbin-Watson stat                 1.968944    Prob(F-statistic)  0.000000
============================================================================
Inverted AR Roots                       .62
============================================================================
```

Appendix II

Running The GPA Sales and Load Forecasting Model

Revised: September 5, 2007

This documentation will assist the user in preparing new forecasts using the GPA Sales and Load Forecast Model developed by PL Mangilao Energy LLC. If you have difficulties with these procedures, please call Kemm Farney at (desk) 610-356-4677 or (cell) 610-909-7116 for additional support.

One of the most important considerations in forecasting with models is version control. You must have a mechanism for knowing – 6 months or 6 years from now – exactly how this forecast was prepared. You will need to know clearly what was history, what adjustments were made to history (if any), what assumptions were made in preparing the forecast, and where the assumptions were drawn. It is imperative that the forecaster keep extensive and careful notes that record each step in the process. These notes need to be a permanent part of the forecast, kept with the forecast, and used as the first tool in "blowing the dust off" an old forecast that suddenly has new interest.

Step 1 – Establish a new working directory. The first step in beginning a new forecast is to initialize a new directory where the forecast will reside. This new directory will be dedicated to this forecast, and should not contain unrelated materials. For the purpose of this example, a new directory was created titled:

L:\Guam Power Authority\Model

This directory will contain four folders: Weather, Data, Documentation, and Programs. The Weather folder will house all of the weather files. The Data folder will house all the historical data, along with the Moody's forecast, the Scenarios, and the Forecast calculated from the Eviews program.

This directory will be referred to later as the “Model Directory\(folder name)”. The first step in preparing to use this directory to hold a new forecast is to copy into that directory all of the files contained in the directory that was previously used to prepare the last good forecast. Failing to use the last good forecast may cause old problems to be inadvertently carried forward into the new forecast.

Step 2 – Update the weather data. The second step, somewhat arbitrarily, is to update the hourly historical weather data for the weather station at the Guam airport. PL Mangilao is currently purchasing this data for GPA from www.weatherbank.com. Weather Bank is widely regarded by utility forecasters as the least expensive and most accurate of the different weather services. Its service does not offer a lot of bells and whistles, but its hourly weather data delivered in Excel spreadsheets, updated as often as the customer asks, is very inexpensive.

The most recent hourly weather data that has been purchased for this project runs through July 5, 2007. It is contained in an Excel spreadsheet that has been prepared for GPA by PL Mangilao that is titled “Guam Weather 070727.xls”. This spreadsheet was previously delivered to GPA as an attachment to email. **A copy of this new spreadsheet must reside in the new directory that was created to contain the forecast.**

Each time updated hourly weather data is received from Weather Bank (only new data is purchased to control expenses), it is appended to this hourly weather file, and the new file is saved with a different date stamp (e.g., “061020”) in the file name. The data is appended by cutting it and pasting it to the bottom of the each page in the spreadsheet, being careful to copy the correct data and to carefully avoid missing or duplicate observations. This task requires approximately two hours to complete, including the time needed for quality control checking.

Once the hourly weather file has been updated, the next step is to update the weather file that contains the monthly summary of the hourly observations. This is the data that is actually used by the forecasting model. The spreadsheet reads the hourly data from the database and summarizes the data, storing it with a monthly frequency.

In updating this spreadsheet, it is very important to copy formulas down the page instead of across the page. Formulas must be copied down the page in order for them to continue to reference the correct month for that column.

This new spreadsheet is titled “Guam Monthly Weather 070727.xls”. This spreadsheet contains a great deal of monthly and even daily weather information, including normal weather averages, that are intended to assist the analyst in evaluating and reporting the forecast. Also, this file is where the forecast program reads in historical weather data.

Step 3 – Modify the model code to read the new weather data. The third step is to modify the model code so that it uses all of this new weather data. If this step in the process is not completed properly, the updated weather data will not be incorporated into the new forecast.

Open the Guam Forecast program in Eviews. In the top part of the forecast code, there is a command labeled:

```
%WEATHER = "Guam Monthly Weather 070727.xls"
```

this line of code tells EViews which file contains the historical weather. Simply update the file name to the latest Guam Monthly Weather file.

Don’t forget to save your work. It is a good practice to save your work after each change or set of changes. It is also a good practice to go to the top of the program and add a comment – comments begin with a single quote mark – indicating who you are, what changes you made to the program, when and why the changes were made.

This completes the modifications required to read new weather data.

Step 4 – Modify the model code to read the new economic forecast from Moodys Economy.com. The fourth step is to modify the model code so that it uses the newest economic forecast for Guam from Moodys Economy.com. Our current arrangement with Moodys is to purchase a new forecast when one is needed and when an update is available. PL Mangilao has adopted this practice for two reasons. First, we really have not known GPA’s planned forecast schedule. Second, and more important, we were also negotiating with Moodys to raise their forecast, and by not subscribing to an on-going service we felt that we had a little more leverage with them.

Moodys has been very good about sending their forecasts in spreadsheet format, just as quickly as they make their write ups available. There are two ongoing challenges, however, that are not likely to be resolved since they are endemic to all of the big forecasting houses. First, the spreadsheet does not always contain the right forecast. These tasks are assigned to junior analysts, quality control is a highly controlled expense, and mistakes are frequent. We must check these forecasts very carefully to make certain that they are what Moodys says they are. This problem is not limited to Moodys; it occurs frequently with all of the forecasting houses.

Second, they do not send the spreadsheets in a consistent format. The forecasting houses do not have this kind of software standardized, so every analyst exports their forecast to Excel a different way. Changes to spreadsheet formats are frequent, random and unannounced. Each spreadsheet should be carefully inspected – somewhere it will say very clearly what the last period of history was in the forecast. This piece of information can be very important in evaluating both the Moodys forecast and the GPA sales forecast.

The EViews program has been written to read Moodys forecast in a standardized format. An example of this acceptable format is found in, for example, the spreadsheet file titled “P_and_L_Economics 060716.xls”. Any new forecast that comes in from Moodys must be first put into exactly this format.

The current Guam forecast from Moodys arrived via email in the form of the spreadsheet file titled “Moodys Guam Forecast 061003.xls” (this title was assigned to the file by PL Mangilao). This file was previously delivered to GPA as an attachment to email. This data has been saved in an updated version of the formatted spreadsheet titled “P_and_L_Economics 061105.xls”. In preparing these updated and formatted spreadsheets, great care must be taken to get exactly the right data concept in each row, as well as exactly the right date in each column. It is important to check this work several times to make certain it is correct. This new formatted file must reside in the Model Directory. The completion of this task requires less than two hours.

After the updated Moodys Economy.com economic forecast has been formatted and saved to the Model Directory, the EViews model code must be modified to read the new economic forecast instead of the old one.

Open the Guam Forecast program in EViews. In the top part of the forecast code, there are two commands labeled:

```
%FORECAST = "GU_Fore 070731.XLS"
%SCENARIO = "Scenarios 061121.xls"
```

These lines of code tell EViews which file contains the Guam forecast from Moodys and the different scenario forecasts. Again, simply update the file names to their latest file version.

Notice that the spreadsheet "Scenarios 061109.xls" is also mentioned. This is the spreadsheet that contains PL Mangilao's estimates of the additions to Employment and Personal Income that will result in Scenarios 3 through 5. If these scenarios are changed, these materials (the spreadsheet and the reference within the code) must also be updated. There is no need to update these materials at this time, since they are current. Once again, we would recommend that for now these changes should be made by PL Mangilao.

That completes this task. It requires less than 1 person-hour to complete.

Step 5 – Modify the model code to read the new internal sales, load, number of customers and pricing data for GPA. The fifth step is to modify the model code so that it takes advantage of the very latest GPA internal data. It is hard to over-emphasize how important it is to have the very latest internal data, in the most error free form that is possible. Errors in this data add noise to the historical data set that makes it much harder to identify the true statistical relationships. The likely outcome is that the forecast will understate the outlook for sales and load growth.

The current version of this file was updated by GPA and is titled "GPA Data 070808.xls". This file (or its updated version) must reside in the Model Directory. As noted above, it is very worthwhile to update this data file – it is the most important file to update when preparing a new forecast. In fact, without updating this file through the most recent month available it is almost not worth preparing a new forecast.

Great care needs to be taken to ensure that this data represents an accurate depiction of GPA's true accounting history. This accounting history may contain very large accounting adjustments (sufficiently large to show up on a graph). Where large accounting adjustments occur, it may be necessary to include a dummy variable in the model (coded one at the time of the adjustment and zero else) to "whiten" the effects of the adjustment out of the accounting history. Similarly, the historical data may contain large "blips" that reflect the occurrence of a large typhoon or earthquake. Dummy variables may also serve to whiten the disruptive effects of a natural disaster from the accounting data.

Other blips may also occur in the historical data. If they are not accounting adjustments or natural disasters, they may be considered "errors" in the accounting history. In the long run it will be best of we work together to investigate each of these, determining if they can be "corrected". If they cannot be corrected, the modeler has a choice between adding a dummy variable for that time period or interpolating between the two nearest reasonable values in the data. After consideration, it is the opinion of PL Mangilao that the use of dummy variables provides a more auditable solution to this problem, and that will be our recommended approach going forward.

To update the EViews program code, open the Guam Forecast program in EViews. In the top part of the forecast code, there is a command labeled:

```
%DATA = "GPA Data 070808.xls"
```

This line of code tells EViews which file contains the historical Guam Data. Simply update the file name to the latest version of GPA Data.

Also, the start date of the Forecast period needs to be changed to one month in the future of the last month of historical data. For example, if the historical data ran through June 2007, then the forecast period would start in July 2007. At the top of the EViews program is a command labeled:

%STARTFORECAST = "2007:07"

This line is telling the program to start the forecasting period in July 2007. To update this simple change the date to reflect one month in the future of the last month of historical data.

One of the primary modeling commitments that GPA must make is to do all that is possible to fill in thee missing data. If GPA will find the data in any format, PL Mangilao will get it into this database in a usable form.

Step 6 – Run the model. The sixth step is to run the model. If all of the file paths have been updated and if all of the spreadsheet file names have been updated, the EViews forecasting program should run without errors. In order to run the model, simply use Windows Explorer to find the program file titled “Guam Forecast 0709XX.prg”. You may simply double click on this file, and EViews will launch automatically and run the program. You may also first enter EViews, and then enter the command “Run Guam Forecast 0709XX.prg” at the command prompt.

Or another way to run the program is by first opening EViews and then open the latest updated version of the Budget Forecast program. There is Run button on the left most part of the tool bar. Simply click the button the program will start to run. This program should run quite quickly and will then create an Excel file that contains all of the forecasting data.

Step 8 – Update forecast reporting spreadsheet. When the EViews forecast program is done running, it will create an Excel file labeled “Forecast (Current Date).xls” that contains the forecast date. This data will need to be pasted into the back of the Guam Forecast Excel file.

First, open the Guam Forecast file in the Documentation directory and scroll to the worksheet labeled “Forecast”, which is the right most worksheet in the Guam Forecast file. Second, open the “Forecast (Current Date).xls” file in the Data directory and copy the entire data in the file. Next, paste the data into the “Forecast” worksheet in the Guam Forecast file into Cell A1.

This new pasted data will update automatically on the all the Guam Forecast file worksheets.

Appendix III

EViews Modeling Program

Revised: September 5, 2007

```
'*********************************************************
'*
'*        Forecast Update program written by K. Farney
'*          and Modified Extensively By Matt Prickett
'*           July 18, 2007 through September 5, 2007
'*
'*
'*********************************************************


'Set name of internal data file.
%INTERNAL = "GPA Data 070905.XLS"
%DAILYWEATHER = "Guam Weather 070825.xls"
%WEATHER = "Guam Monthly Weather 070824.xls"
%FORECAST = "GU_Fore 070731.XLS"
%SCENARIO = "Scenarios 061121.xls"
%DATADIRECTORY = "C:\Documents and Settings\Matt\My
Documents\Guam Forecast\Data\"
%WEATHERDIRECTORY = "C:\Documents and Settings\Matt\My
Documents\Guam Forecast\Weather\"
%DOCUMENTATIONDIRECTORY = "C:\Documents and
Settings\Matt\My Documents\Guam Forecast\Documentation\"
%STARTFORECAST = "2007:07"
%PRICEFORECAST= "FY 08 Projected Sales 070906.xls"


' Do some date algebra to create file name suffixes
%d = @date
%day = @mid(%d,4,2)
%month = @left(%d,2)
%year = @right(%d,2)
%tag = %year + %month + %day
%now = %year + ":" + %month


' Change to the working directory
cd %DATADIRECTORY


db Test{%tag}
```

```
' Create a workspace
wfcreate(wf = Test{%tag}) m 1992:10 2034:12

cd %WEATHERDIRECTORY
pagecreate(page=Daily) 7 1976:1 2007:181

read(aa4385, s=tmp) %DAILYWEATHER  AVERTEMP
for %DWEATHER CDD65 CDD68 CDD70 CDD75 CDD80
series {%DWEATHER} = 0
next

CDD65 = @RECODE(AVERTEMP>@val(@RIGHT("CDD65",2)), AVERTEMP-
@val(@RIGHT("CDD65",2)),0)
CDD68 = @RECODE(AVERTEMP>@val(@RIGHT("CDD68",2)), AVERTEMP-
@val(@RIGHT("CDD68",2)),0)
CDD70 = @RECODE(AVERTEMP>@val(@RIGHT("CDD70",2)), AVERTEMP-
@val(@RIGHT("CDD70",2)),0)
CDD75 = @RECODE(AVERTEMP>@val(@RIGHT("CDD75",2)), AVERTEMP-
@val(@RIGHT("CDD75",2)),0)
CDD80 = @RECODE(AVERTEMP>@val(@RIGHT("CDD80",2)), AVERTEMP-
@val(@RIGHT("CDD80",2)),0)

cd %DATADIRECTORY
pagecreate(page= Quarterly) q 1993q1 2034q4

smpl 1993q1 2034q4
read( ac8, s=Guam July-2007,t)  %FORECAST EMP
read(ac5, s=Guam July-2007,t) %FORECAST POPULATION
read(ac22, s=Guam July-2007,t) %FORECAST REALINCOME

REALINCOME = REALINCOME*1000

smpl 95q4 2034q4
read( an34, s=Guam July-2007,t) %FORECAST CPI

'Read in Scenarios Data
smpl 2006q1 2034q4
read(cb46, s=ScenarioII,t) %SCENARIO EMP_1 INCOME_1
read(cb46, s=ScenarioIII,t) %SCENARIO EMPII INCOMEII
POPULATIONII
read(cb46, s=ScenarioIV,t) %SCENARIO EMPIII INCOMEIII
POPULATIONIII
read(cb46, s=ScenarioV,t) %SCENARIO EMPIV INCOMEIV
POPULATIONIV

pagecreate(page=WeatherMonth) m 1976:1 2034:12
```

```
for %LINKB CDD65 CDD68 CDD70 CDD75 CDD80
link {%LINKB}
{%LINKB}.linkto(c=sum) daily::{%LINKB}
next

unlink *

'Generate Billing Weather
for %BILLW CDD65 CDD68 CDD70 CDD75 CDD80
series BILL{%BILLW}=({%BILLW}+{%BILLW}(-1))/2
next

'Calculate 30 year Weather Normals
smpl @all
series monthseries = @datepart(@date, "mm")

for %base CDD65 CDD68 CDD70 CDD75 CDD80 BILLCDD65 BILLCDD68
BILLCDD70 BILLCDD75 BILLCDD80
     for !month = 1 to 12
     !start = 1977
     !end = 2006
       smpl !start !end
       series dd{!month} =0
       smpl !start !end if monthseries = !month
       series dd{!month} = {%base}
       scalar value{!month} = @mean(dd{!month})
     next
     smpl @all
     series NORM{%base}
    NORM{%base}.fill(l) value1, value2, value3, value4,
value5, value6, value7, value8, value9, value10, value11,
value12
for !month = 1 to 12
    delete dd{!month}
    delete value{!month}
next
next



pagecreate(page=Monthly) m 1992:10 2034:12

for %LINKC CDD65 CDD68 CDD70 CDD75 CDD80 BILLCDD65
BILLCDD68 BILLCDD70 BILLCDD75 BILLCDD80 NORMCDD65 NORMCDD68
NORMCDD70 NORMCDD75 NORMCDD80 NORMBILLCDD65 NORMBILLCDD68
NORMBILLCDD70 NORMBILLCDD75 NORMBILLCDD80
```

```
link {%LINKC}
{%LINKC}.linkto(c=sum) WeatherMonth::{%LINKC}
next

unlink *

for %LINK EMP POPULATION REALINCOME CPI EMP_1 INCOME_1
EMPII INCOMEII POPULATIONII EMPIII INCOMEIII POPULATIONIII
EMPIV INCOMEIV POPULATIONIV
link {%LINK}
{%LINK}.linkto(c=i) quarterly::{%LINK}
next

' Read Sales data from internal data warehouse
smpl 92:10 %now
read( B8, s=TimeSeriesData, t) %INTERNAL RESKWH SGNDKWH
SGDKWH LGKWH POLKWH
read( B15, s=TimeSeriesData, t) %INTERNAL GSSNDKWH GSSDKWH
GSLKWH GSSLKWH
read( B21, s=TimeSeriesData, t) %INTERNAL NAVYKWH

' Read Number Of Customers
smpl 92:10 %now
read( B27, s=TimeSeriesData, t) %INTERNAL RESCUS SGNDCUS
SGDCUS LGCUS POLCUS
read( B34, s=TimeSeriesData, t) %INTERNAL GSSNDCUS GSSDCUS
GSLCUS GSSLCUS
read( B40, s=TimeSeriesData, t) %INTERNAL NAVYCUS

'Read Revenue data from internal data werehouse
read(B65 , s=TimeSeriesData, t) %INTERNAL RESREV SGNDREV
SGDREV LGREV POLREV
read(B65 , s=TimeSeriesData, t) %INTERNAL GSSNDREV GSSDREV
GSLREV GSSLREV
read(B65 , s=TimeSeriesData, t) %INTERNAL NAVYREV

'Read in Typhoon and Accounting Dummies
series DAY = @DATE
series JAN96=@RECODE(DAY=@DATEVAL("1/1/1996",
"MM/DD/YYYY"),1,0)
series FEB96=@RECODE(DAY=@DATEVAL("2/1/1996",
"MM/DD/YYYY"),1,0)
series MAR96=@RECODE(DAY=@DATEVAL("3/1/1996",
"MM/DD/YYYY"),1,0)
series APR96=@RECODE(DAY=@DATEVAL("4/1/1996",
"MM/DD/YYYY"),1,0)
```

```
series MAY96=@RECODE(DAY=@DATEVAL("5/1/1996",
"MM/DD/YYYY"),1,0)
series JUN96=@RECODE(DAY=@DATEVAL("6/1/1996",
"MM/DD/YYYY"),1,0)
series JUL96=@RECODE(DAY=@DATEVAL("7/1/1996",
"MM/DD/YYYY"),1,0)
series AUG96=@RECODE(DAY=@DATEVAL("8/1/1996",
"MM/DD/YYYY"),1,0)
series SEP96=@RECODE(DAY=@DATEVAL("9/1/1996",
"MM/DD/YYYY"),1,0)
series OCT96=@RECODE(DAY=@DATEVAL("10/1/1996",
"MM/DD/YYYY"),1,0)
series NOV96=@RECODE(DAY=@DATEVAL("11/1/1996",
"MM/DD/YYYY"),1,0)
series DEC96=@RECODE(DAY=@DATEVAL("12/1/1996",
"MM/DD/YYYY"),1,0)
series JAN97=@RECODE(DAY=@DATEVAL("1/1/1997",
"MM/DD/YYYY"),1,0)
series FEB97=@RECODE(DAY=@DATEVAL("2/1/1997",
"MM/DD/YYYY"),1,0)
series MAR97=@RECODE(DAY=@DATEVAL("3/1/1997",
"MM/DD/YYYY"),1,0)
series APR97=@RECODE(DAY=@DATEVAL("4/1/1997",
"MM/DD/YYYY"),1,0)
series MAY97=@RECODE(DAY=@DATEVAL("5/1/1997",
"MM/DD/YYYY"),1,0)
series JUN97=@RECODE(DAY=@DATEVAL("6/1/1997",
"MM/DD/YYYY"),1,0)
series JUL97=@RECODE(DAY=@DATEVAL("7/1/1997",
"MM/DD/YYYY"),1,0)
series AUG97=@RECODE(DAY=@DATEVAL("8/1/1997",
"MM/DD/YYYY"),1,0)
series SEP97=@RECODE(DAY=@DATEVAL("9/1/1997",
"MM/DD/YYYY"),1,0)
series OCT97=@RECODE(DAY=@DATEVAL("10/1/1997",
"MM/DD/YYYY"),1,0)
series NOV97=@RECODE(DAY=@DATEVAL("11/1/1997",
"MM/DD/YYYY"),1,0)
series Paka1=@RECODE(DAY=@DATEVAL("12/1/1997",
"MM/DD/YYYY"),1,0)
series Paka2=@RECODE(DAY=@DATEVAL("1/1/1998",
"MM/DD/YYYY"),1,0)
series Paka3=@RECODE(DAY=@DATEVAL("2/1/1998",
"MM/DD/YYYY"),1,0)
series Paka4=@RECODE(DAY=@DATEVAL("3/1/1998",
"MM/DD/YYYY"),1,0)
```

```
series APR98=@RECODE(DAY=@DATEVAL("4/1/1998",
"MM/DD/YYYY"),1,0)
series MAY98=@RECODE(DAY=@DATEVAL("5/1/1998",
"MM/DD/YYYY"),1,0)
series JUN98=@RECODE(DAY=@DATEVAL("6/1/1998",
"MM/DD/YYYY"),1,0)
series JUL98=@RECODE(DAY=@DATEVAL("7/1/1998",
"MM/DD/YYYY"),1,0)
series AUG98=@RECODE(DAY=@DATEVAL("8/1/1998",
"MM/DD/YYYY"),1,0)
series SEP98=@RECODE(DAY=@DATEVAL("9/1/1998",
"MM/DD/YYYY"),1,0)
series OCT98=@RECODE(DAY=@DATEVAL("10/1/1998",
"MM/DD/YYYY"),1,0)
series NOV98=@RECODE(DAY=@DATEVAL("11/1/1998",
"MM/DD/YYYY"),1,0)
series DEC98=@RECODE(DAY=@DATEVAL("12/1/1998",
"MM/DD/YYYY"),1,0)
series JAN99=@RECODE(DAY=@DATEVAL("1/1/1999",
"MM/DD/YYYY"),1,0)
series FEB99=@RECODE(DAY=@DATEVAL("2/1/1999",
"MM/DD/YYYY"),1,0)
series MAR99=@RECODE(DAY=@DATEVAL("3/1/1999",
"MM/DD/YYYY"),1,0)
series APR99=@RECODE(DAY=@DATEVAL("4/1/1999",
"MM/DD/YYYY"),1,0)
series MAY99=@RECODE(DAY=@DATEVAL("5/1/1999",
"MM/DD/YYYY"),1,0)
series JUN99=@RECODE(DAY=@DATEVAL("6/1/1999",
"MM/DD/YYYY"),1,0)
series JUL99=@RECODE(DAY=@DATEVAL("7/1/1999",
"MM/DD/YYYY"),1,0)
series AUG99=@RECODE(DAY=@DATEVAL("8/1/1999",
"MM/DD/YYYY"),1,0)
series SEP99=@RECODE(DAY=@DATEVAL("9/1/1999",
"MM/DD/YYYY"),1,0)
series OCT99=@RECODE(DAY=@DATEVAL("10/1/1999",
"MM/DD/YYYY"),1,0)
series NOV99=@RECODE(DAY=@DATEVAL("11/1/1999",
"MM/DD/YYYY"),1,0)
series DEC99=@RECODE(DAY=@DATEVAL("12/1/1999",
"MM/DD/YYYY"),1,0)
series JAN00=@RECODE(DAY=@DATEVAL("1/1/2000",
"MM/DD/YYYY"),1,0)
series FEB00=@RECODE(DAY=@DATEVAL("2/1/2000",
"MM/DD/YYYY"),1,0)
```

```
series MAR00=@RECODE(DAY=@DATEVAL("3/1/2000",
"MM/DD/YYYY"),1,0)
series APR00=@RECODE(DAY=@DATEVAL("4/1/2000",
"MM/DD/YYYY"),1,0)
series MAY00=@RECODE(DAY=@DATEVAL("5/1/2000",
"MM/DD/YYYY"),1,0)
series JUN00=@RECODE(DAY=@DATEVAL("6/1/2000",
"MM/DD/YYYY"),1,0)
series JUL00=@RECODE(DAY=@DATEVAL("7/1/2000",
"MM/DD/YYYY"),1,0)
series AUG00=@RECODE(DAY=@DATEVAL("8/1/2000",
"MM/DD/YYYY"),1,0)
series SEP00=@RECODE(DAY=@DATEVAL("9/1/2000",
"MM/DD/YYYY"),1,0)
series OCT00=@RECODE(DAY=@DATEVAL("10/1/2000",
"MM/DD/YYYY"),1,0)
series NOV00=@RECODE(DAY=@DATEVAL("11/1/2000",
"MM/DD/YYYY"),1,0)
series DEC00=@RECODE(DAY=@DATEVAL("12/1/2000",
"MM/DD/YYYY"),1,0)
series JAN01=@RECODE(DAY=@DATEVAL("1/1/2001",
"MM/DD/YYYY"),1,0)
series FEB01=@RECODE(DAY=@DATEVAL("2/1/2001",
"MM/DD/YYYY"),1,0)
series MAR01=@RECODE(DAY=@DATEVAL("3/1/2001",
"MM/DD/YYYY"),1,0)
series APR01=@RECODE(DAY=@DATEVAL("4/1/2001",
"MM/DD/YYYY"),1,0)
series MAY01=@RECODE(DAY=@DATEVAL("5/1/2001",
"MM/DD/YYYY"),1,0)
series JUN01=@RECODE(DAY=@DATEVAL("6/1/2001",
"MM/DD/YYYY"),1,0)
series JUL01=@RECODE(DAY=@DATEVAL("7/1/2001",
"MM/DD/YYYY"),1,0)
series AUG01=@RECODE(DAY=@DATEVAL("8/1/2001",
"MM/DD/YYYY"),1,0)
series SEP01=@RECODE(DAY=@DATEVAL("9/1/2001",
"MM/DD/YYYY"),1,0)
series OCT01=@RECODE(DAY=@DATEVAL("10/1/2001",
"MM/DD/YYYY"),1,0)
series Earthquake1=@RECODE(DAY=@DATEVAL("11/1/2001",
"MM/DD/YYYY"),1,0)
series Earthquake2=@RECODE(DAY=@DATEVAL("12/1/2001",
"MM/DD/YYYY"),1,0)
series Earthquake3=@RECODE(DAY=@DATEVAL("1/1/2002",
"MM/DD/YYYY"),1,0)
```

```
series FEB02=@RECODE(DAY=@DATEVAL("2/1/2002",
"MM/DD/YYYY"),1,0)
series MAR02=@RECODE(DAY=@DATEVAL("3/1/2002",
"MM/DD/YYYY"),1,0)
series APR02=@RECODE(DAY=@DATEVAL("4/1/2002",
"MM/DD/YYYY"),1,0)
series MAY02=@RECODE(DAY=@DATEVAL("5/1/2002",
"MM/DD/YYYY"),1,0)
series JUN02=@RECODE(DAY=@DATEVAL("6/1/2002",
"MM/DD/YYYY"),1,0)
series Chataan1=@RECODE(DAY=@DATEVAL("7/1/2002",
"MM/DD/YYYY"),1,0)
series Chataan2=@RECODE(DAY=@DATEVAL("8/1/2002",
"MM/DD/YYYY"),1,0)
series Chataan3=@RECODE(DAY=@DATEVAL("9/1/2002",
"MM/DD/YYYY"),1,0)
series OCT02=@RECODE(DAY=@DATEVAL("10/1/2002",
"MM/DD/YYYY"),1,0)
series NOV02=@RECODE(DAY=@DATEVAL("11/1/2002",
"MM/DD/YYYY"),1,0)
series Pongsona1=@RECODE(DAY=@DATEVAL("12/1/2002",
"MM/DD/YYYY"),1,0)
series Pongsona2=@RECODE(DAY=@DATEVAL("1/1/2003",
"MM/DD/YYYY"),1,0)
series Pongsona3=@RECODE(DAY=@DATEVAL("2/1/2003",
"MM/DD/YYYY"),1,0)
series MAR03=@RECODE(DAY=@DATEVAL("3/1/2003",
"MM/DD/YYYY"),1,0)
series APR03=@RECODE(DAY=@DATEVAL("4/1/2003",
"MM/DD/YYYY"),1,0)
series MAY03=@RECODE(DAY=@DATEVAL("5/1/2003",
"MM/DD/YYYY"),1,0)
series JUN03=@RECODE(DAY=@DATEVAL("6/1/2003",
"MM/DD/YYYY"),1,0)
series JUL03=@RECODE(DAY=@DATEVAL("7/1/2003",
"MM/DD/YYYY"),1,0)
series AUG03=@RECODE(DAY=@DATEVAL("8/1/2003",
"MM/DD/YYYY"),1,0)
series SEP03=@RECODE(DAY=@DATEVAL("9/1/2003",
"MM/DD/YYYY"),1,0)
series OCT03=@RECODE(DAY=@DATEVAL("10/1/2003",
"MM/DD/YYYY"),1,0)
series NOV03=@RECODE(DAY=@DATEVAL("11/1/2003",
"MM/DD/YYYY"),1,0)
series DEC03=@RECODE(DAY=@DATEVAL("12/1/2003",
"MM/DD/YYYY"),1,0)
```

```
series JAN04=@RECODE(DAY=@DATEVAL("1/1/2004",
"MM/DD/YYYY"),1,0)
series FEB04=@RECODE(DAY=@DATEVAL("2/1/2004",
"MM/DD/YYYY"),1,0)
series MAR04=@RECODE(DAY=@DATEVAL("3/1/2004",
"MM/DD/YYYY"),1,0)
series APR04=@RECODE(DAY=@DATEVAL("4/1/2004",
"MM/DD/YYYY"),1,0)
series MAY04=@RECODE(DAY=@DATEVAL("5/1/2004",
"MM/DD/YYYY"),1,0)
series JUN04=@RECODE(DAY=@DATEVAL("6/1/2004",
"MM/DD/YYYY"),1,0)
series Tingting1=@RECODE(DAY=@DATEVAL("7/1/2004",
"MM/DD/YYYY"),1,0)
series Tingting2=@RECODE(DAY=@DATEVAL("8/1/2004",
"MM/DD/YYYY"),1,0)
series Tingting3=@RECODE(DAY=@DATEVAL("9/1/2004",
"MM/DD/YYYY"),1,0)
series OCT04=@RECODE(DAY=@DATEVAL("10/1/2004",
"MM/DD/YYYY"),1,0)
series NOV04=@RECODE(DAY=@DATEVAL("11/1/2004",
"MM/DD/YYYY"),1,0)
series DEC04=@RECODE(DAY=@DATEVAL("12/1/2004",
"MM/DD/YYYY"),1,0)
series JAN05=@RECODE(DAY=@DATEVAL("1/1/2005",
"MM/DD/YYYY"),1,0)
series FEB05=@RECODE(DAY=@DATEVAL("2/1/2005",
"MM/DD/YYYY"),1,0)
series MAR05=@RECODE(DAY=@DATEVAL("3/1/2005",
"MM/DD/YYYY"),1,0)
series APR05=@RECODE(DAY=@DATEVAL("4/1/2005",
"MM/DD/YYYY"),1,0)
series MAY05=@RECODE(DAY=@DATEVAL("5/1/2005",
"MM/DD/YYYY"),1,0)
series JUN05=@RECODE(DAY=@DATEVAL("6/1/2005",
"MM/DD/YYYY"),1,0)
series JUL05=@RECODE(DAY=@DATEVAL("7/1/2005",
"MM/DD/YYYY"),1,0)
series AUG05=@RECODE(DAY=@DATEVAL("8/1/2005",
"MM/DD/YYYY"),1,0)
series SEP05=@RECODE(DAY=@DATEVAL("9/1/2005",
"MM/DD/YYYY"),1,0)
series OCT05=@RECODE(DAY=@DATEVAL("10/1/2005",
"MM/DD/YYYY"),1,0)
series NOV05=@RECODE(DAY=@DATEVAL("11/1/2005",
"MM/DD/YYYY"),1,0)
```

```
series DEC05=@RECODE(DAY=@DATEVAL("12/1/2005",
"MM/DD/YYYY"),1,0)
series JAN06=@RECODE(DAY=@DATEVAL("1/1/2006",
"MM/DD/YYYY"),1,0)
series FEB06=@RECODE(DAY=@DATEVAL("2/1/2006",
"MM/DD/YYYY"),1,0)
series MAR06=@RECODE(DAY=@DATEVAL("3/1/2006",
"MM/DD/YYYY"),1,0)
series APR06=@RECODE(DAY=@DATEVAL("4/1/2006",
"MM/DD/YYYY"),1,0)
series MAY06=@RECODE(DAY=@DATEVAL("5/1/2006",
"MM/DD/YYYY"),1,0)
series JUN06=@RECODE(DAY=@DATEVAL("6/1/2006",
"MM/DD/YYYY"),1,0)
series JUL06=@RECODE(DAY=@DATEVAL("7/1/2006",
"MM/DD/YYYY"),1,0)
series AUG06=@RECODE(DAY=@DATEVAL("8/1/2006",
"MM/DD/YYYY"),1,0)
series SEP06=@RECODE(DAY=@DATEVAL("9/1/2006",
"MM/DD/YYYY"),1,0)
series OCT06=@RECODE(DAY=@DATEVAL("10/1/2006",
"MM/DD/YYYY"),1,0)
series NOV06=@RECODE(DAY=@DATEVAL("11/1/2006",
"MM/DD/YYYY"),1,0)
series DEC06=@RECODE(DAY=@DATEVAL("12/1/2006",
"MM/DD/YYYY"),1,0)
series JAN07=@RECODE(DAY=@DATEVAL("1/1/2007",
"MM/DD/YYYY"),1,0)
series FEB07=@RECODE(DAY=@DATEVAL("2/1/2007",
"MM/DD/YYYY"),1,0)
series MAR07=@RECODE(DAY=@DATEVAL("3/1/2007",
"MM/DD/YYYY"),1,0)
series APR07=@RECODE(DAY=@DATEVAL("4/1/2007",
"MM/DD/YYYY"),1,0)
series MAY07=@RECODE(DAY=@DATEVAL("5/1/2007",
"MM/DD/YYYY"),1,0)
series JUN07=@RECODE(DAY=@DATEVAL("6/1/2007",
"MM/DD/YYYY"),1,0)

series STR06=1
series
STR06=@RECODE(DAY=@DATEVAL("1/1/2006","MM/DD/YYYY"),0,1)
smpl 06:2 %now
series STR06=STR06(-1)

smpl 92:10 %now
'Create Monthly Dummies
```

```
for %mdum JAN FEB MAR APR MAY JUN JUL AUG SEP OCT NOV DEC
   series  {%mdum} =  @DATEPART(@DATE,"MM")
next
JAN= @RECODE(JAN=1, 1,0)
FEB= @RECODE(FEB=2, 1,0)
MAR= @RECODE(MAR=3, 1,0)
APR= @RECODE(APR=4, 1,0)
MAY= @RECODE(MAY=5, 1,0)
JUN= @RECODE(JUN=6, 1,0)
JUL= @RECODE(JUL=7, 1,0)
AUG= @RECODE(AUG=8, 1,0)
SEP= @RECODE(SEP=9, 1,0)
OCT= @RECODE(OCT=10, 1,0)
NOV= @RECODE(NOV=11, 1,0)
DEC= @RECODE(DEC=12, 1,0)

' Read Prices
smpl 92:10 %now
read(B46, s=TimeSeriesData, t) %INTERNAL RESPRI SGNDPRI
SGDPRI LGPRI POLPRI
read(B53, s=TimeSeriesData, t) %INTERNAL GSSNDPRI GSSDPRI
GSLPRI GSSLPRI
read(B59, s=TimeSeriesData, t) %INTERNAL NAVYPRI


'Read Monthly Peak Hour Demands
smpl 95:1 %now
read(ac3, s=TimeSeriesData, t) %INTERNAL MWGPA


' Read weather data
cd %WEATHERDIRECTORY
smpl 92:10 %now
read( C348, s=Monthly Data) %WEATHER  CUMCDD65 NGCDH THI HI
'read(i348, s=Monthly Data) %WEATHER CDD68 CDD70 CDD72
CDD75 CDD80 CDD85
'read(p348, s=Monthly Data) %WEATHER BILLCDD68 BILLCDD70
BILLCDD72 BILLCDD75 BILLCDD80 BILLCDD85

cd %DATADIRECTORY

smpl 92:10 %now
' Begin echoing terminal session to a TXT file.
pon
%OFN = %DOCUMENTATIONDIRECTORY + "Regressions " + %tag +
".TXT"
output(t) %OFN
```

```
'Estimate Customer Equations
equation EQRESCUS.LS RESCUS C
(.5*POPULATION+.5*POPULATION(-1)) Paka1 Paka2 Paka3 OCT99
Chataan1 Chataan2 Chataan3 Pongsona2 Pongsona3 AR(1)
equation EQSGNDCUS.LS SGNDCUS C AUG Paka1 Paka2 Paka3
OCT99 Chataan1 Chataan3 Pongsona2 Pongsona3 APR03 AR(1)
equation EQSGDCUS.LS SGDCUS C
(.5*POPULATION+.5*POPULATION(-1)) Paka1 Paka2 Paka3  OCT99
Chataan1 Chataan3 Pongsona2 Pongsona3 AR(1)
equation EQLGCUS.LS LGCUS C (POPULATION) Paka1 Paka2 Paka3
FEB02 Pongsona3 AR(1)
equation EQPOLCUS.LS POLCUS C EMP Paka1 Paka2 Paka3  SEP99
OCT99 Chataan1 Chataan3 JUN07 AR(1)
equation EQGSSNDCUS.LS GSSNDCUS C @movav(EMP,7) Paka1 Paka2
Paka3 OCT99 sep00 feb01 earthquake3 AR(1)
equation EQGSSDCUS.LS GSSDCUS C
(.5*POPULATION+.5*POPULATION(-1)) Paka1 Paka2 Paka3 OCT99
SEP00 FEB01 may01 may02 feb04 jun05 jul06 AR(1)
equation EQGSLCUS.LS GSLCUS C (POPULATION) Paka1 Paka2
Paka3 feb01 sep00 AR(1)
smpl 1997:1 2007:05
equation EQGSSLCUS.LS GSSLCUS C @movav(emp, 3) JAN97 Paka1
OCT00 NOV00 FEB01 STR06 AR(1)
'equation EQNAVYCUS.LS NAVYCUS C

'Estimate Sales Equations
smpl 92:10 %now
equation EQRESKWH.LS RESKWH C RESPRI/(CPI/126.90230833)
BILLCDD68*RESCUS @movav(.5*EMP+.5*EMP(-1),6) Paka1 OCT99
Chataan1 Chataan2 Pongsona1 Pongsona2
smpl 96:1 %now
equation EQSGNDKWH.LS SGNDKWH C
@movav(SGNDPRI,2)/(CPI/126.90230833) BILLCDD68*SGNDCUS
@movav(SGNDCUS,2) jan96 feb96 apr96 oct96 Earthquake2
Pongsona1
smpl 97:1 %now
equation EQSGDKWH.LS SGDKWH C SGDPRI/(CPI/126.90230833)
BILLCDD65*SGDCUS @MOVAV(EMP,6) Paka1 Paka2 Paka4 OCT00
Chataan1 Chataan3 Pongsona1 Pongsona2
smpl 92:10 %now
equation EQLGKWH.LS LGKWH C LGPRI/(CPI/126.90230833) CDD65
POPULATION sep96 Paka1 Paka2 Pongsona1
equation EQPOLKWH.LS POLKWH C POLPRI/(CPI/126.90230833)
POLCUS Earthquake3 Paka2 APR98 JUN98 JUN99 Chataan2
Pongsona2 AR(1)
```

```
smpl 92:10 %now
equation EQGSSNDKWH.LS GSSNDKWH C
GSSNDPRI/(CPI/126.90230833) CDD80*GSSNDCUS @movav(EMP,6)
may96 jun96 sep97 paka1 jun99 oct99
smpl 99m1 %now
equation EQGSSDKWH.LS GSSDKWH C GSSDPRI/(CPI/126.90230833)
BILLCDD80*GSSDCUS @movav(.5*EMP+.5*EMP(-1),6) JUL99 SEP99
Pongsona1 Pongsona2 OCT03 AR(1)
smpl 92:1 %now
equation EQGSLKWH.LS GSLKWH C GSLPRI/(CPI/126.90230833)
CDD80*GSLCUS @MOVAV(EMP,1) JUL96 SEP96 JUN97 Paka1 AUG01
SEP01 oct98 nov98
equation EQGSSLKWH.LS GSSLKWH C GSSLPRI/(CPI/126.90230833)
GSSLCUS MAY00 APR04 JAN96 Paka1 Paka2 JUN00 SEP00 JAN01 JAN
JUN ar(1)
equation EQNAVYKWH.LS NAVYKWH C NAVYPRI/(CPI/126.90230833)
CDD65*EMP @movav(EMP,3) Paka1 Chataan1 Chataan3 Pongsona1
JUN03 MAY04 AR(1)

'Estimate MW Equation
smpl 00:1 %now
equation EQMWGPA.LS MWGPA C @movav(RESPRI(-3)/(CPI(-
3)/126.90230833),2) @movav(emp,6) Pongsona2 Pongsona3 OCT06
JAN AR(1)

'Add section to input 2008 Price forecast
smpl 2007:6 2007:6
read(i9, s=Sheet1, t) %PRICEFORECAST  RESPRIF SGNDPRIF
SGDPRIF LGPRIF POLPRIF GSSNDPRIF GSSDPRIF GSLPRIF GSSLPRIF
read(i19, s=Sheet1) %PRICEFORECAST NAVYPRIF

smpl 2007:7 2008:9
for %PRICEF RESPRIF SGNDPRIF SGDPRIF LGPRIF POLPRIF
GSSNDPRIF GSSDPRIF GSLPRIF GSSLPRIF NAVYPRIF
{%PRICEF} = {%PRICEF}(-1)
next

smpl 2007:7 2008:9
for %PRICEC RESPRI SGNDPRI SGDPRI LGPRI POLPRI GSSNDPRI
GSSDPRI GSLPRI GSSLPRI NAVYPRI
{%PRICEC} = @recode({%PRICEC}=na, {%PRICEC}F, {%PRICEC})
next


'Add section to calculate price forecasts
smpl 1992:10 2034:12
```

```
for %PRICE  RESPRI SGNDPRI SGDPRI LGPRI POLPRI GSSNDPRI
GSSDPRI GSLPRI GSSLPRI NAVYPRI
     {%PRICE} = @recode({%PRICE}=na,{%PRICE}(-
12)*(CPI/CPI(-12)),{%PRICE})
next


'smpl 1992:10 2034:12
'genr NORMBILLCDD65 = 0
'genr NORMCDD65 = 0
'genr NORMBILLCDD68 = 0
'genr NORMCDD68 = 0
'genr NORMBILLCDD80 = 0
'genr NORMCDD80 = 0
genr NORMTHI = 0
genr NORMHI = 0

'Enter Normal Weather Here -- 30 year Billing Weather is
entered.
'NORMBILLCDD65.fill(o=1993:1,l)    494.0, 456.0, 465.5,
505.2, 533.5, 546.8, 538.6, 532.0, 517.2, 518.8, 521.2,
511.6
'NORMCDD65.fill(o=1993:1,l) 479.8, 432.2, 498.9, 511.6,
555.4, 538.3, 539.0, 525.0, 509.5, 528.2, 514.2, 509.0
'NORMBILLCDD68.fill(o=1993:1,l)    401.0, 367.2, 376.7,
413.7, 442.0, 455.3, 447.1, 439.0, 425.7, 427.3, 429.7,
420.1
'NORMCDD68.fill(o=1993:1,l) 386.8, 347.5, 405.9, 421.6,
462.4, 448.3, 446.0, 432.0, 419.5, 435.2, 424.2, 416.0
'NORMBILLCDD80.fill(o=1993:1,l)    36.2, 24.1, 30.9, 51.6,
77.1, 90.4, 83.5, 72.1, 65.8, 67.5, 68.6, 57.4
'NORMCDD80.fill(o=1993:1,l) 26.5, 21.6, 40.1, 63.1, 91.0,
89.8, 77.2, 66.9, 64.6, 70.5, 66.7, 48.2
NORMTHI.fill(o=1993:1,l) 75.9, 75.6, 76.0, 77.0, 78.0,
78.3, 78.2, 78.2, 78.2, 78.1, 77.1
NORMHI.fill(o=1993:1,l)  83.9, 83.3, 84.4, 86.5, 88.7,
89.5, 88.8, 88.3, 88.2, 88.1, 86.2

for %WEATHERR BILLCDD65 CDD65 BILLCDD68 CDD68 BILLCDD80
CDD80 THI HI
     {%WEATHERR} =
@recode({%WEATHERR}=na,NORM{%WEATHERR},{%WEATHERR})
next


' Extend monthly dummies
```

```
for %MON JAN FEB MAR APR MAY JUN JUL AUG SEP OCT NOV DEC
JAN96 FEB96 MAR96 APR96 MAY96 JUN96 JUL96 AUG96 SEP96 OCT96
NOV96 DEC96 JAN97 FEB97 MAR97 APR97 MAY97 JUN97 JUL97 AUG97
SEP97 OCT97 NOV97 Paka1 Paka2 Paka3 Paka4 APR98 MAY98 JUN98
JUL98 AUG98 SEP98 OCT98 NOV98 DEC98 JAN99 FEB99 MAR99 APR99
MAY99 JUN99 JUL99 AUG99 SEP99 OCT99 NOV99 DEC99 JAN00 FEB00
MAR00 APR00 MAY00 JUN00 JUL00 AUG00 SEP00 OCT00 NOV00 DEC00
JAN01 FEB01 MAR01 APR01 MAY01 JUN01 JUL01 AUG01 SEP01 OCT01
Earthquake1 Earthquake2 Earthquake3 FEB02 MAR02 APR02 MAY02
JUN02 Chataan1 Chataan2 Chataan3 OCT02 NOV02 Pongsona1
Pongsona2 Pongsona3 MAR03 APR03 MAY03 JUN03 JUL03 AUG03
SEP03 OCT03 NOV03 DEC03 JAN04 FEB04 MAR04 APR04 MAY04 JUN04
Tingting1 Tingting2 Tingting3 OCT04 NOV04 DEC04 JAN05 FEB05
MAR05 APR05 MAY05 JUN05 JUL05 AUG05 SEP05 OCT05 NOV05 DEC05
JAN06 FEB06 MAR06 APR06 MAY06 JUN06 JUL06 AUG06 SEP06 OCT06
NOV06 DEC06 JAN07 FEB07 MAR07 APR07 MAY07 JUN07 STR06

     {%MON} = @recode({%MON}=na,{%MON}(-12),{%MON})
next


'Create the Model
%OSN =%DATADIRECTORY + "Regressions " + %tag + ".XLS"
%modname = "GuamForecast"
model {%modname}

for %eqname     EQRESCUS EQSGNDCUS EQSGDCUS EQPOLCUS
EQLGCUS  EQGSLCUS EQRESKWH EQSGNDKWH EQSGDKWH EQLGKWH
EQPOLKWH EQGSSNDKWH EQGSSDKWH EQGSLKWH EQGSSLKWH EQNAVYKWH
EQMWGPA

     {%modname}.merge {%eqname}
next

'Holding Street Light Customers constant
smpl 2007:01 2034:12

for %CON GSSLCUS GSSNDCUS GSSDCUS

{%CON} = @recode({%CON}=na, {%CON}(-1), {%CON})

next

smpl 1992:10 2034:12
genr GSSLCUS_0 = GSSLCUS
genr GSSLCUS_1 = GSSLCUS
genr GSSLCUS_2 = GSSLCUS
```

```
genr GSSLCUS_3 = GSSLCUS
genr GSSLCUS_4 = GSSLCUS

genr GSSNDCUS_0 = GSSNDCUS
genr GSSNDCUS_1 = GSSNDCUS
genr GSSNDCUS_2 = GSSNDCUS
genr GSSNDCUS_3 = GSSNDCUS
genr GSSNDCUS_4 = GSSNDCUS

genr GSSDCUS_0 = GSSDCUS
genr GSSDCUS_1 = GSSDCUS
genr GSSDCUS_2 = GSSDCUS
genr GSSDCUS_3 = GSSDCUS
genr GSSDCUS_4 = GSSDCUS



'Prepare the Baseline forecast
smpl %STARTFORECAST 2034:12

{%modname}.solve(s=d,i=a)


'Forecast Baseline Revenues
genr RESREVF= RESKWH_0*RESPRI
genr SGNDREVF= SGNDKWH_0*SGNDPRI
genr SGDREVF= SGDKWH_0*SGDPRI
genr LGREVF= LGKWH_0*LGPRI
genr POLREVF= POLKWH_0*POLPRI
genr GSSNDREVF= GSSNDKWH_0*GSSNDPRI
genr GSSDREVF= GSSDKWH_0*GSSDPRI
genr GSLREVF= GSLKWH_0*GSLPRI
genr GSSLREVF= GSSLKWH_0*GSSLPRI
genr NAVYREVF= NAVYKWH_0*NAVYPRI

for %REVENUE RESREV SGNDREV SGDREV LGREV POLREV GSSNDREV
GSSDREV GSLREV GSSLREV NAVYREV
     {%REVENUE} = @recode({%REVENUE}=na,
{%REVENUE}F,{%REVENUE})
next


'Forecast the Low Tourism and Low Infastructure Scenario
{%modname}.scenario(n, a=_1) "Low Tourism and Infastructure
Scenario"

pageselect quarterly
```

```
smpl 2007q2 2026q4
read(cg4, s=ScenarioII,t) %SCENARIO POPULATION
read(cg7, s=ScenarioII,t) %SCENARIO EMP
read(cg16, s=ScenarioII,t) %SCENARIO REALINCOME

pageselect monthly
smpl 1993:1 2026:12
link emp
emp.linkto(c=i) quarterly::emp
link realincome
realincome.linkto(c=i) quarterly::realincome
link population
population.linkto(c=i) quarterly::population


'Prepare the Low Tourism and Low Infastructure forecast
smpl %STARTFORECAST 2026:12

{%modname}.solve(s=d,i=a)

'Forecast Baseline Revenues
genr RESREV_1= RESKWH_1*RESPRI
genr SGNDREV_1= SGNDKWH_1*SGNDPRI
genr SGDREV_1= SGDKWH_1*SGDPRI
genr LGREV_1= LGKWH_1*LGPRI
genr POLREV_1= POLKWH_1*POLPRI
genr GSSNDREV_1= GSSNDKWH_1*GSSNDPRI
genr GSSDREV_1= GSSDKWH_1*GSSDPRI
genr GSLREV_1= GSLKWH_1*GSLPRI
genr GSSLREV_1= GSSLKWH_1*GSSLPRI
genr NAVYREV_1= NAVYKWH_1*NAVYPRI

smpl 1992:10 2026:12
for %REVENUE RESREV SGNDREV SGDREV LGREV POLREV GSSNDREV
GSSDREV GSLREV GSSLREV NAVYREV
     {%REVENUE}_1 = @recode({%REVENUE}_1=na,
{%REVENUE},{%REVENUE}_1)
next


'Forecast the High Tourism and Low Infastructure Scenario
{%modname}.scenario(n, a=_2) "High Tourism and Low
Infastructure Scenario"

pageselect quarterly
smpl 2007q2 2026q4
read(cg4, s=ScenarioIII,t) %SCENARIO POPULATION
```

```
read(cg7, s=ScenarioIII,t) %SCENARIO EMP
read(cg16, s=ScenarioIII,t) %SCENARIO REALINCOME

pageselect monthly
smpl 1993:1 2026:12
link emp
emp.linkto(c=i) quarterly::emp
link realincome
realincome.linkto(c=i) quarterly::realincome
link population
population.linkto(c=i) quarterly::population

'Prepare the High Tourism and Low Infastructure forecast
smpl %STARTFORECAST 2026:12

{%modname}.solve(s=d,i=a)

'Forecast Baseline Revenues
genr RESREV_2= RESKWH_2*RESPRI
genr SGNDREV_2= SGNDKWH_2*SGNDPRI
genr SGDREV_2= SGDKWH_2*SGDPRI
genr LGREV_2= LGKWH_2*LGPRI
genr POLREV_2= POLKWH_2*POLPRI
genr GSSNDREV_2= GSSNDKWH_2*GSSNDPRI
genr GSSDREV_2= GSSDKWH_2*GSSDPRI
genr GSLREV_2= GSLKWH_2*GSLPRI
genr GSSLREV_2= GSSLKWH_2*GSSLPRI
genr NAVYREV_2= NAVYKWH_2*NAVYPRI

smpl 1992:10 2026:12
for %REVENUE RESREV SGNDREV SGDREV LGREV POLREV GSSNDREV
GSSDREV GSLREV GSSLREV NAVYREV
     {%REVENUE}_2 = @recode({%REVENUE}_2=na,
{%REVENUE},{%REVENUE}_2)
next


'Forecast the Low Tourism and High Infastructure Scenario
{%modname}.scenario(n, a=_3) "Low Tourism and High
Infastructure Scenario"

pageselect quarterly
smpl 2007q2 2026q4
read(cg4, s=ScenarioIV,t) %SCENARIO POPULATION
read(cg7, s=ScenarioIV,t) %SCENARIO EMP
read(cg16, s=ScenarioIV,t) %SCENARIO REALINCOME
```

```
pageselect monthly
smpl 1993:1 2026:12
link emp
emp.linkto(c=i) quarterly::emp
link realincome
realincome.linkto(c=i) quarterly::realincome
link population
population.linkto(c=i) quarterly::population

'Prepare the Low Tourism and High Infastructure forecast
smpl %STARTFORECAST 2026:12

{%modname}.solve(s=d,i=a)

'Forecast Baseline Revenues
genr RESREV_3= RESKWH_3*RESPRI
genr SGNDREV_3= SGNDKWH_3*SGNDPRI
genr SGDREV_3= SGDKWH_3*SGDPRI
genr LGREV_3= LGKWH_3*LGPRI
genr POLREV_3= POLKWH_3*POLPRI
genr GSSNDREV_3= GSSNDKWH_3*GSSNDPRI
genr GSSDREV_3= GSSDKWH_3*GSSDPRI
genr GSLREV_3= GSLKWH_3*GSLPRI
genr GSSLREV_3= GSSLKWH_3*GSSLPRI
genr NAVYREV_3= NAVYKWH_3*NAVYPRI

smpl 1992:10 2026:12
for %REVENUE RESREV SGNDREV SGDREV LGREV POLREV GSSNDREV
GSSDREV GSLREV GSSLREV NAVYREV
     {%REVENUE}_3 = @recode({%REVENUE}_3=na,
{%REVENUE},{%REVENUE}_3)
next


'Forecast the High Tourism and High Infastructure Scenario
{%modname}.scenario(n, a=_4) "High Tourism and High
Infastructure Scenario"

pageselect quarterly
smpl 2007q2 2026q4
read(cg4, s=ScenarioV,t) %SCENARIO POPULATION
read(cg7, s=ScenarioV,t) %SCENARIO EMP
read(cg16, s=ScenarioV,t) %SCENARIO REALINCOME

pageselect monthly
smpl 1993:1 2026:12
link emp
```

```
emp.linkto(c=i) quarterly::emp
link realincome
realincome.linkto(c=i) quarterly::realincome
link population
population.linkto(c=i) quarterly::population



'Prepare the High Tourism and High Infastructure forecast
smpl %STARTFORECAST 2026:12

{%modname}.solve(s=d,i=a)

'Forecast Baseline Revenues
genr RESREV_4= RESKWH_4*RESPRI
genr SGNDREV_4= SGNDKWH_4*SGNDPRI
genr SGDREV_4= SGDKWH_4*SGDPRI
genr LGREV_4= LGKWH_4*LGPRI
genr POLREV_4= POLKWH_4*POLPRI
genr GSSNDREV_4= GSSNDKWH_4*GSSNDPRI
genr GSSDREV_4= GSSDKWH_4*GSSDPRI
genr GSLREV_4= GSLKWH_4*GSLPRI
genr GSSLREV_4= GSSLKWH_4*GSSLPRI
genr NAVYREV_4= NAVYKWH_4*NAVYPRI

smpl 1992:10 2026:12
for %REVENUE RESREV SGNDREV SGDREV LGREV POLREV GSSNDREV
GSSDREV GSLREV GSSLREV NAVYREV
     {%REVENUE}_4 = @recode({%REVENUE}_4=na,
{%REVENUE},{%REVENUE}_4)
next


smpl 2001:1 2034:12

'Store forecast in a Spreadsheet called "Forecast %NOW.XLS"
%OSN = %DATADIRECTORY + "Forecast " + %tag + ".XLS"


' Write Results to FORECAST spreadsheet output file
smpl 2001:1 2034:12
write(t=xls) %OSN  RESCUS_0 SGNDCUS_0 SGDCUS_0 LGCUS_0
POLCUS_0 GSSNDCUS_0 GSSDCUS_0 GSLCUS_0 GSSLCUS_0 RESKWH_0
SGNDKWH_0 SGDKWH_0 LGKWH_0 POLKWH_0 GSSNDKWH_0 GSSDKWH_0
GSLKWH_0 GSSLKWH_0 NAVYKWH_0 RESPRI SGNDPRI SGDPRI LGPRI
POLPRI GSSNDPRI GSSDPRI GSLPRI GSSLPRI NAVYPRI BILLCDD65
MWGPA_0 RESREV SGNDREV SGDREV LGREV POLREV GSSNDREV GSSDREV
```

```
GSLREV GSSLREV NAVYREV RESCUS_1 SGNDCUS_1 SGDCUS_1 LGCUS_1
POLCUS_1 GSSNDCUS_1 GSSDCUS_1 GSLCUS_1 GSSLCUS_1 RESKWH_1
SGNDKWH_1 SGDKWH_1 LGKWH_1 POLKWH_1 GSSNDKWH_1 GSSDKWH_1
GSLKWH_1 GSSLKWH_1 NAVYKWH_1 MWGPA_1 RESREV_1 SGNDREV_1
SGDREV_1 LGREV_1 POLREV_1 GSSNDREV_1 GSSDREV_1 GSLREV_1
GSSLREV_1 NAVYREV_1 RESCUS_2 SGNDCUS_2 SGDCUS_2 LGCUS_2
POLCUS_2 GSSNDCUS_2 GSSDCUS_2 GSLCUS_2 GSSLCUS_2 RESKWH_2
SGNDKWH_2 SGDKWH_2 LGKWH_2 POLKWH_2 GSSNDKWH_2 GSSDKWH_2
GSLKWH_2 GSSLKWH_2 NAVYKWH_2 MWGPA_2 RESREV_2 SGNDREV_2
SGDREV_2 LGREV_2 POLREV_2 GSSNDREV_2 GSSDREV_2 GSLREV_2
GSSLREV_2 NAVYREV_2 RESCUS_3 SGNDCUS_3 SGDCUS_3 LGCUS_3
POLCUS_3 GSSNDCUS_3 GSSDCUS_3 GSLCUS_3 GSSLCUS_3 RESKWH_3
SGNDKWH_3 SGDKWH_3 LGKWH_3 POLKWH_3 GSSNDKWH_3 GSSDKWH_3
GSLKWH_3 GSSLKWH_3 NAVYKWH_3 MWGPA_3 RESREV_3 SGNDREV_3
SGDREV_3 LGREV_3 POLREV_3 GSSNDREV_3 GSSDREV_3 GSLREV_3
GSSLREV_3 NAVYREV_3 RESCUS_4 SGNDCUS_4 SGDCUS_4 LGCUS_4
POLCUS_4 GSSNDCUS_4 GSSDCUS_4 GSLCUS_4 GSSLCUS_4 RESKWH_4
SGNDKWH_4 SGDKWH_4 LGKWH_4 POLKWH_4 GSSNDKWH_4 GSSDKWH_4
GSLKWH_4 GSSLKWH_4 NAVYKWH_4 MWGPA_4 RESREV_4 SGNDREV_4
SGDREV_4 LGREV_4 POLREV_4 GSSNDREV_4 GSSDREV_4 GSLREV_4
GSSLREV_4 NAVYREV_4


poff

stop
close all objects
exit
```

D Fuel Forecast

GPA Cost Of Fuels Forecast

by

PL Mangilao Energy, LLC
Kemm C. Farney, PhD
and
Peter C. Mayer, PhD

May 2, 2008

Several scenarios depicting the range of outcomes that may be experienced with respect to GPA's future cost of fuel for electricity generation have been prepared to support GPA's internal planning needs, including the current Integrated Resource Planning (IRP) activities. Subjects covered by scenarios include the cost (delivered to Guam) of selected petroleum based fuels, liquefied natural gas (LNG), coal and the cost of credits for CO_2 emissions.

The outlook for petroleum products delivered to Guam is developed to be consistent with Strategic Energy and Economic Research's (SEER's) most recent "Global Petroleum SEER Monthly". This document, dated October 26, 2007, is incorporated as Appendix A of this chapter. Similarly, the outlook for LNG is consistent with SEER's most recent outlook for natural gas, "Natural Gas SEER Monthly". This document, dated January 21, 2008, is incorporated as Appendix B of this chapter. The outlook for thermal coal delivered to Guam has been developed by JD Energy, Inc., titled "Coal Prices – Delivered C&F Guam", dated November 27, 2007 and included as Appendix C of this chapter. Finally, the outlook for the cost of credits for CO_2 emissions was prepared by P&L Economics, Inc. in consultation with JD Energy. These three forecasting organizations have been working closely together for more than a decade. Their forecasts of energy prices are constructed to be rigorously consistent.

The remainder of this Chapter is divided into four sections: "The Delivered Cost of Petroleum Products to Guam;" "The Delivered Cost of LNG to Guam;" "The Delivered Cost of Coal to Guam;" and, "The Market Value of CO2 Emissions Credits."

The Delivered Cost of Petroleum Products to Guam

Global market forces drive the price of oil products in Asia, including Singapore and Guam. Although volatility in product balances and shipping costs can cause relative prices in these markets to deviate from prices elsewhere, such effects are minor and transient. `Crude prices will always be shaped by what is happening to global oil supply and demand, and by

OPEC's management of its surplus capacity (or its inability to do so). Because the cost for transporting crude oil over long distances is far below the historical market price of crude oil, any price deviation within a given local market from global norms will be answered by increases in imports or exports to bring the local market back into equilibrium.

Oil product prices are more likely to vary from crude oil prices in the short-term, because shipping products, especially 'clean' products such as diesel fuel, is more expensive than shipping crude. However, refinery economics do not vary significantly over the long term and as a result, the relationship between product and crude prices, while volatile in the short-run, should not change significantly in a forecast that looks out over two decades.

Table 1, immediately below, presents our base case outlook for the petroleum products that GPA purchases. Prices shown are for the benchmark West Texas Intermediate (WTI) in nominal or current year $/bbl, the US Refiner's Acquisition Cost Of Crude (a benchmark price in energy markets), prices for residual fuel oil and number 2 fuel oil cif Singapore, and prices for residual fuel oil and number 2 fuel oil cif Guam. Residual fuel oil had an average delivered price of $45.92/bbl (cif Guam) in 2005, and is expected to decrease gradually over the forecast time horizon, reaching $110.87/bbl in 2025. This Base Case scenario is constructed to be very similar to the base case contained in the pre-release of the US DOE/EIA 2008 Annual Energy Outlook [http://www.eia.doe.gov/oiaf/aeo/aeoref_tab.html].

The fundamentals of oil markets seem to make a gradual decrease in real prices almost inevitable, once the current global political turmoil is resolved – if it is ever resolved. One way to think about oil prices is that they are artificially inflated over fundamentals by three factors with roughly equal contributions to higher prices – the lower dollar, investment funds that have been attracted by the recent run up in prices, and geo-politics.

In the Base Case scenario, oil productive capacity increases approximately 7 million barrels per day faster than demand growth between 2005 and 2010 as worldwide oil production capacity increases by approximately 15 million barrels per day. This is almost a 20% increase in worldwide oil production capacity. A good portion of the capacity additions was started before the recent sharp increase in oil prices. By the end of 2008 the strong growth in oil productive capacity is expected to cause sharp downward pressures on oil and natural gas prices.

Table 1
Base Case Forecast for Oil Price Delivered To Guam
($/bbl, nominal US$)
Current Year $ per mmBTU

	US RAC Imported Crude	Singapore Resid 180	Singapore Gasoil	Guam Resid	Guam Gasoil	WTI
2005	$46.53	$39.58	$62.09	$40.45	$63.35	$54.91
2006	$58.88	$39.41	$61.37	$40.31	$62.67	$66.05
2007	$60.94	$44.99	$69.22	$45.92	$70.55	$71.95
2008	$62.44	$49.63	$75.59	$50.55	$76.93	$71.92
2009	$65.53	$55.62	$84.01	$56.56	$85.38	$71.57
2010	$68.75	$61.87	$92.81	$62.84	$94.21	$71.98
2011	$68.88	$61.99	$92.99	$62.98	$94.42	$72.26
2012	$68.97	$62.08	$93.11	$63.09	$94.58	$72.56
2013	$69.03	$62.13	$93.19	$63.17	$94.70	$72.73
2014	$69.05	$62.14	$93.21	$63.21	$94.76	$72.75
2015	$69.02	$62.12	$93.18	$63.21	$94.76	$72.67
2016	$71.08	$63.98	$95.96	$65.10	$97.59	$72.47
2017	$73.21	$65.89	$98.83	$67.04	$100.49	$74.45
2018	$75.40	$67.86	$101.78	$69.04	$103.49	$77.53
2019	$77.64	$69.88	$104.82	$71.09	$106.57	$80.74
2020	$79.96	$71.96	$107.95	$73.20	$109.74	$84.09
2021	$83.39	$75.05	$112.57	$76.32	$114.41	$87.73
2022	$86.93	$78.24	$117.36	$79.54	$119.24	$91.47
2023	$90.61	$81.55	$122.32	$82.88	$124.25	$95.25
2024	$94.41	$84.97	$127.45	$86.34	$129.43	$99.11
2025	$98.35	$88.51	$132.77	$89.91	$134.79	$103.02
2026	$102.64	$92.38	$138.57	$93.82	$140.65	$107.21
2027	$107.10	$96.39	$144.58	$97.86	$146.71	$111.73
2028	$111.71	$100.54	$150.80	$102.05	$152.98	$116.50
2029	$116.48	$104.83	$157.25	$106.38	$159.48	$121.79
2030	$121.42	$109.28	$163.92	$110.87	$166.21	$126.71

Of course, global energy markets are fraught with uncertainty, and the body of this report describes those risks, with as much quantification as is possible. Table 2 presents our High Price Case for petroleum markets. Delays in new fields, higher than expected declines in existing fields, supply disruptions and strong demand growth could keep prices high. While these delays might occur for many different reasons, such as a global recession in capital spending like we saw after 2001, it is probably easiest to imagine them as a consequence of the political turmoil currently roiling global politics. This High Price Case scenario is constructed to be very similar to the high price case contained in the US DOE/EIA 2007 Annual Energy Outlook [http://www.eia.doe.gov/oiaf/archive/aeo07/aeohighprice.html].

Table 2
High Price Case Forecast for Oil Price Delivered To Guam
($/bbl, nominal US$)
Current Year $ per mmBTU

	US RAC Imported Crude	Singapore Resid 180	Singapore Gasoil	Guam Resid	Guam Gasoil	WTI
2005	$46.53	$39.58	$62.09	$40.45	$63.35	$54.91
2006	$58.88	$52.99	$79.49	$53.89	$80.79	$66.05
2007	$60.94	$56.81	$85.21	$57.73	$86.54	$71.95
2008	$64.48	$59.34	$89.01	$60.26	$90.34	$72.17
2009	$69.73	$63.42	$95.14	$64.37	$96.50	$74.84
2010	$75.19	$67.67	$101.51	$68.64	$102.91	$78.42
2011	$79.48	$71.53	$107.30	$72.52	$108.73	$82.55
2012	$83.93	$75.54	$113.31	$76.56	$114.78	$86.48
2013	$88.56	$79.70	$119.55	$80.75	$121.06	$91.12
2014	$93.36	$84.03	$126.04	$85.10	$127.59	$96.54
2015	$98.35	$88.52	$132.78	$89.61	$134.36	$102.01
2016	$103.32	$92.99	$139.49	$94.12	$141.11	$107.64
2017	$108.48	$97.63	$146.45	$98.78	$148.11	$112.74
2018	$113.83	$102.45	$153.67	$103.63	$155.38	$117.97
2019	$119.38	$107.44	$161.17	$108.65	$162.91	$123.57
2020	$125.14	$112.63	$168.94	$113.87	$170.73	$129.27
2021	$129.84	$116.85	$175.28	$118.12	$177.12	$134.19
2022	$134.69	$121.22	$181.84	$122.53	$183.72	$138.64
2023	$139.71	$125.74	$188.61	$127.07	$190.54	$143.88
2024	$144.89	$130.40	$195.61	$131.77	$197.58	$149.30
2025	$150.25	$135.22	$202.84	$136.63	$204.86	$154.92
2026	$155.94	$140.34	$210.51	$141.78	$212.59	$160.72
2027	$161.81	$145.63	$218.45	$147.11	$220.58	$166.71
2028	$167.89	$151.10	$226.65	$152.61	$228.83	$172.90
2029	$174.16	$156.75	$235.12	$158.30	$237.36	$179.30
2030	$180.65	$162.59	$243.88	$164.17	$246.17	$185.94

It is also possible that excess oil productive capacity could make it difficult for OPEC to maintain enough discipline. If this were to happen, oil prices could drop sharply. Table 3 presents our Low Price Case. This is the case that we believe will be most likely if the world economy can return to reasonable political stability and moderate economic growth. This Low Price Case scenario was constructed by SEER, and is included in their appendix.

Table 3
Low Price Case Forecast for Oil Price Delivered To Guam
($/bbl, nominal US$)
Current Year $ per mmBTU

	US RAC Imported Crude	Singapore Resid 180	Singapore Gasoil	Guam Resid	Guam Gasoil	WTI
2005	$46.53	$39.58	$62.09	$40.45	$63.35	$54.91
2006	$58.88	$52.99	$79.49	$53.89	$80.79	$66.05
2007	$60.94	$54.06	$82.26	$54.98	$83.59	$71.95
2008	$61.19	$54.55	$82.61	$55.47	$83.94	$69.13
2009	$62.98	$56.42	$85.03	$57.36	$86.39	$69.28
2010	$64.83	$58.35	$87.52	$59.31	$88.92	$69.67
2011	$63.91	$57.52	$86.28	$58.51	$87.71	$68.38
2012	$62.91	$56.62	$84.93	$57.64	$86.40	$62.17
2013	$61.82	$55.64	$83.45	$56.68	$84.96	$63.15
2014	$60.63	$54.57	$81.85	$55.64	$83.40	$62.95
2015	$59.35	$53.41	$80.12	$54.51	$81.70	$63.61
2016	$61.34	$55.21	$82.81	$56.33	$84.43	$65.09
2017	$63.40	$57.06	$85.59	$58.21	$87.25	$67.24
2018	$65.52	$58.97	$88.46	$60.15	$90.16	$69.46
2019	$67.71	$60.94	$91.41	$62.15	$93.16	$71.74
2020	$69.97	$62.97	$94.46	$64.21	$96.25	$74.10
2021	$72.57	$65.31	$97.96	$66.58	$99.80	$76.80
2022	$75.25	$67.72	$101.58	$69.03	$103.47	$79.59
2023	$78.02	$70.22	$105.33	$71.55	$107.25	$82.47
2024	$80.88	$72.79	$109.19	$74.16	$111.17	$85.44
2025	$83.84	$75.45	$113.18	$76.86	$115.21	$88.51
2026	$86.89	$78.20	$117.31	$79.64	$119.38	$91.69
2027	$90.05	$81.04	$121.56	$82.52	$123.69	$94.96
2028	$93.31	$83.98	$125.96	$85.49	$128.14	$98.34
2029	$96.67	$87.00	$130.51	$88.55	$132.74	$101.83
2030	$100.15	$90.13	$135.20	$91.72	$137.49	$105.43

The Delivered Cost of LNG to Guam

LNG delivered to Guam is most likely to come from local Asian gas producers characterized by the Tangguh, Indonesia market hub. As shown in Tables 4, 5 and 6, the Tangguh price must be adjusted for the cost of transporting the LNG to Guam and the cost of regasifying the LNG so that it can be burned in its final application. The size of the smallest LNG tankers requires that storage facilities be available on Guam of at least that magnitude (here are increased costs associated with purchasing a partial tanker load). Additionally, LNG regasification is a technology that requires a minimum throughput to be economic. In order to meet these cost hurdles, it was assumed that other applications for natural gas would be developed, so that the overhead cost of storage and regasification could be shared over larger volumes.

Table 4 presents our base case outlook for the LNG that GPA might purchase. Prices shown are for the commodity cost of LNG purchased at Tangguh, the cost of transport to Guam, the cost of regasification, and the total delivered cost. Natural gas would have had an average delivered price of $10.91/mmBTU (cif Guam) in 2007, and is expected to decrease gradually over the forecast time horizon, reaching $13.90/mBTU in 2025.

Table 4
Base Case Forecast for LNG Delivered To Guam
($/mmBTU, nominal US$)
Nominal $ per MMBtu

	Tangguh Indonesia	Transport	Regas	Guam Delivered Price
2005	5.15	1.30	2.65	9.09
2006	6.37	1.34	2.73	10.44
2007	6.74	1.37	2.80	10.91
2008	6.58	1.37	2.80	10.75
2009	5.95	1.41	2.87	10.22
2010	5.92	1.44	2.94	10.30
2011	6.13	1.48	3.01	10.62
2012	6.34	1.51	3.09	10.94
2013	6.57	1.55	3.16	11.28
2014	6.80	1.59	3.24	11.63
2015	6.86	1.63	3.32	11.82
2016	6.93	1.67	3.41	12.01
2017	7.00	1.71	3.49	12.20
2018	7.07	1.76	3.58	12.40
2019	7.13	1.80	3.67	12.60
2020	7.20	1.85	3.76	12.81
2021	7.27	1.89	3.85	13.02
2022	7.34	1.94	3.95	13.23
2023	7.42	1.99	4.05	13.45
2024	7.49	2.04	4.15	13.67
2025	7.56	2.09	4.25	13.90
2026	7.63	2.14	4.36	14.13
2027	7.71	2.19	4.47	14.37
2028	7.78	2.25	4.58	14.61
2029	7.86	2.30	4.70	14.86
2030	7.93	2.36	4.81	15.11

Table 5 presents our High Price Case for LNG delivered to Guam. In this case, Natural gas is expected to reach $16.43/mBTU in 2025.

Table 5
High Price Case Forecast for LNG Delivered To Guam
($/mmBTU, nominal US$)
Nominal $ per MMBtu

	Tangguh Indonesia	Transport	Regas	Guam Delivered Price
2005	5.15	1.30	2.65	9.09
2006	6.37	1.34	2.73	10.44
2007	6.74	1.37	2.80	10.91
2008	7.16	1.37	2.80	11.33
2009	7.14	1.41	2.87	11.41
2010	7.46	1.44	2.94	11.84
2011	7.59	1.48	3.01	12.08
2012	7.80	1.51	3.09	12.40
2013	7.84	1.55	3.16	12.56
2014	7.78	1.59	3.24	12.61
2015	7.91	1.63	3.32	12.87
2016	8.17	1.67	3.41	13.25
2017	8.42	1.71	3.49	13.62
2018	8.67	1.76	3.58	14.01
2019	8.89	1.80	3.67	14.35
2020	9.11	1.85	3.76	14.71
2021	8.89	1.89	3.85	14.63
2022	9.15	1.94	3.95	15.04
2023	9.45	1.99	4.05	15.49
2024	9.76	2.04	4.15	15.95
2025	10.08	2.09	4.25	16.43
2026	10.41	2.14	4.36	16.92
2027	10.76	2.19	4.47	17.42
2028	11.11	2.25	4.58	17.94
2029	11.47	2.30	4.70	18.47
2030	11.85	2.36	4.81	19.02

Table 6 presents our Low Price Case for LNG delivered to Guam. In this case, Natural gas is expected to reach $13.49/mBTU in 2025.

Table 6
Low Price Case Forecast for LNG Delivered To Guam
($/mmBTU, nominal US$)
Nominal $ per MMBtu

	Tangguh Indonesia	Transport	Regas	Guam Delivered Price
2005	5.15	1.30	2.65	9.09
2006	6.37	1.34	2.73	10.44
2007	6.74	1.37	2.80	10.91
2008	6.14	1.37	2.80	10.31
2009	5.77	1.41	2.87	10.05
2010	5.60	1.44	2.94	9.97
2011	5.79	1.48	3.01	10.28
2012	6.00	1.51	3.09	10.60
2013	6.21	1.55	3.16	10.92
2014	6.43	1.59	3.24	11.26
2015	6.49	1.63	3.32	11.44
2016	6.55	1.67	3.41	11.63
2017	6.62	1.71	3.49	11.82
2018	6.68	1.76	3.58	12.02
2019	6.74	1.80	3.67	12.21
2020	6.81	1.85	3.76	12.42
2021	6.88	1.89	3.85	12.62
2022	6.94	1.94	3.95	12.83
2023	7.01	1.99	4.05	13.05
2024	7.08	2.04	4.15	13.27
2025	7.15	2.09	4.25	13.49
2026	7.22	2.14	4.36	13.72
2027	7.29	2.19	4.47	13.95
2028	7.36	2.25	4.58	14.19
2029	7.43	2.30	4.70	14.43
2030	6.17	2.36	4.81	13.35

The Delivered Cost of Coal to Guam

Coal delivered to Guam is also most likely to come from local Asian gas producers in Indonesia or Australia. Once again, the local price must be adjusted for the cost of transporting the coal to Guam. Table 7 presents our base case outlook for the coal that GPA might purchase. Indonesian coal would have had an average delivered price of $67.80/ton (cif Guam) in 2008, and is expected to reach $69.50/ton in 2025.

Table 7
Base Case Forecast for Coal Delivered To Guam
($/ton, nominal US$)

	Delivered Prices			
	2006$/t		Nominal $/t	
	Australia	Indonesia	Australia	Indonesia
2008	95.20	66.20	97.50	67.80
2009	79.20	55.80	83.14	58.58
2010	69.30	49.20	74.57	52.94
2011	63.40	45.50	69.92	50.18
2012	65.70	46.70	74.27	52.79
2013	66.90	47.40	77.52	54.92
2014	66.20	46.80	78.62	55.58
2015	65.90	46.80	80.22	56.97
2016	65.50	46.40	81.73	57.90
2017	65.10	46.20	83.26	59.09
2018	64.80	45.90	84.95	60.17
2019	64.40	45.60	86.54	61.28
2020	64.40	45.60	88.70	62.81
2021	64.00	45.50	90.35	64.24
2022	63.70	45.20	92.18	65.41
2023	63.30	44.90	93.89	66.60
2024	62.90	44.60	95.63	67.81
2025	62.90	44.60	98.02	69.50
2026	62.50	44.40	99.83	70.92
2027	62.10	44.10	101.67	72.20
2028	61.70	43.90	103.54	73.67
2029	61.40	43.60	105.62	75.00
2030	61.20	43.40	107.90	76.52

Table 8 presents our High Price Case for coal delivered to Guam. In this case, Indonesian coal is expected to reach $93.94/mBTU in 2025.

Table 8
High Price Case Forecast for Coal Delivered To Guam
($/ton, nominal US$)

	Delivered Prices			
	2006$/t		Nominal $/t	
	Australia	Indonesia	Australia	Indonesia
2008	95.20	66.20	97.50	67.80
2009	79.20	55.80	83.14	58.58
2010	85.00	60.28	91.46	64.86
2011	85.00	60.28	93.74	66.49
2012	85.00	60.28	96.09	68.15
2013	85.00	60.28	98.49	69.85
2014	85.00	60.28	100.95	71.60
2015	85.00	60.28	103.48	73.39
2016	85.00	60.28	106.06	75.22
2017	85.00	60.28	108.72	77.10
2018	85.00	60.28	111.43	79.03
2019	85.00	60.28	114.22	81.01
2020	85.00	60.28	117.07	83.03
2021	85.00	60.28	120.00	85.11
2022	85.00	60.28	123.00	87.24
2023	85.00	60.28	126.08	89.42
2024	85.00	60.28	129.23	91.65
2025	85.00	60.28	132.46	93.94
2026	85.00	60.28	135.77	96.29
2027	85.00	60.28	139.16	98.70
2028	85.00	60.28	142.64	101.17
2029	85.00	60.28	146.21	103.70
2030	85.00	60.28	149.87	106.29

The Market Value of CO_2 Emissions Credits

The market for CO_2 emissions is just beginning to take shape, and the future value of traded credits is very uncertain. Engineering studies conducted by JD Energy cause them to believe that the marginal production cost of CO2 credits using technology known today is $150/ton (2007 $). Table 9 presents our Low Emission Price scenario. In this scenario the US is slow to form an organized market and the final rules do not cause highest cost emitters to abate – they are able to simply buy credits to use as offsets to their production. In this scenario, credits reach a price of $77.92/ton by 2025.

Table 9
Low Case Forecast of CO_2 Emissions Credit Prices
($/ton, nominal US$)

	Low Carbon Credit (2006 $/ton)	Low Carbon Credit (nominal $/ton)
2005		
2006		
2007	2.25	2.30
2008	4.30	4.40
2009	6.35	6.67
2010	8.40	9.04
2011	10.45	11.53
2012	12.50	14.13
2013	16.67	19.31
2014	20.83	24.74
2015	25.00	30.43
2016	30.00	37.43
2017	35.00	44.77
2018	40.00	52.44
2019	45.00	60.47
2020	50.00	68.87
2021	50.00	70.59
2022	50.00	72.35
2023	50.00	74.16
2024	50.00	76.02
2025	50.00	77.92
2026	50.00	79.86
2027	50.00	81.86
2028	50.00	83.91
2029	50.00	86.01
2030	50.00	88.16

Table 10 presents our High Emission Price scenario. In this scenario the US is quick to form an efficiently functioning market in credits, and the market rules are sufficiently strict so that the high cost emitters find it more efficient to abate than to purchase offsets. In this scenario, credits reach a price of $233.75/ton by 2025.

Table 10
High Price Case Forecast of CO_2 Emissions Credit Prices
($/ton, nominal US$)

	High Carbon Credit (2006 $/ton)	High Carbon Credit (nominal $/ton)
2005		
2006		
2007	2.25	2.30
2008	9.30	9.52
2009	16.35	17.16
2010	23.40	25.18
2011	30.45	33.58
2012	37.50	42.39
2013	50.00	57.94
2014	62.50	74.23
2015	75.00	91.30
2016	90.00	112.30
2017	105.00	134.30
2018	120.00	157.32
2019	135.00	181.41
2020	150.00	206.60
2021	150.00	211.77
2022	150.00	217.06
2023	150.00	222.49
2024	150.00	228.05
2025	150.00	233.75
2026	150.00	239.59
2027	150.00	245.58
2028	150.00	251.72
2029	150.00	258.02
2030	150.00	264.47

Appendix A
Petroleum Outlook

The Global Petroleum SEER Monthly

Strategic Energy & Economic Research, Inc.
Michael C. Lynch

October 26, 2007

SEER

Global Petroleum SEER Monthly

Strategic Energy and Economic Research Inc.

October 26, 2007

The Winds of October
Blow gentle and sober

Markets remain focused on low US product inventories, but the hurricane season has only about another week to run. Fundamentals should become weaker in the 4th quarter, especially if Iraqi and Nigerian production remain robust.

The decision by OPEC (prompted by Saudi pressure) to raise quotas from November 1 indicates that price is beginning to be more important than the market balance (actual and expected) to the Saudis.

The US subprime mess has resulted in some signs of weakness, including the impact of the weak dollar on European exports, but overall growth is showing signs of nothing more than slight slowing.

Market psychology remains bullish, heightened by fears of a Turkish attack on Iraqi Kurds, Iranian and US skirmishing over uranium enrichment, and a drop in 3rd quarter inventories.

Early warning signs (blue is bullish, red is bearish)

- **Economic growth becomes more anemic and demand remains weak.**
- **Nigerian Delta production continues to grow, and Iraqi exports from Ceyhan remain at 300 tb/d or above.**
- **Non-OPEC supply grows robustly.**
- **Stock markets recover.**
- **Violence affects either Iraqi or Nigerian production.**
- **OPEC reduces quotas for 1st quarter, and discipline tightens.**

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Likely Trends

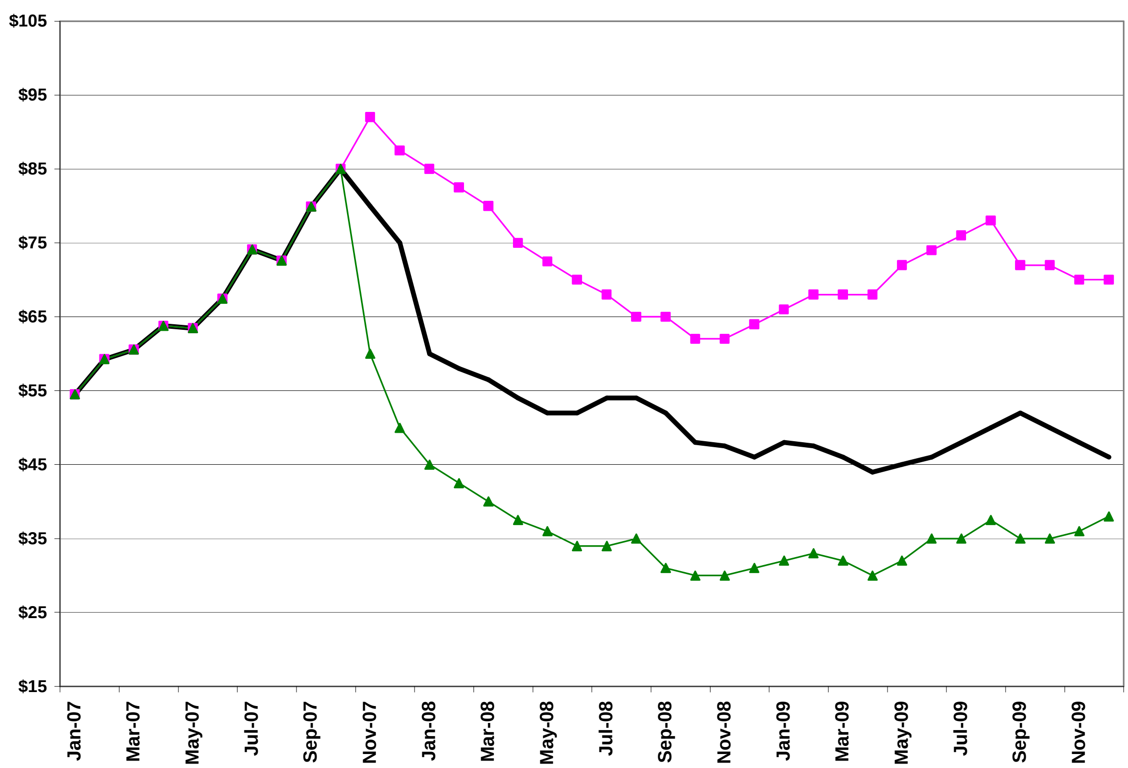
BASE CASE: Weak demand helps bring US product inventories to normal levels but continuing refinery problems slow any recovery. A warm winter helps bring heating oil inventories into balance. High OPEC and non-OPEC production will raise inventories counter-seasonally, and the weak economic outlook should bring prices down later in the fourth quarter. Probability: 50%

HIGH PRICES: US economy is slowed only slightly. Production problems grow in Nigeria and elsewhere, especially in large non-OPEC projects. Backwardation keeps inventories low. OPEC cuts quotas for the first quarter, and some members cut production of heavy oil early. Probability: 25%

The LOW PRICE scenario envisages low heating demand and a recovery of distillate inventories. US economic weakness spreads to Asia, and global inventories rise throughout the 4th quarter. Large investors began to pull out of commodity index funds, especially those weighted towards energy. Probability: 25%

CAUTIONARY NOTES: Funds have re-emphasized energy in their portfolios and are boosting prices beyond what fundamentals justify. Any shift in their strategy would cause a major bear market.

WTI PRICE SCENARIOS



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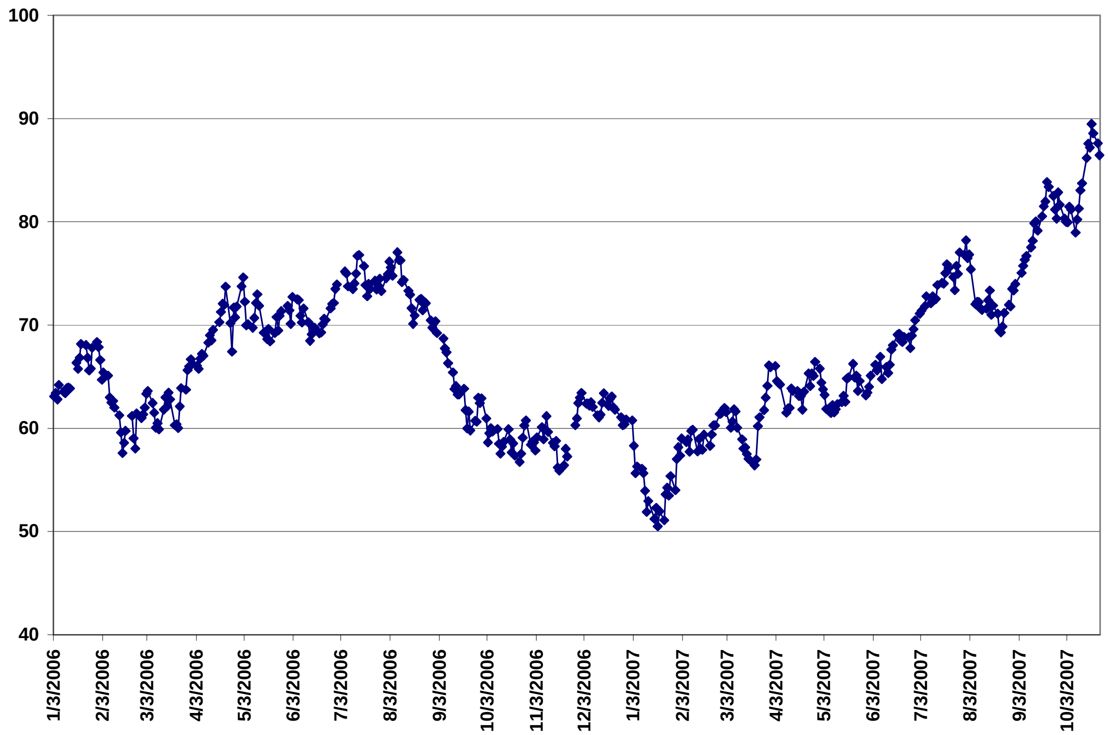
No Wind

Market prices soared on the basis of relatively slim news. The 3rd quarter OECD inventory drawdown was a minor surprise, and US refinery runs continue to be quite low. Backwardation has meant that crude inventories have remained relatively low, but minimal impact of the hurricane season has assisted. With the recent drastic decline in refinery margins, runs have dropped sharply, keeping inventories from building. This appears to reflect the speculative or security premium on crude clashing with weak product prices.

RECENT WTI PRICES



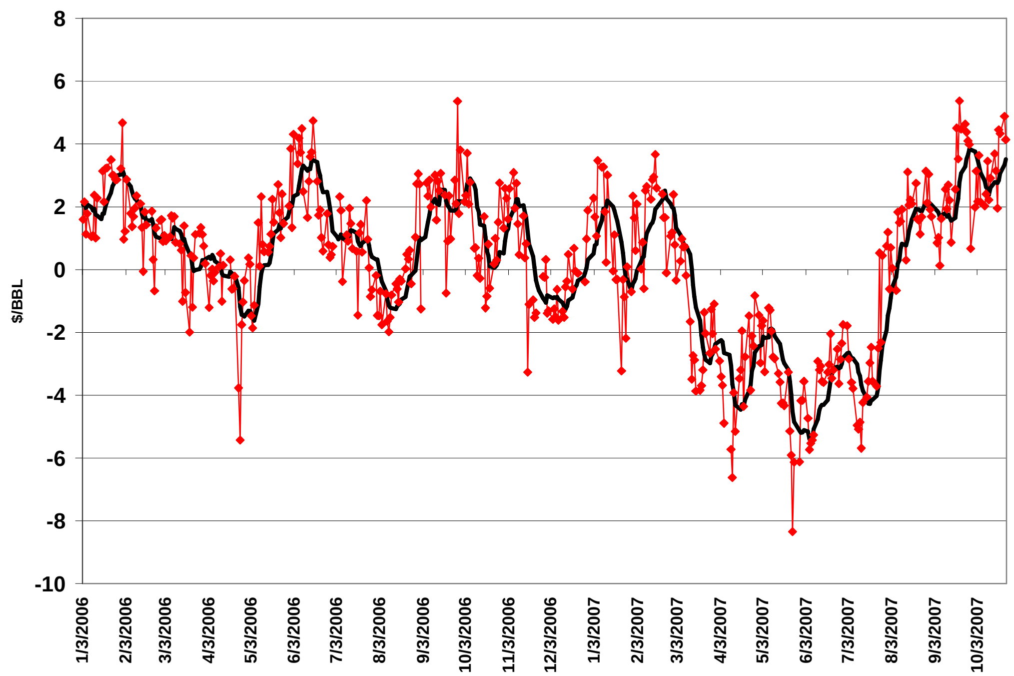
Weakness in the US economy remains a major concern, although it is hard to see in the oil data lately. Non-OECD demand, including Chinese, remains robust and is taken by many as a sign of a demand resurgence in the 4th quarter and next year. This, plus pessimism about non-OPEC supply (especially given recent experience with field delays and technical problems) leads many to predict supply shortages soon.[1]

Although US imports have been relatively low lately, feeding a drop in crude inventories, the recent increase in the trans-Atlantic arbitrage should see significantly higher imports beginning soon. As the figure shows, the current level is above $4/bbl, and it has been well

[1] T. Boone Pickens, the Texas financier, says global production has peaked so all consumption growth will be unmet, but this is obviously nonsense.

above $2-2.50/bbl for about four weeks now; this is the level thought needed to encourage higher imports. To some degree, this must offset the level of backwardation in crude markets, which acts to discourage purchases and inventory holding. No doubt, this is why the WTI-Brent differential has risen so high.

RECENT WTI BRENT DIFFERENTIAL



Geopolitics : The Kurd Has No Friend

The biggest current news is the threat by Turkey to invade northern Iraq and attack bases of the PKK, the insurgent group that has long battled the Turkish government/army, but has recently become active again. This has sent prices spiraling upwards, primarily because the words “conflict” and “Middle East” always cause traders to respond with alarm.

However, the Turks are unlikely to do much more than cross into border regions and attack the mountain bases near there, which are well away from any oil producing areas (located mostly near Kirkuk, over 200 km from the border). Past incursions have accomplished little, and the Turkish government—while facing enormous domestic political pressure to take action—apparently wants a diplomatic solution that would involve the Iraqi government repressing the PKK more effectively. Some military action can be expected, but it is unlikely to be major and should be dismissed by the market fairly quickly.

In Nigeria, there is no apparent progress towards any settlement with rebels, but Shell is reportedly restoring its Delta production.   Estimated exports of Forcados have been about 100 tb/d. Recall that earlier this year, Shell was said to have reached an agreement with MEND that would allow it to resume operations, although details were murky. Possibly, this is a sign that this agreement is functioning and another 350 tb/d or so will be added to

Nigerian production in coming months. Still, there are continued reports of attacks on oil installations and kidnappings of workers, including Shell's EA field, so it remains unclear whether the situation is improving or not. (The government has suggested that the latest kidnapping was an isolated incident, and that negotiations with MEND continue.)

The resignation of Ali Larijani, the chief Iranian nuclear negotiator and a reported moderate, suggests that the tensions over Iran's nuclear program will increase. Reports that many politicians have offered Larijani support imply that the issue remains contentious in the government, and could lead to moderation in the future, but for now, expect that this issue will occasionally raise the temperature in the oil market. Hard-line statements from both Bush and Cheney, backed by the new French president, are hardly suggestive that the US is going to pursue the diplomatic course, and new economic sanctions just announced by the US (unilateral) will raise the temperature in the short run.

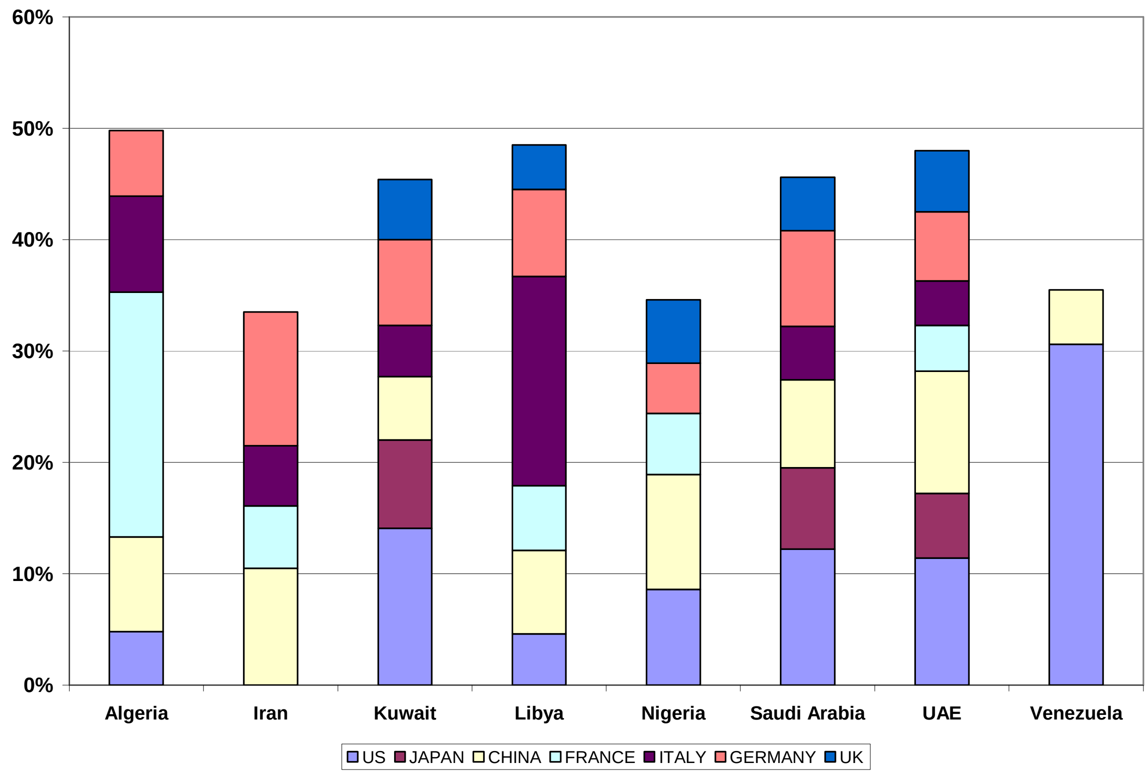
Fundamentals

The economic news continues to be mixed, with the large interest rate cut (0.5%) by the US Fed and the Japanese Central Bank decision to maintain current (superlow) rates bolstering financial markets. However, other news is not as positive, particularly from the housing market. Since the primary uncertainty for the fourth quarter is the rate of consumption (see the August GPS), this is of crucial importance. There have been some indications of a high rate of consumption growth in the non-OECD areas, including China, relative to earlier in the year at least, but given the poor data from those areas this should be viewed cautiously. Traditionally, the IEA has upgraded demand estimates for non-OECD after the fact, and that could be the case again,

The rest of the world appears to be suffering moderately from the effects of the US economic woes, including countries like Britain and Germany, where banks had invested in subprime instruments. Also, the rising dollar is threatening the European export industries (the Japanese yen has not appreciated significantly, and the Chinese yuan is pegged to the dollar), raising concerns in prime exporting economies there. However, most institutions like the IMF still expect only a slight slowdown in economic growth in 2008.

Dollar weakness also contributes to the perception that the price of oil should rise, or at least, that is the way traders react in the short-term. The effect is real, but decidedly indirect longer term. A weak dollar makes oil cheaper—except in countries like Japan and China, where the dollar hasn't lost much value. And it reduces OPEC's revenue relative to their imports, except to the degree which they import from the US, China or Japan. As the figure below shows, most countries get 25-30% of their goods from those three markets (Venezuela being an amusing exception), but a weak dollar means a higher desired price of oil. Translating that into the actual price is not a straightforward exercise, of course.

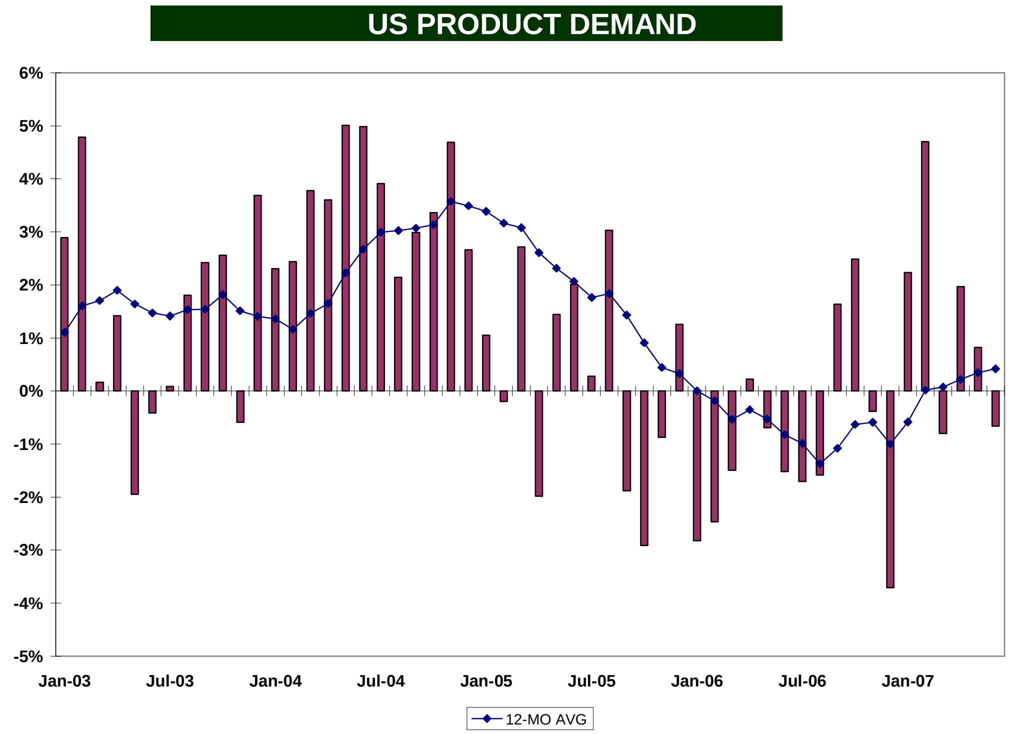
OPEC NATIONS' IMPORT SOURCES



Source: CIA, data for 2006.

US Demand: Flushed Away

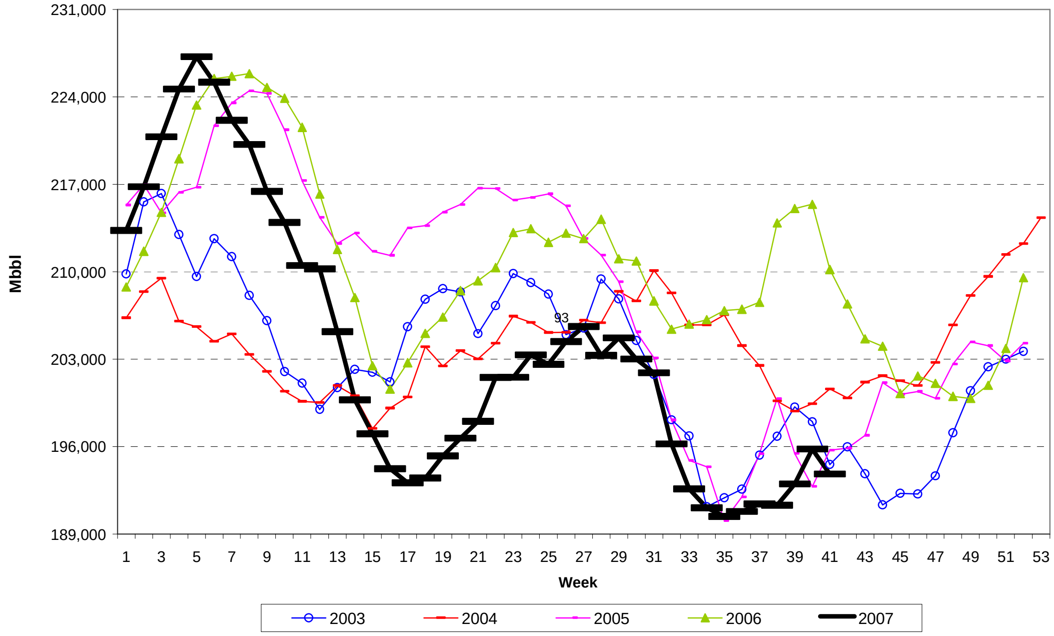
After a lengthy period of concern about 'the runaway train' of demand, the evidence is growing that even the US is responding to higher prices. As the graph below shows, the monthly data (revised from the weekly data) suggests that growth for this year will be very small.



The weekly data suggests that gasoline demand is now shrinking, and in fact, this is not unexpected given high prices and reports that last year's new car efficiency levels increased for the first time in over a decade. The differential between gasoline and crude has dropped sharply in the US in the past few months (wiping out refinery margins), keeping retail prices low even as prices rose to $80, but this is unlikely to continue and an increase of $0.20/gallon (about 8%) can be expected in the next few weeks. On the other hand, the warm weather in many parts of the country which are normally becoming cool at this time of the year should encourage more discretionary driving, offsetting the price effect.

US GASOLINE NVENTORIES

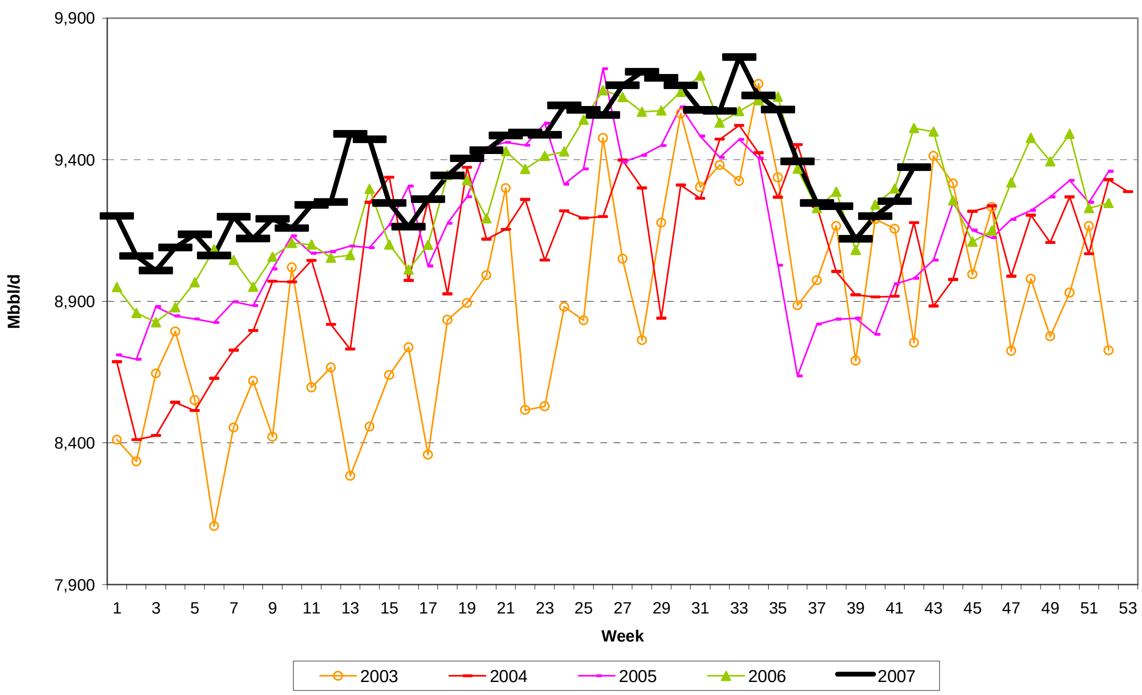
US Total Gasoline Ending Stocks 2003 - 2007



Source: Weekly Petroleum Status Report - DOE

US GASOLINE DEMAND

US Finished Gasoline Product Supplied 2003 - 2007



Source: Weekly Petroleum Status Report (DOE)

The issue of winter weather is of significant importance, since heating oil (and in Asia, kerosene) remains a significant market. The table below shows the experience in the past few years for these fuels, and the following one the range. (Seasonality in non-OECD countries is probably much less, but there is no reliable data.) A warm winter seems likely to reduce consumption by only about 0.5 mb/d, although consumer destocking can exacerbate the effect.

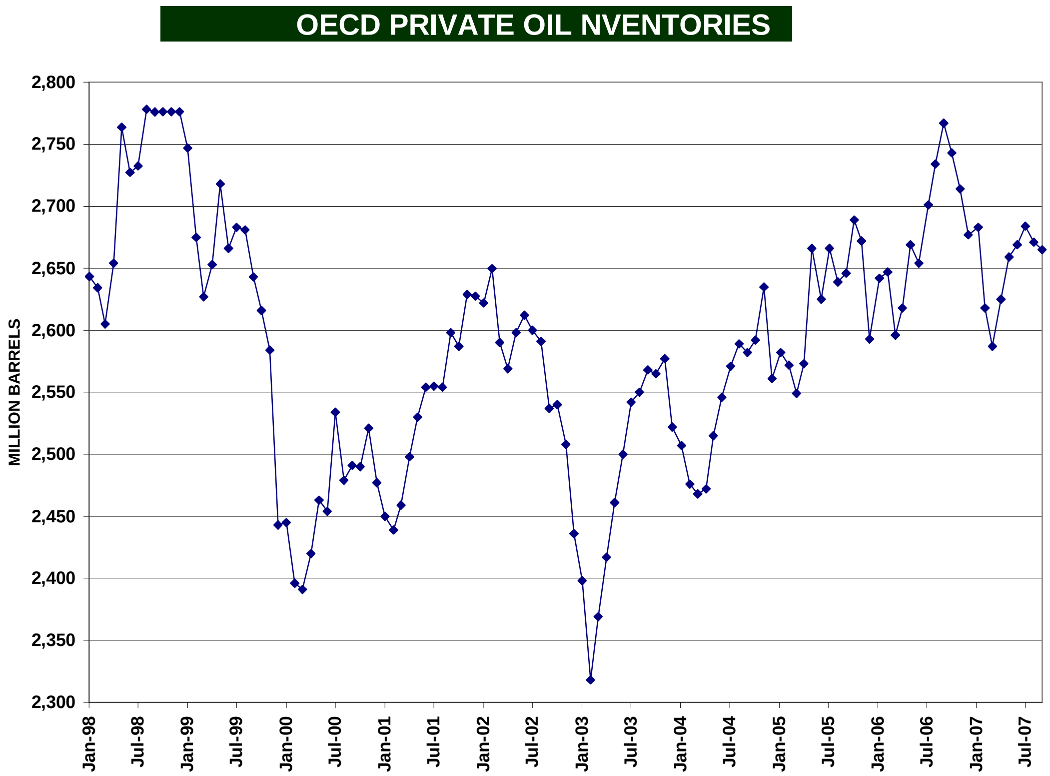
	Average Increase in Fuel Use	
	3rd Quarter to Fourth Quarter	Fourth Quarter to 1st Quarter
N. America	0.2	0.25
Europe	0.35	0
Asia	0.24	0.2
Total	0.79	0.45

	Uncertainty range for heating fuels demand	
	4Q	1Q
N. America	0.1	0.25
Europe	0.15	0.2
Asia	0.2	0.15
Total	0.45	0.6

Inventories

Initial reports suggest 3rd quarter inventories will only moderately. The switch from contango to backwardation will no doubt encourage that trend, although whether more oil ends up in independent or floating storage, or production is reduced in some Middle Eastern countries, remains to be seen. Alternatively, backwardation could encourage new production in order to take advantage of the current price, although the Saudis, who are most capable of responding in this manner, do not usually play the market so minutely.

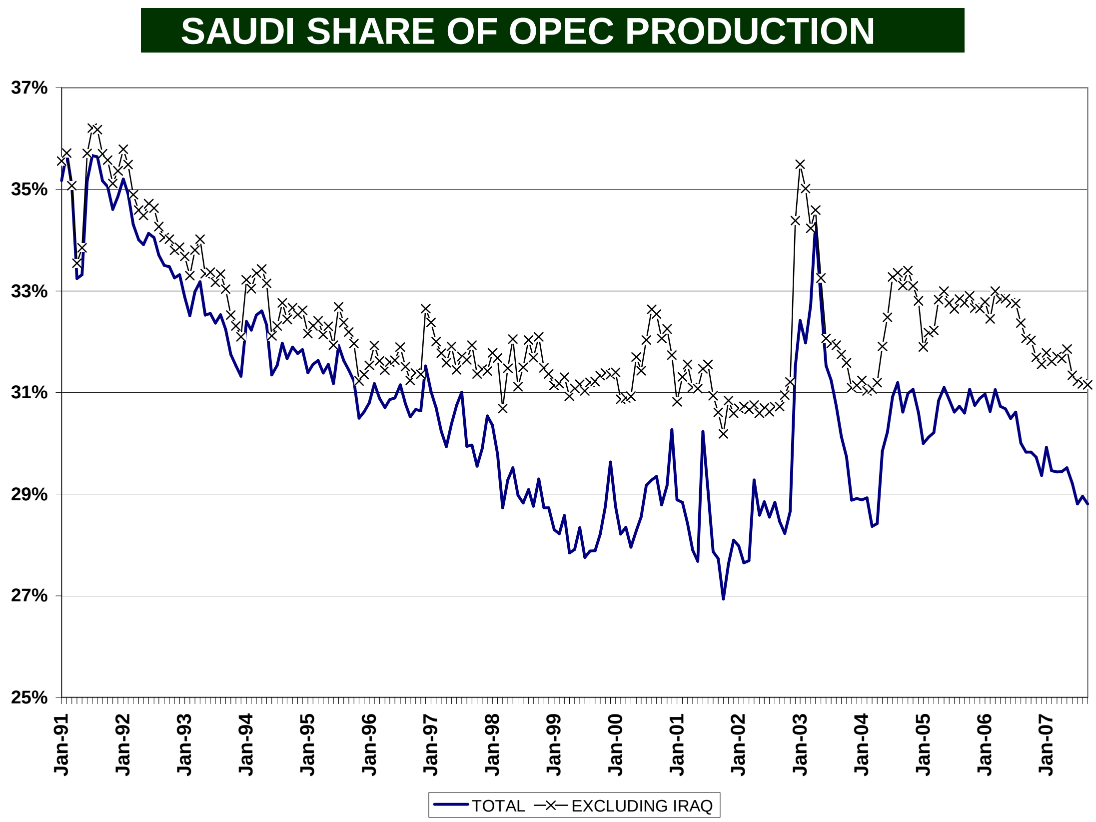
Product inventories continue to be the primary concern, and the ability of the US to rebuild its distillate inventories when European inventories are moderate. Without some improvement in the level of refinery utilization particularly in the US, the winter distillate markets could be tight.



Source: EIG and SEER, Inc.

OPEC: Price or barrels?

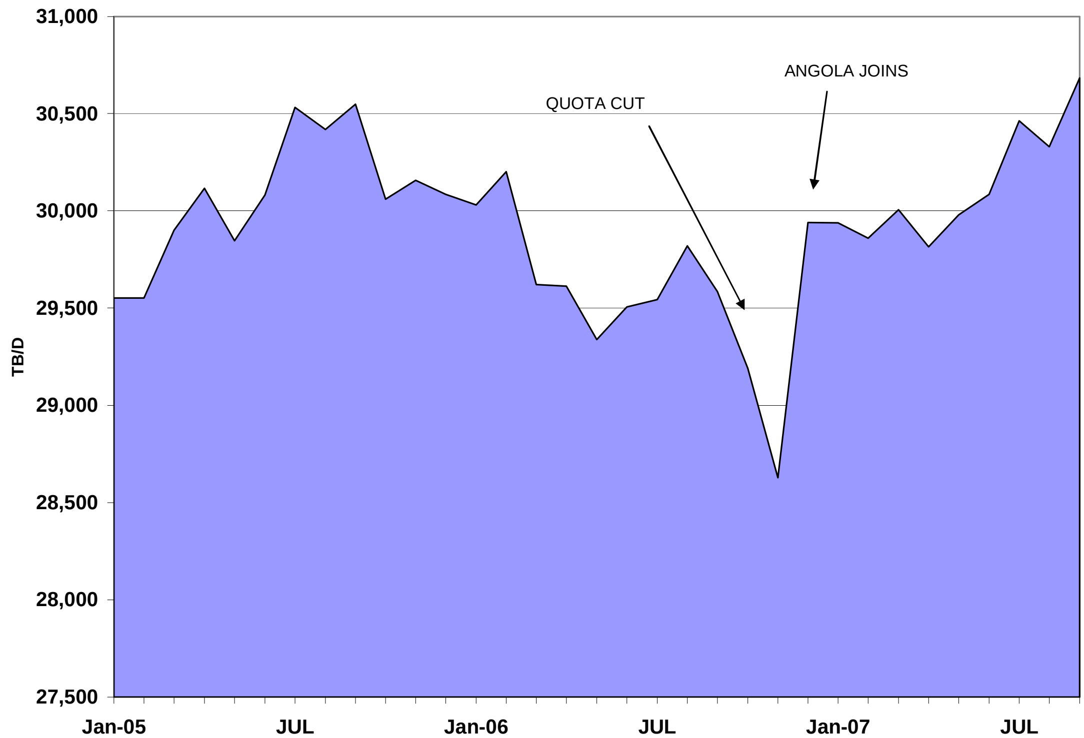
OPEC surprised most market watchers (including this one) by raising quotas 0.5 mb/d, at the behest of Saudi Arabia. This is a reversal of long-standing Saudi policy, which has long been concerned with avoiding inventory overhangs, such as occurred in 1978, 1980-, and 1998. Several recent quota reductions were made in response to perceived inventory builds, in fact, rather than price levels---although OPEC production itself is more responsive to prices. But, as the graph shows, the Saudi share of OPEC production has been dropping recently (though it remains at ‘comfortable’ levels) as other members raise production gradually.



Source: EIG and SEER. Excludes Angola.

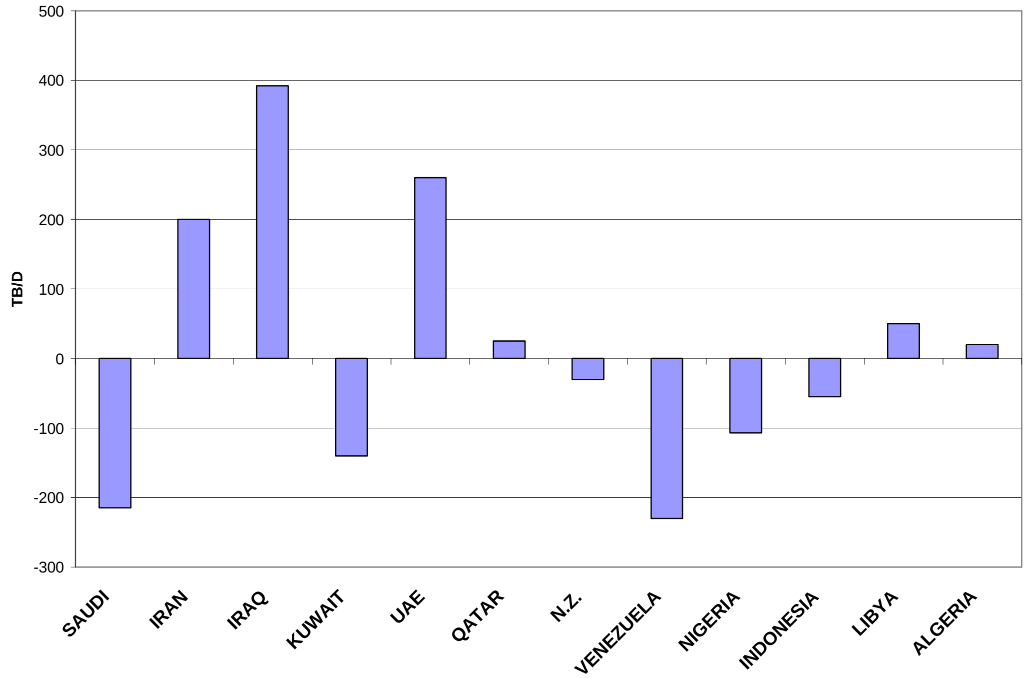
But the trend is definitely likely to worry Saudi planners. The drop should accelerate next year with nearly 1 mb/d from African members coming on-line, even excluding a possible return of Nigerian production. This could see a quick drop to as little as 26% share ((28-29% excluding Iraq). Given the likely balance for next year, the probability of the Saudis forcing other members to cut production sometime during the year seems very high.

RECENT OPEC PRODUCTION



This is especially true given that OPEC production has been creeping up of late. The figure below shows how, after the quota cut late last year, the members slowly began leaking more crude into the market, up about 600 tb/d from January to September, even excluding the increase in Angola. As the figure below shows, Iran and the UAE are the primary quota "violators".

OPEC PRODUCTION CHANGE SINCE NOVEMBER 2006



Should the market next year prove as weak as we anticipate, it could be difficult to rein in production if the Iranians are not willing to participate. If Iraqi and Nigerian production is increasing as mentioned earlier, that will be serious pressure on the Saudis to balance the market.

OPEC Balance, September 2007

COUNTRY	Production	Quota*	Over-Production	Capacity	Spare Capacity	Capacity Utilization
Saudi Arabia	8,335	8,777	-442	11,000	2,665	75.8%
Iran	3,900	3,941	-41	3,900	0	100.0%
Iraq	2,180			2,180	0	100.0%
Kuwait	2,170	2,492	-322	2,400	230	90.4%
UAE	2,635	2,621	14	2,700	65	97.6%
Qatar	830	836	-6	850	20	97.6%
Neutral Zone	525			600	75	87.5%
Venezuela	2,265	2,402	-137	2,265	0	100.0%
Nigeria	2,116	2,185	-69	2,700	584	78.4%
Indonesia	850	855	-5	850	0	100.0%
Libya	1,750	1,742	8	1,720	-30	101.7%
Algeria	1,380	1,379	1	1,380	0	100.0%
Angola	1,747			1,747	0	100.0%
Totals	30,683	27,230		34,292	3,609	89.5%
- Iraq	28,503	27,230	1,273	32,112	3,609	88.8%

*** Quotas are displayed as measured by OPEC's announced cuts versus the apparent production level used to estimate the cut. Current quotas are not related to pre-November 2006 quota levels. Overproduction is obviously a fuzzy term here.**

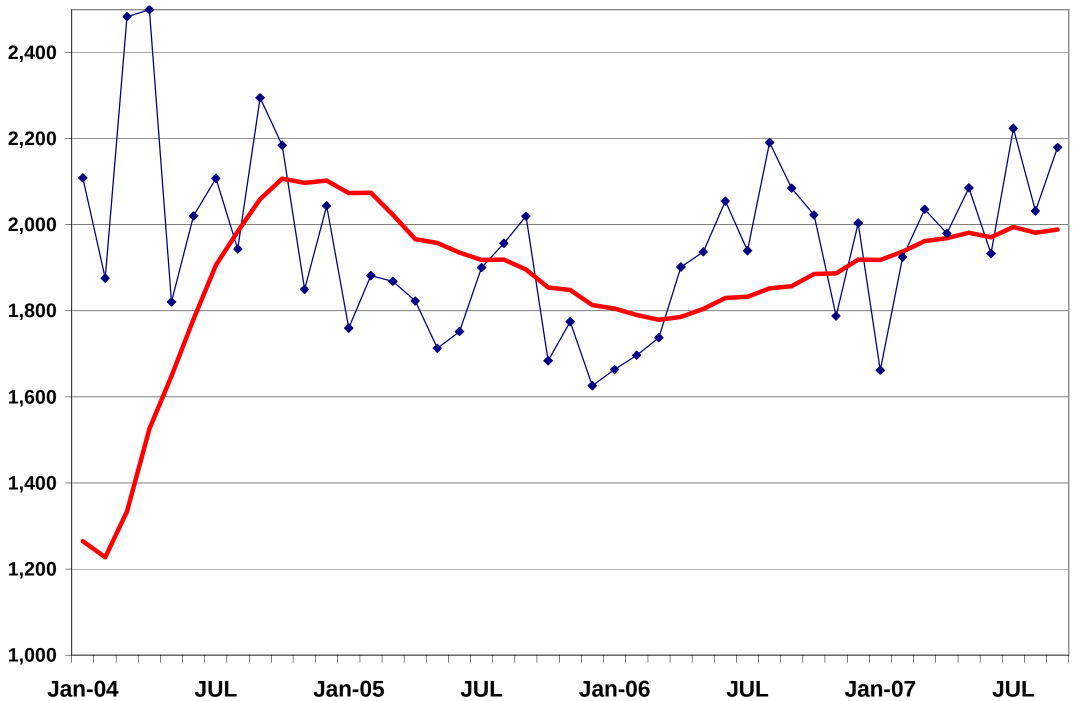
In Iran, the president has been replacing top officials in the ministry and NOC, increasing his control over the sector. Implications for the oil market should be minimal in the short-term, but longer term, the company could experience difficulties as the technocrats and the politicians clash over various issues, such as upstream investment, product prices, and so forth. It's something to keep an eye on, but not to get overly concerned about.

Iraq

The news from Iraq has been surprisingly positive, with signs of a growing coalition against the al Qaeda insurgents and efforts to rein in rogue elements of the Mahdi Army implying an increasing possibility of lower levels of violence in coming months. The moves against al Qaeda are important because al Qaeda has been primarily responsible for suicide bombing attacks against the government and Shi'ite neighborhoods and religious sites. This implies that tensions between Sunnis and Shi'ites could lessen as they work together against a common enemy and possibly, just possibly, address some of the political disagreements that separate them and are preventing the formation of an effective government.

More importantly for the oil market, the northern pipeline to Ceyhan has apparently been operating fairly regularly, and should see as much as 300 tb/d of exports for October. Recent news indicated that it was shut down again by sabotage, but not before Ceyhan storage tanks were full (containing upwards of 8 million barrels). Whether or not the latest attack is a resurgence of activity or will prove to be a more isolated instance of sabotage isn't clear yet.

IRAQI OIL PRODUCTION



Prices, Actual and Forecast

			High Scenario	Low Scenario
	WTI	RAC, Import	WTI	WTI
Jan-07	$54.51	49.51	$54.51	$54.51
Feb-07	$59.27	53.7	$59.27	$59.27
Mar-07	$60.56	56.26	$60.56	$60.56
Apr-07	$63.80	60.4	$63.80	$63.80
May-07	$63.46	61.44	$63.46	$63.46
Jun-07	$67.47	65.14	$67.47	$67.47
Jul-07	$74.12	70.65	$74.12	$74.12
Aug-07	$72.61	69.23	$72.61	$72.61
Sep-07	$79.91	$75.91	$79.91	$79.91
Oct-07	$85.00	$81.00	$85.00	$85.00
Nov-07	$80.00	$76.00	$92.00	$60.00
Dec-07	$75.00	$71.00	$87.50	$50.00
Jan-08	$60.00	$56.00	$85.00	$45.00
Feb-08	$58.00	$54.10	$82.50	$42.50
Mar-08	$56.50	$52.70	$80.00	$40.00
Apr-08	$54.00	$50.25	$75.00	$37.50
May-08	$52.00	$48.30	$72.50	$36.00
Jun-08	$52.00	$48.35	$70.00	$34.00
Jul-08	$54.00	$50.40	$68.00	$34.00
Aug-08	$54.00	$50.45	$65.00	$35.00
Sep-08	$52.00	$48.50	$65.00	$31.00
Oct-08	$48.00	$44.50	$62.00	$30.00
Nov-08	$47.50	$44.00	$62.00	$30.00
Dec-08	$46.00	$42.50	$64.00	$31.00
Jan-09	$48.00	$44.50	$66.00	$32.00
Feb-09	$47.50	$44.00	$68.00	$33.00
Mar-09	$46.00	$42.50	$68.00	$32.00
Apr-09	$44.00	$40.50	$68.00	$30.00
May-09	$45.00	$41.50	$72.00	$32.00
Jun-09	$46.00	$42.50	$74.00	$35.00
Jul-09	$48.00	$44.55	$76.00	$35.00
Aug-09	$50.00	$46.60	$78.00	$37.50
Sep-09	$52.00	$48.65	$72.00	$35.00
Oct-09	$50.00	$46.70	$72.00	$35.00
Nov-09	$48.00	$44.75	$70.00	$36.00
Dec-09	$46.00	$42.75	$70.00	$38.00
2007	$66.19	$65.85	$71.68	$65.89
2008	$52.83	$49.17	$70.92	$35.50
2009	$47.54	$44.13	$71.17	$34.21

Appendix B
Petroleum Outlook

Natural Gas SEER Monthly

Strategic Energy & Economic Research, Inc.
Ron Denhardt

January 21, 2008

Natural Gas SEER Monthly

SEER

Strategic Energy and Economic Research Inc.

January 21, 2008

In a Nutshell

By Ron Denhardt

Vice President, Natural Gas Services

- **Assuming little economic growth and Cooling Degree Days (CDD) 5% greater than normal, Henry Hub prices are expected to average $7.43 per MMBtu during the non-heating season. This compares to the forward market of $8.09 per MMBtu and an average price of $6.88 per MMBtu in 2007..**
- **Based on current weather forecasts, working gas storage is expected to end March at 1450 Bcf, 150 Bcf below last year. Still we expect working gas storage injections to be strong enough during the non-heating season to bring October storage close to last year's record of 3567 Bcf.**
- **There is substantial downside risk to prices from a possible recession.**

April - October Supply Demand Balance (Bcfd)

Sector	2008	2007	Change	%Change
Residential	5.6	5.5	0.0	0.8%
Commercial	4.7	4.7	0.0	0.8%
Industrial	17.3	17.2	0.0	0.3%
Electric Power	21.6	21.7	-0.1	-0.4%
Other	4.61	4.71	-0.1	-2.2%
Total Deliveries	53.8	53.9	-0.1	-0.1%
Dry Gas Production	53.3	52.2	1.0	2.0%
Canada & Mexico	7.7	8.4	-0.7	-8.8%
LNG	2.6	2.4	0.2	8.9%
Net Imports	10.3	10.8	-0.4	-4.4%
Supplements	0.2	0.2	0.0	1.7%
Total New Supply	63.8	63.2	0.6	0.9%
Storage Witddrawals	-9.9	-8.8	-1.2	11.9%
Total Primary Supply	53.8	54.4	-0.6	-1.1%

Storage (Bcf)

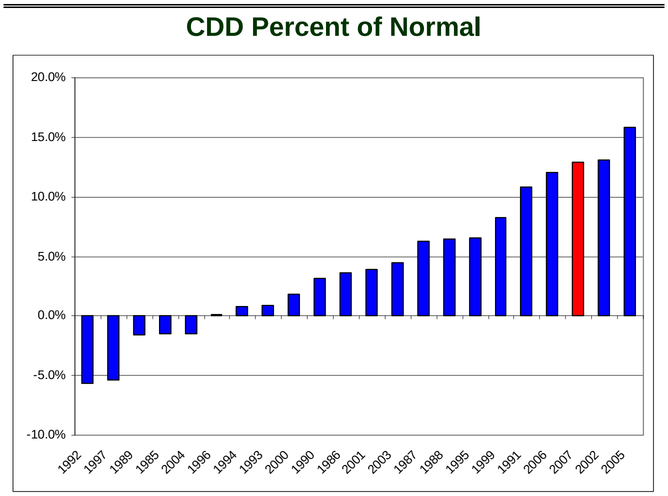
MAR 2008	1451	OCT 2008	3525
MAR 2007	1603	OCT 2007	3567
Difference	-152		-42

Based on current weather forecasts, working gas storage is expected to end March at 1450 Bcf or 150 Bcf below last year and 50 Bcf below last month's projection. The lower working gas storage is likely to support higher prices than projected a month ago. Still, we expect working gas storage injections to be strong enough during the non-heating season to bring October storage close to last years record 3567 Bcf. Storage injections are projected to be higher than last year because natural gas consumption is expected to be flat and supply should grow about .9% during the coming non-heating season.

The Rockies Express pipeline should be in full operation by late February and this will contribute to US production growing by two percent (1 Bcfd) over a year ago. A decline in Canadian imports will cause US pipeline imports to decline .7 Bcfd and LNG imports are projected to increase .2 Bcfd. Net supply should be about .6 Bcfd (.9% higher than last year).

The possibility or a recession or at least very slow economic growth in combination with more moderate temperatures than last year makes it likely that natural gas demand will be relatively flat. Many economists suggest that the US economy has already entered a recession while others suggest that a recession is not likely. At best the economic outlook is for slow growth. In addition, last year cooling degree days (CDD) were 12% above normal. (See the graph on the next page.). This year is expected to be warmer than normal but only 5 non-heating seasons in the last 23 had CDD 10% greater than normal. Our current projections assume CDD will be 5 percent greater than normal.

Assuming little economic growth and CDD 5% greater than normal, we are projecting Henry Hub prices to average $7.43 per MMBtu during the non-heating season. This compares to the forward market of $8.09 per MMBtu and an average price of $6.88 per MMBtu in 2007. In addition to uncertainties about economic growth, weather, and potential supply disruptions from geopolitical events and/or hurricanes, inelastic supply and demand makes the price uncertainty very high.



There is very little fuel oil switching capability during the summer and natural gas prices are so far below oil (1% New York Harbor residual fuel oil is expected to trade at close to $10 per MMBtu for the non-heating season) that oil prices are likely to have little influence on the fundamentals market. However, changes in oil prices could influence natural gas prices through the paper market. Production shut-ins could provide a floor on natural gas prices if there is a recession and/or milder than normal weather. Last year when Henry Hub prices were close to $6.00 per MMBtu, some production was shut in.

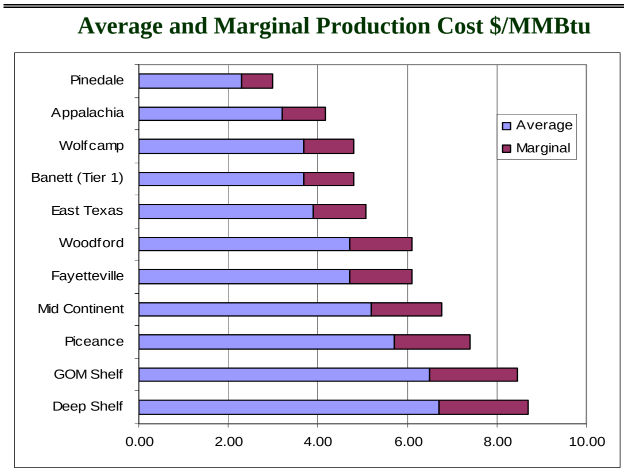
LNG imports were quite strong (2.6 Bcfd) with Henry Hub prices of $6.25 per MMBtu in August but dropped to 1.2 Bcfd in September with Henry Hub prices of approximately $6.00 per MMBtu. Yhe sharp drop in imports from August to September reflects seasonal changes in demand for LNG from Europe rather than the impact of lower natural gas prices. UK forward market prices for LNG are currently $1.30 per MMBtu higher than the US. Unless UK forward prices decline, US LNG imports could decline this year even at current prices.

OIL MARKET:

West Texas Intermediate Oil Prices are expected to average $85 per barrel in 2008. The major downside price risk is a slow down in world economic growth and the upside risk is a significant supply disruption. The International Energy Agency (IEA) and the Energy Information Agency (EIA) January reports project world oil consumption to grow 2.4% and 1.9% (1.6 million bbl/d respectively). Given that the US economy has either already entered a recession or at least faces very slow growth, we believe these projections are too high. Oil consumption grew 1.4% in 2006 and 1.2% in 2007. Still given the strong inventory draw in November (38 million barrel inventory draw versus a normal 3 million barrel) it is likely that production growth will be required to meet demand in 2008. Non-OPEC production is expected to rise by about 0.9 million bbl/d in 2008 and by 1.6 million bbl/d in 2009. This compares with a gain of 0.6 million bbl/d recorded last year. Most of this potential production growth is in Saudi Arabia, Iraq and Nigeria. Thus OPEC's production decisions will have a major impact on prices in 2008. OPEC's next two meetings are scheduled for February 1st and March 5th.

In 2009, higher non-OPEC production and planned additions to OPEC capacity should relieve some of the tightness in the market. The level of surplus production capacity is projected to grow from its current level of under 2 million barrels per day (bbl/d) to more than 4 million bbl/d by the end of 2009. The International Energy Agency projects that after 2010, OPEC spare capacity will decline and reach minimal levels by 2012 and prices are likely to increase substantially.

PRODUCTION COST



Source: Pickering Partners

The graph above shows estimated average and marginal production cost by region. (It was assumed the marginal production cost was 30% higher than the average production cost. This is part of the difficulty of modeling supply; it is necessary to know how the marginal production cost changes as a function of the level of production. Substantial production losses would take place at prices below $6.50 per MMBtu. Some estimates of the marginal cost of production in western Canada are as high as $8.00 per MMBtu.

Supply - Demand Balance

The tables below show the historic year over year changes in supply and disposition and US production. September production was 3.1% higher than the previous year.

Consumption Year over Year Change (Bcfd)

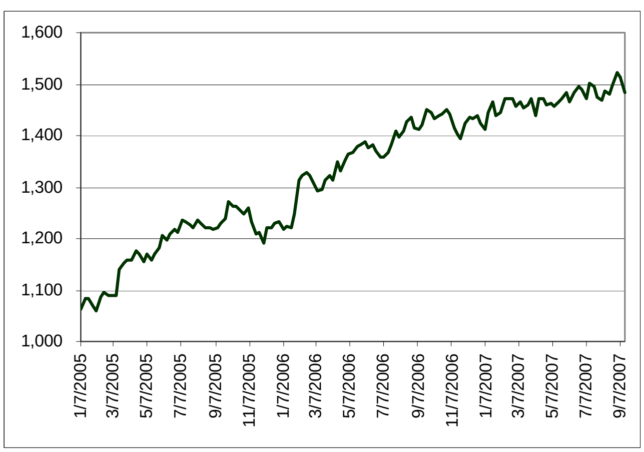
Month	Residen-tial	Com-mercial	Indus-trial	Power	Total
			2007-2006		
Jan	2.9	1.1	1.2	4.0	9.2
Feb	7.1	3.1	1.3	2.9	14.4
Mar	-0.3	0.0	-0.5	0.3	-0.4
Apr	1.8	1.1	-0.2	1.0	3.8
May	0.4	0.3	0.0	0.1	0.8
Jun	-0.1	0.0	0.0	-0.1	-0.1
Jul	0.1	0.0	0.1	-3.3	-3.1
Aug	0.1	0.0	0.1	5.4	5.7
Sep	-0.3	-0.2	0.2	4.4	4.1
Oct	-1.6	-0.5	0.7	0.0	-1.4

Supply and Disposition Year over Year Change (Bcfd)

Month	Marketed Produciton	Dry Production	Net Imports	Storage With-drawals	Balancing Item	Con-sumption
			2007-2006			
Jan	0.8	1.0	0.7	13.3	-5.7	9.4
Feb	0.8	1.0	1.9	8.4	3.4	14.8
Mar	1.4	1.5	1.5	-5.1	1.8	-0.4
Apr	1.3	1.4	1.7	4.7	-3.9	3.9
May	0.8	0.8	1.0	-2.7	1.8	0.9
Jun	1.0	1.1	1.3	-2.4	-0.1	0.0
Jul	1.4	1.5	1.3	-4.8	-1.1	-3.0
Aug	1.4	1.5	1.7	2.2	0.5	5.9
Sep	1.4	1.5	0.5	2.2	0.1	4.3
Oct	1.4	1.5	0.6	-4.0	0.6	-1.3

The table below shows the US natural gas rig count.

US Natural Gas Rig Count



The table below shows projected US production

. US Natural Gas Production (Bcfd)

	2006	2007	04-05	05-06	06-07
JAN	49.8	50.8	-2.9%	-1.2%	2.1%
FEB	49.6	50.6	-0.3%	-3.0%	1.9%
MAR	50.1	51.6	-0.5%	-3.6%	3.0%
APR	50.3	51.6	-1.5%	-2.0%	2.8%
MAY	50.5	50.9	-1.6%	0.0%	0.7%
JUN	51.1	52.3	-1.3%	0.2%	2.2%
JUL	50.9	52.4	-2.5%	1.1%	3.0%
AUG	50.9	52.4	-3.3%	2.4%	3.0%
SEP	51.2	52.8	-9.3%	14.3%	3.1%
OCT	51.2		-9.4%	12.0%	
NOV	51.1		-5.2%	6.0%	
DEC	50.7		-3.1%	3.3%	
AVE YTD	50.6	51.7	-3.4%	0.9%	2.4%

Production will receive a boost from the Independence Project that is expected to flow 50 million cubic feet per day by next week and 1 billion cubic feet per day by the end of the year. The Independence Hub platform, which will be the world's deepest production facility in a water depth of 7,920 feet in Mississippi Canyon Block 920, 110 miles from the Mississippi River Delta. Barnett Shale has already reached 1.7 Bcf/d and is continuing to grow. Energy Transfer Partners (ETP) has completed connecting its Barnett Shale pipeline system to several major interstate and intrastate pipelines. ETP installed 243 miles of 42-inch pipe that will connect its Barnett Shale producers and its Bethel storage facility to pipelines at the Carthage pipeline hub. Substantial growth is expected evolving plays, including the Fayetteville and Woodville shales, the Jonah field, the Pinedale and Anticline tight sands, and the Wyodak and Big George coalbed methane plays.

The Rockies Express Pipeline system will allow more gas to flow from Colorado and Wyoming to the Midwest and Northeast. The initial segment of REX Phase I went into service in February 2006 with completion of the pipeline segment from Uinta-Piceance Colorado to Wyoming Interstate Pipeline and Colorado Interstate Gas at Wamsutter, Wyoming. The segment completed in February 2007 extended REX east to the Cheyenne Hub.

REX Phase II is scheduled should be flowing close to capacity by late February. The pipeline will connect REX Phase I to Panhandle Eastern Pipeline, near Mexico, Mo. Phase II includes construction of 713 miles of pipeline, several compressor stations along both it and the Phase I pipeline, and an additional supply lateral to Echo Springs, Wyo. Phase II will have the capacity to deliver 1.6 Bcfd to its Missouri terminus. Rex Phase III, planned for completion in 2008 and 2009, will extend the pipeline first to Lebanon and then to Clarington, Ohio, increasing overall capacity to 1.8 Bcfd. However, there are concerns that it will now slip by eight months because of delays obtaining an Environmental Impact Statement.

LNG

During 2008, world LNG supply is expected to grow 25% (6.8 Bcfd) to 36.8 Bcfd. Gross LNG imports to U.S. markets should be approximately 2.6 Bcfd in 2008 . The U.S. will be directly impacted by Sakhalin, Tangguh, Yemen and RasGas liquefaction terminals (owners of this gas have contracts with US / Mexico regas facilities). In addition, the U.S. will be indirectly impacted by all cargoes to Europe via QatarGas. The following projects are scheduled for 2008.

- Sakhalin II – Russia's 1.3 Bcfd facility. Plant will supply Costa Azul (Mexico) and Japan with gas. As LNG imports increase to Mexico, U.S. exports could be lower.
- Northwest Shelf Train 5 – Australia's 0.6 Bcfd facility. Online 4Q 2008 will supply Asia Pacific
- Tangguh – Indonesia's 1.0 Bcfd facility will supply Costa Azul (Mexico), Fujian LNG (China), K-Power (Korea) and POSCO (Korea)
- QatarGas II Train 4 and Train 5 – 2 Bcfd will supply U.K. and Europe
- Yemen LNG – 0.9 Bcfd will supply U.S., U.K. and Kogas (Korea).
- RasGas III Train 6 – 1.0 Bcfd will supply U.S. and Asian markets.

U.S. LNG regasification capacity will increase 6.4 Bcfd in 2008, essentially doubling total import capability to 12.4 Bcfd. The schedule for regas facilities are:

- Cheniere's Sabine Pass (2.6 Bcfd) online March 2008.
- Freeport LNG (1.5Bcfd) online March 2008.
- Dominion's Cove Point expansion to 1.8 Bcfd (from 1 Bcfd) online during the second half of 2008.
- Sempra's Cameron initial phase 1.5 Bcfd online second half of 2008.

Canada and Mexico will each add 1 Bcfd of regasification capacity during 2008.

- Respol's Canaport (Canada) 1 Bcfd online toward the end of 2008.
- Sempra's Costa Azul (Mexico) 1.1 Bcfd by middle of 2008.

Canada

WCSB Canadian field receipts are about .4 Bcfd below 2006.

Canadian Exports and WCSB Field Receipts

Bcfd

	Net Canadian Exports			W. Canadian Field Receipts			
Month	2007	2006-2005	2007-2006	2007	2008	2007 - 2006	2008-2007
Jan	9.5	-1.1	1.0	16.7	16.2	-0.4	-0.4
Feb	10.2	-0.7	1.8	16.8		-0.2	
Mar	8.4	-0.1	-0.3	16.9		-0.2	
Apr	8.4	0.6	-0.4	17.1		-0.4	
May	8.2	0.3	-0.2	16.7		-0.4	
Jun	8.7	0.6	0.1	16.2		-0.3	
Jul	9.3	0.2	-0.3	16.4		-0.3	
Aug	10.0	-0.2	0.5	16.5		-0.7	
Sep	9.4	-0.8	0.7	16.3		-0.4	
Oct	10.1	-0.8		16.4		-0.5	
Nov		-1.1		16.2		-0.3	
Dec		-1.5		16.0		-0.4	
Ave YTD	9.2	-0.2	0.3	16.5		-0.4	
% Ch	5.1%			-2.5%			

Source:National Energy Board, Pipeline Receipt data,

US Consumption

Residual Fuel Oil Product Supplied (Bcfd Equivalent)

Residual Fuel Oil Product Supplied (Bcfd Equivalent)

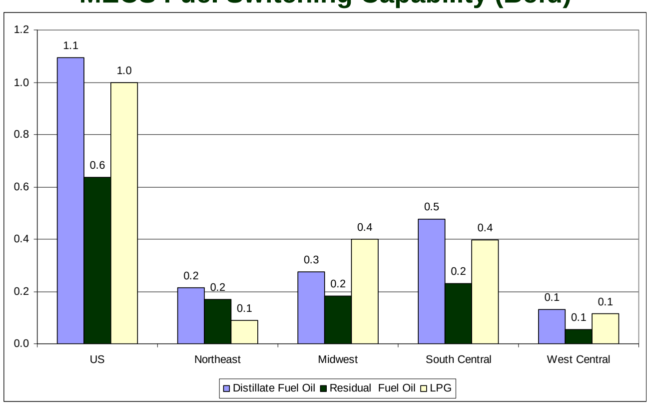
	2006	2007	05-04	06-05	07-06
JAN	5.7	5.2	0.2	-0.5	-0.5
FEB	*4.5*	5.2	-0.9	-0.6	0.7
MAR	5.3	4.2	-0.2	0.1	-1.1
APR	*4.0*	4.7	-0.3	-0.7	0.7
MAY	*3.7*	4.3	-0.1	-0.9	0.6
JUN	*3.7*	4.1	-0.1	-1.3	0.5
JUL	*4.1*	4.7	0.0	-1.4	0.6
AUG	*4.7*	4.0	1.7	-1.7	-0.7
SEP	*3.3*		*1.5*	-3.0	
OCT	3.7		*0.8*	-2.3	
NOV	3.2		*0.7*	-2.8	
DEC	4.5		*0.7*	-1.8	
AVE	4.2		0.3	-1.4	

Italics are estimates.

The data above shows residual fuel oil "product supplied". Many analysts use this data to measure "fuel switching" but inventory changes can make product supplied different than consumption. Also, bunker fuel accounts for a significant portion of this residual fuel oil consumption. Consequently, this data has only limited value in understanding fuel switching.

The 2002 Manufacturing Energy Consumption Survey (MECS)[1] asked industrial customers about their fuel switching *capability*. However, the study did not establish how much fuel switching actually takes place or how long fuel switching could take place. Further, tightening environmental regulations have reduced fuel switching capability since the study was conducted. The graph below summarizes the results of the survey. The estimated fuel switching capability has been reduced substantially from the 1998 survey. The 1998 survey indicated fuel switching capability of approximately 1.5 Bcfd for distillate, residual fuel oil, and liquefied petroleum gas (LPG). The sharpest reduction in fuel switching capability was in residual fuel oil. The estimated residual fuel oil switching capability was reduced by .9 Bcfd to .6 Bcfd. Since reported residual fuel oil consumption on an annual basis is only .5 Bcfd, it is unlikely that even .6 Bcfd could be maintained for a sustained time period. Some more recent but less extensive surveys indicate that industrial fuel switching to residual fuel oil could be a little as .15 Bcfd.

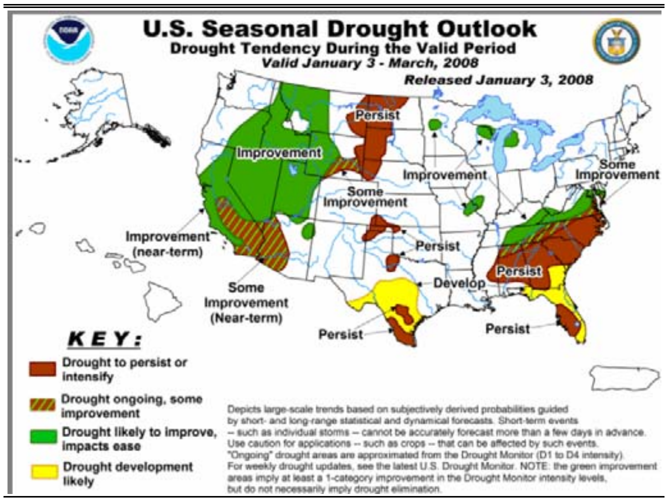
MECS Fuel Switching Capability (Bcfd)



In the electric power sector there is approximately 1.4 Bcfd of fuel switching capability to residual fuel oil, during the winter and about 2.7 Bcfd, on a peak day. Distillate fuel switching capability is approximately 1 Bcfd on a peak day and less than .6 Bcfd on average during the winter. A recent study by the Electric Power Institute indicated only about 76 out of 410 combined cycle units used distillate fuel oil. 30 combined cycle units account for 90% of distillate fuel oil consumption. All but 6 of these units were constructed as qualified facilities2 before 1998.

The power plants that can burn residual fuel oil are steam units and are about 30% less efficient than gas combined cycle units. If the gas combined cycle unit capacity is fully utilized, then gas and residual fuel units compete on the $/MMBtu basis, after a penalty adjustment to residual fuel oil for emissions. However, if gas combined cycle units compete with steam units, residual fuel oil must be priced 30% less than gas on a Btu basis**.**

Drought Outlook



The forecast continues to indicate persisting drought across the Southeast through March 2008, with the odds favoring expansion into Florida and southeastern Georgia. Precipitation totals for 2007 were around 15 inches below normal in many of the exceptional drought areas that stretched across portions of Alabama, Georgia, and the Carolinas. Despite recent rainfall, the ongoing La Nina is expected to bring abnormally mild and dry weather to the region for most of the winter. In contrast, at least some degree of improvement is expected from Tennessee and Kentucky northeastward through the Middle Atlantic States, including some areas of exceptional drought in the central and western stretches of this region. Small areas of moderate drought in the

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[1] Energy Information Agency, *Manufacturing Energy Consumption Survey*, 1998 http://www.eia.doe.gov/emeu/mecs/mecs2002/data02/shelltables.html

[2] QF Qualified facilities were power plants constructed by non-regulated entities that contracted with regulated electric utilities for the sale of their power. Under this regime the plants were often required by electric utilities to have an alternate fuel. After 1998 merchant plants sold electric power directly, and few of these plants have fuel switching capability.

Midwest should be eliminated, but drought relief is not expected in drought areas covering parts of the western Plains from the Dakotas to northern Texas. Farther south, recently-developed drought is expected to persist in southern Texas, eventually expanding to cover a large portion of central and southern Texas by early spring. Meanwhile, drought improvement should continue across the interior Pacific Northwest and the northern and central Rockies. For the first half of January 2008, a series of storms is poised to bring heavy to excessive precipitation to much of California and, to a lesser extent, other areas across the Southwest and southern Rockies. As a result, drought improvement, at least in the near term, is forecast for western California and the Sierra Nevada, with some improvement anticipated in other parts of the Southwest and interior California. The forecast continues to show persisting

Economic Outlook

2005-06	*3.3%*	*3.2%*	*2.4%*	*2.6%*	*2.9%*
2006-07	*1.5%*	*1.9%*	*2.8%*	*2.8%*	*0.4%*
2007-08	*3.1%*	*2.6%*	*1.7%*	*1.8%*	*2.3%*

Annual Rates from Previous Quarter

2006	*4.8%*	*2.4%*	*1.1%*	*2.1%*	*2.6%*
2007	*0.6%*	*3.8%*	*4.9%*	*2.0%*	*2.8%*
2008	*1.7%*	*1.6%*	*1.6%*	*2.4%*	*1.8%*

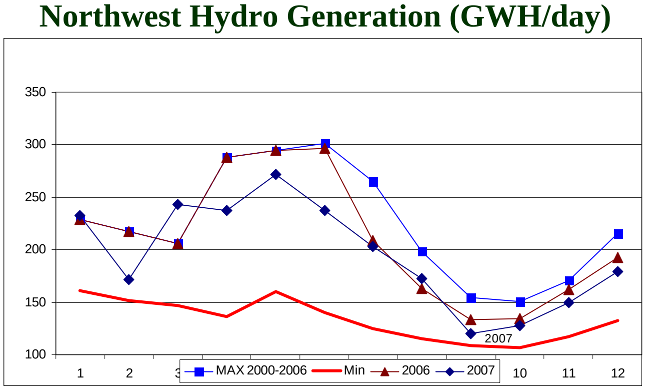
GDP Deflator (2000 =100)

2006	115.50	116.35	117.03	117.53	116.57
2007	118.75	119.53	119.84	119.88	119.50
2008	119.94	119.77	120.08	121.32	120.27

Pct Change Previous Period

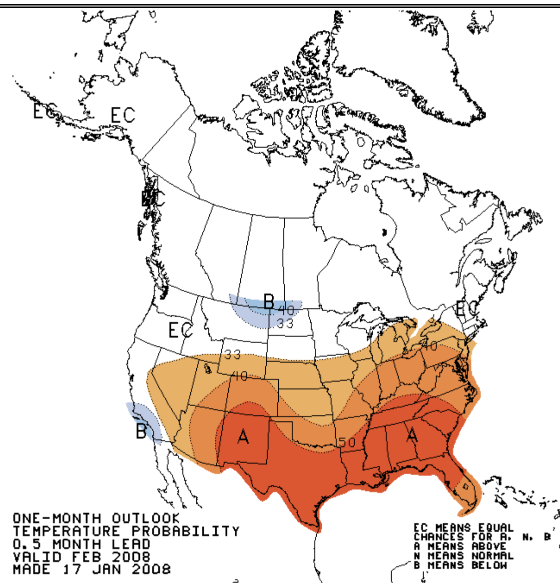
2006	*3.4%*	*3.5%*	*2.4%*	*1.7%*	*2.8%*
2007	*4.2%*	*2.6%*	*1.0%*	*2.0%*	*2.5%*
2008	*1.0%*	*0.2%*	*0.2%*	*1.2%*	*0.7%*

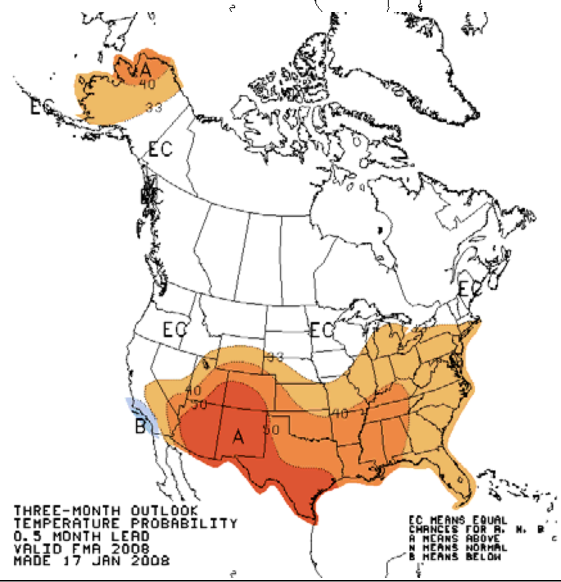
Northwest Hydro Generation (GWH/day)



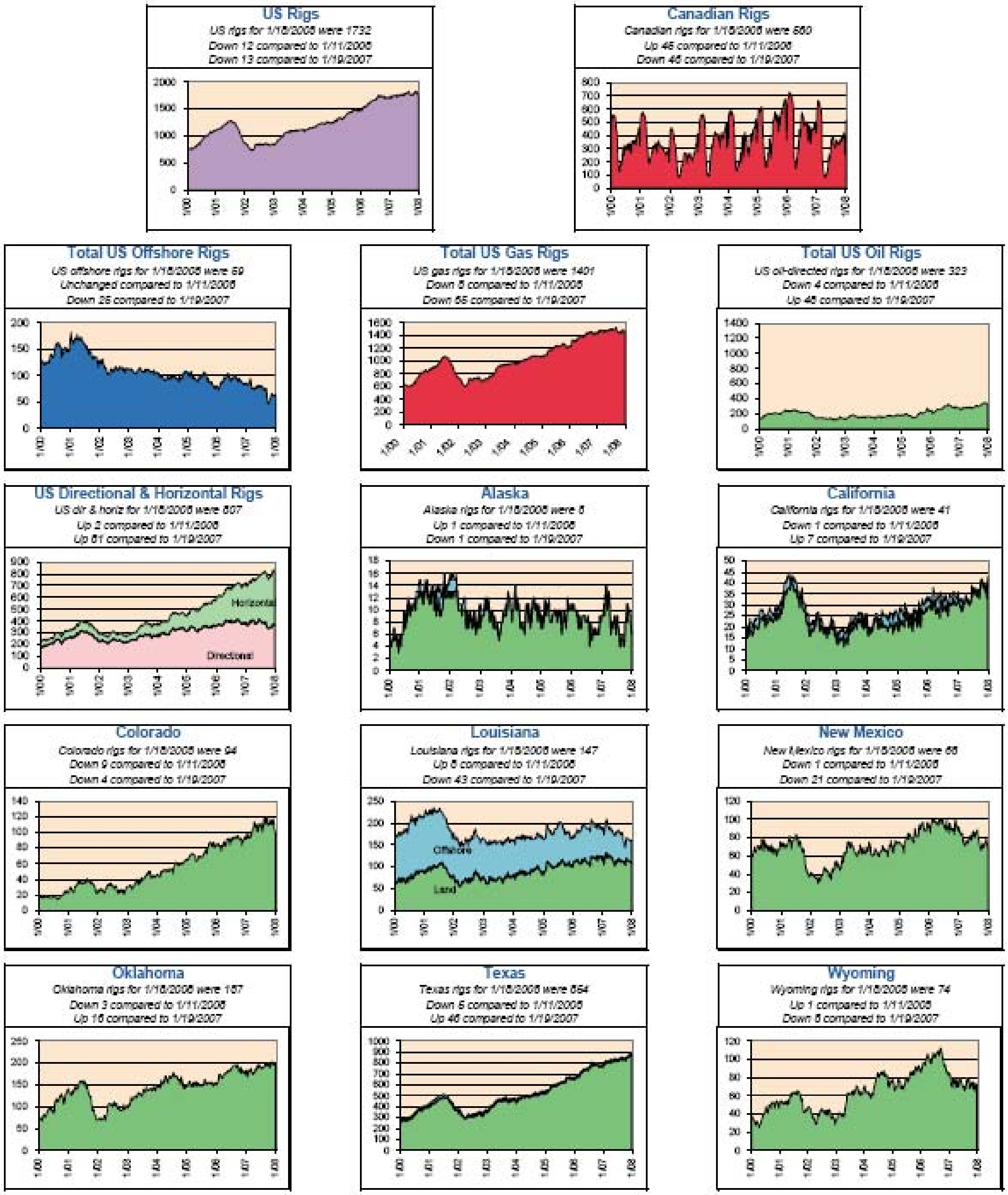
Weather

Almost all forecasters are projecting a warmer than normal weather in through April.





Baker Hughes North American Rig Report for 1/18/2008



Existing and Proposed North American LNG Terminals

CONSTRUCTED

A. Everett, MA : 1.035 Bcfd (DOMAC - SUEZ LNG)
B. Cove Point, MD : 1.0 Bcfd (Dominion - Cove Point LNG)
C. Elba Island, GA : 1.2 Bcfd (El Paso - Southern LNG)
D. Lake Charles, LA : 2.1 Bcfd (Southern Union - Trunkline LNG)
E. Gulf of Mexico: 0.5 Bcfd (Gulf Gateway Energy Bridge - Excelerate Energy)

APPROVED BY FERC

1. Hackberry, LA : 1.8 Bcfd (Cameron LNG - Sempra Energy)
2. Bahamas : 0.84 Bcfd (AES Ocean Express)*
3. Bahamas : 0.83 Bcfd (Calypso Tractebel)*
4. Freeport, TX : 1.5 Bcfd (Cheniere/Freeport LNG Dev.)
5. Sabine, LA : 2.6 Bcfd (Sabine Pass Cheniere LNG)
6. Corpus Christi, TX: 2.6 Bcfd (Cheniere LNG)
7. Corpus Christi, TX : 1.1 Bcfd (Vista Del Sol - ExxonMobil)
8. Fall River, MA : 0.8 Bcfd (Weaver's Cove Energy/Hess LNG)
9. Sabine, TX : 2.0 Bcfd (Golden Pass - ExxonMobil)
10. Corpus Christi, TX: 1.0 Bcfd (Ingleside Energy - Occidental Energy Ventures)**
11. Logan Township, NJ : 1.2 Bcfd (Crown Landing LNG - BP)
12. Port Arthur, TX: 3.0 Bcfd (Sempra Energy)
13. Cove Point, MD : 0.8 Bcfd (Dominion)
14. Cameron, LA: 3.3 Bcfd (Creole Trail LNG - Cheniere LNG)
15. Sabine, LA: 1.4 Bcfd (Sabine Pass Cheniere LNG - Expansion)
16. Freeport, TX: 2.5 Bcfd (Cheniere/Freeport LNG Dev. - Expansion)
17. Hackberry, LA : 0.85 Bcfd (Cameron LNG - Sempra Energy - Expansion)
18. Pascagoula, MS: 1.5 Bcfd (Gulf LNG Energy LLC)
19. Pascagoula, MS: 1.3 Bcfd (Bayou Casotte Energy LLC - ChevronTexaco)
20. Port Lavaca, TX: 1.0 Bcfd (Calhoun LNG - Gulf Coast LNG Partners)
21. Elba Island, GA: 0.9 Bcfd (El Paso - Southern LNG)

APPROVED BY MARAD/COAST GUARD

22. Port Pelican: 1.6 Bcfd (Chevron Texaco)
23. Offshore Louisiana : 1.0 Bcfd (Main Pass McMoRan Exp.)
24. Offshore Boston: 0.4 Bcfd (Neptune LNG - SUEZ LNG)
25. Offshore Boston: 0.8 Bcfd (Northeast Gateway - Excelerate Energy)

ANADIAN APPROVED TERMINALS

6. St. John, NB : 1.0 Bcfd (Canaport - Irving Oil/Repsol)
7. Kitimat, BC: 1.0 Bcfd (Kitimat LNG - Galveston LNG)
8. Rivière-du- Loup, QC: 0.5 Bcfd (Cacouna Energy - TransCanada/PetroCanada)
9. Quebec City, QC : 0.5 Bcfd (Project Rabaska - Enbridge /Gaz Met/Gaz de France)

EXICAN APPROVED TERMINALS

0. Altamira, Tamulipas : 0.7 Bcfd (Shell/Total/Mitsui)
1. Baja California, MX : 1.0 Bcfd (Energia Costa Azul - Sempra Energy)
2. Baja California, MX : 1.5 Bcfd (Energy Costa Azul - Sempra Energy - Expansion)
3. Manzanillo, MX: 0.5 Bcfd

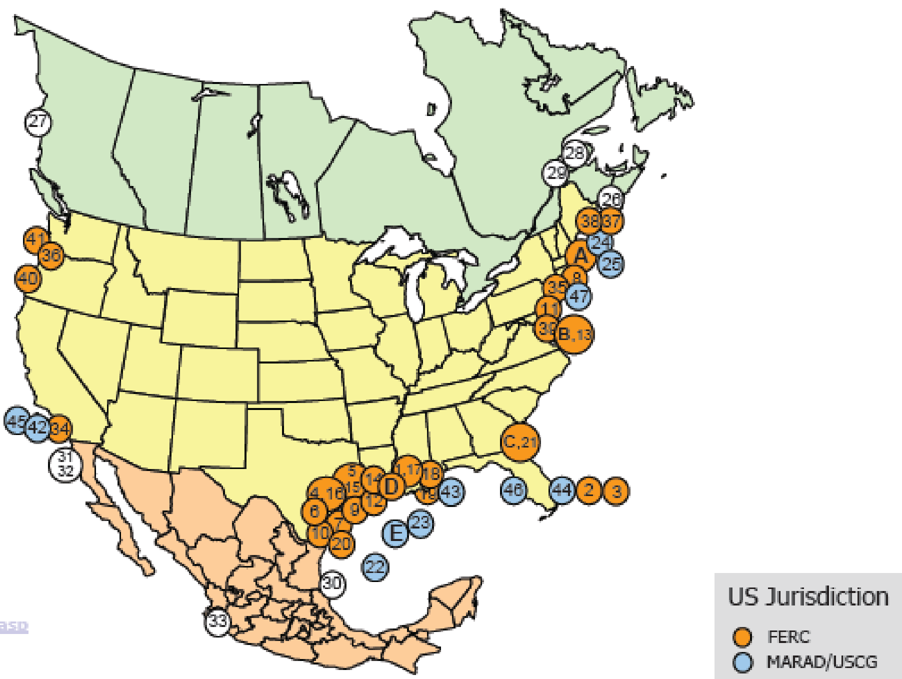
ROPOSED TO FERC

4. Long Beach, CA : 0.7 Bcfd, (Mitsubishi/ConocoPhillips - Sound Energy Solutions)
5. LI Sound, NY: 1.0 Bcfd (Broadwater Energy - TransCanada/Shell)
6. Bradwood, OR: 1.0 Bcfd (Northern Star LNG - Northern Star Natural Gas LLC)
7. Pleasant Point, ME : 2.0 Bcfd (Quoddy Bay, LLC)
8. Robbinston, ME: 0.5 Bcfd (Downeast LNG - Kestrel Energy)
9. Baltimore, MD: 1.5 Bcfd (AES Sparrows Point – AES Corp.)
0. Coos Bay, OR: 1.0 Bcfd (Jordan Cove Energy Project)
1. Astoria, OR: 1.5 Bcfd (Oregon LNG)

ROPOSED TO MARAD/COAST GUARD

2. Offshore California : 1.4 Bcfd, (Clearwater Port LLC - NorthernStar NG LLC)
3. Gulf of Mexico: 1.4 Bcfd (Bienville Offshore Energy Terminal - TORP)
4. Offshore Florida: 1.9 Bcfd (SUEZ Calypso - SUEZ LNG)
5. Offshore California: 1.2 Bcfd (OceanWay - Woodside Natural Gas)
6. Offshore Florida: 1.2 Bcfd (Hoëgh LNG - Port Dolphin Energy)
7. Offshore New York: 2.0 Bcfd (Safe Harbor Energy - ASIC, LLC)

Existing and Proposed North American LNG Terminals



CRUDE OIL, PETROLEUM PRODUCT AND COMPETITIVE GAS PRICES

	Crude Oil ($/bbl)		$/MMBtu: Petroleum Product Spot Prices New York Harbor			Oil Price to NE Generators Less Spot Gas Price New England			Oil Price to NE Generators Less Efficiency Adjusted	
	WTI	RAC	Distillate	No.6 Resid 0.3%S	No.6 Resid 1.0%S	Distillate	No.6 Resid 0.3%S	No.6 Resid 1.0%S	No.6 Resid 0.3%S	No.6 Resid 1.0%S
2007										
Jan	54.51	50.74	11.02	6.85	5.95	4.06	-0.11	-1.01	2.47	1.57
Feb	59.28	54.42	11.97	7.78	6.32	1.82	-2.37	-3.83	1.33	-0.13
Mar	60.44	56.80	12.53	8.19	6.68	4.73	0.39	-1.12	3.27	1.76
Apr	63.98	60.65	13.18	8.38	7.28	5.11	0.31	-0.79	3.29	2.18
May	63.46	61.64	13.39	9.03	8.23	8.19	1.17	0.37	4.07	3.27
Jun	67.49	65.07	14.21	9.22	8.50	7.95	1.61	0.89	4.42	3.70
Jul	74.12	71.15	14.81	9.59	8.79	8.35	3.13	2.33	5.54	4.74
Aug	72.36	69.46	14.34	10.08	8.73	7.79	3.53	2.18	5.97	4.62
Sep	79.91	73.39	15.35	10.08	9.02	9.25	3.98	2.92	6.26	5.20
Oct	85.80	78.00	16.13	11.06	9.60	9.39	4.32	2.86	6.83	5.37
Nov	94.77	87.77	17.31	11.82	10.54	9.83	4.34	3.06	7.11	5.82
Dec	88.50	84.25	18.19	12.56	11.21	8.16	2.53	1.18	6.18	4.83
2008										
Jan	90.00	85.50	17.27	11.85	10.49	9.07	3.65	2.29	6.67	5.30
Feb	89.00	83.60	17.19	11.80	10.50	9.04	3.65	2.35	6.65	5.35
Mar	88.11	83.11	17.34	11.93	10.60	10.12	4.70	3.38	7.38	6.05
Apr	83.70	78.70	16.23	11.15	9.90	9.03	3.95	2.69	6.62	5.36
May	82.87	77.87	16.13	11.08	9.85	9.02	3.97	2.74	6.61	5.38
Jun	82.04	77.04	16.01	11.00	9.78	8.81	3.80	2.58	6.47	5.24
Jul	81.22	76.22	15.80	10.86	9.64	8.65	3.70	2.49	6.36	5.14
Aug	80.41	75.41	15.66	10.76	9.56	8.59	3.69	2.49	6.31	5.11
Sep	79.60	74.60	15.51	10.66	9.47	9.55	4.70	3.51	6.93	5.74
Oct	78.81	73.81	15.35	10.54	9.37	9.15	4.34	3.17	6.66	5.49
Nov	78.02	73.02	15.20	10.44	9.28	7.93	3.17	2.01	5.86	4.70
Dec	77.24	72.24	15.04	10.34	9.18	7.42	2.71	1.56	5.53	4.37
2009										
Jan	79.60	79.60	15.50	10.65	9.46	6.75	1.90	0.71	5.11	3.92
Feb	79.52	74.47	15.49	10.64	9.45	6.85	2.01	0.82	5.18	3.99
Mar	79.44	74.37	15.47	10.63	9.45	7.61	2.77	1.58	5.67	4.48
Apr	78.65	73.55	15.32	10.53	9.35	8.10	3.30	2.13	5.98	4.81
May	77.86	72.74	15.17	10.42	9.26	8.05	3.30	2.14	5.94	4.78
Jun	77.08	71.93	15.01	10.32	9.16	7.83	3.13	1.98	5.79	4.64
Jul	76.31	71.14	14.86	10.21	9.07	7.61	2.96	1.82	5.65	4.51
Aug	75.55	70.35	14.71	10.11	8.98	7.42	2.81	1.69	5.52	4.39
Sep	75.17	69.94	14.64	10.06	8.94	7.38	2.79	1.67	5.49	4.36
Oct	74.79	69.54	14.57	10.01	8.89	7.21	2.65	1.53	5.37	4.26
Nov	74.42	69.14	14.50	9.96	8.85	6.77	2.23	1.12	5.09	3.97
Dec	74.05	68.75	14.42	9.91	8.80	6.38	1.87	0.76	4.83	3.73
2002	26.12	24.56	5.31	4.08	3.57	1.97	0.74	0.23	2.06	1.56
2003	31.12	28.60	6.09	5.23	4.43	0.12	-0.74	-1.54	1.50	0.70
2004	41.44	36.91	8.09	7.72	4.43	1.41	-1.22	-2.25	1.27	0.24
2005	56.49	50.33	11.78	8.25	6.75	3.15	-1.08	-2.57	2.33	0.84
2006	66.02	60.05	13.00	8.16	7.36	5.96	1.12	0.32	3.74	2.93
2007	72.05	67.78	14.37	9.55	8.40	7.05	1.90	0.75	4.73	3.58
2008	82.58	77.59	16.06	11.03	9.80	8.86	3.84	2.60	6.50	5.27
2009	76.87	72.13	14.97	10.29	9.14	7.33	2.64	1.50	5.47	4.32
2010	70.03	64.57	13.84	9.51	8.45	6.14	1.81	0.75	4.65	3.59
2011	68.82	63.06	13.41	9.21	8.18	5.71	1.51	0.49	4.36	3.33
2012	69.24	63.18	13.49	9.27	8.23	5.51	1.29	0.26	4.23	3.20

WESTERN SPOT GAS PRICES

$/MMBtu

	Alberta		BC/US Border					California		
DATE	AECO-C	Empress Border	NW Pipe Sumas, WA	PGT Kingsgate	Kern River Opal, WY	El Paso San Juan	Waha Permian	North	South	PG&E City Gate
2007										
JAN	6.22	6.44	6.46	6.25	5.79	6.12	6.27	6.43	6.39	6.74
FEB	7.23	7.51	7.22	6.96	6.32	6.92	7.10	7.16	7.19	7.55
MAR	6.94	6.20	6.55	6.44	4.93	6.09	6.10	6.55	6.22	6.90
APR	6.97	6.79	6.78	6.97	4.55	6.65	6.99	6.95	6.95	7.36
MAY	6.71	6.85	6.86	6.90	3.92	6.68	7.17	7.02	7.02	7.47
JUN	6.13	6.23	6.36	6.44	2.75	6.52	6.91	6.66	6.75	7.09
JUL	5.19	5.33	5.55	5.57	3.82	5.50	5.88	5.93	5.97	6.30
AUG	4.89	4.95	5.40	5.42	3.04	5.56	5.94	5.68	5.89	6.10
SEP	4.87	5.03	5.26	5.26	1.21	5.24	5.38	5.47	5.40	5.93
OCT	6.28	6.81	6.72	6.44	2.80	6.18	6.45	6.65	6.58	7.01
NOV	6.16	6.35	7.29	6.37	3.29	5.44	5.67	6.59	5.37	7.00
DEC	6.42	6.30	7.59	6.70	5.64	6.54	6.56	6.87	6.88	7.21
2008										
JAN	7.27	7.26	7.54	7.07	6.36	6.90	6.93	7.17	7.16	7.51
FEB	7.08	7.29	7.87	7.18	6.80	7.08	6.86	7.31	7.23	7.67
MAR	6.88	7.09	7.53	6.99	6.73	6.95	7.02	7.19	7.10	7.53
APR	6.63	6.83	6.84	6.73	6.53	6.76	6.83	7.00	6.92	7.33
MAY	6.55	6.74	6.71	6.64	6.45	6.69	6.76	6.92	6.84	7.25
JUN	6.58	6.78	6.69	6.68	6.48	6.72	6.79	6.96	6.87	7.29
JUL	6.65	6.85	6.71	6.75	6.55	6.79	6.86	7.03	6.94	7.36
AUG	6.56	6.75	6.56	6.65	6.45	6.69	6.76	6.93	6.84	7.25
SEP	6.57	6.76	6.52	6.67	6.46	6.70	6.77	6.94	6.85	7.26
OCT	6.80	7.01	6.70	6.90	6.69	6.93	7.00	7.18	7.09	7.51
NOV	7.04	7.25	7.48	7.14	6.92	7.16	7.23	7.42	7.32	7.75
DEC	7.30	7.52	7.99	7.41	7.19	7.42	7.49	7.69	7.58	8.03
2009										
JAN	7.41	7.63	8.36	7.52	7.29	7.52	7.59	7.80	7.67	8.13
FEB	7.30	7.52	8.22	7.41	7.27	7.40	7.47	7.69	7.56	8.01
MAR	7.01	7.22	7.70	7.11	7.02	7.26	7.33	7.39	7.40	7.85
APR	6.37	6.57	6.56	6.47	6.39	6.62	6.69	6.75	6.77	7.18
MAY	6.28	6.47	6.42	6.38	6.33	6.55	6.62	6.66	6.69	7.09
JUN	6.34	6.53	6.43	6.44	6.41	6.61	6.68	6.72	6.75	7.16
JUL	6.42	6.61	6.45	6.51	6.49	6.68	6.75	6.77	6.82	7.23
AUG	6.46	6.66	6.45	6.56	6.52	6.72	6.79	6.80	6.87	7.28
SEP	6.50	6.70	6.43	6.60	6.46	6.75	6.82	6.81	6.90	7.31
OCT	6.59	6.79	6.47	6.69	6.43	6.84	6.91	6.86	6.98	7.40
NOV	6.89	7.09	7.30	6.99	6.66	7.14	7.21	7.10	7.28	7.72
DEC	7.18	7.39	7.83	7.28	6.96	7.42	7.49	7.40	7.56	8.02
2000	3.75	3.77	5.01	4.79	3.73	3.84	4.14	5.66	6.20	
2001	3.61	3.59	3.84	3.86	3.53	3.60	4.03	6.13	8.02	
2002	2.57	2.57	2.68	2.73	1.97	2.66	3.13	2.99	3.16	3.07
2003	4.84	4.89	4.71	4.79	4.41	4.59	5.42	4.91	5.10	5.21
2004	5.01	5.20	5.14	5.15	5.19	5.18	5.41	5.35	5.45	5.69
2005	7.25	7.43	7.38	7.54	7.24	7.25	7.63	7.54	7.46	7.90
2006	5.83	5.94	5.91	5.84	5.35	5.81	5.89	6.10	6.04	6.46
2007	6.17	6.23	6.50	6.31	4.01	6.12	6.37	6.50	6.38	6.89
2008	6.83	7.01	7.10	6.90	6.63	6.90	6.94	7.14	7.06	7.48
2009	6.73	6.93	7.05	6.83	6.69	6.96	7.03	7.06	7.11	7.53
2010	6.71	6.91	7.00	6.81	6.64	6.94	7.01	7.13	7.08	7.51
2011	6.87	7.08	7.14	6.98	7.01	7.25	7.32	7.23	7.38	7.83
2012	7.19	7.40	7.43	7.29	7.30	7.52	7.59	7.52	7.67	8.13

Note: Historic Data is From Natural Gas Week, Monthly Data to 2012 is provided in Excel

MIDWEST AND EASTERN SPOT GAS PRICES
$/MMBtu

DATE	Aqua Dulce South, TX	Katy	Carthage, TX	KA/OK Panhandle	Ventura Iowa	Henry Hub Cash Market	Columbia Gas Broad Run, WV	Chicago City Gate	Transco Z6 (non-NY)	Algonquin	Tenn Zone 6
2007											
JAN	5.97	6.43	6.41	5.97	6.57	6.34	6.60	6.35	7.46	7.41	7.94
FEB	7.15	7.17	7.13	7.07	8.16	8.11	8.17	7.93	10.52	10.60	10.00
MAR	6.48	6.53	6.46	6.04	6.71	7.09	7.38	6.77	8.69	8.25	8.61
APR	7.23	7.30	6.96	6.55	7.05	7.55	7.86	6.22	8.54	8.52	8.57
MAY	7.46	7.44	7.31	6.64	7.09	7.64	8.11	7.46	8.26	8.31	8.26
JUN	7.27	7.33	7.02	6.31	6.67	7.48	7.89	7.25	7.99	8.06	7.97
JUL	5.89	5.90	5.88	5.65	5.90	6.20	6.52	6.11	6.82	6.91	6.87
AUG	6.04	6.11	6.11	5.72	5.86	6.23	6.31	6.19	6.97	7.00	6.88
SEP	5.78	6.00	5.63	5.20	5.49	5.97	6.13	5.87	6.45	6.55	6.39
OCT	6.48	6.65	6.51	6.19	6.61	6.68	6.90	5.87	7.20	7.19	7.16
NOV	6.33	6.15	5.44	5.44	6.66	7.01	7.44	6.48	7.74	7.93	7.70
DEC	6.73	6.65	6.63	6.33	7.09	7.10	7.26	7.11	8.86	12.34	10.72
2008											
JAN	7.40	7.29	7.35	6.73	7.66	7.52	7.86	7.63	9.83	11.02	11.10
FEB	7.52	7.41	7.10	6.75	7.11	7.75	8.08	7.62	9.06	9.10	9.17
MAR	7.39	7.29	7.02	6.69	7.03	7.63	7.93	7.50	8.17	8.20	8.26
APR	7.21	7.10	6.85	6.53	6.86	7.44	7.74	7.31	8.01	8.05	8.10
MAY	7.13	7.01	6.77	6.46	6.79	7.36	7.66	7.23	8.00	7.97	8.02
JUN	7.16	7.03	6.81	6.50	6.83	7.39	7.68	7.26	8.03	7.99	8.05
JUL	7.23	7.11	6.86	6.54	6.88	7.46	7.76	7.33	8.02	7.98	8.04
AUG	7.13	7.00	6.75	6.42	6.77	7.36	7.67	7.22	7.92	7.88	7.94
SEP	7.14	7.00	6.75	6.43	6.77	7.37	7.68	7.23	7.91	7.88	7.93
OCT	7.37	7.21	6.99	6.66	6.99	7.60	7.91	7.46	8.19	8.16	8.21
NOV	7.60	7.44	7.20	6.85	7.20	7.84	8.16	7.68	8.45	8.41	8.47
DEC	7.87	7.73	7.41	7.03	7.42	8.11	8.45	7.95	8.67	8.63	8.69
JAN	7.99	7.86	7.61	7.39	7.69	8.21	8.51	8.06	9.24	9.20	9.27
FEB	7.87	7.75	7.54	7.33	7.62	8.10	8.38	7.96	9.13	9.09	9.15
MAR	7.58	7.46	7.25	7.05	7.33	7.80	8.08	7.67	8.39	8.35	8.41
APR	6.93	6.82	6.61	6.42	6.70	7.16	7.43	7.03	7.73	7.69	7.75
MAY	6.84	6.71	6.52	6.33	6.61	7.06	7.33	6.93	7.63	7.59	7.64
JUN	6.90	6.76	6.56	6.36	6.66	7.12	7.40	6.99	7.69	7.65	7.71
JUL	6.97	6.83	6.62	6.41	6.71	7.19	7.47	7.06	7.76	7.73	7.78
AUG	7.02	6.88	6.67	6.47	6.75	7.24	7.52	7.10	7.80	7.77	7.82
SEP	7.05	6.90	6.70	6.50	6.78	7.27	7.56	7.13	7.84	7.80	7.86
OCT	7.13	6.96	6.76	6.54	6.84	7.36	7.66	7.21	7.94	7.90	7.96
NOV	7.43	7.25	7.01	6.78	7.10	7.66	7.98	7.50	8.25	8.22	8.27
DEC	7.72	7.57	7.30	7.06	7.39	7.95	8.27	7.79	8.56	8.52	8.58
2000	4.09	4.17	4.09	4.13	4.19	4.23	4.47	4.42	4.85	4.34	4.40
2001	3.94	4.01	3.96	3.97	4.04	4.07	4.29	4.15	4.51	4.92	5.11
2002	3.19	3.27	3.23	3.14	3.18	3.33	3.48	3.33	3.72	3.63	3.74
2003	5.34	5.36	5.16	5.35	5.51	5.64	5.70	5.49	6.33	6.33	6.37
2004	5.60	5.66	5.55	5.42	5.60	5.84	6.16	5.81	6.71	7.41	7.08
2005	7.90	8.03	7.85	7.62	7.99	8.79	9.28	8.45	9.75	9.81	9.87
2006	6.36	6.39	6.36	6.00	6.33	6.76	6.99	6.62	7.41	7.91	8.03
2007	6.57	6.64	6.46	6.09	6.66	6.95	7.21	6.63	7.96	8.26	8.09
2008	7.34	7.22	6.99	6.63	7.02	7.57	7.88	7.45	8.36	8.44	8.50
2009	7.28	7.15	6.93	6.72	7.02	7.51	7.80	7.37	8.16	8.13	8.18
2010	7.25	7.10	7.01	6.82	7.07	7.46	7.73	7.37	8.07	8.03	8.09
2011	7.39	7.33	7.26	7.09	7.30	7.59	7.84	7.55	8.19	8.15	8.20
2012	7.68	7.61	7.54	7.37	7.58	7.87	8.13	7.84	8.44	8.43	8.48

Note: Historic Data is From Natural Gas Week, Monthly Data to 2012 is provided in Excel

BASIS
$/MMBtu

	AECO	Tennessee Zone 6			Chicago City Gate			Northern California			Southern California			
DATE	Henry Hub	AEC0-C	Chicago City Gate	Henry Hub	AEC0-C	KA/OK Panhandle	Henry Hub	AEC0-C	Sumas	Kingsgate	N.Cal	Blanco	Opal WY	Henry Hub
2007														
JAN	-0.12	1.72	1.59	1.60	0.13	0.38	0.01	0.21	-0.03	0.18	-0.04	0.27	0.60	0.05
FEB	-0.88	2.77	2.07	1.89	0.70	0.86	-0.18	-0.07	-0.06	0.20	0.03	0.27	0.87	-0.92
MAR	-0.15	1.67	1.84	1.52	-0.17	0.73	-0.32	-0.39	0.00	0.11	-0.33	0.13	1.29	-0.87
APR	-0.58	1.60	2.35	1.02	-0.75	-0.33	-1.33	-0.02	0.17	-0.02	0.00	0.30	2.40	-0.60
MAY	-0.93	1.55	0.80	0.62	0.75	0.82	-0.18	0.31	0.16	0.12	0.00	0.34	3.10	-0.62
JUN	-1.35	1.84	0.72	0.49	1.12	0.94	-0.23	0.53	0.30	0.22	0.09	0.23	4.00	-0.73
JUL	-1.01	1.68	0.76	0.67	0.92	0.46	-0.09	0.74	0.38	0.36	0.04	0.47	2.15	-0.23
AUG	-1.34	1.99	0.69	0.65	1.30	0.47	-0.04	0.79	0.28	0.26	0.21	0.33	2.85	-0.34
SEP	-1.10	1.52	0.52	0.42	1.00	0.67	-0.10	0.60	0.21	0.21	-0.07	0.16	4.19	-0.57
OCT	-0.40	0.88	1.29	0.48	-0.41	-0.32	-0.81	0.37	-0.07	0.21	-0.07	0.40	3.78	-0.10
NOV	-0.85	1.54	1.22	0.69	0.32	1.04	-0.53	0.43	-0.70	0.22	-1.22	-0.07	2.08	-1.64
DEC	-0.53	4.20	3.29	3.66	0.91	1.17	0.37	0.39	-0.84	0.12	-0.01	0.29	1.10	-0.16
2008														
JAN	-0.63	2.15	1.66	1.51	0.49	0.94	-0.15	-0.09	-0.87	-0.19	0.21	0.15	0.59	-0.51
FEB	-0.67	2.08	1.55	1.41	0.53	0.87	-0.14	0.02	-0.77	-0.08	0.14	0.15	0.44	-0.51
MAR	-0.74	1.37	0.76	0.63	0.61	0.81	-0.13	0.14	-0.50	0.05	0.09	0.15	0.39	-0.51
APR	-0.81	1.47	0.79	0.66	0.68	0.79	-0.13	0.23	0.02	0.14	0.07	0.15	0.40	-0.51
MAY	-0.81	1.47	0.79	0.66	0.68	0.77	-0.13	0.24	0.08	0.15	0.06	0.15	0.40	-0.51
JUN	-0.81	1.46	0.78	0.65	0.68	0.76	-0.13	0.26	0.16	0.17	0.04	0.15	0.40	-0.51
JUL	-0.81	1.38	0.71	0.58	0.67	0.79	-0.13	0.27	0.21	0.17	0.03	0.15	0.40	-0.51
AUG	-0.80	1.38	0.71	0.58	0.67	0.81	-0.14	0.24	0.24	0.15	0.05	0.15	0.40	-0.51
SEP	-0.79	1.34	0.69	0.55	0.65	0.80	-0.14	0.20	0.26	0.12	0.08	0.15	0.39	-0.51
OCT	-0.79	1.38	0.74	0.60	0.64	0.80	-0.15	0.17	0.29	0.09	0.14	0.15	0.42	-0.48
NOV	-0.80	1.42	0.78	0.62	0.64	0.84	-0.16	0.13	-0.29	0.04	0.18	0.15	0.43	-0.48
DEC	-0.80	1.38	0.74	0.58	0.64	0.92	-0.16	0.07	-0.61	-0.03	0.21	0.15	0.40	-0.51
JAN	-0.80	1.86	1.20	1.06	0.66	0.68	-0.15	0.31	-0.64	0.20	-0.03	0.15	0.40	-0.52
FEB	-0.80	1.85	1.19	1.05	0.66	0.64	-0.14	0.35	-0.57	0.24	-0.09	0.15	0.29	-0.54
MAR	-0.79	1.37	0.71	0.57	0.66	0.62	-0.13	0.36	-0.34	0.25	0.04	0.15	0.39	-0.40
APR	-0.78	1.35	0.70	0.57	0.65	0.61	-0.13	0.36	0.17	0.26	0.04	0.15	0.38	-0.39
MAY	-0.78	1.34	0.69	0.56	0.65	0.61	-0.13	0.37	0.24	0.28	0.04	0.15	0.36	-0.37
JUN	-0.78	1.34	0.70	0.57	0.65	0.63	-0.13	0.38	0.29	0.28	0.04	0.15	0.34	-0.37
JUL	-0.78	1.34	0.70	0.57	0.64	0.64	-0.13	0.36	0.32	0.26	0.05	0.15	0.33	-0.37
AUG	-0.77	1.34	0.70	0.56	0.64	0.64	-0.14	0.33	0.35	0.24	0.07	0.15	0.35	-0.37
SEP	-0.77	1.27	0.64	0.50	0.63	0.64	-0.14	0.31	0.38	0.21	0.09	0.15	0.44	-0.37
OCT	-0.77	1.28	0.66	0.51	0.62	0.67	-0.15	0.27	0.39	0.17	0.13	0.15	0.55	-0.37
NOV	-0.77	1.35	0.73	0.58	0.61	0.72	-0.16	0.22	-0.18	0.11	0.18	0.15	0.63	-0.37
DEC	-0.77	1.37	0.76	0.60	0.61	0.73	-0.16	0.22	-0.43	0.11	0.17	0.15	0.61	-0.38
2000	-0.48	0.66	-0.01	0.18	0.67	0.29	0.19	1.91	0.65	0.87	0.54	2.36	2.46	1.97
2001	-0.46	1.50	0.95	1.04	0.54	0.18	0.08	2.52	2.29	2.27	1.89	4.42	4.49	3.95
2002	-0.76	1.17	0.41	0.41	0.76	0.20	0.00	0.41	0.31	0.26	0.18	0.50	1.19	-0.17
2003	-0.80	1.53	0.89	0.74	0.65	0.13	-0.15	0.07	0.20	0.12	0.19	0.51	0.69	-0.54
2004	-0.84	2.07	1.26	1.23	0.81	0.39	-0.03	0.34	0.20	0.20	0.10	0.27	0.26	-0.40
2005	-1.53	2.62	1.42	1.08	1.19	0.83	-0.34	0.29	0.17	0.00	-0.09	0.21	0.22	-1.33
2006	-0.93	2.19	1.40	1.26	0.79	0.62	-0.14	0.27	0.19	0.26	-0.06	0.24	0.69	-0.72
2007	-0.77	1.91	1.43	1.14	0.48	0.57	-0.29	0.32	-0.02	0.18	-0.11	0.26	2.37	-0.56
2008	-0.77	1.52	0.89	0.75	0.63	0.82	-0.14	0.16	-0.15	0.07	0.11	0.15	0.42	-0.50
2009	-0.78	1.42	0.78	0.64	0.64	0.65	-0.14	0.32	0.00	0.22	0.06	0.15	0.42	-0.40
2010	-0.75	1.38	0.71	0.63	0.66	0.55	-0.09	0.42	0.13	0.32	-0.05	0.15	0.44	-0.38
2011	-0.72	1.33	0.65	0.61	0.68	0.47	-0.04	0.36	0.09	0.26	0.15	0.14	0.37	-0.21
2012	-0.69	1.30	0.65	0.61	0.65	0.47	-0.04	0.33	0.09	0.22	0.15	0.15	0.37	-0.21

Note: Historic Data is From Natural Gas Week, Monthly Data to 2010 is provided in Excel

Natural Gas Supply and Demand (BIlion Cubic Feet per Day)

	2008 JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	Total	% Change 2007-08
Dry Gas Production	53.0	52.9	52.9	53.3	53.2	53.3	53.5	53.1	53.1	53.4	53.5	53.0	53.3	2.5%
Canada & Mexico	8.2	7.9	7.4	7.7	7.3	7.6	8.1	8.2	7.7	7.6	7.5	7.9	7.8	-8.5%
LNG	1.0	1.8	2.1	2.4	2.4	2.7	2.7	2.8	2.6	2.5	2.6	2.5	2.3	21.1%
Net Imports	9.2	9.6	9.6	10.1	9.7	10.3	10.8	11.0	10.2	10.0	10.2	10.4	10.1	-3.0%
Supplements	0.2	0.2	0.2	0.2	0.2	0.1	0.2	0.2	0.2	0.2	0.2	0.2	0.2	2.6%
Total New Supply	62.4	62.7	62.7	63.6	63.1	63.8	64.5	64.2	63.5	63.6	63.8	63.6	63.6	1.6%
Net Withdrawals	18.7	16.8	4.3	-5.0	-15.4	-13.6	-7.4	-6.1	-11.1	-11.0	4.5	16.8	-0.1	
Total Primary Supply	81.1	79.5	67.0	58.6	47.7	50.2	57.1	58.1	52.3	52.6	57.1	80.4	62.9	-0.3%
Demand														
Residential	27.5	26.2	19.5	13.2	5.3	3.9	4.0	2.7	3.9	6.0	18.3	26.6	13.1	-0.6%
Commercial	14.4	13.6	10.8	8.4	4.1	3.9	4.1	3.0	4.2	5.4	11.7	14.6	8.2	-1.1%
Industrial	20.0	20.3	18.1	16.6	16.8	16.5	17.1	17.3	18.1	18.4	18.7	19.1	18.1	0.4%
Lease and Plant Fuel	3.1	3.1	3.1	3.1	3.1	3.1	3.1	3.1	3.1	3.1	3.1	3.1	3.1	-1.2%
Transportation	2.3	2.3	1.9	1.7	1.4	1.5	1.5	1.6	1.4	1.4	1.6	2.0	1.7	-1.9%
Electric Power	13.8	14.1	13.6	15.6	17.0	21.4	27.3	30.3	21.6	18.2	14.9	15.0	18.6	-0.2%
Total Demand	81.1	79.5	67.0	58.6	47.7	50.2	57.1	58.1	52.3	52.6	68.4	80.4	62.9	-0.3%

	2009 JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	Total	% Change 2008-09
Dry Gas Production	53.3	53.5	53.6	53.6	53.8	53.8	53.8	53.2	53.1	53.3	53.4	53.0	53.5	0.2%
Canada & Mexico	8.0	7.6	7.2	7.0	6.5	6.9	7.5	7.4	6.9	6.8	7.3	7.6	7.2	-7.2%
LNG	2.7	2.9	2.8	2.9	3.0	3.3	3.2	3.1	3.0	3.0	3.2	3.1	3.0	28.8%
Net Imports	10.7	10.6	10.0	9.9	9.5	10.2	10.6	10.5	9.9	9.8	10.5	10.8	10.2	1.2%
Supplements	0.2	0.2	0.2	0.2	0.2	0.1	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.4%
Total New Supply	64.3	64.3	63.8	63.7	63.5	64.1	64.6	63.8	63.2	63.3	64.0	63.9	63.9	0.4%
Net Withdrawals	17.9	18.7	5.8	-4.8	-14.7	-12.3	-6.7	-4.6	-10.2	-9.5	6.2	18.6	0.3	
Total Primary Supply	82.2	82.9	69.6	58.9	48.8	51.8	57.9	52.9	52.9	53.7	70.2	82.5	64.2	2.1%
Demand														
Residential	27.9	27.1	20.1	12.5	5.7	4.3	4.1	4.1	4.1	6.9	18.4	26.7	13.4	2.1%
Commercial	14.7	14.2	11.1	8.0	4.2	3.9	4.3	4.5	4.5	5.7	11.7	14.6	8.3	1.5%
Industrial	20.0	20.8	18.5	17.6	16.8	17.1	16.8	17.6	17.6	18.0	18.8	19.4	18.2	0.3%
Lease and Plant Fuel	3.1	3.1	3.2	3.2	3.2	3.2	3.1	3.1	3.1	3.1	3.1	3.1	3.1	1.0%
Transportation	2.2	2.3	1.8	1.6	1.4	1.5	1.5	1.4	1.4	1.4	1.6	2.0	1.7	-1.3%
Electric Power	14.2	15.4	14.8	16.0	17.5	22.0	28.1	22.2	22.2	18.6	16.6	16.7	19.5	4.5%
Total Demand	82.2	82.9	69.6	58.9	48.8	51.8	57.9	52.9	52.9	53.7	70.2	82.5	64.2	2.1%

Working Gas Storage (Bcf)

	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC
2005	1994	1564	1284	1499	1875	2197	1284	2662	2932	3194	3189	2635
2006	2371	1886	1692	1945	2310	2617	1692	2969	3323	3452	3407	3070
2007	2379	1649	1603	1720	2179	2580	1603	3017	3316	3567	3440	2840
2008	2261	1685	1451	1570	2069	2393	1451	2828	3206	3525	3265	2800
2009	2252	1624	1386	1557	2042	2338	1386	2762	3152	3449	3190	2722

Natural Gas Supply and Demand (Trillion Cubic Feet)

	JAN	FEB	MAR	APR	MAY	JUN	2008 JUL	AUG	SEP	OCT	NOV	DEC	Total	% Change 2006-07
Supply														
Dry Gas Production	1.64	1.53	1.64	1.60	1.65	1.60	1.66	1.65	1.59	1.66	1.60	1.64	19.47	2.5%
Canada & Mexico	0.25	0.23	0.23	0.23	0.23	0.23	0.25	0.25	0.23	0.23	0.23	0.25	2.84	-8.5%
LNG	0.03	0.05	0.07	0.07	0.08	0.08	0.08	0.09	0.08	0.08	0.08	0.08	0.86	
Net Imports	0.29	0.28	0.30	0.30	0.30	0.31	0.34	0.34	0.31	0.31	0.30	0.32	3.69	-3.0%
Supplments	0.01	0.01	0.01	0.00	0.00	0.00	0.01	0.01	0.00	0.01	0.01	0.01	0.06	2.6%
Total New Supply	1.93	1.82	1.94	1.91	1.96	1.91	2.00	1.99	1.90	1.97	1.91	1.97	23.23	1.6%
Net Withdrawals	0.58	0.58	0.23	-0.12	-0.50	-0.32	-0.18	-0.25	-0.38	-0.34	0.14	0.52	-0.05	
Total Primary Supply	2.51	2.31	2.08	1.76	1.48	1.51	1.77	1.80	1.57	1.63	2.05	2.49	22.96	-0.3%
Demand														
Residential	0.85	0.76	0.61	0.40	0.16	0.12	0.12	0.08	0.12	0.19	0.55	0.82	4.78	-0.6%
Commercial	0.45	0.39	0.33	0.25	0.13	0.12	0.13	0.09	0.13	0.17	0.35	0.45	2.99	-1.1%
Industrial	0.62	0.59	0.56	0.50	0.52	0.49	0.53	0.54	0.54	0.57	0.56	0.59	6.62	0.4%
Lease and Plant Fuel	0.10	0.09	0.10	0.09	0.10	0.09	0.10	0.10	0.09	0.10	0.09	0.10	1.13	-1.2%
Transportation	0.07	0.07	0.06	0.05	0.04	0.04	0.05	0.05	0.04	0.04	0.05	0.06	0.63	-1.9%
Electric Power	0.43	0.41	0.42	0.47	0.53	0.64	0.85	0.94	0.65	0.56	0.45	0.46	6.80	-0.2%
Total Demand	2.51	2.31	2.08	1.76	1.48	1.51	1.77	1.80	1.57	1.63	2.05	2.49	22.96	-0.3%

	JAN	FEB	MAR	APR	MAY	JUN	2009 JUL	AUG	SEP	OCT	NOV	DEC	Total	% Change 2007-08
Supply														
Dry Gas Production	1.65	1.55	1.66	1.61	1.67	1.61	1.67	1.65	1.59	1.65	1.60	1.64	19.56	0.5%
Canada & Mexico	0.25	0.22	0.22	0.21	0.20	0.21	0.23	0.23	0.21	0.21	0.22	0.24	2.64	-6.9%
LNG	0.08	0.09	0.09	0.09	0.09	0.10	0.10	0.10	0.09	0.09	0.10	0.10	1.11	
Net Imports	0.33	0.31	0.31	0.30	0.30	0.30	0.33	0.33	0.30	0.30	0.31	0.33	3.75	1.4%
Supplments	0.01	0.01	0.01	0.00	0.00	0.00	0.01	0.01	0.00	0.01	0.01	0.01	0.06	0.7%
Total New Supply	1.99	1.86	1.98	1.91	1.97	1.92	2.00	1.98	1.89	1.96	1.92	1.98	23.38	0.6%
Net Withdrawals	0.56	0.54	0.18	-0.14	-0.46	-0.37	-0.21	-0.14	-0.31	-0.29	0.18	0.58	0.12	
Total Primary Supply	2.55	2.41	2.16	1.77	1.51	1.55	1.79	1.83	1.59	1.67	2.11	2.56	23.49	2.3%
Demand														
Residential	0.87	0.79	0.62	0.38	0.18	0.13	0.13	0.09	0.12	0.21	0.55	0.83	4.89	2.4%
Commercial	0.46	0.41	0.35	0.24	0.13	0.12	0.13	0.10	0.13	0.18	0.35	0.45	3.04	1.7%
Industrial	0.62	0.60	0.57	0.53	0.52	0.51	0.52	0.53	0.53	0.56	0.56	0.60	6.66	0.6%
Lease and Plant Fuel	0.10	0.09	0.10	0.09	0.10	0.09	0.10	0.10	0.09	0.10	0.09	0.10	1.15	1.3%
Transportation	0.07	0.07	0.06	0.05	0.04	0.04	0.05	0.05	0.04	0.04	0.05	0.06	0.62	-1.0%
Electric Power	0.44	0.45	0.46	0.48	0.54	0.66	0.87	0.97	0.67	0.58	0.50	0.52	7.13	4.8%
Total Demand	2.55	2.41	2.16	1.77	1.51	1.55	1.79	1.83	1.59	1.67	2.11	2.56	23.49	2.3%

Working Gas Storage (Bcf)

	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC
2005	1994	1564	1284	1499	1875	2197	2450	2662	2932	3194	3189	2635
2006	2371	1886	1692	1945	2310	2617	2779	2969	3323	3452	3407	3070
2007	2379	1649	1603	1720	2179	2580	2894	3017	3316	3567	3440	2840
2008	2261	1685	1451	1570	2069	2393	2578	2828	3206	3525	3265	2800
2009	2252	1624	1386	1557	2042	2338	2536	2762	3152	3449	3190	2722

U.S. Electricity Supply (Billion Killowatt-hours)

	2007													2006-07
Net Electricity Generation	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	Total	
Coal	174.4	162.1	158.3	145.1	156.3	172.4	183.8	189.0	168.3	161.2	160.4	173.3	2004.6	1.8%
Petroleum	5.6	8.5	4.9	4.7	4.5	5.4	5.3	7.0	4.6	4.5	3.7	3.6	62.4	4.1%
Natural Gas	52.8	52.0	50.2	54.8	60.1	74.7	90.1	113.4	81.0	72.3	51.7	53.4	806.5	9.8%
Nuclear	74.0	65.2	64.3	57.3	65.0	68.1	70.6	72.8	67.6	61.7	64.1	71.1	801.9	1.9%
Renewables	32.3	24.6	31.0	30.4	32.2	29.0	28.3	26.1	20.7	20.9	24.6	28.5	328.6	-7.9%
Electric Sector	339.1	312.6	308.6	292.2	318.1	349.7	378.1	408.2	342.2	320.7	304.5	329.9	4003.9	2.5%
Other Sectors	13.3	11.9	12.6	12.1	12.6	12.6	13.3	13.8	12.7	12.0	11.9	12.8	151.6	-3.2%
Total Generation	352.4	324.4	321.2	304.3	330.7	362.3	391.4	422.1	355.0	332.6	316.4	342.8	4155.5	2.2%

	2008													% Change 2006-07
Net Electricity Generation	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	Total	
Coal	178.0	167.4	160.3	141.4	151.6	166.0	182.3	181.5	166.5	159.8	158.6	180.2	1993.3	-0.6%
Petroleum	4.9	5.4	4.6	4.6	4.7	5.7	5.8	6.9	4.8	4.5	4.1	4.1	59.9	-3.9%
Natural Gas	51.9	48.6	51.3	56.0	62.3	76.4	100.2	105.7	77.5	66.7	53.6	55.4	805.6	-0.1%
Nuclear	73.4	61.2	63.8	59.2	65.1	72.0	73.6	72.3	65.3	61.6	63.1	71.2	801.7	0.0%
Renewables	31.2	26.7	30.7	31.4	34.2	32.8	30.2	27.3	23.1	24.1	25.9	29.4	346.9	5.6%
Electric Sector	339.4	309.2	310.7	292.6	317.9	352.8	392.0	393.6	337.3	316.6	305.2	340.3	4007.5	0.1%
Other Sectors	13.3	11.9	12.8	12.4	12.5	12.7	14.1	14.4	13.1	13.2	12.7	13.4	156.5	3.2%
Total Generation	352.7	321.2	323.5	305.0	330.4	365.5	406.1	408.0	350.3	329.7	317.9	353.7	4164.0	0.2%

	2009													2008-09
Net Electricity Generation	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	Total	
Coal	180.6	167.4	162.4	143.9	154.7	169.2	185.5	184.7	169.7	162.4	161.2	183.8	2025.5	1.6%
Petroleum	5.3	5.7	4.6	4.4	4.5	5.6	5.7	6.8	4.6	4.3	4.2	4.0	59.8	-0.2%
Natural Gas	53.4	53.3	56.1	57.8	64.4	78.9	103.5	109.3	80.2	68.8	60.0	62.4	848.1	5.3%
Nuclear	72.7	62.9	63.3	58.7	64.6	71.4	73.0	71.7	64.8	61.1	62.6	70.7	797.4	-0.5%
Renewables	32.1	27.9	32.0	32.4	35.4	34.0	31.4	28.4	24.4	25.2	27.2	30.5	360.8	4.0%
Electric Sector	344.3	317.1	318.4	297.3	323.6	359.0	399.1	400.9	343.6	321.8	315.2	351.3	4091.7	2.1%
Other Sectors	13.7	12.1	12.9	12.5	12.7	12.9	14.2	14.5	13.2	13.3	12.8	13.5	158.4	1.2%
Total Generation	357.9	329.2	331.3	309.8	336.3	371.9	413.4	415.4	356.9	335.1	328.0	364.8	4250.0	2.1%

Appendix C
International Coal Outlook

Coal Prices – Delivered C&F Guam

JD Energy, Inc.
John W. Dean

November 25, 2007

Coal Prices – Delivered C&F Guam

Purpose

The purpose of this report is to give indicative prices for the period 2008- 2030 for steam coal suitable for use in power generation to the island of Guam.

Introduction

Currently Guam is not consuming coal but the geography suggests that the only logical sources of supply are Australia and Indonesia. Although China is also relatively close it is not considered as the long-term projection is for Chinese exports to decline, as internal demand and pricing will render indigenous markets more attractive.

As large exporters of coal, Australia is the largest exporter of coal combining steam and coking coal while Indonesia is the largest exporter of steam coal, these sources are considered long-term sources of coal. Indonesia's internal demand is growing and there are some environmental issues covering both the rain forests and wildlife species, which do give rise to concerns of availability in the longer term. However, this report assumes that any reductions in Indonesian exports will impact more upon shipments into the Atlantic rather than upon nearer Asia/Pacific destinations.

The coal quality emanating from these two sources are quite different. The majority of the coals from Australia are mid-volatile bituminous coals with low sulphur and calorific values of around 11,300 Btu/lb. Coals from Indonesia are very wide-ranging but the majority of future production will be of a sub-bituminous nature with high levels of inherent moisture, high volatiles, mostly low in ash and sulphur but also having a calorific value of around 9,100 Btu/lb.

Assumptions

The assumptions used in this report are set out in Appendix 1

The International Seaborne Coal Trade

A Brief History

Historically this was an important trade primarily to supply ships bunkers and some power plants around the world but the volume, following wholesale conversion to oil, dropped to about 25 Mt in 1974, which was its nadir. The two oil crises of the 1970s reversed this trend although initially it was Europe where there was a history of coal-fired generation that picked up demand quickly with the Asia/Pacific markets some years behind.

Today Japan is the largest importer of steam coal although it did not start importing until 1980, which coincided with Australia's starting steam coal exports. By the mid-1990s Asia/Pacific demand had overtaken that of Europe as Taiwan and Korea followed Japan into heavy reliance upon coal for new generating capacity. The market had now split into two distinct trading areas; the Atlantic markets and the Pacific markets and even today Japan, Taiwan and Korea account for about 45% of total demand for imported seaborne steam coal.

A trade that was around 25 Mt in 1974 had grown to around 600 Mt by 2006.

The charts that follow show how both the demand and the supply have switched from the Atlantic to the Pacific since 1990 when the Atlantic demand was still just bigger than that of the Pacific market. At the same time the supply growth to world markets since the late 1990s has been met largely by Indonesia, Russia and China although in recent years Chinese exports have declined but this has been largely replaced by growth in Vietnamese exports.

Figure 1 Development of Seaborne Steam Coal Demand

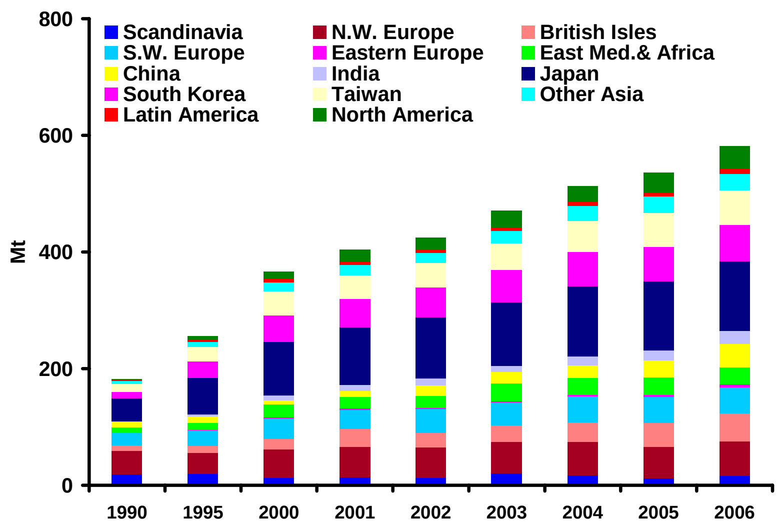
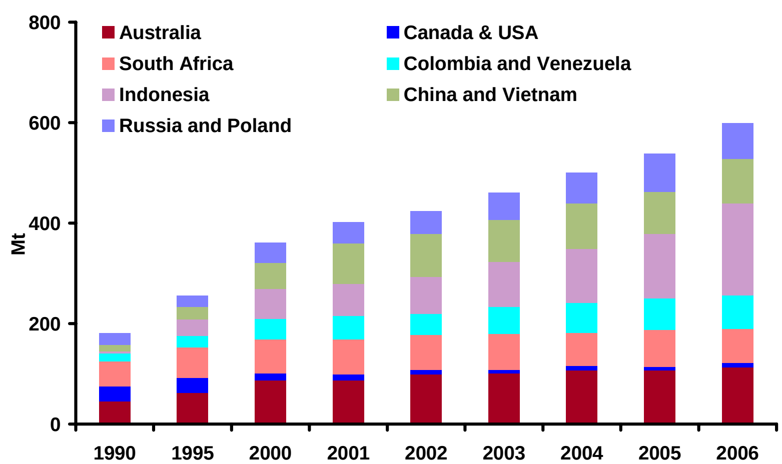


Figure 2 Development of Seaborne Steam Coal Supply



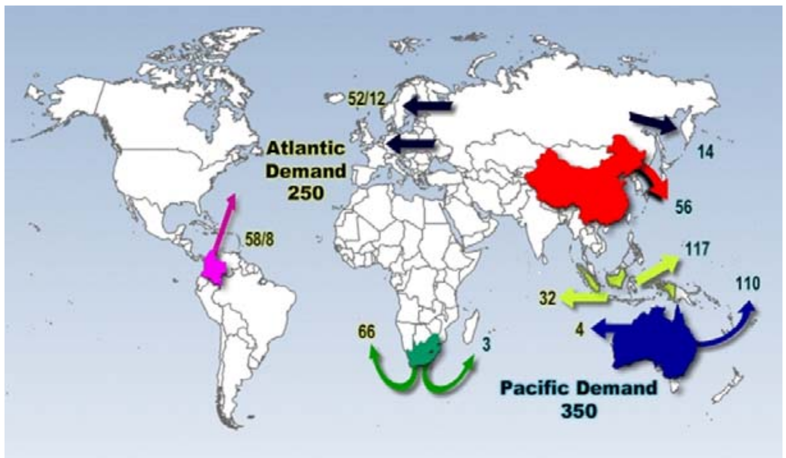
Operation

As set out above the market is split into two distinct trading areas, the Atlantic and the Pacific largely balanced within each basin by established supply sources. Until around 1996/7 the USA was a key payer in this global trade being required, as the supplier of last resort, to balance the Atlantic and world markets. However as cheaper sources came on stream, supported by a strong US dollar, the USA was squeezed to become a marginal player with the roles of supplier of last resort and the balancer of world trade moving to Australia. A weak dollar and weak freight markets made this move very easy.

As a result of this for the last 10 years or so this has meant that the Atlantic market has operated in deficit while the Pacific has operated in surplus with this surplus being moved into the Atlantic to balance the world market. In theory this has meant Australian coal being moved to satisfy demand but in reality Indonesia with a lower cost structure and a lower freight has tended to fill this gap.

It is somewhat ironic that over recent months the exchange rate difficulties that had driven the USA out of the supply market are now allowing supplies from this source back in. High prices and extreme freight costs from Australia make supplies from the USA cheap.

Figure 3 Trade Flow Patterns – 2006 in Metric tonnes

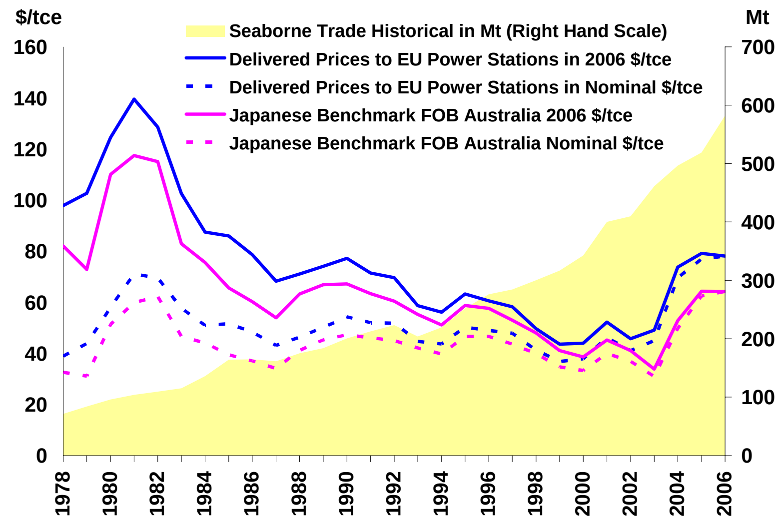


Pricing

Historic Pricing & Volumes

The chart that follows show how the delivered price to Europe and the annually determined Japanese contract price have developed since 1978. The use of a tonne of coal equivalent (tce) being a coal with a calorific value of 7,000 kilocalories/kilogram net or 12,600 btu/lb net both on an as received basis is used to eliminate the variability of coal supplied.

Figure 4 Evolution of Trade & Prices – Nominal & Real 2006 dollars



The use of nominal prices shows how in these terms prices have remained reasonably flat except for the period following the second oil crisis (early 1980's) that coincided with the Solidarity Union disruption in Poland and the more recent market upheavals. Polish exports that were running at about 45 Mtpa in 1979 declined to around 15 Mt in 1981 and it took about 1984 years before Poland returned to 1979 levels. It was left exclusively to US exporters to meet this deficit. It is also worth noting that in n 2002/03 the price of coal in nominal terms was the same as it was in 1978. Prices once again took off in late 2003 driven by a tighter supply/demand balance and what is most commonly referred to as the China effect that drove up the freight market.

When these same price series are looked at in real terms it is interesting to note that despite the very high level of price through 2006 the real price was nowhere near approaching the levels of 1981/2. However most recent price movements that have lifted current prices up to around $150/tce mean that coal is now trading at the same real levels that is was 25 years ago.

These series, delivered prices to European Power Stations and the Japanese benchmark[1], are used because they have been running for a long period. The European Power Station series very closely resembles the delivered price to ARA (Amsterdam/Rotterdam/Antwerp ports) and although only about 50 Mt pass through these ports there has grown a paper trade that turns over about 20 times that quantity. This paper trade is largely conducted using the API#2 (an All prices Index c&f ARA)[2]. The Japanese trade from Australia runs at about 60 Mt per annum.

[1] The "benchmark system" was a system under which all the Japanese utilities bought 100% of their annual coal requirement from Australia at the same price fixed for the period April to March with annual price negotiations. This operated from the early 80s to the mid 90s but around 1996/7 when the utilities recognized that they were paying not only too much for the coal compared to the Europeans, who were buying largely spot coal, but also they had allowed the Australian producers to become very uncompetitive This required a change and so they switch to a "reference price" basis which meant that they would buy some coal, say 40%, at higher prices and then seek discounts for the increments such that the overall price was drastically reduced over a period of a couple of years. They also started to buy some spot coal, which was a major departure for them. This system still effectively operates today although there is a measure of competition in the prices paid by the utilities. It was this pressure on the Australian producers that delivered very significant productivity increase from 1996 – 2001.

[2] This is a daily index produced by Tradition Financial Services for data acquired from a number of contributors together with prices for 1,2, 3 and 4 months ahead, together with 6 quarters and 4 years.

How Pricing is established today

As stated above the supplier of last resort and hence the price driving mantle moved from the USA to Australia in the late 1990s. However for a period up until late 2003 there was a very marked oversupply as China, Russia and Indonesia poured coal onto the market. During this period the two trading basins tended to settle independently even though there was always cheap coal available from Indonesia in particular, supported by very low freights which will be discussed in the shipping section later.

One other point to note is that in the period from 2000-2003 traditional exporters such as South Africa and Australia were having to ease back on production to accommodate coal from the newer exporters and as late as November 2003 coal from Australia was still being sold at about US dollars 28/t fob vessel.

Despite rising oil prices and the linking of gas to oil in most contracts today coal prices are still based on the long run marginal cost (LRMC) of production. This LRMC represents the full cash cost of producing coal and loading it into vessel plus a return on the capital tied up in the operation. Cash costs for each of the major exporting countries are represented in Figure 5 that follows. These represent the estimated cash costs that contribute to each country's export capacity. The proximity to major markets of suppliers such as Indonesia make it easy for them to simply be a price taker and even the high cost suppliers such as Russia and China can by virtue of their location supply nearby markets and take the price.

The price driving marginal production in Australia is that production that is represented by the weighted average cost of the 25% of production that sits at the top of the cost curve. It should be noted that in Australia many of the mines right at the top of the cost curve are mines that produce coking as well as steam coal. Given they are selling the majority of their coal are far higher prices than steam coal the latter is to some extent almost capable of being considered to be a by-product.

The best way to understand the pricing is to see how the ARA price tends to settle in line with Australian delivered cost price. In this ocean freight plays a major part but over the years 2006 and 2007 year to date the role of the LRMC of Australian coal production and sea freight is very apparent with the average price settling at or around the C&F price of Australian coal delivered to the ARA ports.

Figure 6 shows the average delivered cost to ARA from some of the main producing regions in 2006 clearly showing the price setting role of Australia and the price taking roles of the others. The year to date 2007 Australian cost emphasises Australia's in price setting.

Figure 5 Estimated Fob Ocean-going Vessel Cash Costs - 2007

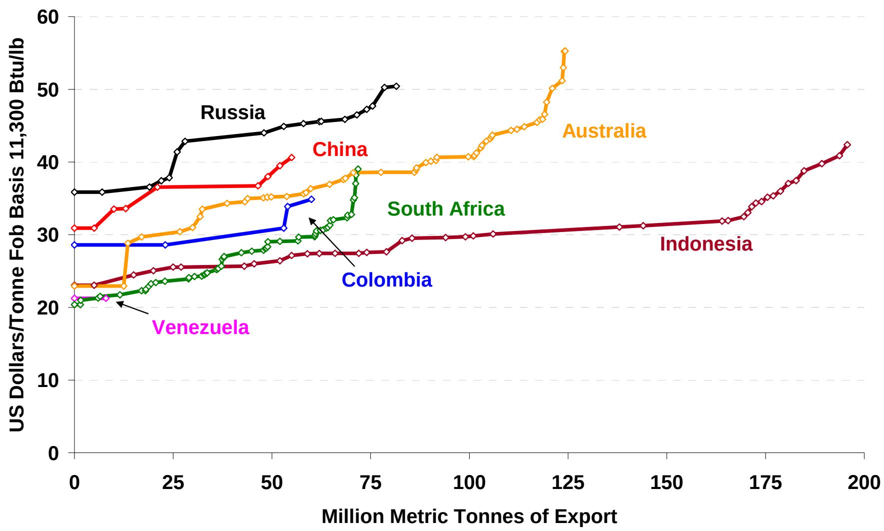
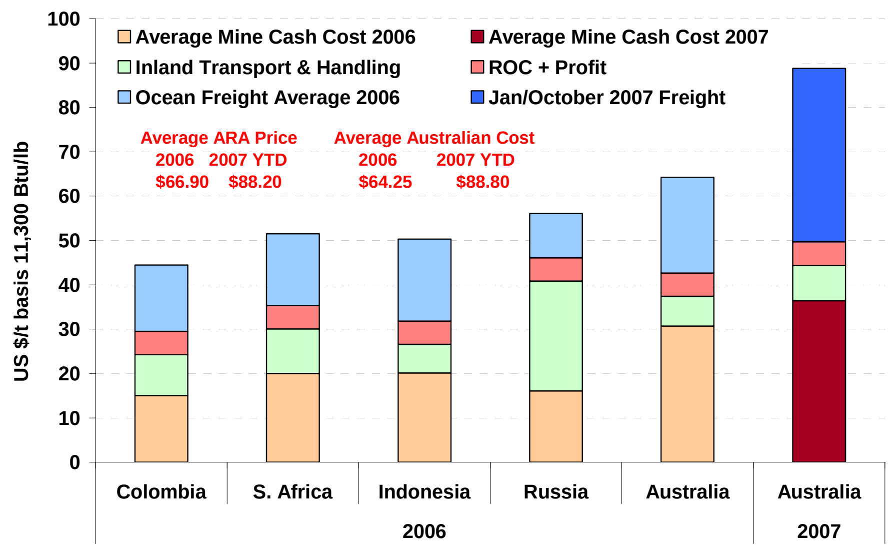


Figure 6 How Australian Coal Drives the Global Spot Price



Naturally the Japanese are not buying on the basis of an ARA price but the Europeans do settle their contract tonnage in the period October to December for the following years and this still represents about 35% of their total purchase of coal. As a result when the Japanese move in to negotiate their prices in December through March the Australians, being well aware of European delivered prices, negotiate at levels that effectively mean the Japanese will pay a delivered price not too different from the Europeans. Although the freight market to Japan is not particularly transparent the lower freight cost to Japan yields much higher fob prices for the Australians on sales into the Pacific markets.

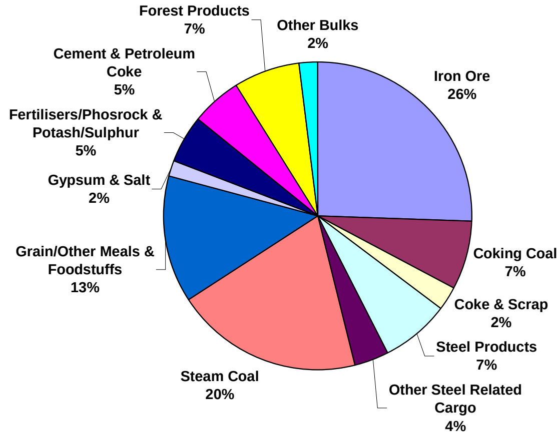
By February/March of each year the contract business is dealt with and the market reverts to many months of spot trading with the Australian LRMC setting the global prices.

The Freight Market

Demand for dry bulk movements

As can be seen in Figure 6 the role played by ocean shipping rates in setting delivered prices cannot be overemphasised. However, while the steam coal trade is 100% dependent upon the dry bulk shipping industry to move the product the steam coal trade only represents 20% of the demand for dry bulk movements.

Figure 7 Distribution of the Dry Bulk Trade by Cargo Type



The dominance of the wider steel related movements that account for about 46% of the total trade is obvious and it has been this trade that has driven the freight market into uncharted territory.

While most coal and steel related cargo is moved in either panamax or capesize vessels the fleet as a whole is a collection of vessels ranging from around 10,000 tonnes deadweight (dwt) to around 300,000 dwt. Traditionally they are classified into four categories:

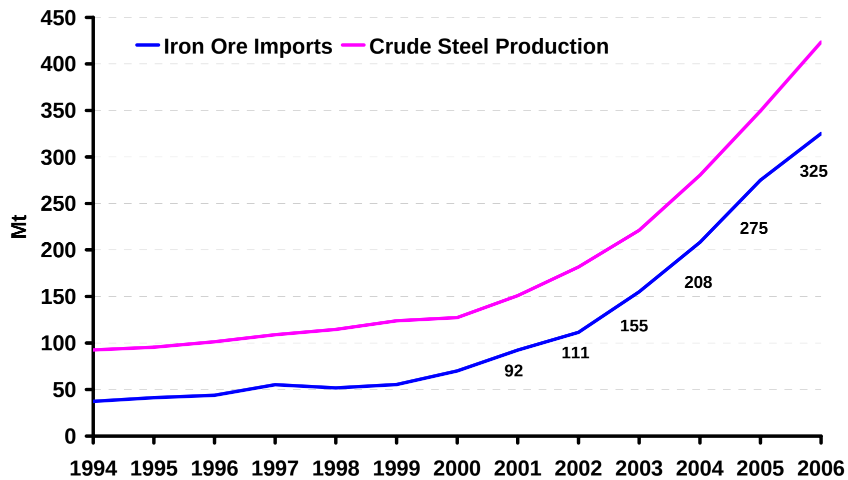
Handysize	10 – 40,000 dwt
Handymax	40 – 60,000 dwt
Panamax	60 – 80,000 dwt
Capesize	> 80,000 dwt

For this report the shipping rate applied to the forecast of shipping rates to Guam has assumed the use of panamax vessels. Currently there is probably a surplus of panamax capacity within the fleet but a dire shortage of capesize capacity has led to situation whereby the panamax rates have increased as they fill the gap in the market arising from the shortage of capesize ships.

It has been the unparalleled growth in demand for steel related movements that has been the force behind the creation of the shortage of shipping capacity. Five years ago there was a fleet surplus. The growth in steam coal at about 160 Mt and coking coal at about 20 Mt would have been accommodated in the usual fleet replacement programme. However, it has been the enormous increase in the demand for iron ore that has driven the market ever upwards.

In this China has been the driving force and has produced what has come to be referred to as the China effect. Import demand for iron ore alone has grown from 92 Mt in 2001 to 325 Mt in 2006. This growth created yet another difficulty for the shipping industry as Australia, the natural supplier for China, could not meet the surge in demand and it was left to Brazil to fill the gap. The problem with this was that the distance required in moving the extra demand was immediately doubled. This had the effect of reducing the productivity of the fleet in the capesize category. The increased length of journey for the additional iron ore is around 7,000 miles which equates to about an additional 25 days sailing. Given the fact that the vessel also has to reposition itself these figure can be doubled and the consequence of this maths on the supply/demand balance is clear.

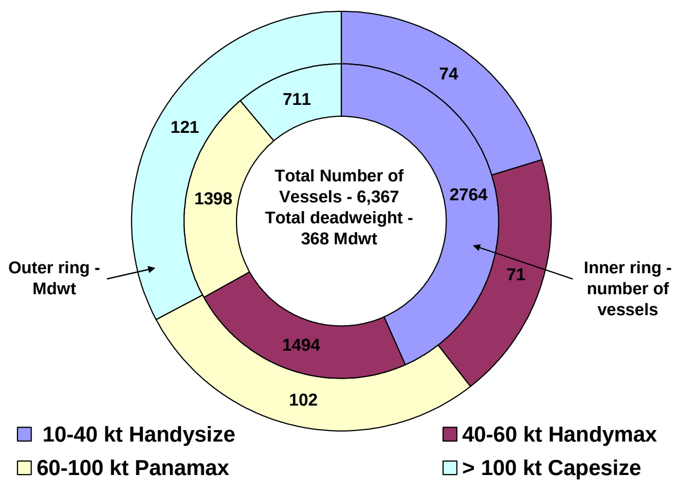
Figure 8 Chinese Crude Steel Production and Iron Ore Imports



At the same time since late 2003 declining availability of Chinese steam coal has put greater pressure on Australia and late 2003 witnessed extreme waiting times develop in Australian ports building up to over 70 vessels at its height early in 2004; a number that represented about 12% of the total capesize fleet. This waiting continued off Newcastle during 2004, and only by mid-2005 was it really showing signs of being brought under control. Nevertheless, as recent events have shown, this did not turn out to be a permanent fix. By late 2004, the demand for coking coal from Australia was such that some of the Queensland ports developed similar queuing problems and it was thought that this would also eventually be brought under control.

At the time of writing (late November 2007) these problems still exist and long waiting times and longer journeys are continuing to hold the market above the normal level that would be dictated by supply and demand.

Figure 9 Dry Bulk Fleet as at January 1st 2007

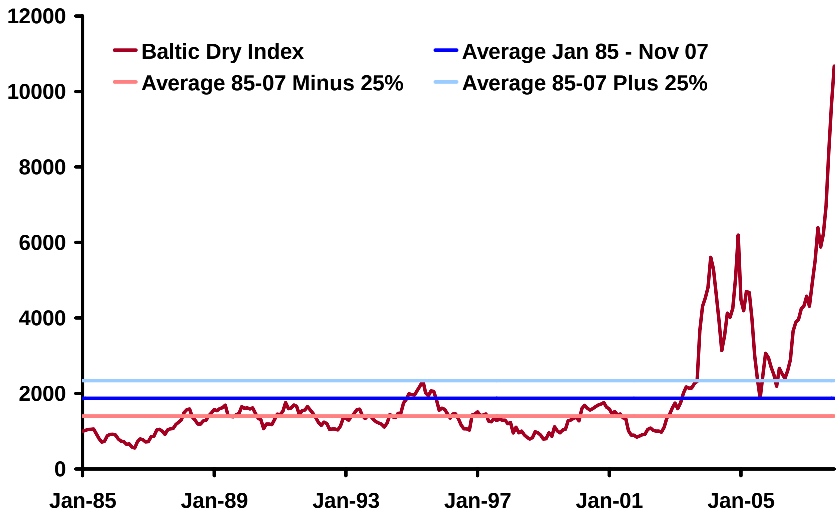


The dry bulk shipping market has reached unprecedented levels over recent years and never ceases to shock. The measure of this can be measured by the Baltic Dry Index[3] which came into being in January 1985 and for most of the period up to mid-2003 had traded at a level of plus or minus 25% of the mean value. This in itself was considered extremely volatile but normally imbalances of the supply/demand for ships were corrected within an 18 month to 2 year cycle and the market accepted this volatility.

For all the reasons set out above the market has taken off and currently it operating at a different level because of the shortage of ships in large part created by queues off Australia and Brazil and lower productivity due to longer journeys in the iron ore trade.

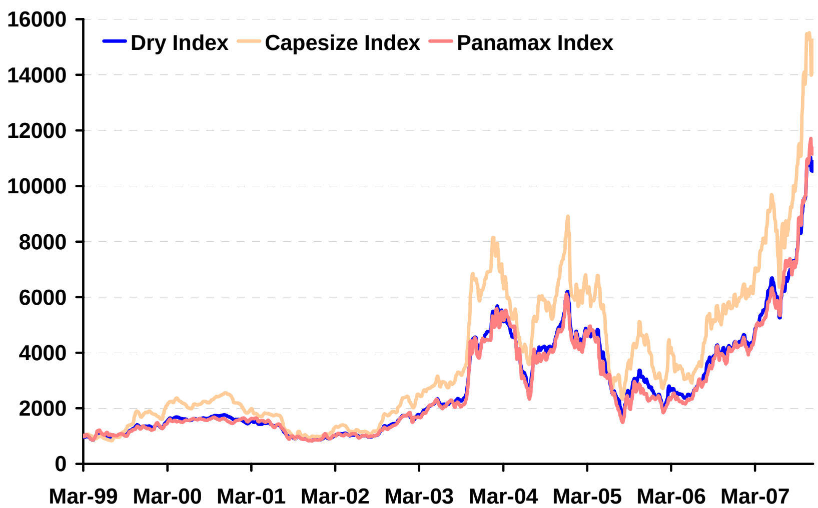
[3] The Baltic Dry Index is a composite index made up of a mixture of panamax and capesize voyage charters and time charters. Since March 1999 separate indices have been introduced for capesize and panamax vessels to supplement the dry index.

Figure 10 History of the Baltic Dry Index to November 2007



The dry index does not tell the whole story as the capesize index shows. The shortage of vessels in this class has tended to take it away from the panamx index even though it has had the effect of dragging it up with it.

Figure 11 Dry, Capesize and Panamax Indices from March 1999



The Forecast

Production and fob costs

In making this forecast a great deal of analysis has been conducted on future supply costs in all producing countries but in three countries in particular, Australia, South Africa and Russia greater attention has been paid because these are the countries that can have a major influence on pricing.

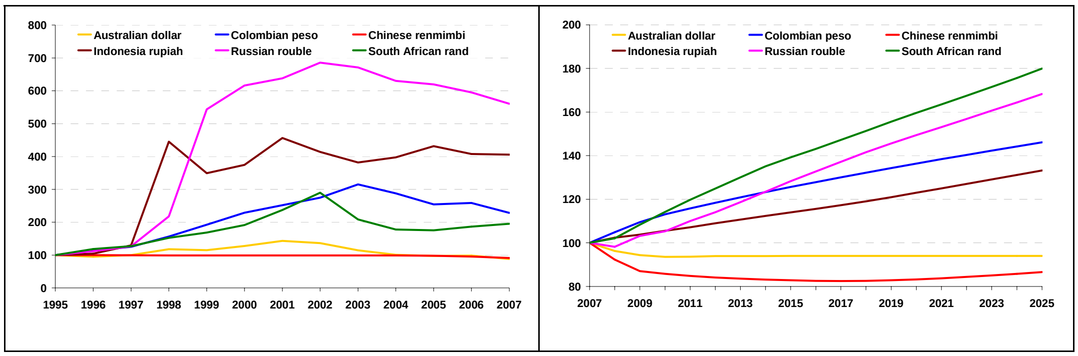
Russia, although not a high cost producer at the mine level, has a high rail cost involved in moving product 5-6000 kilometres to port over a rail network owned by the government that extracts an economic rent and has put up rail tariffs by around

212% in the last 4 years with more to come in 2008. A marked correction in the freight rates that reduces Russia's freight differential effectively means that ultimately Russia imposes a floor to the market.

South Africa, a long-term and important supplier, has a problem of rising costs exacerbated by an unskilled workforce that struggles to improve productivity. At the same time reserves in the traditional areas are declining and starting in the next 5-10 years a wholesale move to other reserves will be required. These reserves are more than twice the distance from the exit ports. Australia as the price driver can supply the coal the market needs and consequently its cost of production is fundamental to future coal pricing.

In all of this exchange rates play an important role.

Figure 12 Exchange Rate Movements – History and Forecasts

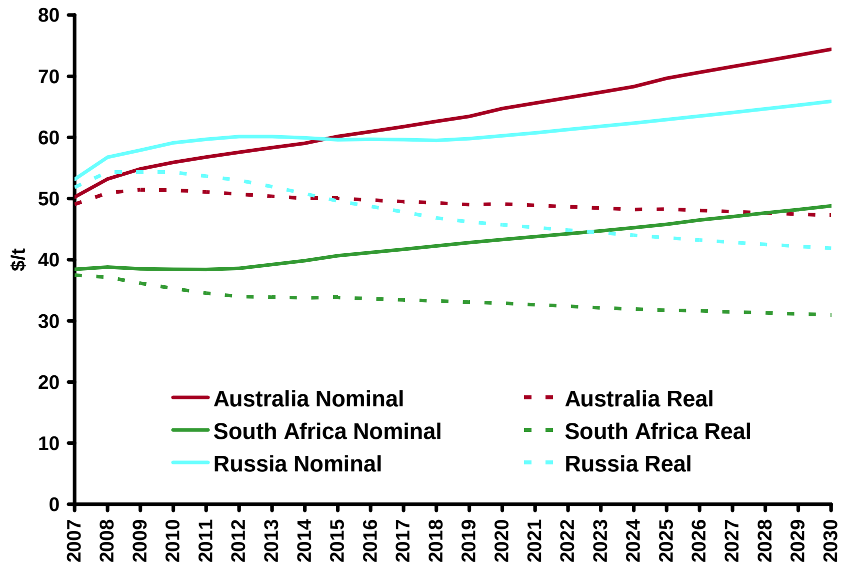


The history of exchange rates is all indexed to 1995 being equal to 100. What is apparent from this is the ease with which Indonesia and Russia were able to use their weak exchange rates to enter the market. China's entry was related more to a government directive to expand the economy via an export led growth that now requires more coal internally and the withdrawal of tax incentives on exports. Even Australia's movement represented 50% depreciation at its height.

The forecast which index all currencies to 100 in 2007 foresees a continuing strength for the Australian dollar and the Chinese renminbi. All the other currencies are forecast to continue to depreciate against what is also forecast to be a period of sustained weakness for the US dollar. The effect of these currency movements upon the projected future fob LRMC for the countries that can effectively influence one way or another future pricing is set out in Figure 11.

It is by using this forecast of future LRMC projections that the world price is forecast taking into account both the forecast direction of the freight market and ensuring that at any stage two producers in particular, Russia and South Africa can "live with" the price set by Australia and the freight market. What is clear from this is the weak rand will pose no problem for South Africa while high inflation and short-term currency strength in Russia could influence prices. However, during most of this period the freight markets strength will be such that Russian exporters will be protected from any fall in Australian prices.

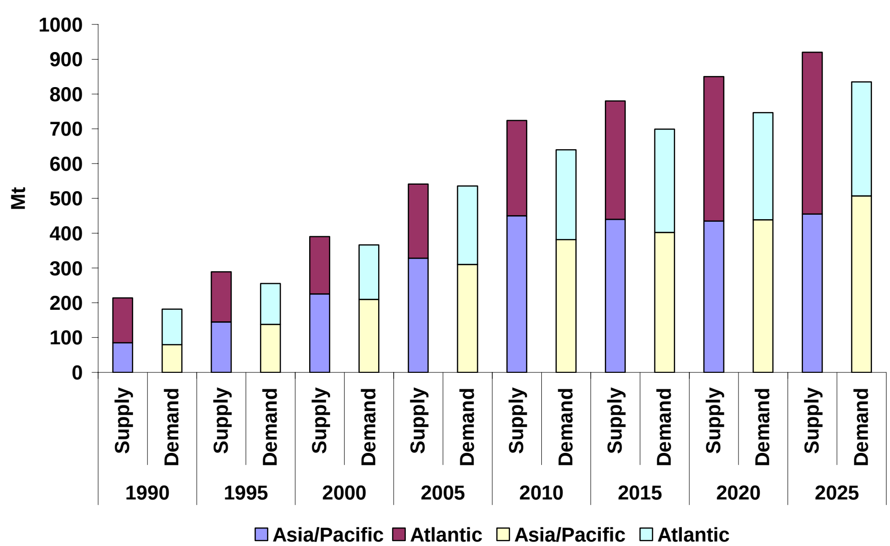
Figure 13 Forecast of LRMC fob Costs



Supply/Demand

The only other issue beyond freight that could affect prices is that of the supply demand balance. What the balance of supply and demand shows is how until around 2003 (not depicted in the chart) the surplus traded at around 10% with new capacity always more than meeting new demand. Post 2003 declining Chinese availability was not adequately replaced by increased Australian supply because of the port problems despite the best efforts of the Indonesians to expand supply. At the same time there was a surge in demand from newer importers such as India, China and the United States. On top of all this three years of poor performance of Japanese nuclear plants meant that Japanese imports of coal were held at higher levels than anticipated. By 2005 the market was almost in deficit and has remained tight ever since.

Figure 14 Forecast of Supply vs. Demand



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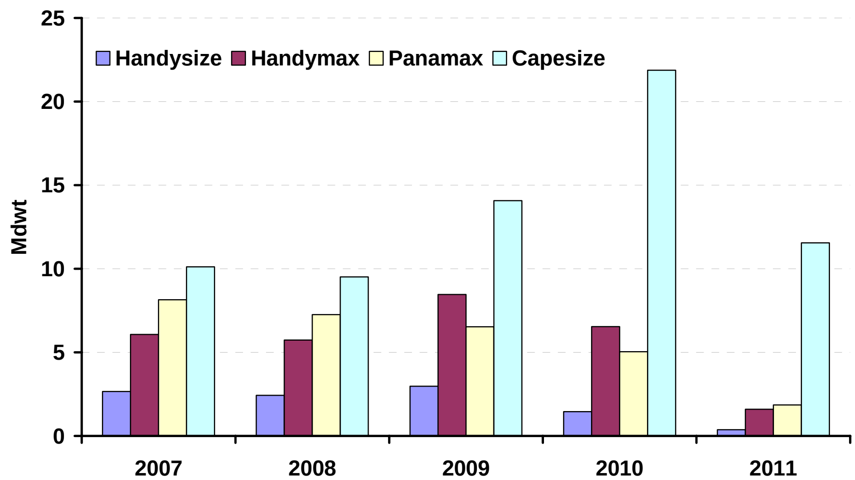
Looking forward significant expansions are forecast for Colombia, South Africa, Russia and Australia although these will in part be offset be reduced capacity in Indonesia and China. At the same time Japanese demand will remain flat and imports into Europe and the USA will decline. Offsetting these demand declines will be increased demand fro China, India and other Asian economies but the net effect is the balance to improve.

Freight

The year 2007 will see the biggest ever delivery in one year of new shipping capacity ever at almost 26 Mdwt. However, ensuing years will give an even greater boost to capacity and by the end of 2010 a massive 180 Mdwt will have been added to the fleet which stood at 368 Mdwt (see figure 9) at the beginning of 2007.

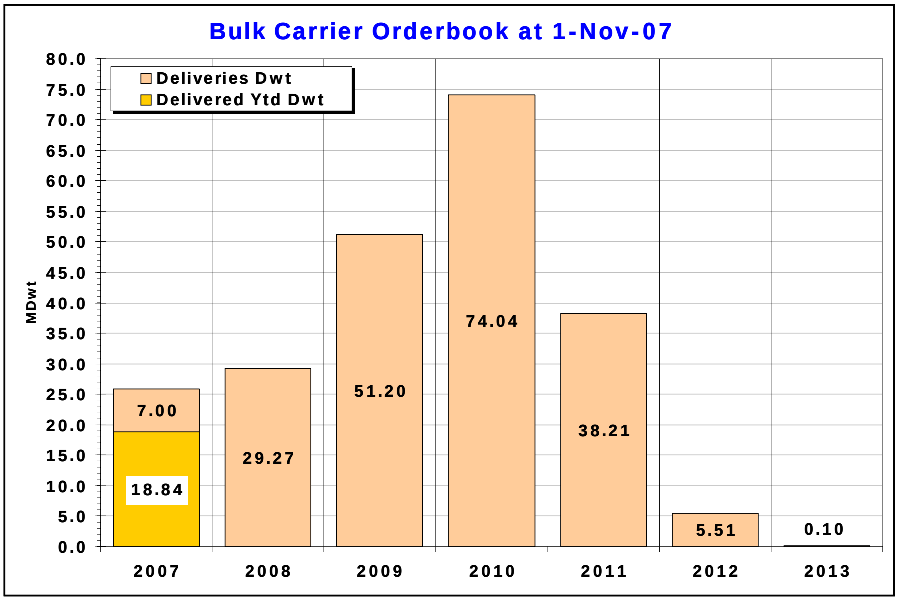
As at July this year the orderbook stood at 134 Mdwt.

Figure 15 The Dry Bulk Vessel Orderbook as at July 2007



Four months later it stands at 224 Mdwt with the majority of the increase being in the capesize and to a lesser extent the panamax vessels.

Figure 16 Current State of the Orderbook



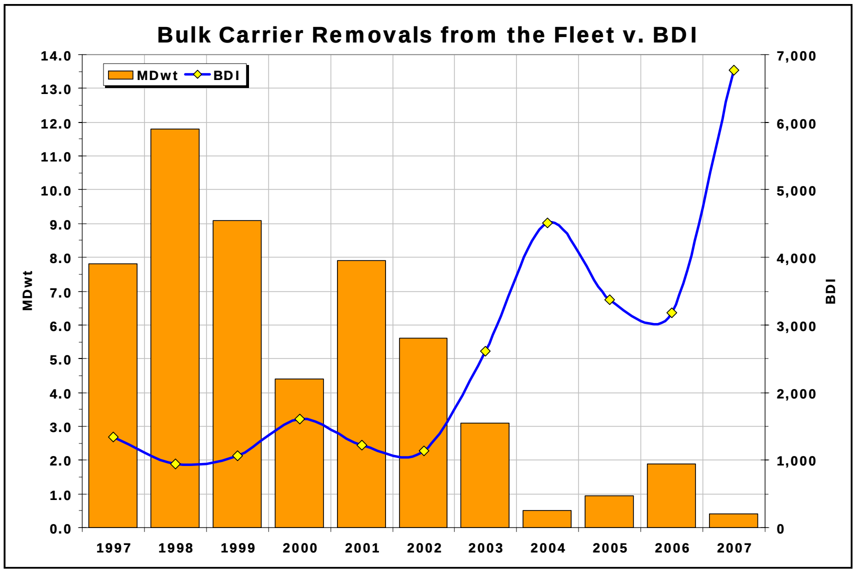
Source: Galbraiths

The total dry bulk trade grew from around 2 Bt in 2000 to around 2.8 Bt in 2006. The addition of the above vessels to the fleet will add a further carrying capacity of around 1.5 Bt to the fleet and by any assessment it is difficult to see how the overall demand for dry bulk movements could double in 5 years.

There is a small offset to this and that is the removals from the fleet, primarily through age, but also through losses at sea. The recent history suggests that owners will be slow to scrap vessels given the earning power of fully depreciated assets. The final chart shows how in recent years, despite high values for scrap steel very few retirements have been as a result of the high freight market.

Owners will scrap vessels once the market turns but that will be too late to prevent a crash as the market corrects itself. History tells us this is what happens and there is no reason to believe that history is wrong. The only difference this time is that the height of the market suggests that the correction will be bigger than anything ever seen before.

Figure 17 History of Fleet Removals



Price Forecast to Guam

These forecasts are set out in the tables and charts that follow. The prices are based on an Australian coal having a calorific value of 11,330 Btu/lb and an Indonesian coal having a calorific value of 9,100 Btu/lb both on a gross as received basis. They are also expressed in both metric tonnes of 1000 kilograms which equates to approximately 2,204 pounds weight and in short tons of 2000 pounds weight. Finally the delivered prices are expressed in dollars per million Btu's.

There is also a series of charts that set out these forecasts graphically. Obviously the chart representing the delivered prices in dollars per million Btu's is the only chart that brings these two forecasts to a common calorific value basis and makes the comparison of two entirely different coals more realistic. Naturally there are other issues that will affect the performance of these coals in the boiler that will further influence their respective competitiveness.

Table 1 Coal Prices and Freight Rates in US Dollars per Metric Tonne

	Coal Prices fob				Panamax Freight Rates				Delivered Prices			
	Nominal $/t		Real 2006$/t		Nominal $/t		Real 2006$/t		Nominal $/t		Real 2006$/t	
	Australia	Indonesia	Australia	Indonesia	Australia	Indonesia	Australia	Indonesia	Australia	Indonesia	Australia	Indonesia
2008	68.0	48.9	65.1	46.8	31.4	20.3	30.1	19.4	99.4	69.2	95.1	66.2
2009	62.0	44.9	58.2	42.2	22.4	14.5	21.0	13.6	84.4	59.5	79.2	55.8
2010	58.0	42.3	53.3	38.8	17.4	11.3	16.0	10.4	75.4	53.6	69.3	49.2
2011	56.8	41.5	51.0	37.3	13.8	9.1	12.4	8.2	70.6	50.6	63.5	45.5
2012	57.6	41.9	50.7	36.9	17.1	11.1	15.0	9.8	74.6	53.1	65.8	46.8
2013	58.3	42.4	50.4	36.6	19.1	12.5	16.5	10.8	77.5	54.8	66.9	47.4
2014	59.0	42.9	50.0	36.3	19.1	12.4	16.2	10.5	78.1	55.3	66.2	46.9
2015	60.1	43.7	50.0	36.4	19.2	12.5	15.9	10.4	79.3	56.2	66.0	46.7
2016	60.9	44.3	49.8	36.2	19.2	12.5	15.7	10.2	80.2	56.8	65.5	46.4
2017	61.8	44.9	49.5	36.0	19.5	12.7	15.6	10.2	81.2	57.6	65.1	46.2
2018	62.6	45.5	49.3	35.8	19.7	12.8	15.5	10.1	82.3	58.3	64.8	45.9
2019	63.4	46.1	49.0	35.6	19.9	13.0	15.4	10.0	83.3	59.1	64.4	45.6
2020	64.7	47.1	49.1	35.7	20.1	13.1	15.3	9.9	84.8	60.2	64.4	45.7
2021	65.6	47.7	48.9	35.6	20.3	13.2	15.1	9.9	85.9	60.9	64.0	45.4
2022	66.5	48.4	48.7	35.4	20.5	13.3	15.0	9.8	87.0	61.7	63.6	45.1
2023	67.4	49.0	48.4	35.2	20.7	13.5	14.9	9.7	88.1	62.5	63.3	44.9
2024	68.3	49.7	48.2	35.0	20.8	13.6	14.7	9.6	89.1	63.2	62.9	44.6
2025	69.7	50.7	48.3	35.1	21.0	13.7	14.6	9.5	90.7	64.4	62.8	44.6
2026	70.6	51.4	48.1	35.0	21.2	13.8	14.4	9.4	91.8	65.2	62.5	44.4
2027	71.6	52.1	47.8	34.8	21.4	13.9	14.3	9.3	92.9	66.0	62.1	44.1
2028	72.5	52.7	47.6	34.7	21.5	14.0	14.1	9.2	94.0	66.8	61.8	43.9
2029	73.4	53.4	47.4	34.5	21.7	14.1	14.0	9.1	95.1	67.6	61.5	43.7
2030	74.4	54.1	47.3	34.4	21.9	14.2	13.9	9.0	96.2	68.4	61.2	43.4

Table 2 Delivered Prices in US Dollars per Short Ton and per Million Btu's

	Delivered Prices							
	Nominal $/short ton		Real 2006$/short ton		Nominal $/mmbtu		Real 2006 $/mmbtu	
	Australia	Indonesia	Australia	Indonesia	Australia	Indonesia	Australia	Indonesia
2008	90.2	62.8	86.3	60.1	4.0	3.4	3.8	3.3
2009	76.6	54.0	71.9	50.6	3.4	3.0	3.2	2.8
2010	68.4	48.6	62.9	44.7	3.0	2.7	2.8	2.5
2011	64.1	45.9	57.6	41.3	2.8	2.5	2.5	2.3
2012	67.7	48.2	59.7	42.4	3.0	2.6	2.6	2.3
2013	70.3	49.8	60.7	43.0	3.1	2.7	2.7	2.4
2014	70.9	50.2	60.1	42.5	3.1	2.8	2.7	2.3
2015	72.0	51.0	59.9	42.4	3.2	2.8	2.6	2.3
2016	72.8	51.6	59.4	42.1	3.2	2.8	2.6	2.3
2017	73.7	52.2	59.1	41.9	3.3	2.9	2.6	2.3
2018	74.7	52.9	58.8	41.7	3.3	2.9	2.6	2.3
2019	75.6	53.6	58.4	41.4	3.3	2.9	2.6	2.3
2020	77.0	54.6	58.4	41.4	3.4	3.0	2.6	2.3
2021	78.0	55.3	58.1	41.2	3.4	3.0	2.6	2.3
2022	78.9	56.0	57.8	41.0	3.5	3.1	2.5	2.3
2023	79.9	56.7	57.4	40.7	3.5	3.1	2.5	2.2
2024	80.9	57.4	57.1	40.5	3.6	3.2	2.5	2.2
2025	82.3	58.4	57.0	40.5	3.6	3.2	2.5	2.2
2026	83.3	59.1	56.7	40.3	3.7	3.2	2.5	2.2
2027	84.3	59.9	56.4	40.0	3.7	3.3	2.5	2.2
2028	85.3	60.6	56.1	39.8	3.8	3.3	2.5	2.2
2029	86.3	61.3	55.8	39.6	3.8	3.4	2.5	2.2
2030	87.3	62.0	55.5	39.4	3.9	3.4	2.4	2.2

Figure 18 Forecast of Nominal Fob and Freight Costs

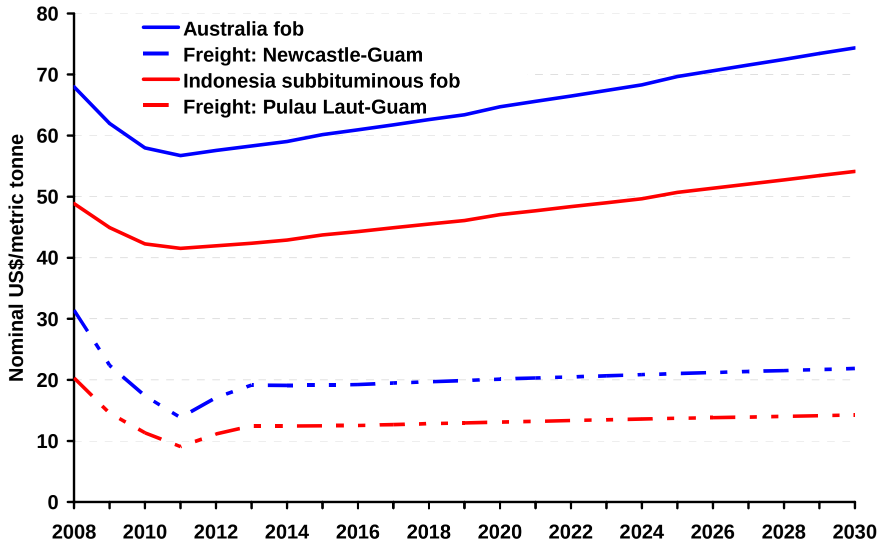


Figure 19 Forecast of Real Fob and Freight Costs

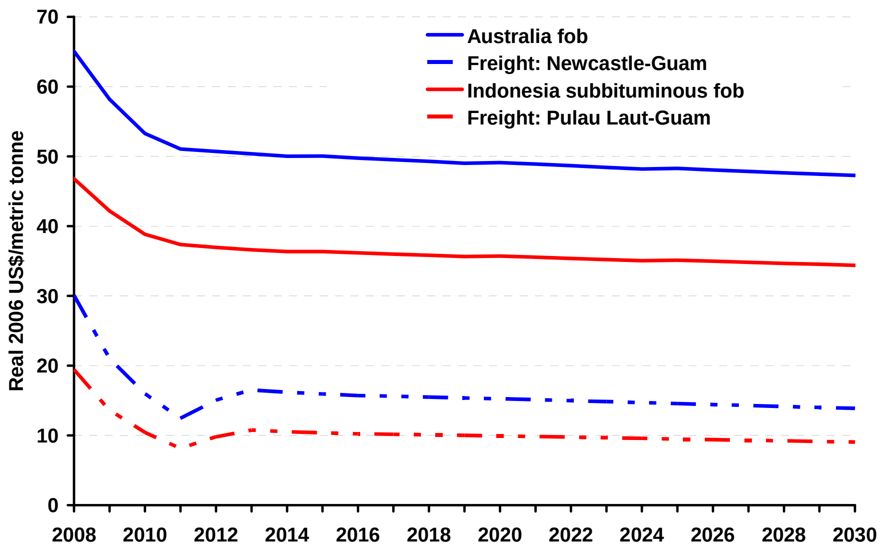


Figure 20 Delivered Price to Guam – Nominal and Real Dollars/t

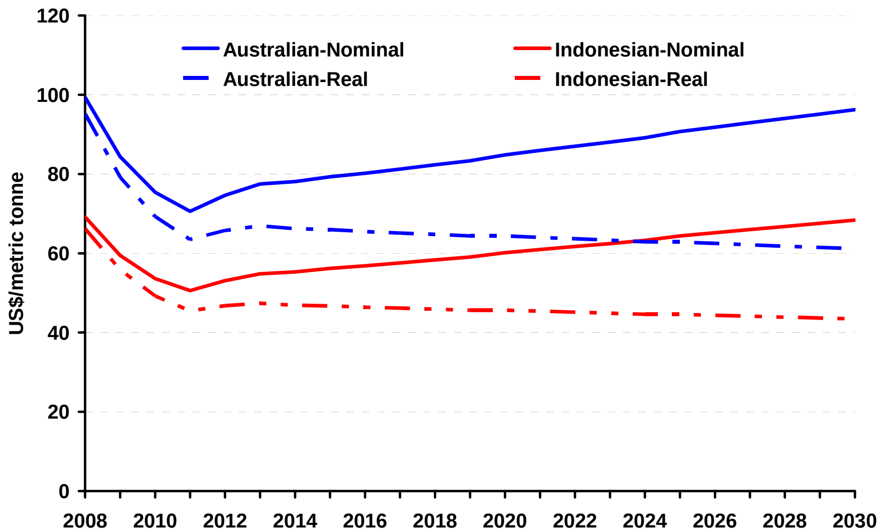
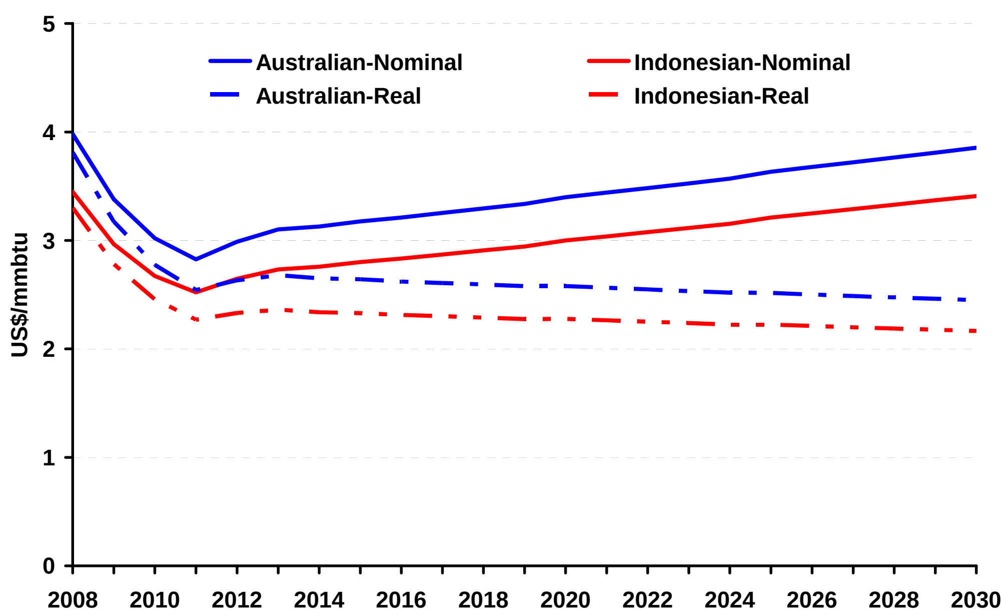


Figure 21 Delivered Price to Guam – Nominal and Real Dollars/mmbtu



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Appendix - Assumptions

Exchange Rates to 1 United States dollar

	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2020	2025	2030
Australian dollar	1.33	1.21	1.17	1.15	1.15	1.15	1.15	1.15	1.15	1.15	1.15	1.15	1.15
S. African rand	6.8	7.2	7.5	8.0	8.4	8.8	9.2	9.5	9.9	10.2	11.7	13.2	14.9
Russian rouble	27.2	25.7	25.6	26.4	27.0	27.7	28.2	28.9	29.7	30.5	33.8	36.4	39.0

US dollar Deflator

2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2020	2025	2030
100	102.5	104.5	106.6	108.8	111.2	113.5	115.8	118.0	120.2	131.8	144.3	157.4

Oil Price

70 dollars per barrel real

E Supply Side Options

November 16, 2007

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
Macheche 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 2007 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 in the heat recovery steam generator (HRSG) 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 from the 500 kilowatt range 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 20 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, several thousand 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 500 and 800 acres) to allow for construction and operation, development of access roads, and access to a transmission interconnection point. The land use of the facility after the construction would be approximately 100 acres, but the location of the facility with regard to other infrastructure will determine how much free space is actually required post-construction. It is important to note that significant study of the wind patterns at proposed site locations is necessary to identify suitable sites and to support development of the data required to characterize the wind in order to select an appropriate wind turbine for the site. 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, impacts on the avian and bat communities, land use planning issues, and cultural disturbance issues will need to be considered and, if necessary, resolved.

Operating Constraints

Wind turbine operation begins when the wind speed reaches 3.5-4.0 meters per second (m/s) (8-9 mile per hour (mph)) with output increasing with increasing wind speed until the rate wind speed, usually about 12-14 m/s (27-31 mph) at which point the output remains at the rated capacity until the cut-out speed. At the cutout speed, usually about 24 m/s (54 mph) the wind turbine blades are feathered so that the rotor no longer rotates, and no power is produced.

Hence, the primary operating constraint is the lack of dispatch control of the wind turbines. Generation only occurs while the wind is blowing. To have the wind turbine producing at the rated capacity, the wind would have to be consistently blowing at or above about 13 m/s (30 mph). One implication of this operation is that, depending on the wind regime at the selected site location, the wind turbines may not operate at rated capacity for a significant number of hours each year, but instead something less. Such operation can be forecast, and the proper wind turbine selected for the proposed site, when sufficient wind data have been collected and analyzed.

Installation of a wind farm will likely displace higher cost power generation. In certain cases, a wind farm may result in the need for different control strategies to cover fluctuations in wind turbine generation, whether those changes are due to changes in wind speed or to low demand in periods of high winds.

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, without shut-down of the wind farm as a whole. Mature forced outage rates can be expected to be in the two to three percent range.

Environmental Issues

The operation of wind turbines cause no air emissions, use no water and create no waste water for disposal. The operation of wind turbines can cause some danger to birds and bats unless sited properly, and modest levels of near field noise can be detected.

Primary environmental issues during the construction period relate to siting and installation of both the access roads and the wind turbines themselves, as well as the construction of the electric collection system and any transmission lines required.

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 a HRSG with an SCR to meet BACT requirements, a new steam turbine, 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	Nov-07						
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	1x1 LM6000	10x2 MW On-shore	Piti 7- 1x1 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	500 to 800	5 to 15	10 to 25	10 to 25
Plant Direct Costs	$000	$ 195,000	$ 72,000	$ 28,750	$ 51,600	$ 56,160	$ 45,600
Plant Direct Costs	$/kW	$ 3,250	$ 1,200	$ 1,438	$ 860	$ 5,616	$ 1,140
Interconnections Costs	$000	$ 52,500	$ 205,200	$ 10,500	$ 7,350	$ 10,500	$ 12,600
Owner Costs	$000	$ 49,500	$ 55,440	$ 7,850	$ 11,790	$ 13,332	$ 11,640
Capital Cost	$000	$ 300,250	$ 334,000	$ 48,538	$ 71,601	$ 85,608	$ 70,980
Capital Cost	$/kW	$ 5,004	$ 5,567	$ 2,427	NA	$ 8,561	$ 1,775
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	Jun-12	Jul-11	Jul-11	Jul-10	Oct-11	Jul-10
Retirement	Date	Jun-42	Jun-41	Jul-31	Jul-40	Oct-41	Jul-40
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%	2.0%	2.0%	5.5%	5.5%
New FOR for 1st yr	%	8.0%	6.0%	3.0%	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%	96.0%	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	$	$ 3,228,750	$ 2,613,750	NA	$ 1,537,500	$ 2,767,500	$ 1,230,000
G&A	$	$ 330,947	$ 267,909	NA	$ 157,594	$ 283,669	$ 126,075
Other	$	$ 599,625	$ 507,375	NA	$ 333,125	$ 440,750	$ 348,500
Cap Ex	$	$ 768,750	$ 615,000	NA	$ 435,625	$ 615,000	$ 430,500
FOM	$	$ 4,928,072	$ 4,004,034	NA	$ 2,463,844	$ 4,106,919	$ 2,135,075
FOM	$/kW-yr	$ 82.13	$ 66.73	NA	$ 41.06	$ 410.69	$ 53.38
VOM	$	$ 2,060,681	$ 1,212,165	NA	$ 2,206,140	$ 5,690,441	$ 1,669,196
VOM	$/MWh	$ 4.61	$ 2.56	NA	$ 4.61	$ 76.88	$ 5.64
Total Non-Fuel O&M	$	$ 6,988,752	$ 5,216,199	$ 400,000	$ 4,669,984	$ 9,797,360	$ 3,804,271
Total Non-Fuel O&M	$/MWh	$ 15.64	$ 11.03	NA	$ 9.76	$ 132.36	$ 12.85

Notes:
All costs in 2007$
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 interconnection 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
Manufacturing slots for wind turbines are currently sold out through 2009.

F Demand Side Options

GUAM POWER AUTHORITY

Demand Side Management Study

June 2008

R·W·BECK

GUAM POWER AUTHORITY

Demand Side Management Study

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June 9, 2008

Via e-mail: jcruz@gpagwa.com

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

Subject: **Demand-Side Management Study**

Dear Mr. Cruz:

At the request of Guam Power Authority ("GPA"), R. W. Beck, Inc., performed an evaluation of the cost-effectiveness of residential and commercial demand-side management ("DSM") measures for potential implementation by GPA. The purpose of the study was to supplement certain integrated resource planning ("IRP") analyses and studies currently being undertaken by GPA for filing with the Guam Public Utilities Commission. The study identified potential DSM measures that could be used by residential and commercial electric customers of GPA to reduce electric energy consumption and estimated the potential benefits and impacts to GPA's electric system.

The study was performed under that certain agreement dated July 10, 2007 between GPA and R. W. Beck (the "Agreement"). The Demand Side Management Study report has been prepared for the use of GPA for the specific purposes identified in the report and should not be relied upon for any other purpose or by any other party unless authorized by R. W. Beck in accordance with the Agreement.

The projections presented in the report were developed on the basis of the assumptions and circumstances described therein. In preparing the report, we have made certain assumptions with respect to conditions that may exist or events that may occur in the future. While we believe the use of such assumptions to be reasonable for the purposes stated herein, we offer no other assurances with respect thereto, and it should be anticipated that some future conditions may vary significantly from those assumed therein due to unanticipated events and circumstances. To the extent that future conditions differ from those assumed in the analysis, actual results and outcomes may vary from those projected.

The conclusions, observations and recommendations contained in the report attributed to R. W. Beck constitute the opinions of R. W. Beck. To the extent that statements, information, and opinions provided by GPA or others have been used in the preparation of the report, R. W. Beck has relied upon the same to be accurate and for which no assurances are intended and no representations or warranties are made. R. W. Beck makes no certification and gives no assurances except as explicitly set forth in the report. The report summarizes our work up to

R·W·BECK

the date of the report; changed conditions which occur or become known after such date could affect the results presented in the report to the extent of such changes.

We appreciate the continuing opportunity to provide services to GPA and we wish to thank you and members of your staff for the assistance provided as we conducted the study. Should you have any questions, please feel free to give me a call at (206) 695-4789.

Sincerely,

R. W. BECK, INC.

Youssef A. Hegazy, Ph.D.
Executive Consultant

c: A. Muzzin

EXECUTIVE SUMMARY

At the request of Guam Power Authority ("GPA"), R. W. Beck, Inc., was retained to perform an evaluation of the cost-effectiveness of residential and commercial demand-side management ("DSM") program measures for potential implementation by GPA. The study is designed to supplement the integrated resource planning ("IRP") analyses and studies currently being undertaken by GPA for filing with the Guam Public Utilities Commission ("GPUC"). This report is also intended to satisfy the requirements of the GPUC that GPA perform a DSM study as part of its IRP filing.

This DSM study was conducted in a manner to provide a practical investigation of DSM program potential for GPA, evaluating the cost of the program measure commensurate with the size and scope of GPA's electric system. The analysis was conducted in two phases: (i) a technical screening assessment, and (ii) an economic screening analysis.

The technical screening assessment involved a review of all DSM measures recommended for consideration by GPA and R. W. Beck. DSM measures were rated for potential implementation in the GPA service area. Those measures with ratings indicating an average or better potential for implementation were considered for further evaluation during the economic screening analysis. The DSM measures considered for evaluation, a description of the methodology, and the results of the technical screening assessment are summarized in the report section titled *Technical Screening Assessment*. Additional detailed results of the technical screening assessment are provided in Appendix A.

The results of the technical screening assessment of 23 DSM programs, identified four potential DSM measures for evaluation through an economic screening analysis for each GPA consumer class. Each measure was evaluated for cost-effectiveness by comparing DSM measure costs against marginal supply-side costs that could be avoided if the DSM measures were instituted by GPA's retail customers.

Table ES-1
DSM Measures Evaluated for Economic Potential

	Residential	Commercial
Energy efficiency equipment measures:		
Energy efficient lighting retrofit	X	X
Renewable energy measures:		
Solar photovoltaic	X	X
Solar thermal	X	X
Energy information programs:		
Energy audits (includes use of infrared heat detection equipment)	X	X

In performing this economic screening analysis, industry-standard techniques and formulae were applied to the evaluation of the DSM measures. Assumptions on DSM measure energy and demand impacts and costs were developed from available information on typical equipment costs, energy savings estimates specific to GPA's retail customer characteristics, and typical DSM program costs for electric utilities. Specific assumptions used to evaluate each of the DSM measures are presented in Appendix B. The economic screening analysis was performed from the perspective of GPA (e.g., marginal power supply costs of GPA were compared to DSM measure costs).

Per the scope of services for this study, projections of DSM program saturations, potential customer penetration rates, and utility incentive programs were not evaluated. Instead, the economic screening was performed by assuming an implementation of 1,000 retail customer participants per DSM measure, beginning with calendar year 2008.

Cost-effectiveness evaluations were performed for three different perspectives on DSM program implementation, as follows.

> **Utility Cost Test –** A measure of whether the benefits of avoided utility costs are greater than the costs incurred by a utility to implement the DSM program.
>
> **Rate Impact Measure ("RIM") Test –** A measure of whether utility ratepayers that do not participate in a DSM program would see an increase in retail rates as a result of other customers participating in a utility-sponsored DSM program.
>
> **Total Resource Cost ("TRC") Test –** A measure of whether the combined benefits of the utility and customers participating in the DSM program are greater than the combined costs to implement the DSM program.

Summary results of the economic screening are presented below in Table ES-2. The table provides present value benefit to cost ratios computed over a 20-year study period from 2008 through 2027 for each DSM measure for each of the cost-effectiveness tests described above.

GPA established that a DSM measure must pass both the Utility Cost Test and the RIM Test before it would promote a DSM measure as part of its IRP filing. A benefit to cost ratio of greater than 1.0 for the Utility Cost Test and the RIM Test indicates that GPA could promote and develop a given DSM program such that the program would reduce GPA's operating costs at a level greater than the cost of the program and that net benefits derived from the program would not cause an increase in the retail rates charged to GPA customers.

None of the DSM measures evaluated for economic potential were found to pass both the Utility Cost Test and RIM Test criteria. As such, GPA is not including any projections of DSM impacts in its IRP filing. However, GPA may choose to implement DSM programs for reasons that are different than the economic conditions considered. For instance, GPA may choose to ignore adverse retail rate impacts and implement DSM programs based on the TRC Test results.

Additionally, DSM programs that have been implemented by GPA were eliminated from the analysis. GPA has previously implemented four programs (1998-2000). These programs are commercial Lighting; commercial air conditioning; residential air conditioning; and residential water heating. Although the economics of these programs seemed promising at the time, implementation was cut short in year 2000 due to lack of funds and reorganization. Additional energy and demand savings could be achieved if GPA is allowed to re-energize and fund these programs.

Table ES-2
Summary Results of DSM Cost-Effectiveness

	Benefit/Cost Ratio		
	Utility Cost Test	RIM Test	TRC Test
Residential Measures:			
Energy efficient lighting retrofit	21.353	0.730	4.193
Solar photovoltaic	29.418	0.744	0.205
Solar thermal	16.508	0.679	0.416
Residential energy audits	3.094	0.592	0.722
Commercial Measures:			
Energy efficient lighting retrofit	13.833	0.889	1.258
Solar photovoltaic	31.418	0.888	0.258
Solar thermal	11.508	0.809	0.416
Commercial energy audits	4.636	0.568	0.694

Section 1
INTRODUCTION AND DESCRIPTION OF STUDY

At the request of Guam Power Authority ("GPA"), R. W. Beck, Inc., was retained to perform an evaluation of the cost-effectiveness of residential and commercial demand-side management ("DSM") program measures for potential implementation by GPA. The study is designed to supplement the integrated resource planning ("IRP") analyses and studies currently being undertaken by GPA for filing with the Guam Public Utilities Commission ("GPUC"). This report is also intended to satisfy the requirements of the GPUC that GPA perform a DSM study as part of its IRP filing.

This study was performed under that certain agreement dated July 10, 2007 between GPA and R. W. Beck (the "Agreement"). This report has been prepared for the use of GPA for the specific purposes identified in this report and is solely for the information of and assistance to GPA and should not be relied upon for any other purpose or by any other party unless authorized by R. W. Beck in accordance with the agreement.

The projections presented in this report were developed on the basis of the assumptions and circumstances described herein. In preparing this report, we have made certain assumptions with respect to conditions that may exist or events that may occur in the future. While we believe the use of such assumptions to be reasonable for the purposes stated herein, we offer no other assurances with respect thereto, and it should be anticipated that some future conditions may vary significantly from those assumed herein due to unanticipated events and circumstances. To the extent that future conditions differ from those assumed in the analysis, actual results and outcomes may vary from those projected.

The conclusions, observations, and recommendations contained herein attributed to R. W. Beck constitute the opinion of R. W. Beck. To the extent that statements, information, and opinions provided by GPA or others have been used in the preparation of this report, R. W. Beck has relied upon the same to be accurate and for which no assurances are intended and no representations or warranties are made. R. W. Beck makes no certification and gives no assurances except as explicitly set forth in this report. This report summarizes our work up to the date of this report; changed conditions which occur or become known after such date could affect the results presented in the report to the extent of such changes.

Section 2
APPROACH AND METHODOLOGY

Technical Screening Assessment

The first step in the study process included a technical screening assessment, which involved a review of all DSM measures recommended by GPA and R. W. Beck. Each potential DSM program measure was rated for its appropriateness for implementation in the GPA system based on knowledge of local retail customer end-use characteristics (e.g., appliance saturation, dwelling and building types and ages, and saturation of industrial classifications) and whether a given DSM recommendation was likely to be adopted by customers in the GPA service area.

Each potential DSM program was ranked from low to high (numerically, 0 to 5, with 5 indicating a high potential for implementation). DSM measures were ranked independently for the residential and commercial classes and for utility facilities and services. DSM measures with ratings indicating an average or better potential for implementation were considered for further evaluation in the economic screening analysis. Additionally, DSM programs that have been or are being implemented by GPA were eliminated from the analysis. GPA has previously implemented four programs (1998-2000). These programs are commercial Lighting; commercial air conditioning; residential air conditioning; and residential water heating. Although the economics of these programs seemed promising at the time, implementation was cut short in year 2000 due to lack of funds and reorganization.

Summary results of the technical screening assessment are shown below in Table 2-1. Additional results and comments are provided in Appendix A.

Table 2-1
Summary Results of DSM Technical Screening

	Applicability to GPA	
	Residential	Commercial
Energy efficiency equipment measures:		
Boiler/furnace retrofits/installations	1.8	1.8
Air conditioning retrofits/installations	2.8	2.8
Heat pumps retrofits/installations	2	2.6
Insulation of air ducts	1.4	2.2
Insulation of boilers and pipes	1.8	1.4
Clock thermostats and equipment system timers (summer)	2.4	2.4
Clock thermostats and equipment system timers (winter)	2.2	1.4
Energy efficient lighting retrofit	4.2	4.6
Electric motor replacements	0.4	1

	Applicability to GPA	
	Residential	Commercial
Renewable energy measures:		
Solar photovoltaic	3.8	3.8
Solar thermal	3.8	3.8
Day lighting technologies		1.8
Energy information programs:		
Energy audits	3.4	3.6
Public education programs	2	2
Use of infrared heat detection equipment	2.2	2.4
Equipment inspection programs	1.8	1.8
Load management measures:		
Load management (HVAC)	1	2.2
Load management (water heating)	1	1.4
Demand control techniques and equipment		1.4
Smart meters or automated equipment	0.8	1.2
Time-of-use meters	1	1.4
Rate design:		
Time-of-day rates	1.2	1.4
Seasonal rates	1	1
Interruptible rates		1

Scoring: 5 – Highly applicable to GPA retail customers.
1 – Low applicability to GPA retail customers.
0 – Existing program; no new initiative required.

Economic Screening Analysis

Based on the results of the technical screening analysis, four potential DSM programs for each customer class were identified for further evaluation in the economic screening analysis (see Table 2-2). As described below, industry-standard economic benefit-cost evaluations were used to evaluate the economic potential of each DSM measure. As described below, assumptions on DSM measure energy and demand impacts and costs were developed from available information on typical equipment costs, energy savings estimates specific to GPA's customer characteristics, and typical DSM program costs for electric utilities. Potential avoided marginal costs for GPA were based on the initial results of the IRP currently being developed by GPA. The economic analysis was conducted for a twenty-year study period (2008 through 2027).

DSM Measure Assumptions

Table 2-2 provides a general description of each DSM measure. Customer participation levels were assumed to be 1,000 in 2008, with no incremental participants through the end of the study period. By modeling the DSM measure installations at the first year of the study, the DSM measures were modeled to have the greatest possible net present benefits. As required, new DSM measure installations were modeled to occur at the end of the useful life of the measure to maintain the persistence of the DSM demand and energy reductions over the study period.

Table 2-2
DSM Measure Descriptions

DSM Measure	General Description
Residential Measures:	
Energy efficient lighting retrofit	Retrofit existing incandescent and florescent lamps with compact florescent and high-efficiency florescent lamps.
Solar photovoltaic	Install solar photovoltaic electric generation system at residential dwelling.
Solar thermal	Install solar thermal water heating system at residential dwelling.
Residential energy audits	Dwelling energy efficiency and infrared heat detection audits conducted by utility.
Commercial Measures:	
Energy efficient lighting retrofit	Retrofit existing incandescent and florescent lamps, compact florescent, HID, and high-efficiency florescent lams and fixtures.
Solar photovoltaic	Install solar photovoltaic electric generation system at business.
Solar thermal	Install solar thermal water heating system at business.
Commercial energy audits	Business energy efficiency and infrared heat detection audits conducted by utility.

GPA Cost Assumptions

Evaluation of DSM program measures requires a comparison of the DSM measure costs against avoidable utility operating and capital costs. In general, the modeled utility cost and system characteristics include the following:

- Avoidable capital costs for future GPA generation facilities;
- Avoidable O&M costs for future GPA generation facilities;
- Avoidable GPA transmission costs;
- GPA transmission and distribution losses;
- GPA financing costs and assumptions;
- Projections of average base (non-fuel) retail rates for GPA customers; and
- Projections of average and marginal GPA fuel costs.

These assumptions were developed from a number of sources, including the current GPA IRP analyses, fuel and power market price projections, and GPA retail rates. The sources and derivation of these assumptions, along with other major assumptions utilized for this study, are documented in Appendix B. Modeled annual and present value GPA electric system costs, rates, and characteristics are presented in Appendix C for two example DSM program measures.

DSM Benefit-Cost Tests

For this study, industry standardized formulae were adopted for computing DSM measure costs and benefits. We have relied upon three of the standard tests for this study: the Utility Cost Test, the Rate Impact Measure ("RIM") Test, and the Total Resource Cost ("TRC") Test. In general terms, the equations that define the three standard tests can be described as follows.

Utility Cost Test:

Benefits	=	Avoided Energy Supply Costs (net generation level decreases × marginal energy costs)
	+	Avoided Capital Supply Costs (net generation level decreases × incremental capital costs)
	+	Avoided O&M Supply Costs (net gen. or distrib. level decreases × marginal O&M costs)
	+	Participation Charges
Costs	=	Increased Energy Supply Costs (net generation level increases × marginal energy costs)
	+	Increased Capital Supply Costs (net generation level increases × incremental capital costs)
	+	Increased O&M Supply Costs (net gen. or distrib. level increases × marginal O&M costs)
	+	Utility program costs (administrative costs)
	+	Incentives (utility incentives, rebates, etc.)

Rate Impact Measure ("RIM") Test:

Benefits	=	Avoided Energy Supply Costs (net generation level decreases × marginal energy costs)
	+	Avoided Capital Supply Costs (net generation level decreases × incremental capital costs)
	+	Avoided O&M Supply Costs (net gen. or distrib. level decreases × marginal O&M costs)
	+	Revenue Gains (net meter level increases × retail rates)
	+	Participation Charges
Costs	=	Increased Energy Supply Costs (net generation level increases × marginal energy costs)
	+	Increased Capital Supply Costs (net generation level increases × incremental capital costs)
	+	Increased O&M Supply Costs (net gen. or distrib. level increases × marginal O&M costs)
	+	Revenue Losses (net meter level decreases × retail rates)
	+	Utility program costs (administrative costs)
	+	Incentives (utility incentives, rebates, etc.)

Total Resource Cost ("TRC") Test:

Benefits	=	Avoided Energy Supply Costs (net generation level decreases × marginal energy costs)
	+	Avoided Capital Supply Costs (net generation level decreases × incremental capital costs)
	+	Avoided O&M Supply Costs (net gen. or distrib. level decreases × marginal O&M costs)
	+	Avoided Participant Costs (avoided capital, O&M, etc.)
	+	Tax Credits
Costs	=	Increased Energy Supply Costs (net generation level increases × marginal energy costs)
	+	Increased Capital Supply Costs (net generation level increases × incremental capital costs)
	+	Increased O&M Supply Costs (net gen. or distrib. level increases × marginal O&M costs)
	+	Incremental Participant Costs (capital costs, O&M, etc.)
	+	Utility DSM Program A&G Costs

The computations reflect all of the incurred incremental costs and avoided incremental costs (benefits) that were used to evaluate the DSM measures.

Section 3
RESULTS

GPA has established that a DSM measure must pass both the Utility Cost Test and the RIM Test before GPA would promote a DSM measure as part of its IRP filing. A benefit to cost ratio of greater than 1.0 for the Utility Cost and RIM Tests indicates that GPA could promote and develop a given DSM program such that the program would reduce GPA's operating costs at a level greater than GPA's cost of implementing the program and that the program would not cause an increase in the retail rates charged by GPA. A summary of net benefits (or costs) and the benefit to cost ratio are provided for each evaluated DSM measure in Table 5.

Table 3-1
Summary Results of DSM Cost-Effectiveness

	NPV Benefit (Costs) ($000)			Benefit/Cost Ratio		
	Utility Cost Test	RIM Test	TRC Test	Utility Cost Test	RIM Test	TRC Test
Residential Measures:						
Energy efficient lighting retrofit	420	(161)	331	21.353	0.730	4.193
Solar photovoltaic	8,278	(2,921)	(32,901)	29.418	0.744	0.205
Solar thermal	1,556	(770)	(2,293)	16.508	0.679	0.416
Residential energy audits	249	(328)	(183)	3.094	0.592	0.722
Commercial Measures:						
Energy efficient lighting retrofit	1,902	(255)	420	13.833	0.889	1.258
Solar photovoltaic	16,555	(2,140)	(48,803)	31.418	0.888	0.258
Solar thermal	1,556	(386)	(2,293)	11.508	0.809	0.416
Commercial energy audits	727	(892)	(518)	4.636	0.568	0.694

None of the DSM measures evaluated for economic potential were found to pass both the Utility Cost and Rate impact Measure ("RIM") Test criteria. As such, GPA is not including any projections of DSM impacts in its IRP filing. However, GPA may choose to implement DSM programs for reasons that are different than the economic conditions considered by GPA. For instance, GPA may choose to ignore adverse retail rate impacts and implement DSM programs based on the Total Resource Cost ("TRC") Test results. Furthermore, it is our understanding that GPA will continue to implement its existing electric utility facility maintenance and efficiency programs, and that GPA will continue to offer public information programs on energy conservation.

G Guam Environmental Assessment

R·W·BECK

March 7, 2008

via E-mail

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

Subject: **Environmental Regulations in the Guam Piti/Cabras Area**

Dear John:

A number of questions have arisen with respect to the potential for developing new generation in the vicinity of the Cabras and Piti power plants (the "Cabras/Piti Area"). You asked us to consider the questions and provide answers to the extent that we were able.

The nature of the questions is such that the answers to a certain extent depend on technical analyses and to a certain extent rely on professional judgment considering the current situation, potential new projects and past history. We have provided the best responses possible considering the previously mentioned conditions. Please keep in mind that all possible new developments may not fit precisely into the answers as provided.

The questions that you provided are reiterated in the following text. Each is in turn followed by our response.

Regarding Air Quality Issues

Question 1(a): Non-Attainment for SOx:

The Cabras/Piti Area currently holds the status "non-Attainment for SOx"; i.e. there is a construction ban in effect for any proposed new source or modification to an existing source. Either redesignation to "Attainment for SOx" or a 325 Waiver is necessary prior to construction. A request for redesignation was submitted to USEPA in 1996 (as a requirement for obtaining the 325 Waiver for Cabras 3-4), but USEPA has not redesignated this area. A second 325 Waiver was issued by the USEPA in 1999 (Piti 8-9).

i. Which do you think will be less difficult/time-consuming: redesignating the Cabras/Piti area to Attainment, or obtaining another 325 Waiver?

Response:

If I were going to build a new power plant in the Cabras/Piti Area, I would initiate the redesignation process immediately since redesignating the area to correct status will probably a prerequisite to any new or modified conditions associated with any 325 Waiver in the Cabras/Piti area. Then, once the requirements for redesignation of USEPA were clarified, I would work with GPA to mobilize the efforts of Guam EPA and the necessary consultants to meet those

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requirements. GPA involvement is essential to coordinating the needed local cooperation of the governor's office and Guam EPA. We have some idea of what those requirements would be from past communications with USEPA [See Attachment 1]. The process promises to be a fairly complex and time-consuming effort. A key element is the need for one year of certified air quality monitoring data to support attainment status. Such data were submitted to and accepted by USEPA during July 2001 [See Attachment 2]. However, it's not unreasonable to expect that additional monitoring data would be required which will impact the schedule.

In any case, once the redesignation process was well defined, I would develop a permitting and construction schedule for the new proposed power plant. Assuming that redesignation could not be accomplished in time to then initiate permitting efforts, I would seek a 325 waiver to permit and construct the plant coincidentally with the redesignation process in anticipation of successful redesignation.

Question 1(b): Best Available Control Technology

We understand that Best Available Control Technology (BACT) is required for PSD permitting.

i. Where can we find detailed information about BACT?

ii. Is there a list of appropriate BACT for the Cabras/Piti area (i.e. non-attainment for SOx)?

iii. If BACT is incorporated into the proposed facility, how will it be reviewed and approved?

Response:

i. Numerous references may be found in the following text.
ii. BACT may be different for each generation technology, for each pollutant and for each location. So, no list is available. Furthermore, LAER applies in a non-attainment area as compared to BACT as described below.
iii. The BACT analysis is part of the PSD permitting process. As such it would be submitted as part of the PSD application and then reviewed by USEPA IX, the permitting agency charged with PSD permitting on Guam.

A key requirement of New Source Review (NSR) under Prevention of Significant Deterioration (PSD) regulations is a Best Available Control Technology (BACT) analysis to demonstrate that the control of air contaminant emissions from a proposed source will represent BACT. BACT is specifically determined for each PSD-affected proposed source on a case-by-case basis. USEPA policy requires that the BACT analysis utilize a "top-down" procedure which requires identifying and implementing the most stringent, technically feasible control for each applicable PSD regulated pollutant unless economic, energy or environmental impacts are shown to be excessive. For example, if the costs associated with the most stringent, technically feasible control for a pollutant are shown to be excessive, the next most stringent level of control must be analyzed to determine economic, energy and environmental impacts. This progression is continued until the most effective; technically feasible control is identified for which the impacts are not excessive. Therefore, in conformance with USEPA policy requiring a top-down analyses, the basic approach of each BACT analysis is to:

1. determine the applicability of each PSD regulated pollutant;
2. identify available pollution control technologies for pollutants which BACT is required and review specific BACT determinations for similar recent projects; and
3. eliminate pollution control technologies which are shown to be not technically feasible.

The applicability of each PSD regulated pollutant would be determined by estimating the uncontrolled emissions of each regulated pollutant, which are the six criteria pollutants, and then comparing those emissions to determine which of those six are significant. That test of significance is made by comparing the estimated emissions to the values published at 40 CFR 52.21(b) (23). BACT analysis would be preformed for each pollutant so identified.

Available pollution control technologies for each BACT analysis pollutant for the specifically proposed generation technology would then be identified through prudent engineering practice and review of the USEPA's RACT/BACT/LEAR Clearinghouse. The assessment of technical feasibility of each technology so identified is then made applying good engineering judgment and data from the clearinghouse related to economic, energy and environmental impacts. Based on this analysis, the most stringent, technically feasible control option is identified for each applicable pollutant.

The following excerpts from USEPA web sites provide discussions of key points related to the question at hand and references to useful information.

The USEPA Process

"Major new stationary sources of air pollution and major modifications to major stationary sources are required by the Clean Air Act to obtain an air pollution permit before beginning construction. The process is called New Source Review (NSR) and is required whether the major source or modification is planned for an area where the national ambient air quality standards (NAAQS) are exceeded (nonattainment areas) or an area where air quality is acceptable (attainment and unclassifiable areas). Permits for sources in attainment areas are referred to as prevention of significant air quality deterioration (PSD) permits while permits for sources located in nonattainment areas are referred to as NAA permits. The entire program, including both PSD and NAA permit reviews, is referred to as the NSR program.

No source or modification subject to PSD review may be constructed without a permit. PSD permits mandate the installation of pollution controls that represent the best available control technology (BACT). BACT is defined as an emission limit based on the maximum degree of reduction of each pollutant subjected to regulation under the Clean Air Act. BACT is done on a case-by-case basis, and considers energy, environmental, and economic impacts.

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Permits in nonattainment areas (NAAs) must meet the lowest achievable emission rate (LAER). In all cases, the BACT and LAER must be at least as strict as any existing NSPS for the source. The important difference between the New Source Review permits and the NSPS program is that NSR is source specific, whereas the NSPS program applies to all sources nationwide. This gives states the authority to require more stringent controls to meet the ambient air quality standards in specific geographic areas."

"Under EPA's "New Source Review" (NSR) program, if a company is planning to build a new plant or modify an existing plant such that air pollution emissions will increase by a large amount, then the company must obtain an NSR permit. The NSR permit is a construction permit which requires the company to minimize air pollution emissions by changing the process to prevent air pollution and/or installing air pollution control equipment. For more information on the NSR program, go to http://www.epa.gov/nsr.

The terms "RACT," "BACT," and "LAER" are acronyms for different program requirements under the NSR program.

RACT, or Reasonably Available Control Technology, is required on existing sources in areas that are not meeting national ambient air quality standards (i.e., non-attainment areas). BACT, or Best Available Control Technology, is required on major new or modified sources in clean areas (i.e., attainment areas).

LAER, or Lowest Achievable Emission Rate, is required on major new or modified sources in non-attainment areas.

BACT and LAER (and sometimes RACT) are determined on a case-by-case basis, usually by State or local permitting agencies. EPA established the RACT/BACT/LAER Clearinghouse, or RBLC, to provide a central data base of air pollution technology information (including past RACT, BACT, and LAER decisions contained in NSR permits) to promote the sharing of information among permitting agencies and to aid in future case-by-case determinations. However, data in the RBLC are not limited to sources subject to RACT, BACT, and LAER requirements. Noteworthy prevention and control technology decisions and information are included even if they are not related to past RACT, BACT, or LAER decisions."

"The RBLC (http://www.epa.gov/ttn/catc/rblc/htm/rbxplain.html) data base contains case-specific information on the "Best Available" air pollution technologies that have been required to reduce the emission of air pollutants from stationary sources (e.g., power plants, steel mills, chemical plants, etc.). This information has been provided by State and local permitting agencies. The Clearinghouse also contains a regulation data base that summarizes EPA emission limits required in New Source Performance Standards (NSPS), National Emission Standards for Hazardous Air Pollutants (NESHAP), and Maximum Achievable Control Technology (MACT) standards.

New and Emerging Environmental Technology (NEET), (http://www.epa.gov/ttn/catc/neet_moreinfo.html) is now open to technology users to search for new technologies and to technology providers to update or list their technologies.

RBLC (http://www.epa.gov/ttn/catc/rblc/htm/onlinelibrary.html) includes links to other Web Sites that provide technical information or guidance in making RACT, BACT and/or LAER decisions. These include sites maintained by federal, state and local agencies, the United Nations, industry trade associations and others."

Question 1(c): Prevention of Significant Deterioration Permitting

In order to have any design option approved by the USEPA, it is necessary to demonstrate that the emissions from any proposed facility will not result in exceedence of permissible Prevention of Significant Deterioration (PSD) increments or National Ambient Air Quality Standard (NAAQS) values. In order to do this, it is necessary to collect Ambient Air Quality (AAQ) data for one year in the Cabras/Piti areas. Using this data, it is then necessary to perform an AAQ Impact Analysis.

i. Is it necessary to obtain up-to-date AAQ monitoring data in the Cabras/Piti area prior to construction of a new source or modification to an existing source?

ii. Is it necessary to have the AAQ monitoring units evaluated prior to collection of the one year of data?

Response:

i. Air quality monitoring data were collected in the vicinity of Cabras and Piti during the late 1990s. A summary of those data was submitted to USEPA during 2000 showing no exceedances of the NAAQS. If no significant changes have occurred with respect to the operation of the major and minor sources in that area since 2000, a case could be made that no additional monitoring would be required for a PSD permit application. While that is likely to be acceptable to USEPA, Section 325 of the Clean Air Act (CAA) allows insular territories like Guam to petition to be exempted from many requirements of the CAA. Such a petition could possibly be used if time was critical to allow the permit application to be considered and even approved based on later monitoring of ambient air quality. In other words the monitoring could take place while the permitting process was moving forward rather than before an application could be made.

ii. Ambient air quality monitors for such studies would need to be audited to ensure that the data collected were accurate. There could be significant costs and schedule considerations associated with putting suitable monitors back in place near Cabras and Piti and then operating and auditing them.

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Regarding Water Quality Issues

Question 2(a):Thermal Discharge

It is necessary to perform a 316(a) demonstration, showing that thermal discharge would not adversely impact the marine ecosystem outside of the designated "Mixing Zone". As such, there is a condition restricting the temperature increase at the edge of the Mixing Zone to no more than one degree Celsius.

i. Is a 316(a) permit necessary if a cooling tower is incorporated into the design? How about once-through cooling?

ii. Is a 316(a) permit necessary if the proposed facility is offset by the retirement or modification of another facility?

Response:

i. From the following discussion, the location of the proposed discharge and the type of plant would affect the answer to this question. However, once thermal cooling would almost certainly invoke a 316(a) requirement.

ii. The offset concept has not been historically applied in any consistent fashion to NPDES permitting. However, a proposed discharge to Piti Channel would presumably commingle with discharges from the Cabras and Piti power plants. The plants have a fixed combined mixing zone as discussed in the following text. Therefore, reductions in the thermal discharges from either power plant would serve to physically compensate for a new discharge and could assist in meeting the temperature requirement at the edge of the mixing zone.

There are several factors that must be considered when assessing the need for a 316(a) demonstration. The key factors are where the outfall will be located, what type of plant will be involved and which agency will be the permitting authority. If the point source discharge of a heated effluent will be discharged to Piti Channel, where it would be commingled with the discharge from the Cabras Power Plant, it may be addressed as a 316(a) discharge in the resulting NPDES permit for that discharge, and it would almost certainly be required to be addressed in the current NPDES permit for Cabras Power Plant from USEPA (See http://www.guampowerauthority.com/operations/strategicplanning/documents/CabrasNPDESPermitGU0020001withattachment.pdf). The NPDES for the Cabras Power Plant at paragraph 16(h) references discharges from the Cabras Power Plant and the Piti Power Plant and sets a fixed mixing zone for the combined discharges. This concept is consistent with the regulatory requirement for lack of interference with biological communities or important species in mixing zones, which is included in the Cabras Power Plant NPDES at Paragraph 16(g).

The requirements of Section 316(a) of the Clean Water Act come into play when effluent limitations of Section 301 or the new source performance standards of Section 306 are invoked. Both apply to specific industries. Many types of power production are not specifically addressed in the regulations associated with Section 301 or Section 306. However, there are effluent guidelines for steam electric power plants. Therefore, if a type of steam electric generation will be proposed, then Section 316(a) compliance would need to be addressed in any associated NPDES permit. Power plants based on internal combustion engines or combustion turbine technology, excluding combined cycle combustion turbine plants which would be considered as steam electric, would not necessarily invoke Section 316(a) compliance. However, it is always a permit writer's prerogative to include thermal discharge limitations in any NPDES permit.

The Territory of Guam has not been delegated NPDES permitting authority by USEPA (http://cfpub.epa.gov/npdes/statestats.cfm). Therefore, USEPA Region IX would issue any NPDES permit for a new power plant. While USEPA Region IX would consult with Guam EPA and would require Guam EPA concurrence relative to Section 401 for water quality certification for any NPDES permit, Region IX is typically involved in NPDES permitting on the west coast of the continental U. S. and may tend to struggle over the analysis of any local Guam permit applications.

In summary, any discharge to Piti Channel of a significant thermal discharge may, if for no other reason then its combined effect with the Cabras Power Plant discharge; would likely require compliance with Section 316(a). If a steam electric power plant was proposed, compliance with 316(a) would be required no matter where the discharge was located. In any case, NPDES permitting may require a protracted schedule because USEPA Region IX will be the permitting authority. Furthermore, the basis of a 316(a) demonstration may be only thermal monitoring at the reasonably well defined boundary of the currently designated mixing zone. The more difficult analysis of where to establish mixing zone boundaries to minimize adverse impacts on the marine ecosystem was addressed when the Cabras Power Plant NPDES was negotiated.

Having said all of this, the effluent guidelines are undergoing extensive review by USEPA. The related studies are published in two parts: 1) 821-B-05-005 – *Preliminary Engineering Report: Steam Electric Detailed Study* (August 2005) and 2) 821-R-06-015 – *Interim Detailed Study Report for the Steam Electric Power Generating point Source Category* (November 2006). Both are available at (http://cfpub.epa.gov/npdes/techbasedpermitting/effguide.cfm). Significant revisions of the effluent guidelines are expected late during 2008.

Regarding Water Quality Issues

Question 2(b): Pollutant Discharge

Prior to construction, it is necessary to obtain a National Pollutant Discharge Elimination System (NPDES) permit, which defines all the limitations for discharge into Piti Channel and into the Public Utility Agency of Guam (PUAG) sewer system.

i. Will the NPDES Permit need to be modified to permit the discharge of brine blowdown and stormwater into Piti Channel?

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Response:

An NPDES permit will be required from USEPA Region IX for any point source discharge of water pollutants (http://www.epa.gov/npdes/pubs/101pape.pdf .). A construction NPDES will be required prior to construction if construction runoff is directed by ditches or swales to Piti Channel, wetlands or the Philippine Sea (http://www.epa.gov/npdes/pubs/cgp_appendixe.pdf). There are specific guidelines for managing the potential pollution derived from construction sites (http://cfpub.epa.gov/npdes/stormwater/swppp.cfm). Guam EPA may require a similar local permit.

An NPDES permit will be required to discharge water pollutants, including brine, to Piti Channel, wetlands, the Philippine Sea or to a municipal sewer system. Furthermore, a stormwater NPDES may be required to discharge stormwater from a point source discharge to Piti Channel, wetlands or the Philippine Sea from an operating power plant depending on the type of plant and what materials are stored on site. Stormwater discharges to a municipal sewer system are generally not allowed. Guam EPA may require a similar local permit and each NPDES permit will require a water quality certification from Guam EPA.

If you have any questions regarding this letter, please contact me at 303.299.5231.

Sincerely,

R. W. BECK, INC.

John M. McNurney
Principal and Senior Director
Environmental Services

JMM/slk

c:Angelo Muzzin

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Attachment 1

E-Mail to John Cruz dated October 19, 2006:
From: McNurney, John M. [mailto:JMcNurney@RWBeck.com]
Sent: Thursday, October 19, 2006 7:04 AM
To: John J Cruz, Jr
Cc: Alan Gilbert; Muzzin, Angelo
Subject: Redesignation

John C.,

I trust that this is what you had in mind. If not, let me know what else you may need.

Alan Gilbert and I made unofficial contacts with legal and technical personnel at Region IX, respectively. As we expected, USEPA agrees that a petition for redesignation of the Cabras-Piti area was submitted during 1996 based on air quality modeling and ambient monitoring. At that time, Region IX was looking forward to additional technical input from GPA in the form of additional ambient air quality monitoring and procedural changes from GEPA including revisions to the state implementation plan. However, the issue was not pressed by the governor of Guam, so USEPA apparently did not follow through on its data requests.

If GPA chooses to pursue redesignation after a 10-year hiatus, it will face a number of potential obstacles. Alan Gilbert and I have developed the following list of expected challenges:

- While some individuals are still at USEPA (including USEPA's lead attorney), some others will need to be familiarized with the project.
- The policies and regulatory focus at USEPA IX may have changed.
- USEPA will likely want to see additional ambient air quality monitoring data.
- USEPA will likely want to see evidence that fuel switching has been taking place as required.
- USEPA will likely also expect to see activities by GEPA that GPA will not directly control, including SIP revision, updated regulations and new permit conditions on the Cabras-Piti power plants.
- USEPA will likely also expect to see GEPA create a sulfur dioxide maintenance plan.
- Staff and administration at GEPA has likely changed.

It is also likely that unexpected issues will arise. This is not surprising when dealing with a 10-year-old petition as well as local and federal regulators. However, the Section 325 exemption available to GPA can be a powerful tool to manage those challenges.

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If GPA wants to proceed, we (John and Alan through our respective firms) would propose a phased process. First, we would work with USEPA to formally ask for consideration of the formerly submitted petition and then determine what USEPA would need to reactivate the request for redesignation. Second, we would work with GPA and GEPA to determine how and when USEPA's requests could be met. Third, we would assist GPA and GEPA to prepare submissions to USEPA if GPA decides that going forward is practical. This step could involve 325 exemption requests. Fourth, we would work with USEPA to finalize the redesignation of the Cabras-Piti area.

John M.

R·W·BECK

Attachment 2 - Letter Dated July 5, 2001 to Guam EPA from USEPA

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY, REGION 9
75 Hawthorne Street, San Francisco, CA 94105
PACIFIC INSULAR AREA PROGRAMS
PHONE (415) 744-1977 FAX (415) 744-1604
machol.ben@epa.gov www.epa.gov/region09/islands

To: Barbara Torres
Fax: (671) 646-2512

FROM: Ben Machol

SUBJECT: Piti/Cabras Monitoring Letter

19 July 2001

3 Pages

I mailed this out today.

R·W·BECK

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
REGION IX
75 Hawthorne Street
San Francisco, CA 94105

July 5, 2001

SUBJECT: Data Completeness for Ambient Monitoring in the Vicinity of Piti/Cabras Power Plant.

Jesus Salas, Administrator
Guam Environmental Protection Agency
P.O. Box 22439 GMF
Barrigada, Guam 96913

Dear Mr. Salas:

The Technical Support Office received a request from Guam EPA to review ambient monitoring for sulfur dioxide (SO_2) at five monitoring locations in the vicinity of Piti/Cabras Power Plant. The purpose of the review was to determine the sufficiency of the data relative to the redesignation of the area to attainment of the National Ambient Air Quality Standard (NAAQS). The ambient monitoring is being conducted under the nonattainment designation for SO2 made in 1987. EPA Region 9 has agreed to allow 4 consecutive quarters of clean monitoring data providing that 75% data completeness requirement is met. Based on the review of data received through September 2000 the five monitoring locations met the 75% data completeness for the following consecutive quarters:

Apra Heights -	4Q99	through	3Q00
Dededo -	4Q99	through	3Q00
Nimitz Hill -	1Q99	through	4Q99
Orote Point -	4Q99	through	3Q00
Piti -	4Q99	through	3Q00

In addition to meeting the 75% completeness requirement, no exceedances of the NAAQS for SO_2 occurred according to reported data from 1998 through 2000 at any of the monitoring stations in the vicinity of Piti/Cabras. We therefore do not need any additional monitoring data in support of the Piti/Cabras redesignation request. As a reminder, limited monitoring may be continued by agreement under any maintenance plan submitted.

If you have any additional questions please feel free to contact me at (415)744-1195.

Sincerely,

Catherine Brown

Catherine Brown,
Technical Support Office

cc: John Kennedy
Barabara Torres ✓
Ben Machol

H Energy Policy Act of 2005 Implications

May 28, 2008

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

Subject: **Energy Policy Act of 2005 and Its Implications for GPA**

Dear Mr. Cruz:

The Energy Policy Act of 2005 included a number of changes and updates to PURPA. These changes may impact Guam Power Authority as discussed below.

What is PURPA?

PURPA is the Public Utility Regulatory Policies Act of 1978. This legislation was passed by Congress to encourage conservation of energy supplied by electric utilities, optimize the efficiency of use of facilities and resources by electric utilities, and provide for equitable rates to electric consumers. The 1978 legislation established six standards for utilities to follow. The Energy Policy Act of 1992 added four more standards and, most recently, the Energy Policy Act of 2005 added an additional five standards. The purpose of this letter is to focus on the five newest standards and their implication for GPA.

Why?

PURPA applies to any electric utility with total annual retail sales of 500 million kilowatt-hours or greater. This includes GPA.

Energy Policy Act of 2005 – Standards

1. **Net Metering.** Each electric utility shall make available upon request net metering service to any electric consumer that the utility serves. The term "net metering service" means service to an electric consumer under which electric energy generated by that consumer from an eligible on-site generating facility and delivered to the local distribution facilities may be used to offset electric energy provided by the electric utility to the consumer during the applicable billing period.
2. **Fuel Diversity.** Each electric utility shall develop a plan to minimize dependence on one fuel source and to ensure that the electric energy it sells to consumers is generated using a diverse range of fuels and technologies, including renewable technologies.

1001 Fourth Avenue, Suite 2500 Seattle, WA 98154-1004 Phone (206) 695-4700 Fax (206) 695-4701

3. **Fossil Fuel Generation Efficiency**. Each electric utility shall develop and implement a ten-year plan to increase the efficiency of its fossil fuel generation.
4. **Smart Metering**. Each electric utility shall offer all of its customer classes (and individual customers upon customer request), a time-based rate schedule under which the rate charged by the utility varies during different time periods and reflects the variance, if any, in the utility's costs of generating and purchasing electricity at the wholesale level. The time-based rate schedule shall enable the electric consumer to manage energy use and cost through advanced metering and communications technology. (This reflects the opening paragraph of the standard. The second paragraph of the standard lists some of the types of time-based rate schedules that may be offered and the third paragraph provides that each electric utility subject to the first paragraph shall provide each customer requesting a time-based rate with a time-based meter capable of enabling the utility and customer to offer and receive such rate.)
5. **Interconnection**. Each electric utility shall make available, upon request, interconnection service to any electric consumer that the electric utility serves. "Interconnection service" means service to an electric consumer under which an on-site generating facility on the consumer's premises shall be connected to the local distribution facilities. Interconnection services shall be offered based upon the standards developed by the Institute of Electrical and Electronics Engineers: IEEE Standard 1547 for Interconnecting Distributed Resources with Electric Power Systems, as they may be amended from time to time. In addition, agreements shall be established whereby the services that are offered shall promote current best practices of interconnection for distributed generation, including but not limited to practices stipulated in model codes adopted by associations of state regulatory agencies. All such agreements and procedures shall be just and reasonable, and not unduly discriminatory or preferential.

What action is required?

- PURPA requires electric utilities to "consider" each standard and then "make a determination" regarding whether or not it is appropriate to implement the standard.
- Consideration and determination are required, but the decision to implement is discretionary.
- The Guam Public Utilities Commission (GPUC) must "consider and determine" the standards prior to ruling on implementation of a standard.

Deadlines for the 2005 Standards

- The deadline to begin consideration for smart metering and interconnection was August 8, 2006 and the deadline to begin consideration for net metering, fuel diversity and fossil fuel generation efficiency was August 8, 2007.

- The deadline to make a determination for smart metering and interconnection was August 8, 2007 and the deadline to make a determination for net metering, fuel diversity and fossil fuel generation efficiency was August 8, 2008.
- Failure to meet the proscribed dates usually requires the appropriate Public Utilities Commission to include review of the issue in future rate proceedings.

Proposed GPA Action Plan

- **Net Metering**. The Guam Legislature has passed a law that requires electric utilities to provide net metering service. Implementation of net metering will require the GPUC to define the rules, procedures and tariffs that would apply to customers requesting net metering. GPA and GPUC will also need to outline standards to be adopted to govern the physical interconnections and safety standards. GPA should determine, in conjunction with GPUC, the appropriate time for the regulatory process to begin on this issue. In light of the fuel diversity goals outlined in the Integrated Resource Plan (IRP), the net metering effort should start in the near future.
- **Fuel Diversity**. GPA's recent efforts on its IRP are designed to develop a strategy for fuel diversity of its generation resources. As discussed in the IRP, GPA will undertake a significant effort to acquire renewable generation in the near term. It is expected that the acquisition process will begin during 2008. The IRP also outlines GPA's desire to reduce its dependence on fuel oil by the use of LNG as a part of its fuel mix. These efforts are a significant step in diversifying GPA's fuel mix.
- **Fossil Fuel Generation Efficiency**. GPA's IRP examines several generation efficiency improvements. These efforts, including repowering some facilities with LNG, are examined at a high level. Subsequent to the acceptance of the IRP by the GPUC, it may be appropriate to develop a more detailed 10-year tactical plan of efficiency improvements.
- **Smart Metering**. The primary focus of most smart metering efforts has been on the implementation of time of use (TOU) tariffs and customer metering investments to support TOU data. The implementation of TOU on Guam would require significant study. For most utilities there exists a significant price differential between the cost of power during on-peak hours and the cost of power during off-peak periods. A large price differential drives the positive economic outcome for TOU metering. However, given the current resource mix of the GPA system, one in which the price difference between on-peak and off-peak is not great, TOU may not be economical. As GPA starts to diversify its fuel mix, then the TOU approach may be economic. Smart metering also envisions cost reductions associated with improvements in the distribution function of a utility. Smart metering and TOU activities should be considered in the near future.

- **Interconnection**. It is anticipated that the regulatory efforts defining the policies and procedures for net metering will also include policies and procedures for interconnection. The development of net metering tariffs will also include the offer of interconnection to the GPA system and the requirements for physical connection and safety requirements. A significant amount of work has been undertaken in the area of interconnection by mainland utilities and this information and data should help guide GPA toward implementation.

Sincerely,

R. W. BECK, INC.

Angelo Muzzin
Principal and Senior Director

Direct: (206) 695-4405
amuzzin@rwbeck.com

AM:bb

I Vertical Axis Turbine Viability

GLOBAL ENERGY CONCEPTS
THE Wind Resource

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April 14, 2008

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

Via email: jcruz@gpagwa.com

Subject: **Viability of Vertical Axis Turbine Technology**

Dear Mr. Cruz:

Global Energy Concepts, LLC (GEC) prepared this letter to answer your question regarding why horizontal-axis wind turbines (HAWTs) are currently more common and are regarded as more economically competitive than vertical-axis turbines (VAWTs). It is beyond the scope of our preliminary assessment to present detailed analysis comparing the merits of HAWTs versus VAWTs; however, potential height restrictions and typhoon risks elicited questions about the applicability of VAWTs on Guam. This discussion documents key differences and limitations between HAWTs and VAWTs that decisionmakers should consider regarding VAWTs. Figures 1 and 2 show a typical 3-bladed HAWT and a 2-bladed VAWT.

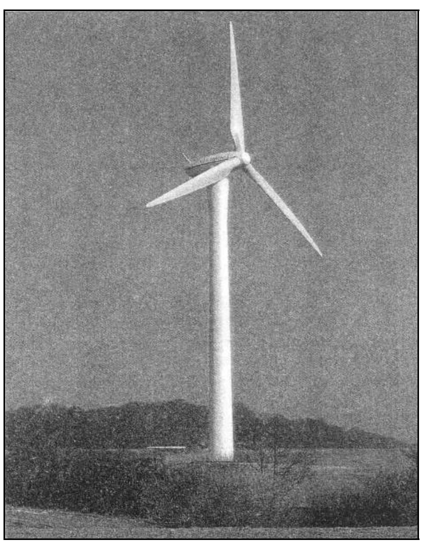


Figure 1. Typical Modern 3-Bladed HAWT

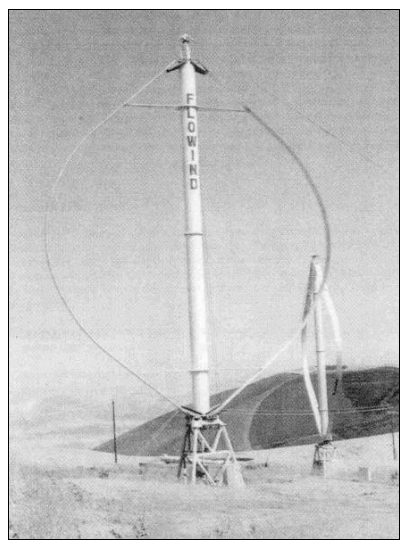


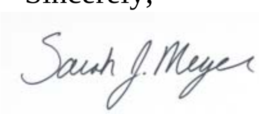
Figure 2. A Commercial 2-Bladed VAWT

Theoretically, VAWTs may offer an attractive alternative to HAWTs for locations with height and space restrictions. Many VAWT models can be installed without the use of high-capacity cranes and are not as sensitive to turbulent or omni-directional winds. Also, the major components of a VAWT, such as the drivetrain, are usually ground-mounted, allowing easier access for maintenance.

However, there are inherent limitations in any VAWT that impede its ability to offer a lower cost of energy in comparison to HAWTs. A fundamental limitation of VAWTs is their low height, which prevents the rotor from accessing stronger winds that typically prevail as height above the ground increases. In addition, the maximum aerodynamic efficiency of VAWTs will be lower than available HAWT designs. This difference is likely to be between 15% and 25%. Due to the lower efficiency, the VAWT will capture less energy for the same swept area. For a given swept area, the mass of the rotor and support structure of a VAWT will be greater than that of an equivalent HAWT. This mass difference will likely translate into a cost difference. The savings that a VAWT may enjoy due to lower drivetrain and maintenance costs are unlikely to balance the lower energy capture and higher initial rotor costs.

A few companies are marketing VAWTs as commercially available units; however, none of these companies have constructed and pilot tested their machines or had their claims of lower cost of energy independently verified. Any consideration of VAWTs should be done under the assumption that it is a demonstration project and manufacturer claims are under evaluation. In the 25-year history of the wind energy industry, virtually every government-sponsored research program has examined this issue, multiple companies have designed and built prototype VAWTs, a small number of companies have built more than 20 machines, and none have been a commercial success. Given these reasons, VAWTs are not economically competitive with HAWTs and will not be considered in our site assessment on Guam.

Sincerely,



Sarah Meyer
Senior Project Coordinator

cc: Angelo Muzzin, R.W. Beck

J Description of Analysis Tools

STRATEGIST

INTEGRATED STRATEGIST AND OPTIMIZATION

Strategist is composed of multiple application modules incorporating all aspects of utility planning and operations.

Strategist has been the industry standard for integrated resource planning for more than 25 years. Users include municipalities, electric cooperatives, state commissions, consulting firms, and investor-owned utilities. Strategist is composed of multiple application modules incorporating all aspects of utility planning and operations. This includes forecasted load modeling, marketing and conservation programs, production cost calculations including the dispatch of energy resources, optimization of future decisions, non-production-related cost recovery (e.g. construction expenditures, AFUDC, and property taxes), full pro-forma financial statements, and rate design.

PROVIEW Module

Ventyx's PROVIEW Module utilizes a proprietary dynamic programming algorithm to optimally select and rank alternative resource plans based on 10 different objective functions (including minimizing utility cost and maximizing earnings per share). Resource alternatives are evaluated while also considering purchases from and sales to a spot energy market. PROVIEW can evaluate all types of supply and demand-side alternatives:

1. Supply Side Alternatives – hydro, storage, and thermal units; multiple types of power purchase and sales contracts; and transmission interface enhancements. In addition, refurbishment, repowerment, mothballing, and/or retirement of both existing and newly added resources can be modeled. Distributed generation and renewal resources (wind, solar, biomass, geothermal, etc.) can also be represented.
2. Demand-Side Resources – energy efficiency, load control, and demand-response resources can be represented. Examples include traditional demand-side resources, such as direct load control and efficient appliance rebates, as well as time-of-use rates and real-time pricing programs.

Differential Cost Effectiveness (DCE) Module

This Module calculates the benefit-cost (B/C) ratios for each supply and demand alternative against a base resource plan. The use of a base resource plan allows the DCE Module to identify the yearly marginal capacity and energy savings for each alternative. PROVIEW and the DCE Module use the same database to define the operational characteristics and costs of supply and demand alternatives, so that cost-effective options can be directly incorporated into a full optimization analysis in PROVIEW.

Load Forecast Adjustment (LFA) Module

Our Load Forecast Adjustment Module is a multi-purpose tool for modeling and modifying load forecasts and modeling Demand Side Management (DSM) programs. The LFA Module is used in conjunction with the Differential Cost Effectiveness (DCE) Module, PROVIEW, and other Strategist modules to evaluate DSM programs. Using the LFA, a strategic planner may address key issues related to future electricity

Ventyx
Performance Proven

demand and impacts attributed to each customer group. Results from this analysis are automatically transferred to other Strategist modules to determine production costs, system reliability, cost-eff ectiveness of DSM initiatives, financing, and revenue requirements, and a variety of other indicators affected by loads.

Capital Expenditure and Recovery (CER) Module

The Ventyx CER Module provides detailed capital project modeling that is critical to accurately evaluating the economics of resource alternatives that require capital outlay. The CER can be used to model the entire capital budget of a utility company, or just the incremental capital projects associated with resource alternatives under evaluation using PROVIEW. Results from the CER Module are automatically transferred to PROVIEW, and to the Financial Reporting and Analysis (FIR) Module.

Financial Reporting and Analysis (FIR) Module

The Financial Reporting and Analysis Module provides a method of evaluating fi nancial and rate impacts of alternative construction programs, fuel cost scenarios, regulatory actions, and financial strategies. The FIR Module provides a sound structure for performing extensive analyses of the aff ects on a utility's financial condition of future inflation rates, interest rates, regulatory policies, and financial market conditions. The Class Revenue Module is a component of the FIR Module and provides for jurisdictional and customer class cost-of-service and rate projections consistent with the financial projection. The FIR Module is capable of efficiently producing planning studies in a short period of time, as well as providing the necessary detail to reflect the long-range financial structure of the company accurately.

Class Revenue Module (CRM)

Our CRM Module provides the capability to analyze long-range rate strategy and the implications of utility plans on customer classes. The CRM picks up where the jurisdictional logic in the FIR ends. All rate base and expense items that have been classified and allocated to the jurisdictions are subsequently allocated to the rate classes. Revenue requirements are then calculated to meet the target return-on-rate base. One or more rate classes may have user-input rates, allowing the rates for other rate classes to “float” in order to achieve a target return at the jurisdictional level. Additionally, the user has extensive flexibility in determining the actual structure of rates for each class, with varying proportions of expenses being recovered through the demand, energy, and customer charge portions of the total rate.

KEY BENEFITS

- Dynamic Programming Algorithm generates and evaluates all appropriate resource plans
- Evaluate the economics of resource alternatives that require capital outlay
- Analyze long-range rate strategy and its implications
- Multi-area resource optimization
- Quickly evaluate financial, rate, and shareholder impacts
- Minimize scope by reducing the need for external systems and spreadsheets
- Ensure data integrity through sound data integration
- Assess affects of market volatility on resource plans using Monte Carlo analysis

K Bibliography

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L Acknowledgements

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- **Public Utilities Commission of Guam**
  Jeffrey Johnson, Chairman

- **Consolidated Commission on Utilities**
  Simon A. Sanchez II, Chairman
  Benigno Palomo, Vice Chairman-GPA
  Eloy P. Hara, Vice Chairman-GWA
  Gloria Nelson, Secretary
  Joana "Margaret" Castro Blas, Commissioner

- 29th Guam Legislature
  Senator James V. Espaldon
  Vicente Lizama, Staff Assistant

- Bank of Guam (Financial Institution)
  Joseph P. Bradley, Senior VP/ Trust& Economic & Market Statistics Officer

- Community Representative (Environmental)
  Joanne Brown, Guam Soil & Water Conservation Liaison – UOG

- Department of Public Works / Civilian Military Task Force
  Larry P. Perez, Director / Chairman
  Dominic Muna, Solid Waste Management Superintendent
  Mario Garcia, Planner, Highway Division - Federal Highway
  Maria Duarte, Management Analyst IV, Solid Waste Management Division

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  Stephen C. Ruder, Chairman of the Board
  Jennifer O'Mallan, Staff Assistant

- Guam Contractors Association
  James Martinez, Executive Director

- Guam Energy Office
  Jlawrence M. Cruz, Director
  Noel Cruz, Engineer II

- Guam Environmental Protection Agency
  Lorilee T. Crisostomo, Administrator
  Michael J. Gawel, Planner IV
  Edwin Aranza, Planner III
  Raymond Calvo, Planner II
  Peter Q. Cruz, Environmental Health Spec. Supervisor

- Guam Hotel & Restaurant Association
  Mary P. Torre, President

- Naval Facilities Marianas
  Captain Paul T. Fuligni, Commanding Officer
  Commander Matthew Suess, Operations Officer
  Jack Brown, Utilities & Energy Conservation Manager

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  Joaquin P. Cruz, Deputy General Manager
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Michael Lynch, President and Director of Global Petroleum Service, Strategic Energy & Economic Research Inc. (SEER)
Ronald Denhardt, CEO and Vice President, Natural Gas and Power, Strategic Energy & Economic Research Inc. (SEER)
James T. Jensen, Senior Consultant, International Gas, Strategic Energy & Economic Research Inc. (SEER)

Winzler & Kelly / R.W. Beck & Consultants

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Youssef Hegazy, Ph.D., Executive Consultant – R.W. Beck, Inc.
Kenneth Rose, Ph.D., Independent Consultant
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Christina Garcia, Acting Deputy Administrator
Eleanor Umagat - Lujan, Executive Assistant
Francisco Santos, Computer Specialist

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Roberta S.N. Flores, Administrative Assistant
Bruce Best, Research Associate, University of Guam

All stakeholder meeting attendees including:

Guam Congresswoman Office Representative
Office of Senator Lujan Representative
Village Mayors
Local and Off-island Vendors, Engineers, Consultants & Contractors
GPA Independent Power Producers

GPA's Strategic Planning and Operations Research Division (SPORD):

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Bea Davis, Administrative Assistant, Executive Office/SPORD
Jennifer G. Sablan, Special Projects Engineer
Lorraine O. Shinohara, P.E., Special Projects Engineer
Maria Paz A. Tison, Special Projects Engineer
Rodney C. Cruz, Special Projects Engineer
Roel A. Cahinhinan, P.E., Special Projects Engineer
Francis J. Iriarte, P.E., Special Projects Engineer