GUAM POWER AUTHORITY
WATER SYSTEMS DIESEL UNITS

2011 ANNUAL EMISSION FEE CALCULATION WORKSHEET

2011 Annual Emissions[1]

Regulated Pollutant	Actual Annual Emission (Tons/Year)
SO2	0.00
NOx	0.00
VOC	0.00
PM (total)	0.00
Total Tons/Year	**1.00**

Regulated HAP Pollutant	TOTAL Actual Annual Emission (Tons/Year)
Total HAPs	**1.00**

[1]Based upon previous years, the actual fees incurred never reach the minimum amount to be paid per standby generator. Thus we will be basing our annual fees on the number of standby generatos (refer to note below).

2011 Annual Fee Calculations

Cost for Regulated Pollutant @ $6.00 /Ton	$6.00
Cost for HAPs @ $60 /Ton	$60.00
Total 2011 Annual Fee Due:	**$66.00**

2011 Annual Minimum Fee is per individual diesel unit is	**$100.00**
X 124 Water Systems Diesel standby generator units	x 124
2011Annual Minimum Fee	**$12,400.00**

NOTE(s):

In accordance to Section 1104.24(g) of the Guam Air Pollution Control Standards and Regulations, the base rate is $6.00 per ton for regulated pollutant and $60.00 per ton for hazardous air pollutants. For federal oversight sources, the minimum annual fee shall be $500.00. For non-federal oversight sources, the minimum annual fee shall be $100.00.

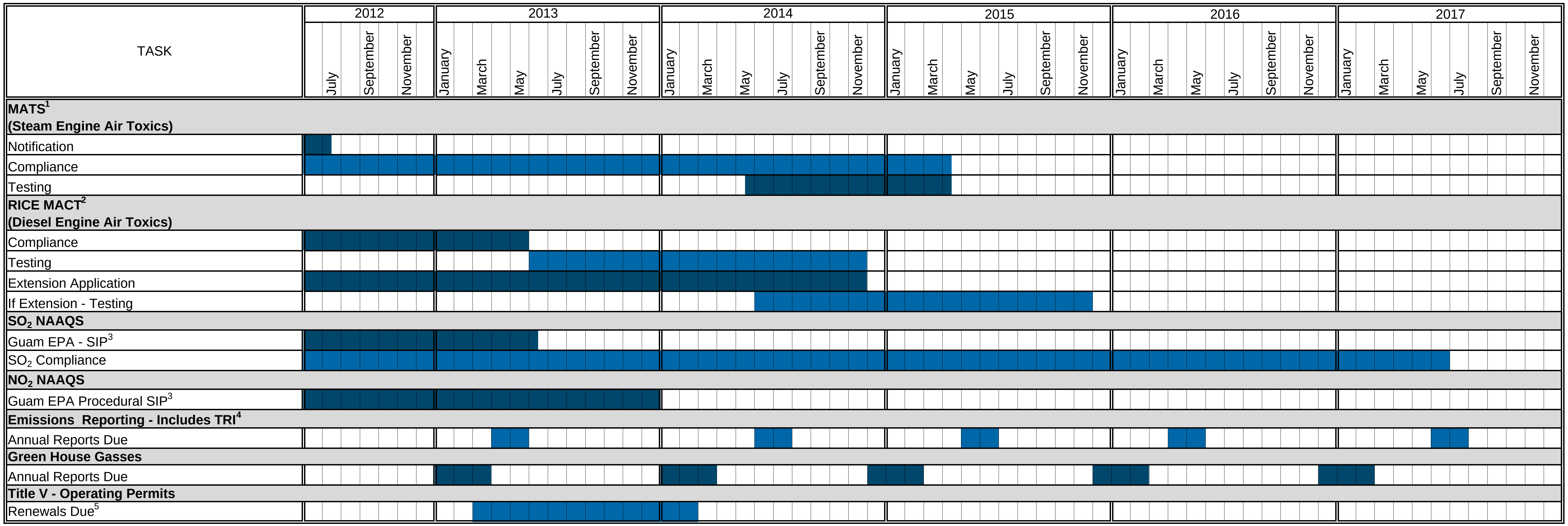
APPENDIX E

Compliance Chart

REGULATION	National Ambient Air Quality Standards	1-HR SO2 Standard	1-HR NO2 Standard	EGU MACT	DIESEL MACT (RICE MACT)		Greenhouse Gas Requirements	Clean Water Act Section 316b Requirements
REQUIREMENT	**New Short-term NAAQS:** Sulfur Dioxide (2010) - 1 Hour Average (3,24 and Annual) Nitrogen Dioxide (2010) - 1 Hour Average (Annual only) **Other New NAAQS:** Ozone (2008) - Reduced 8 Hour Average Lead (2008) - Reduced Quarterly Average (1/10) PM2.5 (2006) - Reduced 24 Hour Average (1/2) Carbon Monoxide - No change ***These combined make existing and new sources subject to tremendous pressure on emissions***			• Requires all Steam Electric Generating Units (EGU) to meet very low air emission rates of 11 toxic metals, including Mercury and emissions of chlorides and fluorides (surrogates for dioxins and furans)	• Requires all Diesel Engines greater than 500 HP to emit less than 23 ppm Carbon Monoxide. If emissions > 23 ppm, reduce emission to 23 ppm or 70% control.		• New Source or Major Modification Permitting Rules: Requires Best Available Control Technology at permitting. Generally requires energy efficiency. • New Source Performance Standards: Current proposal does not apply to non-continental sources. • Each Title V facility must apply to add GHG to Title V permit by July 1, 2012	• New Source or Major Modification Permitting Rules: Requires Best Technology Available (BTA) at permitting or permit revision. •Existing Facilities: Requires extensive operational changes to the existing cooling water intakes.
GPA Subject to Regulatory Requirements?	**YES**	**YES**	**YES**	**YES**	**YES, based on Carbon Monoxide test results for units. Emergency Engines not yet reviewed.**		**All units as they are built or modified. Existing modify Title V Permits**	**All units (Cabras 1,2,3 and 4; Tanguisson 1 and 2) are subject to the rule.**
DEADLINES / MILESTONES		• Final Rule: Jun 22, 2010 • Initial Designation: Jun 22, 2011 [Guam requests "unclassified", No EPA response] • New Monitors by December 2012, with 3 years of data by 2015. • State attainment decisions by June 2011, EPA attainment decisions by June 2012. • State Implementation Plan Due to EPA: Jun 22, 2013 • Attainment by Jun 22, 2017	• Final Rule: feb 9, 2010 • Guam Monitoring Plans Due Jul 1, 2011 • Guam Monitoring to begin: Jul 1, 2013 • Attainment Designation: Jul 1, 2016 • Guam Implementation Plan Due: January 1, 2018 • Compliance Date: Jan 1, 2021	• Initial Notification sent to USEPA 7/6/2012. • Request for one-year extension due October 29, 2012. • **Request for additional one-year extension due to reliability issues due (Due April 29, 2013)** •Testing Requirements Between April 16, 2014 and April 16, 2015 - each unit will need to be tested (stack tests) for compliance with the rule. • Quarterly stack testing for metals - estimated at $200,000 per year for all 4 units (Cabras 1&2, Tanggo 1&2) Note: CEM for PM (not recommended by TRC due to unreliability of available monitors)	• Final Rule: Aug 20, 2010 • Initial Notification Deadline: Feb 11, 2011 (completed April 2012, late filing) • Extension request for fast track diesels and exemption request for slow speed diesels July 2012 • Compliance Date May 3, 2013 • One-year Extension Compliance Date: May 3, 2014 (request filed) • Conduct performance tests to demonstrate compliance within 180 days after compliance date (December 16, 2013 or 2014)		• New Source or Major Modification Permitting Rules: Jun 3, 2010 • New Source Performance Standards: Proposed Rules expected to be finalized Fall of 2012. • Existing units need TitleV permit modifications.	• Final Rule expected Fall 2012. • Compliance required at NPDES permit renewal. Tanguissen received renewal permit before requirements Final. Requirement for study and mitigation in new permit. Requirement for study and mitigation in drfat cabras permit.
EFFECTIVE DATES	• Need to install control device such as "scrubbers" by May 2017. • Proposed scrubbers for each Cabras 1&2, Tango 1&2 units to meet SO2 NAAQS would also meet the MATS requirements.		• Attainment by Jul 1, 2017.	• Compliance Date: April 16, 2015 • One-year extension compliance: • One-year extension compliance (reliability issues)	• **Compliance Date: May 3, 2013** • One-year Extension Compliance Date: May 3, 2014 (request submitted)		• **New Source or Major Modification Permitting Rules: Jun 3, 2010**	• **Upon permit renewal**
GPA Options for COMPLIANCE		• Option 3 For RFO, use of Wet or Dry Scrubber to meet SO2 emission limits. • Option 2: Switch to ULSD orOption 1: Switch to LNG	• All units as they are built or modified.	• OPTION 1: Reduced Metal in Oil - may possibly meet standard. However, reduction of metals in current RFO supply may lead to significant increase in fuel costs. • OPTION 2: Installation of Electrostatic Precipitators (ESPs) • OPTION 3 for TANGUISSON: Tanguisson has the option to reduce rated capacity of each unit to 25MW from 26.5 MW to avoid MATS requirements.	• ULSD-fired units (Fast Track Diesels) expected to add Oxidation Catalyst to the exhaust stream. 2-3 months shipment, installation and testing (once engineered and purchased). Units will only need to be offline for 1-2 days.	RFO-Fired Units (SSD) - sending exhaust gases directly to catalyst will oxidize SO2, creating sulfuring acid. • OPTIONS: (1) Apply for Exemption (Request Submitted) (2) Use Lower Sulfur Diesel Oil and Control Costs (3) Use Liquefied Natural Gas - Not subject to Rule (4) Installation of dry limestone scrubbing plus baghouse, then catalyst	• Energy efficient operation of units and plant.	2 Options: • Option1: Demonstrate mimimal fish impingement. • Option 2: reduce inflow to 0.5 feet per second.
INSTALLED CAPITAL COST		**Option 3** - Installation of control equipment using Scrubbers: • Wet FGD system = Cabras 1&2 @$ 79M per unit; Cabras 3&4 @ 58.5 M per unit. • Lime Spray Drying system = Cabras 1&2 @ $129 M per unit; Cabras 3&4 @ $ 97M per unit.		**Option 2** - <u>MATS compliance only</u> with the Installation of control equipment using Electrostatic Precipitators (ESP) • Cabras 1&2 = $17.4M per unit • Tanguisson 1&2 = $7.0M per unit	• Tenjo $170,000 each if separate • Dededo $100,000 each if separate • Manenggon 1&2 $203,000 each if separate • Talofofo 1 and 2 $170,000 each if separate TOTAL COST = $2,166,000	• Cost Impacts of other options: (1) [none] (2) $73,000,000 per year increase Cabras 3&4 $3,060,000 MEC 8&9 $3,441,000 (3) Cost of LNG Conversion (4) $58,000,000 per year increase Cabras 3&4 $191,175,000 MEC 8&9 $218,190,000	• Could require capital costs.	• Costs Unknown
ANNUAL OPERATING COSTS (O&M)		Option 3: Cabras $2,000,000/year/unit: Tango: $800,000/year/unit		• Compliance Test = $25,000 per unit • Initial Mercury Test - $12,000 per unit NOTE: Travel Costs for testing company not included. Annual Operating Cost • Cabras = $442,200 per unit • Tanguisson = $175,500 per unit	• Tenjo $183,000 • Dededo $72,000 • Manenggon 1&2 $74,000 • Talofofo 1 and 2 $61,000 TOTAL COST = $390,000	• Cost Impacts of other options: (1) [none] (2) Operating Costs Cabras 3&4 $551,000 MEC 8&9 $620,000 (3) Cost of LNG Fuel (4) $58,000,000 per year increase Cabras 3&4 $4,190,000 MEC 8&9 $4,700,000	• Could be cost savings.	• Study cost $140,000 per site
PENALTY FEES		• $37,000 per unit for each day of non-compliance.	• $37,000 per unit for each day of non-compliance.	• $37,000 per unit for each day of non-compliance.	• $37,000 per unit for each day of non-compliance.	• $37,000 per unit for each day of non-compliance.	• $37,000 per unit for each day of non-compliance.	• $37,000 per unit for each day of non-compliance.

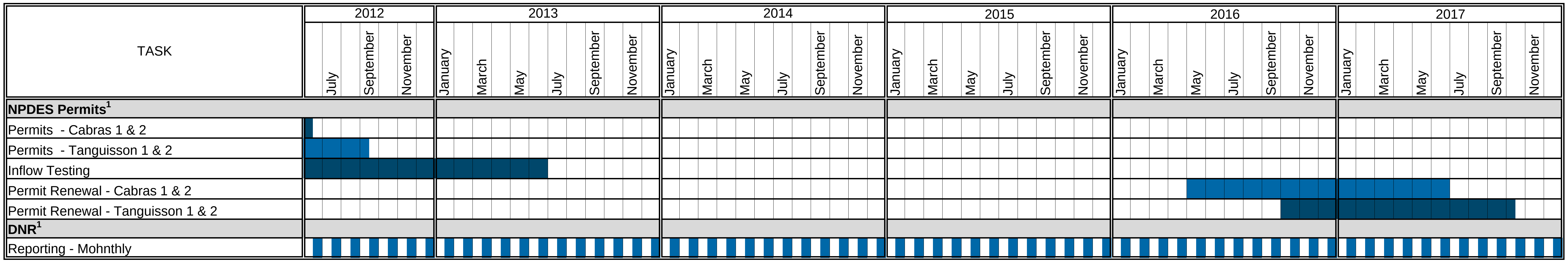
ADDITIONAL INFORMATION				TESTING COSTS IN 2014:
				• Cabras 1&2 $100,000 each
				• Tanguisson 1&2 $100,000 each
				NOTE: Start-ups, shutdown and tune-up requirements must be considered.
					• Issue: limited number of suppliers
					• Issue: oxidation could be up to 40% SO2
					>>> 33% or higher increase in cost of fuel
					>>> 33% or higher increase in cost of fuel
					>>> More fuel would be needed to heat exhaust gases to temperature high enough to convert to CO (very expensive)
					>>> need feasibility study
					• Issues with LNG conversion			

Guam Power Authority
Clean Air Act
Compliance Windows



[1]MATS - Affected units: Cabras 1 & 2; Tanguisson 1 & 2
[2]RICE MACT - Affected Units:
Tenjo 1-6; Dededo 1-4; Manenggon 1 & 2; Talofofo 1 & 2; Cabras 3 & 4; MEC 8 & 9; All Stand-by Generators
[3]Guam EPA Compliance SIP due 18 months after USEPA non-attainment declaration
[4]Includes Toxic Release Inventory (TRI) Community Right to Know reporting
[5]Title V Renewals for:
Cabras 1-4; Tanguisson; MEC 8 & 9; Tenjo 1-6; Dededo 1-4; Maneggon 1 & 2; Talofofo 1 & 2

Guam Power Authority
Clean Water Act
Compliance Windows



[1]Applies to Cabras 1 & 2; Tanguisson 1 & 2TS - Affected units: Cabras 1 & 2; Tanguisson 1 & 2

Environmental Strategic Plan (ESP)

ADDENDA

February 2013

The following changes / additional information shall be included in GPA's Environmental Strategic Plan. These changes resulted from additional work conducted by GPA and its consultant, TRC Environmental in the course of investigating options for environmental compliance.

ADDENDUM 1: **Correction to Economic Impact of compliance with the RICE MACT rule**.

In the original Environmental Strategic Plan, Section 4.1.3.5 Economic Impact illustrated costs associated with compliance to the RICE MACT to be $2,200,000.00 in capital costs for the fast track diesel units. Further research showed that construction and installation would cost at least an additional $1,000,000.00 for the small diesel units and $100,000,000 to $400,000,000 for the slow speed diesel units, in addition to the original costs indicated. The revised paragraph below reflects the corrected amount, which has increased from $2,000,000.00 to $3,000,000 - $4,500,000. These changes were also reflected on the Compliance Chart in Appendix E (attached).

There are also some corrections to estimated compliance costs for the slow speed diesels. In the original Environmental Strategic Plan, the Compliance Chart in Appendix E showed that costs associated with compliance to the RICE MACT Option 3 to be the cost for conversion to LNG. However, in discussions with TRC in relation to GPA's Integrated Resource Plan, it was determined that conversion to LNG would also require installation of oxidation catalyst to comply with requirements. Thus, installation and O&M costs for oxidation catalyst should be included in Option 3, in addition to cost for conversion to LNG. These changes were also reflected on the Compliance Chart in Appendix E (attached).

The section is also revised, as follows:

4.1.3.5 Economic Impact

The Boiler MACT will cost approximately $48,400,000 for ESP installations on the Cabras and Tanguisson steam units. As indicated earlier, GPA could remove this cost entirely by advancing the installation of the NAAQS compliance equipment, scrubbers. The cost for the scrubbers is estimated at $220,000,000 for wet scrubbers or $362,000,000 for dry scrubbers. In addition, quarterly testing is estimated to cost $200,000 per year for all four steam units.

The RICE MACT is estimated to cost $3,000,000 to $4,250,000 in capital, construction and installation costs and $300,000 per year for compliance at the Ultra-Low Sulfur Diesel Units (assuming that the Dededo diesels are not included). At the slow speed diesels however, the cost would be $100,000,000 to $400,000,000 capital, construction and installation costs for control or more than $70,000,000 per year increase fuel and maintenance costs if fuel was converted to Ultra Low Sulfur Diesel. If these units were converted to LNG, the capital cost would involve cost for converting to LNG, in addition to about $3,000,000 to $4,000,000 capital cost for each unit, as well as $500,000 to $600,000 additional annual O&M costs.

ADDENDUM 2: **Correction to Penalty Fees in Compliance Chart**.

Penalty Fees Per Unit, Per Day of non-compliance should be $37,500.00 instead of $37,000 as originally indicated on the chart. Corrected Compliance Chart is attached.

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GPA Options for COMPLIANCE		• Option 3 For RFO, use of Wet or Dry Scrubber to meet SO2 emission limits. • Option 2: Switch to ULSD orOption 1: Switch to LNG	• All units as they are built or modified.	• OPTION 1: Reduced Metal in Oil - may possibly meet standard. However, reduction of metals in current RFO supply may lead to significant increase in fuel costs. • OPTION 2: Installation of Electrostatic Precipitators (ESPs) • OPTION 3 for TANGUISSON: Tanguisson has the option to reduce rated capacity of each unit to 25MW from 26.5 MW to avoid MATS requirements.	• ULSD-fired units (Fast Track Diesels) expected to add Oxidation Catalyst to the exhaust stream. 2-3 months shipment, installation and testing (once engineered and purchased). Units will only need to be offline for 1-2 days.	RFO-Fired Units (SSD) - sending exhaust gases directly to catalyst will oxidize SO2, creating sulfuring acid. • OPTIONS: (1) Apply for Exemption (Request Submitted) (2) Use Lower Sulfur Diesel Oil and Control Costs (3) Use Liquefied Natural Gas - subject to rule if dual-fired (use of %5 Diesel Fuel for ignition) (4) Installation of dry limestone scrubbing plus baghouse, then catalyst	• Energy efficient operation of units and plant.	2 Options: • Option1: Demonstrate mimimal fish impingement. • Option 2: reduce inflow to 0.5 feet per second.
INSTALLED CAPITAL COST		**Option 3** - Installation of control equipment using Scrubbers: • Wet FGD system = Cabras 1&2 @$ 79M per unit; Cabras 3&4 @ 58.5 M per unit. • Lime Spray Drying system = Cabras 1&2 @ $129 M per unit; Cabras 3&4 @ $ 97M per unit.		**Option 2** - MATS compliance only with the Installation of control equipment using Electrostatic Precipitators (ESP) • Cabras 1&2 = $17.4M per unit • Tanguisson 1&2 = $7.0M per unit	• Tenjo $340,000 each if separate • Dededo $200,000 each if separate • Manenggon 1&2 $406,000 each if separate • Talofofo 1 and 2 $340,000 each if separate TOTAL COST = $3,000,000 to $4,250,000	• Cost Impacts of other options: (1) [none] (2) $73,000,000 per year increase Cabras 3&4 $3,060,000 MEC 8&9 $3,441,000 (3) Cost of LNG Conversion Cabras 3&4 $3,060,000 MEC 8&9 $3,441,000 (4) $58,000,000 per year increase Cabras 3&4 $191,175,000 MEC 8&9 $218,190,000	• Could require capital costs.	• Costs Unknown
ANNUAL OPERATING COSTS (O&M)		Option 3: Cabras $2,000,000/year/unit: Tango: $800,000/year/unit		• Compliance Test = $25,000 per unit • Initial Mercury Test - $12,000 per unit NOTE: Travel Costs for testing company not included. Annual Operating Cost • Cabras = $442,200 per unit • Tanguisson = $175,500 per unit	• Tenjo $183,000 • Dededo $72,000 • Manenggon 1&2 $74,000 • Talofofo 1 and 2 $61,000 TOTAL COST = $390,000	• Cost Impacts of other options: (1) [none] (2) Operating Costs Cabras 3&4 $551,000 MEC 8&9 $620,000 (3) Cost of LNG Fuel Cabras 3&4 $551,000 MEC 8&9 $620,000 (4) $58,000,000 per year increase Cabras 3&4 $4,190,000 MEC 8&9 $4,700,000	• Could be cost savings.	• Study cost $140,000 per site
PENALTY FEES		• $37,500 per unit for each day of non-compliance.	• $37,500 per unit for each day of non-compliance.	• $37,500 per unit for each day of non-compliance.	• $37,500 per unit for each day of non-compliance.	• $37,500 per unit for each day of non-compliance.	• $37,500 per unit for each day of non-compliance.	• $37,500 per unit for each day of non-compliance.

ADDITIONAL INFORMATION				TESTING COSTS IN 2014:
				• Cabras 1&2 $100,000 each
				• Tanguisson 1&2 $100,000 each
				NOTE: Start-ups, shutdown and tune-up requirements must be considered.
					• Issue: limited number of suppliers
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					>>> 33% or higher increase in cost of fuel
					>>> 33% or higher increase in cost of fuel
					>>> More fuel would be needed to heat exhaust gases to temperature high enough to convert to CO (very expensive)
					>>> need feasibility study
					• Issues with LNG conversion			

C Capacity Reserve Analysis

February 14, 2013

via e-mail: **jsablan@gpagwa.com**

Mrs. Jennifer Sablan
Guam Power Authority
P.O. Box 2977
Hagatna, Guam 96932

Subject: **Guam Power Authority Integrated Resource Plan – Capacity Reserve Analysis**

Mrs. Sablan,

The Guam Power Authority (GPA) engaged R. W. Beck, an SAIC Company, to assist in evaluating which of the GPA generating units are candidates for ongoing operations and which units are candidates for retirement. R. W. Beck has conducted a capacity reserve analysis, in coordination with GPA, to assist GPA in deciding which units are needed to provide reliable power to meet system demand, either actively or in a reserve role, versus those units that could be retired. The capacity reserve is the difference between the dependable capacity available and the anticipated peak demand. The analysis included a review of the size and reliability of GPA's primary energy producing units and an assessment of the combination of units that provide for the most efficient reserve capacity.

R. W. Beck in coordination with GPA developed a list, a dispatch stack, of the GPA units based on operating costs, to identify the existing units that should be dispatched to meet system demand in the most cost effective manner. This analysis included a review with GPA to identify any unit or system drivers or constraints that would result in adjustment to the stack, such as operating limits in the permits, or units that supply voltage support to the grid. Of the units that did not actively dispatch to meet system demand, we evaluated which were operable, which could be the most efficient resources for reserve capacity, and which units could be useful for other reasons, such as voltage support. Of the units shown to be the best candidates for reserve and reliability purposes, we assessed the need for any significant maintenance, repairs, renewals, upgrades, or enhancements to help ensure the units meet industry standards of operability and be expected to provide for adequate, long-term reliability.

R. W. Beck and GPA performed a second iteration of the analysis after conducting the modeling of the long-term resource planning to determine if any proposed generating options resulted in adjustment to the analysis described above for the existing units.

Reliable Delivery of Power

Meeting system demand requires not only generation, but also transmission and distribution. The Institute of Electrical and Electronics Engineers (IEEE) has established reliability indicators that are commonly used by electric power utilities. The three primary indicators are System Average Interruption Frequency Index (SAIFI), System Average Interruption Duration Index (SAIDI), and Customer Average Interruption Duration Index (CAIDI). SAIFI is the average number of interruptions that a customer would experience over a year. SAIDI is the average outage duration for each customer served, and CAIDI is the average outage duration that any given customer would experience. The table below shows the indicators for publicly owned utilities based on the American Public Power Associations (APPA) 2009 survey along with the indicators for GPA. The data in the table is presented to help quantify and understand the capacity reserve analysis discussed further herein and is from the APPA 2009 Distribution Reliability & Operations Survey.

Table 1
Reliability Indices

Measure	SAIFI (Frequency)	SAIDI (Minutes)	CAIDI (Minutes)
Top Quartile Range	0.25	14.66	38.74
Upper Middle Quartile Range	0.54	34.27	61.63
Lower Middle Quartile Range	0.87	50.84	75.33
Bottom Quartile Range	2.09	174.55	169.57
Average	0.88	68.98	86.75
GPA (Oct 2010 – Sep 2011)	16.78	738.26	43.98

Based on the relatively high SAIFI, SAIDI, and CAIDI values above, reliability is a major issue for GPA. Because reserve capacity can increase reliability, the need to have sufficient and reliable reserve capacity is important to GPA. It should be noted that the data above includes interruptions caused not only by issues with generation, but also transmission and distribution. While we cannot quantify the degree to which the above values are a function of transmission/distribution issues, we understand that generation reliability is significant issue for GPA. Therefore, our analysis has focused primarily on the GPA generating units.

GPA System Supply and Demand

Typical utility practice is to employ a combination of baseload, intermediate, and peaking units to meet system demand for capacity and energy. Baseload units provide the majority of the required system energy and are typically dispatched at full load and designed to operate on a continuous basis to meet the minimum system capacity and energy demand. These units typically have lower operating costs and commonly utilize boiler and steam turbine (ST) technology. Intermediate units are typically employed to provide the varying capacity and energy needs of the system on a daily or weekly basis. Historically, these units have higher costs than baseload units, but are generally designed to have more operating flexibility to follow system load. Intermediate units are typically based on combustion turbine (CT) technology in combined cycle with a ST peaking units are typically employed to provide capacity and energy to cover the peak system capacity and energy demand sometimes for only a few hours. These units typically have higher operating costs per unit of production, but can cycle on and off frequently and ramp up to full production quickly. Reciprocating engines (Recip) and CT are often utilized for peaking service.

The existing generating resources operated by GPA are summarized in the table below. GPA has generating resources with a total nameplate rating of approximately 550 MW.

Table 2
Summary of GPA Generation Resources

Unit	Technology	Fuel	Nameplate Capacity, MW	Service Date
Cabras 1	Boiler & ST	RFO No. 6	66	1974
Cabras 2	Boiler & ST	RFO No. 6	66	1975
Cabras 3	Slow Speed Recip	RFO No. 6	39.3	1996
Cabras 4	Slow Speed Recip	RFO No. 6	39.3	1996
Dededo CT 1	CT	Diesel No. 2	23	1992
Dededo CT 2	CT	Diesel No. 2	23	1994
Dededo Recip 1-4	Medium Speed Recip	Diesel No. 2	2.5 ea/10 total	1972
Macheche CT	CT	Diesel No. 2	22	1993
Marbo CT	CT	Diesel No. 2	16	1993
MDI Recip 1 & 2	Medium Speed Recip	Diesel No. 2	5.3 ea/10.6 total	1993
Piti 8 (MEC)	Slow Speed Recip	RFO No. 6	44.2	1999
Piti 9 (MEC)	Slow Speed Recip	RFO No. 6	44.2	1999
Piti 7 (TEM)	CT	Diesel No. 2	40	1997
Talofofo Recip 1 & 2	Medium Speed Recip	Diesel No. 2	4.4 ea/8.8 total	1994
Tanguisson 1 (PRU)	Boiler & ST	RFO No. 6	26.5	1976
Tanguisson 2 (PRU)	Boiler & ST	RFO No. 6	26.5	1976
Tenjo Recip 1-6	Medium Speed Recip	Diesel No. 2	4.4 ea/26.4 total	1994
Yigo CT	CT	Diesel No. 2	22	1993

Understanding the system demand in terms of peak and average capacity needs, as well as the load shape, is the first step in assessing capacity reserves. To that end we have reviewed the historical system demand and the projections for future system demand in coordination with GPA. The results of this review indicate an historic peak demand of approximately 270 megawatts (MW). The historical and projected system demand is presented in the figure below.

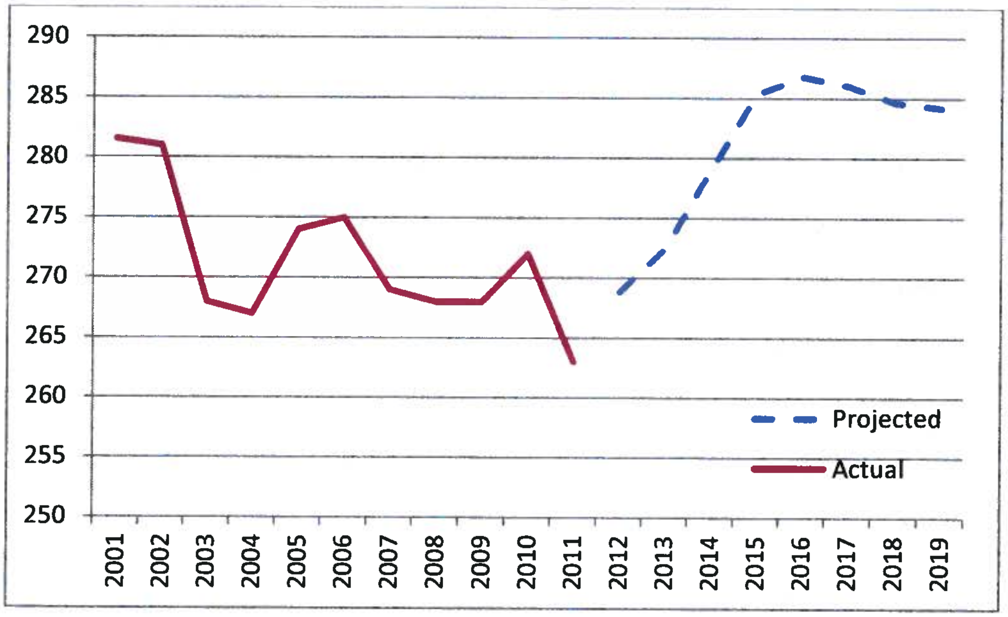

Figure 1 - Historical and Projected System Demand

GPA has approximately 550 MW of installed power generating capacity to meet its peak load of approximately 270 MW. The available generation over and above the 270 MW needed to meet the system peak load, 280 MW of installed capacity, represents approximately 100 percent of the peak system demand, which is significant back up generation.

Reserve Margins

Electric utilities in the mainland U.S. are typically required to have access to certain levels of capacity on reserve to support the grid in the event of a forced or scheduled outage of the units that are typically dispatched to meet system demand. The capacity reserves can be maintained in various forms, including maintaining units with capacity equal to a percentage of peak system demand, either as spinning or non-spinning reserves, and/or having a certain level of interruptible load that can be curtailed to reduce system demand. Reserves can be determined by a loss of load probability (a statistical approach) or by the size of a single generating unit within a service territory. There are varying philosophies relating to how to determine the amount of capacity reserves to maintain.

Selection of a capacity reserve margin is not an exact science. Statistically, the probability that there would be a service interruption due to insufficient capacity is a complex calculation involving a number of variables with different probabilities of occurrence. Mathematically, having a greater number of smaller units provides higher probability of reliability than having fewer larger units.

Further, stand alone systems generally require larger reserve margins than those that have interconnections to other systems.

In the 1930's ConEd in New York was the first utility to attempt to quantify the amount of excess capacity needed to assure a high degree of reliability. ConEd considered the loss of its single largest unit or 15 percent of the peak demand as reasonable basis for setting reserve margins. In the 1970's one Pennsylvania utility determined that it had a service interruption rate of 1 day in 10 years, based on historical data of its system as it was planning for the addition of new generation. These methods of setting reserve margins became the basis for the industry standards that are still used in today.

Statistical analysis is used in some cases, based on the number of units being employed to meet demand and the forced outage rates of those units, to determine the expected potential duration of time that system demand would not be met. For example, as was the case with the Pennsylvania utility, a target may be to maintain sufficient additional capacity to statistically avoid failing to meet system demand for more than 1 day in every 10 years. For large systems with numerous generating units, this philosophy works to reduce the percentage of excess capacity required assuming low forced outage rates. Another method is to maintain sufficient additional capacity to support loss of large generating units or transmission assets, and may include geographic consideration. As of a result of the varying methodologies employed, typical capacity reserves in the mainland U.S range from 10 to 18 percent of peak system demand.

It is important to note that relative to large systems in the mainland U.S. the GPA system has a small peak demand and has a small number of generating units. The impact of the loss of one unit can be more significant to a smaller system than to a larger system, because it likely represents a larger portion of the generation being operated to meet the load. Therefore, it is prudent to be conservative in determining the amount of capacity reserve to maintain and what form that capacity takes.

Current Dispatch Stack

To gain insight into the amount and form of GPA's capacity reserve we developed a simple dispatch stack, based on the operating cost for each unit, which identified the most cost effective way to dispatch the units into service. Figure 2 below shows the dispatch stack of the existing GPA units.

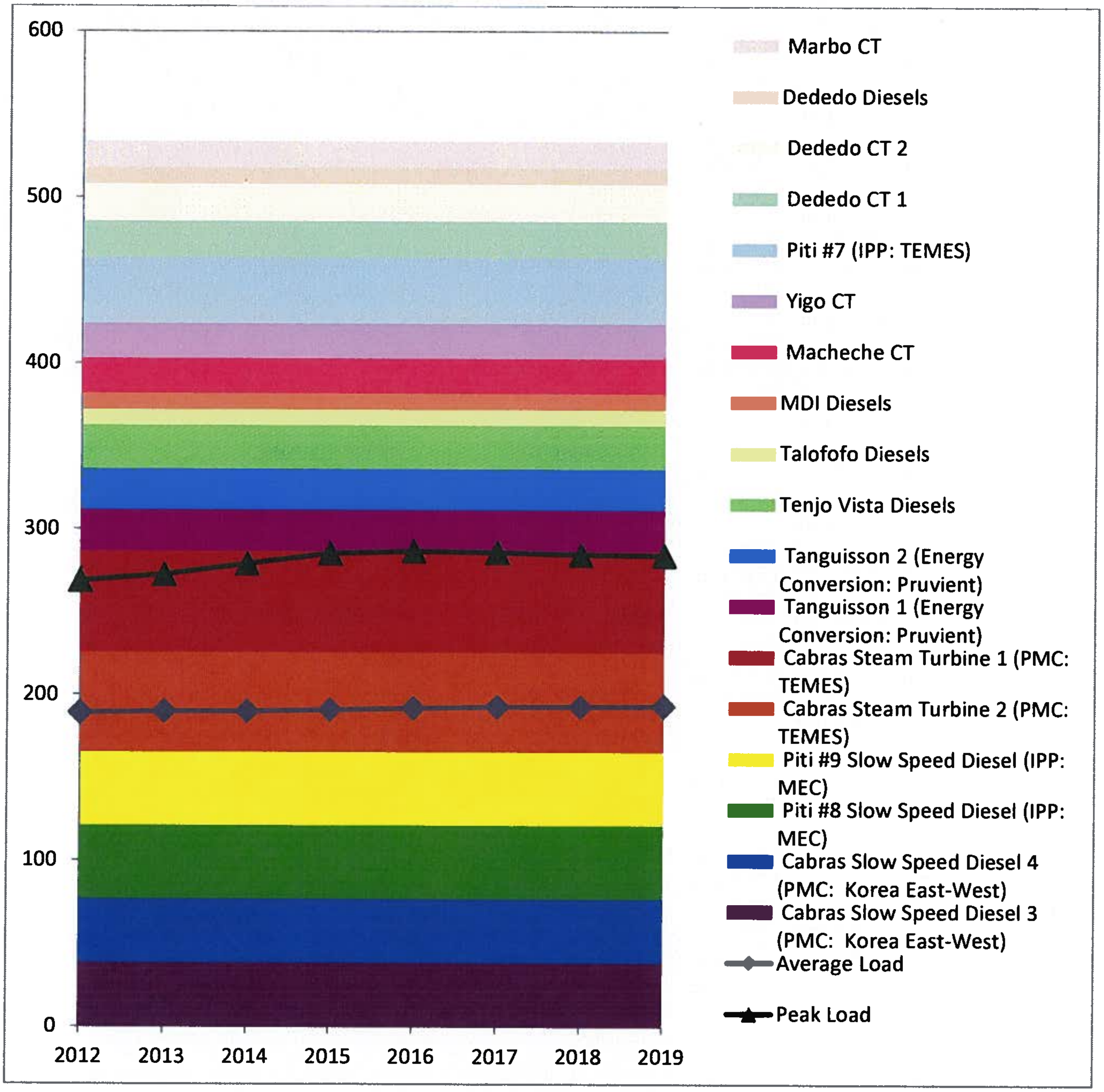

Figure 2 - Current Unit Dispatch Stack

Based on the dispatch stack presented in Figure 2 above, the slow speed Recips (Cabras 3 and 4 along with Piti 8 and 9) are the most economical units and should be used to meet load first. These four units can provide a majority of the capacity (and energy) needed to meet the GPA system average load. However, to provide the balance of the capacity needed to meet the average system demand the Cabras 2 unit would need to be dispatched. Cabras 2 would only need to be dispatched at part load to meet the average system demand. Based on economic dispatch, the Cabras 1 unit would be the next unit to be placed into service to meet peak system demand.

The Cabras 1 and 2 units are conventional boiler and ST technology. This technology is typically used in baseload service and is generally not designed to be most efficient at part load or to quickly swing load to meet variances in system demand. The next units in the dispatch stack are the Tanguisson 1 and 2 units, which are also conventional boiler and ST technology. GPA has indicated that the Tenjo Recips are often called on to meet system demand because there are multiple units that can be started and shutdown quickly, which can be operated at part load, and have the ability to load follow more readily than the larger Cabras and Tanguisson units. Further, historical data indicates that GPA does utilize units higher in the stack, such as Macheche and Piti 7 to meet system demand, during times when units lower in the stack are not available.

N-2 Methodology

A dispatch stack based on operating costs provides some insight into a cost effective way to dispatch units to meet system demand. This approach, used in conjunction with the loss of the single largest unit (N-1) philosophy can begin to quantify a reserve margin for the GPA system. GPA is a small isolated system with few generating units relative to the larger systems in the main land U.S. A single unit on the GPA system meets the demand of a large percentage of the system demand. Therefore, to be conservative in our analysis, we considered the loss of the two largest units (N-2) rather than just the loss of the single largest unit. The resulting dispatch stack for the GPA system using this N-2 methodology resulted in the loss of the Cabras 1 and 2 units and is depicted in Figure 3 below. The N-2 approach results in the loss of system capacity of between 122 MW and 132 MW, or approximately 45 percent of peak demand. The revised dispatch stack, incorporating the loss of the two largest units indicates that several other existing units, including Tanguisson 1 and 2, the Tenjo Recips, the Talafofo and MDI Recips, and the Macheche and Yigo CTs, become critical to GPA being able to successfully meet system demand.

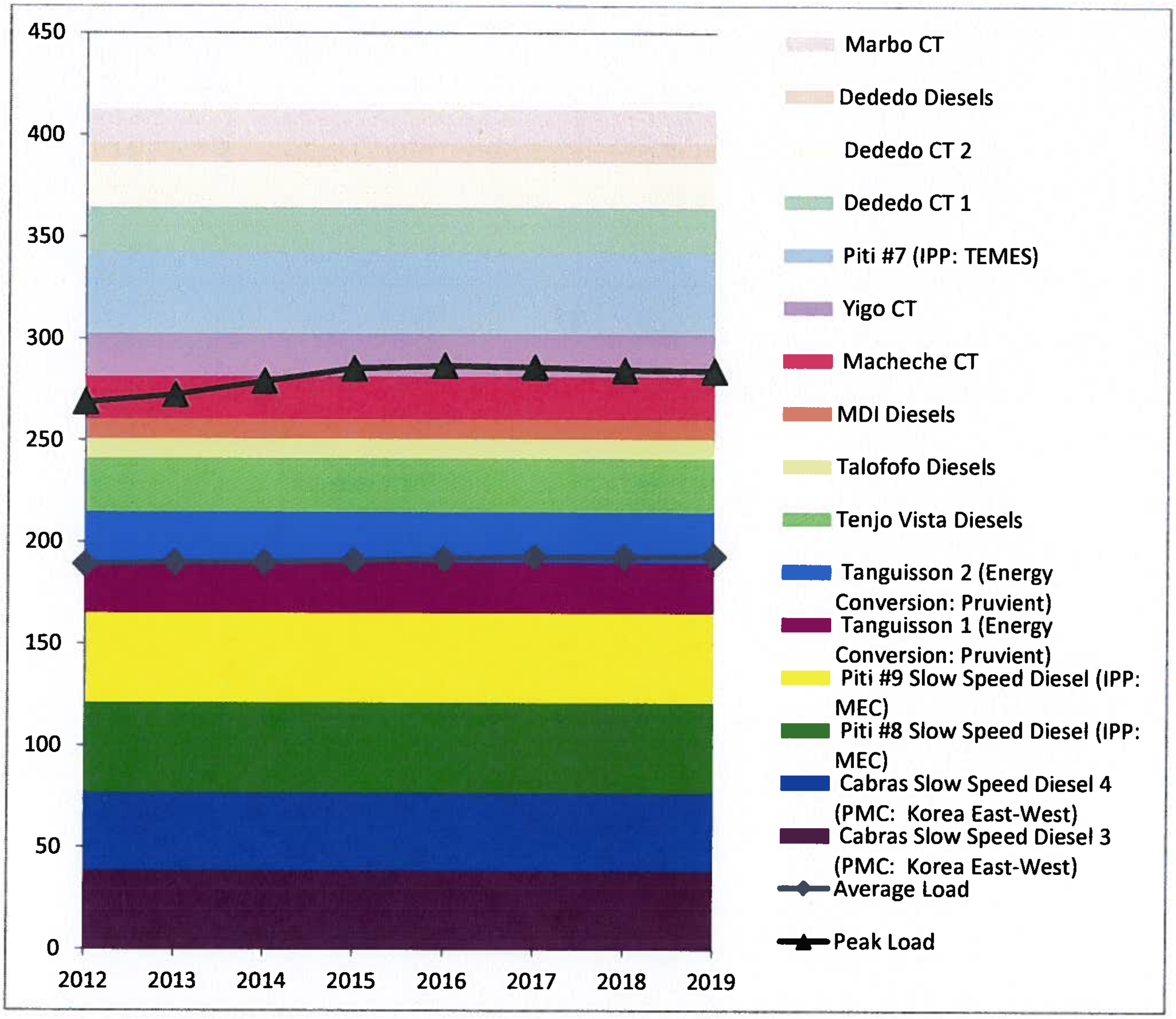

Figure 3 – Current N-2 Dispatch Stack

A 45 percent reserve margin might seem excessive based on discussion comparison to mainland U.S. utilities, but other factors should be considered, such as the availability of the units and the system.

Forced Outage Rates

To further refine the N-2 methodology we analyzed the availability, specifically the forced outage rates, of the units involved in meeting GPA system demand to determine if any of the units have excessively high or significantly low forced outage rates. Baseload units that are expected to deliver a large portion of the system capacity and energy needs that have high forced outage rates coupled with reserve units that also have high forced outage rates can disguise a seemingly high reserve margin, which may result in a system with excessive service interruptions. The available capacity (versus nameplate rating) and the equivalent forced outage rates for the GPA units are presented in table 3 below.

Table 3
Summary of Unit Available Capacity and EFOR

Unit	Technology	Nameplate Capacity, MW	Available Capacity, MW	EFOR, % (1)
Cabras 1	Boiler & ST	66	66	7.0
Cabras 2	Boiler & ST	66	66	13.0
Cabras 3	Slow Speed Recip	39.3	39.3	2.0
Cabras 4	Slow Speed Recip	39.3	39.3	4.0
Dededo CT 1	CT	23	0	NA
Dededo CT 2	CT	23	0	NA
Dededo Recip 1-4	Medium Speed Recip	2.5 ea/10 total	7.5	0.0
Macheche CT	CT	22	19	0.0
Marbo CT	CT	16	0	NA
MDI Recip 1 & 2	Medium Speed Recip	5.3 ea/10.6 total	10.6	0.0
Piti 8 (MEC)	Slow Speed Recip	44.2	44.2	3.0
Piti 9 (MEC)	Slow Speed Recip	44.2	44.2	3.0
Piti 7 (TEM)	CT	40	40	0.0
Talofofo Recip 1 & 2	Medium Speed Recip	4.4 ea/8.8 total	8.8	0.5
Tanguisson 1 (PRU)	Boiler & ST	26.5	26.5	3.0
Tanguisson 2 (PRU)	Boiler & ST	26.5	26.5	3.0
Tenjo Recip 1-6	Medium Speed Recip	4.4 ea/26.4 total	26.4	0.6
Yigo CT	CT	22	0	0.1

(1) Data provided from Generation Administration for 2008 through 2012.

A review of the availability and forced outage data shows that the availability of the units is trending upward, which should work to mitigate service disruptions. However, the two largest units have the highest forced outage rates. Therefore, the units that provide the reserve capacity need to have high availability and low forced outage rates. Should the Cabras 1 and 2 units be out of service, then the Tanguisson units, the recip units, and a CT unit would be needed to meet the system demand.

Growth Planning

Figure 4 contains various forecast scenarios for GPA. The high tourism – high infrastructure scenario (H&H), peaking in 2014 at 332 MW then tapering down in 2018 to 297 MW represents the earliest peak GPA would have to meet with its existing units as new resources would not yet be available. New resources would not yet be available because of construction schedules and in some cases unavailability of a fuel resource, which has been determined through another study. Similar scenarios show impact of decreasing assumptions in tourism or infrastructure activities which are primarily related to the military buildup activities over three to four years. A delay in the military buildup activities due to environmental assessment requirements, EPA Delay scenario, would require capacity needed to support 329 MW peak in 2017 for buildup activities.

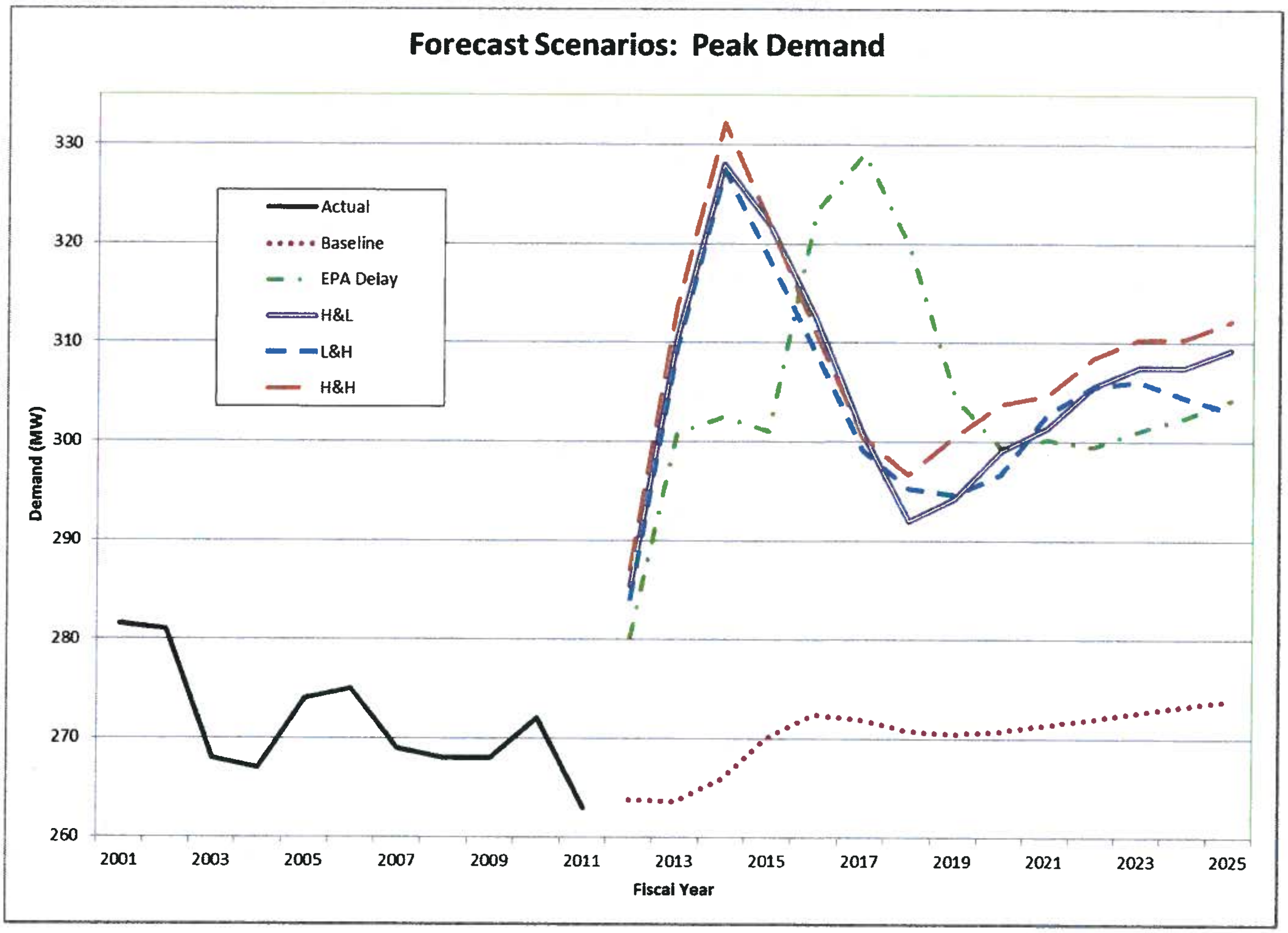

Figure 4 – Forecast Scenarios

The revised dispatch stack presented in Figure 5 below is based on the N-2 methodology and shows GPA has sufficient installed capacity to support peak load under the H&H projection.

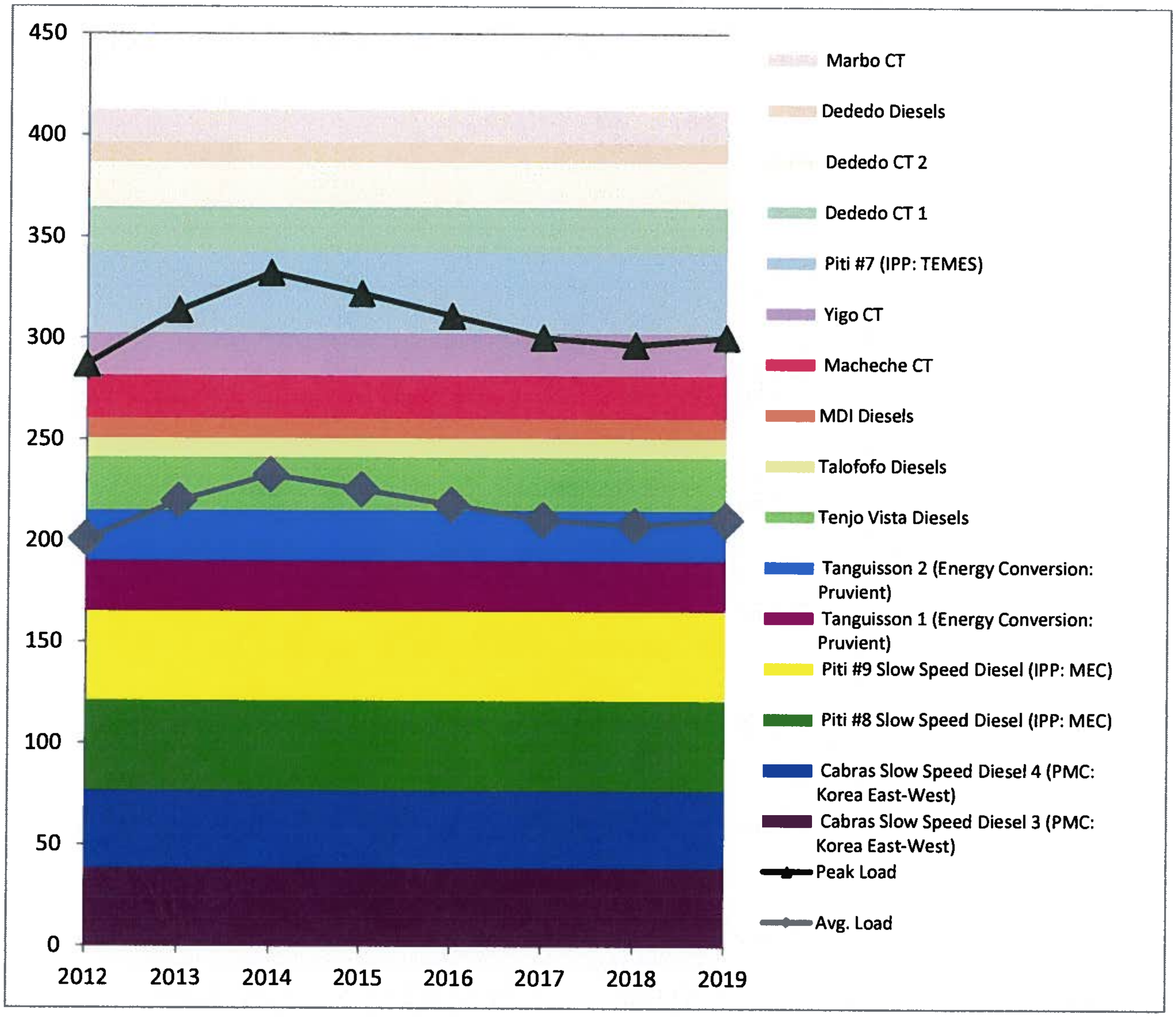

Figure 5 – Forecast N-2 Unit Dispatch Stack

Capital investment to maintain high unit availability for Piti 7 (TEMES CT) and all units that fall under it in the dispatch order should be considered to meet reserve margin requirements based on an N-2 or loss of load probability methodology. Additionally, other unit retirements may be considered after 2019 when buildup activities subside and new resources are available that can improve overall operating costs.

Conclusions

The results of our analysis indicate that the following units should be considered for retirement and capital expenditures related to the units should be refocused on units lower in the dispatch stack.

- Marbo CT
- Dededo Diesel
- Dededo CT 1
- Dededo CT 2

We note, officially "retiring" units typically has more relevance in large competitive markets with multiple participants, including independent system operators and independent power producers, with capacity and energy markets. GPA operates in an island system and is the only power provider on the system. Therefore, the retirement decision and associated actions do not have a mandated deadline and may need to be deferred until the generating resources identified by the long-term resource planning study are in service.

Should you have any questions or like to discuss the analysis included herein please contact me at 913-768-0090 or bruner@saic.com.

Sincerely,

SAIC Energy, Environment & Infrastructure, LLC

Robert A. Brune
Senior Project Manager

RAB

ec: John Cruz, Jr., GPA
Steve Brodsky, SAIC
Jennifer White, SAIC

D Demand Side Management

September 18, 2012

VIA E-MAIL

John Cruz
Manager, SPORD
Guam Power Authority
P.O. Box 2977
Hagatna, Guam 96932-2977

Subject: **2012 Demand-Side Management Study**

Dear Mr. Cruz:

At the request of Guam Power Authority ("GPA"), R. W. Beck, Inc., an SAIC Company ("R. W. Beck") 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 pursuant to Amendment No. 1 to Contract No. C-10-010 dated February 28, 2012 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. Should you have any questions, please feel free to give me a call at (407) 648-3588.

Sincerely,

R. W. BECK, INC.

Navid Nowakhtar, M. A., LEED GA
Economic Consultant

c: J. White
c: J. Schaefer

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EXECUTIVE SUMMARY

At the request of Guam Power Authority ("GPA"), R. W. Beck, Inc., an SAIC Company ("R. W. Beck"), 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 potential DSM options. DSM measures previously examined for GPA during prior IRP efforts for technical potential were combined with R. W. Beck's existing database of DSM measures deployed in other projects, and the entire set of measures were evaluated for technical potential using updated engineering estimates of energy and peak demand savings.

Technical potential (energy and demand savings) estimates were prepared using weather patterns specific to GPA, and were vetted to make sure that savings estimates were reasonable compared to approximate Guam baselines. A wide array of technical options was considered for both the residential and commercial sector, including measures previously abandoned, to ensure updated engineering intelligence pertaining to certain measures was evaluated objectively. DSM measures were also qualitatively evaluated for implementation in the GPA service area, and factors such as scalability, viability on an island terrain and in a tropical climate, and adoption potential were considered. Consistent with the scope of services for this study, the two measures in each sector (residential and commercial) that were deemed most promising from a technical perspective were considered for further evaluation during the economic screening analysis.

The economic analysis was performed using a cost-benefit evaluation model developed by R. W. Beck in partnership with EPRI (the "EPRI Model"). R. W. Beck developed this concise spreadsheet tool to assist utilities with the assessment of the costs and benefits associated with electric system improvements and efficiencies ("Programs"), including capital improvement projects, distributed generation and storage, and other energy efficiency incentives or efforts that reduce demand and energy consumption. The key components of avoided cost (or benefits) that are analyzed in this tool are: Avoided or Delayed Generation or Purchased Power Capacity Additions (demand savings), Avoided Costs of Energy Production, Avoided Transmission and Distribution cost (including avoided capital expenditures), System

Loss savings, Avoided ongoing Operation and Maintenance ("O&M") costs associated with Transmission and Distribution system improvements (if any) and the value of potential power market sales of resources that are free to serve the external market in place of the energy generation that has been avoided as a result of the Program. The central Program Cost components are generally treated as exogenous (or external estimates entered by the user) and include the ability to model specific incentives with customer adoption projections or generic Projects with an all-in cost. Benefit-Cost ratios are then developed based on all input and analyses. Not all elements of avoided cost are applicable for a given utility Program, and R. W. Beck has taken care to specify benefits and costs according to the measure in question. Table ES-1 below summarizes the measures that were evaluated for economic potential by sector.

Table ES-1
DSM Measures Evaluated for Economic Potential

Residential	Commercial
2.5 Ton Central A/C – New Unit	60 Ton Chiller, 8 x 5 Operation
CFL Lighting (25 Watts)	CFL Lighting (25 Watts)

In performing this economic screening analysis, industry-standard techniques and formulae were applied to the evaluation of the DSM measures. The GPA Smart Grid Business Case model and the GPA IRP data warehouse were used as the main sources of information on marginal resource characteristics and energy and demand rates. 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, detailed projections of DSM program saturations, potential customer penetration rates, and utility incentive programs were not developed. Instead, the economic screening was performed based on a conservative estimate of adoption per DSM measure based on projected GPA customer counts by sector, beginning in calendar year 2013 with no incremental increases during the study period. Importantly, the economic analysis did not assume any level of incentive on the part of GPA for a given measure.

Cost-effectiveness evaluations were performed for three different perspectives on DSM program implementation, as follows[1].

Utility Cost Test ("UCT") – 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.

[1] The EPRI model result is identical to the Total Resource Cost Test described below. Additional ratios were developed from the constituent components of avoided cost and measure cost as tracked in the EPRI model.

> **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 the period 2013-2022 for each DSM measure for each of the cost-effectiveness tests described above.

GPA established that a DSM measure must pass both the UCT 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 UCT 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 UCT 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. Furthermore, to the extent GPA desires to explore increased incentive levels in the future, the results shown herein will be impacted. Refer to Section 3 of this report for a more detailed tabular summary of the cost-effectiveness screening as well as some important assumptions underpinning the results.

Table ES-2
Summary Results of DSM Cost-Effectiveness

	B/C Ratio		
Residential Measures	**UCT**	**RIM**	**TRC**
2.5 Ton Central A/C - New Unit	10.619	0.914	0.357
CFL Lighting (25 Watts)	2.234	0.691	1.916
Commercial Measures			
60 Ton Chiller, 8 x 5 Operation	83.637	0.988	1.447
Commercial CFL Lighting (25 Watts)	3.805	0.792	3.264

In addition to the results presented in this report, Appendix A provides detailed results tables from the EPRI model summarizing the ultimate economic screening analysis results for each of the four measures.

Section 1
INTRODUCTION AND DESCRIPTION OF STUDY

At the request of Guam Power Authority ("GPA"), R. W. Beck, Inc., an SAIC company, ("R. W. Beck") 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 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.

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. The technical screening assessment involved a review of potential DSM options. DSM Measures previously examined for GPA during prior IRP efforts for technical potential were combined with R. W. Beck's existing database of DSM measures deployed in other projects, and the entire set of measures were evaluated for technical potential using updated engineering estimates of energy and peak demand savings.

Technical potential (energy and demand savings) estimates were prepared using weather patterns specific to GPA, and were vetted to make sure that savings estimates were reasonable compared to approximate Guam baselines. A wide array of technical options was considered for both the residential and commercial sector, including measures previously abandoned, to ensure updated engineering intelligence pertaining to certain measures was evaluated objectively. DSM measures were also qualitatively evaluated for implementation in the GPA service area, and factors such as scalability, viability on an island terrain and in a tropical climate, and adoption potential were considered. Consistent with the scope of services for this study, the two measures in each sector (residential and commercial) that were deemed most promising from a technical perspective were considered for further evaluation during the economic screening analysis.

Economic Screening Analysis

The economic analysis was performed using a cost-benefit evaluation model developed by R. W. Beck in partnership with EPRI (the "EPRI Model"). R. W. Beck developed this concise spreadsheet tool to assist utilities with the assessment of the costs and benefits associated with electric system improvements and efficiencies ("Programs"), including capital improvement projects, distributed generation and storage, and other energy efficiency incentives or efforts that reduce demand and energy consumption. The key components of avoided cost (or benefits) that are analyzed in this tool are: Avoided or Delayed Generation or Purchased Power Capacity Additions (demand savings), Avoided Costs of Energy Production, Avoided Transmission and Distribution cost (including avoided capital expenditures), System Loss savings, Avoided ongoing O&M costs associated with Transmission and Distribution system improvements (if any) and the value of potential power market sales of resources that are free to serve the external market in place of the energy generation that has been avoided as a result of the Program. The central Program Cost components are generally treated as exogenous (or external estimates entered by the user) and include the ability to model specific incentives with customer adoption projections or generic Projects with an all-in cost. Benefit-Cost ratios are then developed based on all inputs and analyses. Not all elements of avoided cost are applicable for a given Program, and R. W. Beck has taken care to specify benefits and costs according to the measure in question.

DSM Measure Assumptions

Table 2-1 provides a general description of each DSM measure that was deemed most desirable in the technical screening and for which an economic evaluation was conducted. Per the scope of services for this study, detailed projections of DSM program saturations, potential customer penetration rates, and utility incentive programs were not developed. Instead, the economic screening was performed based on a conservative estimate of adoption per DSM measure based on projected GPA customer counts by sector, beginning in calendar year 2013 with no incremental increases during the study period. Importantly, the economic analysis did not assume any level of incentive on the part of GPA for a given measure. 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 (e.g. lighting measures), 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 2-1
DSM Measure Descriptions

DSM Measure	General Description
Residential Measures:	
2.5 Ton Central A/C – new unit	Install a new 2.5 Ton Central A/C unit with an estimated SEER of 14.5 to replace units that have an estimated SEER of 7.0.
CFL Lighting (25 Watts)	Replace a 100 Watt incandescent light bulb with a CFL.
Commercial Measures:	
60 Ton Chiller, 8 x 5 operation	Replace existing chiller on a commercial scale with a brand new 60 ton chiller that dispatches on an 8 hours per day, 5 days per week schedule for locations where such dispatch is appropriate.
Commercial CFL Lighting (25 Watts)	Replace traditional 100 Watt commercial lighting with CFLs at a commercial scale.

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:

- Avoided capital costs for future GPA generation facilities;
- Avoided O&M costs for future GPA generation facilities;
- Avoided 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, the GPA Smart Grid Business Case model, and available projections of GPA's future customer base, energy requirements, and peak demand. Appendix A contains a complete pro forma summarizing the results of the four measures that were evaluated economically, and delineates the results of R. W. Beck's analysis of all system characteristics above. The elements of avoided cost that are applicable (i.e., result in tangible savings) differ by Program. For example, a Program that results in a very small reduction in peak demand will not be sufficient to cause a delay in the next incremental capacity addition for a given utility. Refer to Appendix A for detailed line item costs and benefits that have been estimated for each measure.

DSM Benefit-Cost Tests

For this study, industry standardized formulae were adopted for computing DSM measure costs and benefits[2]. We have relied upon three of the standard tests for this study: the Utility Cost Test ("UCT"), 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.)

[2] The EPRI model result is identical to the Total Resource Cost Test described below. Additional ratios were developed from the constituent components of avoided cost and measure cost as tracked in the EPRI model.

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, as applicable to the measure in question.

GPA has established that a DSM measure must pass both the UCT 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 UCT and 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 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 3-1 below.

Table 3-1
Summary Results of DSM Cost-Effectiveness

	NPV ($000)			B/C Ratio		
Residential Measures [1], [3]	**UCT**	**RIM [4]**	**TRC**	**UCT**	**RIM**	**TRC**
2.5 Ton Central A/C - New Unit	$1,908	($198)	($3,793)	10.619	0.914	0.357
CFL Lighting (25 Watts)	$245	($198)	$212	2.234	0.691	1.916
Commercial Measures [2], [3]						
60 Ton Chiller, 8 x 5 Operation	$16,391	($198)	$5,125	83.637	0.988	1.447
Commercial CFL Lighting (25 Watts)	$556	($198)	$523	3.805	0.792	3.264

Footnotes

[1] Based on 1,000 customer adoptions/bulbs, and marginal cost and resource information derived from Guam's Integrated Resource Plan assumptions and Guam's Smart Grid Business Case.

[2] Chiller assumes adoption by 250 commercial customers who on average dispatch the chiller on an 8 hours a day 5 days per week schedule. Commercial CFL evaluated based on 1,000 bulbs being distributed.

[3] Engineering estimates for energy and demand savings utilized to develop B/C ratios based on Guam-specific weather patterns and technical measure modeling performed by SAIC. Adoption estimates based on conservative assumptions as a percentage of projected Guam customer counts by sector. The top 2 technical measures by sector were evaluated economically.

[4] Due to a lack of Guam incentives, and the assumption of marginal resource costs to capture both avoided costs and revenue loss, the NPV of the RIM Test from strictly a dollar differential perspective is driven solely by estimated Guam A&G costs in each case, or approximately $26,000 per year. B/C ratios differ by measure for the RIM test due to the varying contribution of A&G costs to the overall B/C picture.

None of the DSM measures evaluated for economic potential were found to pass both the UCT 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 by GPA. For instance, GPA may choose to ignore adverse retail rate impacts and implement DSM programs based on the TRC Test results. Furthermore, to the extent

GPA desires to explore increased incentive levels in the future, the results shown herein will be impacted. Finally, 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.

EPRI - Demand and Energy Reduction Cost-Benefit Model

Summary of Avoided Costs and Program/Project Costs

(Nominal $)

Line	*Guam Power Authority: DSM_2012 - RES Prog. #1*		Units	Const.	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
	General Assumptions:													
1	Inflation	[1]	%	2.40%		2.40%	2.40%	2.40%	2.40%	2.40%	2.40%	2.40%	2.40%	2.40%
2	Discount Rate	[2]	%	5.25%										
	Projected Loads and Pricing:													
3	Forecasted Gross Energy for Load	[3]	MWh		1,664,029	1,672,870	1,688,316	1,699,590	1,706,988	1,707,460	1,710,423	1,713,391	1,730,525	1,747,830
4	Marginal Generation Energy Price	[4]	$/MWh		80.00	81.92	83.89	85.90	87.96	90.07	92.23	94.45	96.71	99.04
5	Forecasted Peak Demand	[5]	MW		272.5	279.1	285.4	286.8	286.0	284.6	284.2	287.0	289.9	292.8
6	Demand Price	[6]	$/kW-yr		350.00	358.40	367.00	375.81	384.83	394.06	403.52	413.21	423.12	433.28
	Projected Program Impacts:													
7	Projected Program Energy Reduction	[7]	MWh		981.0	981.0	981.0	981.0	981.0	981.0	981.0	981.0	981.0	981.0
8	Projected Program Peak Demand Reduction	[8]	MW		0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3
9	Losses based on Historical Loss Percentage	[9]	MWh	6.95%	115,668	116,283	117,357	118,140	118,654	118,687	118,893	119,100	120,291	121,493
10	Load portion of Losses	[10]	MWh	75.0%	86,751	87,212	88,017	88,605	88,991	89,015	89,170	89,325	90,218	91,120
11	No-Load portion of Losses	[11]	MWh	25.0%	28,917	29,071	29,339	29,535	29,664	29,672	29,723	29,775	30,073	30,373
12	Losses based on Loss Percentage (Resulting from Program)	[12]	MWh	6.95%	115,668	116,283	117,357	118,140	118,654	118,687	118,893	119,100	120,291	121,493
13	Load portion of Losses	[13]	MWh	75.1%	86,867	87,328	88,135	88,723	89,110	89,134	89,289	89,444	90,338	91,242
14	No-Load portion of Losses	[14]	MWh	24.9%	28,801	28,954	29,222	29,417	29,545	29,553	29,604	29,656	29,952	30,252
15	Loss Percentage Change	[15]	%		0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
16	Load portion of Losses	[16]	%		0.1%	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%
17	No-Load portion of Losses	[17]	%		-0.4%	-0.4%	-0.4%	-0.4%	-0.4%	-0.4%	-0.4%	-0.4%	-0.4%	-0.4%
	Avoided Capacity Additions/Purchases:													
18	Generating Unit Capital Costs	[18]	$/MW		2,140,000	2,191,360	2,243,953	2,297,808	2,352,955	2,409,426	2,467,252	2,526,466	2,587,101	2,649,192
19	Generating Unit Fixed O&M Costs	[19]	$/MW-yr		42,000.00	43,008.00	44,040.19	45,097.16	46,179.49	47,287.80	48,422.70	49,584.85	50,774.88	51,993.48
20	Pass-Through Demand Charge (for Purchases)	[20]	$/kW-yr		350.00	358.40	367.00	375.81	384.83	394.06	403.52	413.21	423.12	433.28
21	Dependable Capacity of Peak Demand Reduction	[21]	%	100.00%										
22	***Avoided Capacity Additions/Purchases Cost***	[22]	**$(000)**		**98.00**	**100.35**	**102.76**	**105.23**	**107.75**	**110.34**	**112.99**	**115.70**	**118.47**	**121.32**
	Avoided Energy Production/Purchase:													
	Marginal Resource Characteristics													
23	Heat Rate	[23]	btu/kWh	8,350										
24	Fuel Prices	[24]	$/mmBtu		17.96	18.40	18.84	19.29	19.75	20.23	20.71	21.21	21.72	22.24
25	Variable O&M Costs	[25]	$/MWh		5.00	5.12	5.24	5.37	5.50	5.63	5.76	5.90	6.04	6.19
26	Emissions Allowance Costs	[26]	$/MWh		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
27	*Marginal Resource Costs*	[27]	$/MWh		155.00	158.72	162.53	166.43	170.42	174.51	178.70	182.99	187.38	191.88
	Contract Characteristics													
28	*Tariff or Market Purchase Price*	[28]	$/MWh		55.00	56.32	57.67	59.06	60.47	61.92	63.41	64.93	66.49	68.09
29	***Avoided Energy Production/Purchase Cost***	[29]	**$(000)**		**152.06**	**155.70**	**159.44**	**163.27**	**167.19**	**171.20**	**175.31**	**179.51**	**183.82**	**188.23**
	Avoided System Losses:													
30	***Avoided System Losses Cost***	[30]	**$(000)**		**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**
31	Load portion of Losses Cost	[31]	$(000)		(9.25)	(9.53)	(9.84)	(10.15)	(10.44)	(10.69)	(10.97)	(11.25)	(11.63)	(12.03)
32	No-Load portion of Losses Cost	[32]	$(000)		9.25	9.53	9.84	10.15	10.44	10.69	10.97	11.25	11.63	12.03
	Avoided Transmission System Improvements:													
33	Load Growth (Organic)	[33]	%			2.4%	2.3%	0.5%	-0.3%	-0.5%	-0.2%	1.0%	1.0%	1.0%
34	Load Reduction (With Project or Program)	[34]	MW		0.28	0.28	0.28	0.28	0.28	0.28	0.28	0.28	0.28	0.28
35	Cost of Transmission Upgrades - Typical Growth	[35]	$/MW		1,500,000	1,536,000	1,572,864	1,610,613	1,649,267	1,688,850	1,729,382	1,770,887	1,813,389	1,856,910
36	Typical Load Growth Requiring Upgrades	[36]	MW	50.0										
37	***Avoided Transmission System Improvements Cost***	[37]	**$(000)**		**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**

EPRI - Demand and Energy Reduction Cost-Benefit Model

Summary of Avoided Costs and Program/Project Costs

(Nominal $)

Line	Guam Power Authority: DSM 2012 - RES Prog. #1		Units	Const.	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
	Avoided Distribution System Improvements:													
38	Capital Budget for Distribution System Improvements - Growth	[38]	$/MW		0	0	0	0	0	0	0	0	0	0
39	***Avoided Distribution System Improvements Cost***	[39]	**$(000)**		**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
	Avoided T&D Improvements O&M Costs:													
40	Avoided O&M Costs associated with Avoided T&D Improvements	[40]	$(000)		0	0	0	0	0	0	0	0	0	0
41	***Avoided O&M Costs:***	[41]	**$(000)**		**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
	Potential Power Market Sales:													
42	Market Value of Surplus Energy	[42]	$/MWh		0	0	0	0	0	0	0	0	0	0
43	***Surplus Energy Sales Value:***	[43]	**$(000)**		**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
44	***Total Gross Program Benefits***	[44]	**$(000)**		**250**	**256**	**262**	**268**	**275**	**282**	**288**	**295**	**302**	**310**
45	***Total Gross Program Benefits***	[45]	**NPV $(000)**		**$2,106**									
	Program Costs													
46	Rebate Costs per Customer	[46]	$		0	0	0	0	0	0	0	0	0	0
47	Rebate Customers	[47]	#		0	0	0	0	0	0	0	0	0	0
48	Project Costs	[48]	$(000)		6,026	26.0	26	26	26	26	26	26	26	26
49	**Total Program Costs**	[49]	**$(000)**		**6,026**	**26**	**26**	**26**	**26**	**26**	**26**	**26**	**26**	**26**
50	**Benefit to Cost Ratio**	[50]	**#**		**0.0**	**9.8**	**10**	**10**	**11**	**11**	**11**	**11**	**12**	**12**
51	**Benefit to Cost Ratio**	[51]	**NPV**		**0.4**									
52	***Net System Benefits***	[52]	**$(000)**		**(5,775.9)**	**230.1**	**236.2**	**242.5**	**248.9**	**255.5**	**262.3**	**269.2**	**276.3**	**283.6**
53	***Net System Benefits***	[53]	**NPV $(000)**		**($3,793)**									

Line	*Guam Power Authority: DSM 2012 - RES Prog. #1*	Units	Const.	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022

Footnotes (references to sources may be superseded by user adjustments to key inputs):

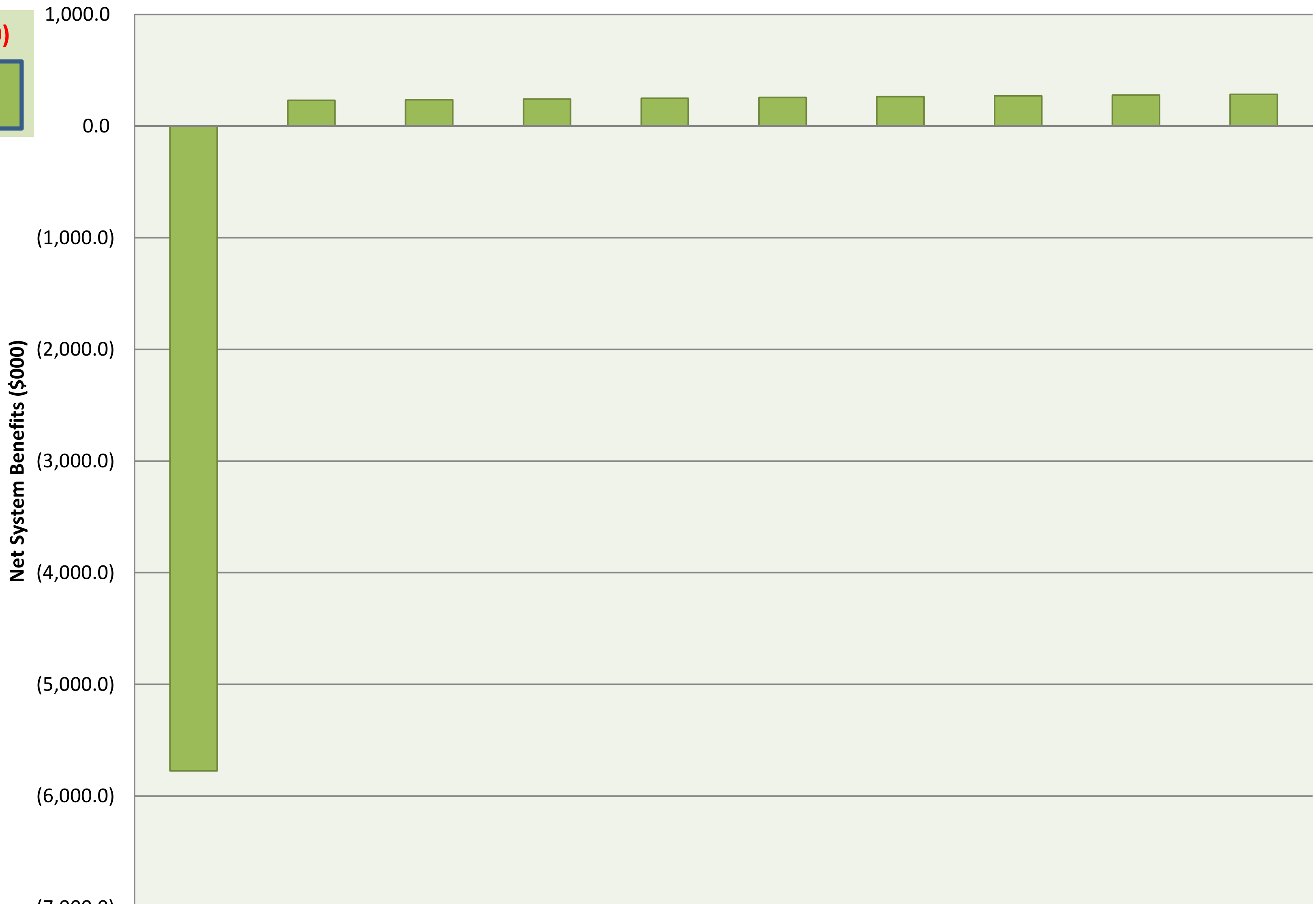
[1] Source: Blue Chip Economic Indicators Report, November 2010.
[2] Based on the most recent R. W. Beck standard assumption used to support power supply analyses.
[3] Total Retail Sales plus losses equals Gross Energy for Load. Gross Energy For Load is used to compute baseline and projected losses.
[4] Energy price for resources that are on the margin (or serve the last incremental portion of demand) in the market
[5] Peak Demand represents annual non-coincident peak of the utility or the coincident peak of the utility with their wholesale provider, as appropriate
[6] Demand price for wholesale power purchase contracts expected for utilities that purchase capacity from a third party
[7] Total annual energy reduction resulting from a Project or a Rebate. Represents an estimate based on the specific characteristics of the Program, as appropriate
[8] Total annual demand reduction resulting from a Project or a Rebate. Represents an estimate based on the specific characteristics of the Program, as appropriate
[9] Projection of losses assuming baseline system performance and projected Gross Energy for Load.
[10] Based on allocation of losses for baseline system performance from the Inputs sheet.
[11] Based on allocation of losses for baseline system performance from the Inputs sheet.
[12] Based on projected system performance resulting from the Program, as a function of baseline projected Gross Energy for Load. The difference in losses is valued at the market price for energy
[13] Based on allocation of losses for alternative system performance from the Inputs sheet.
[14] Based on allocation of losses for alternative system performance from the Inputs sheet.
[15] Relative to baseline system performance.
[16] Relative to baseline system performance.
[17] Relative to baseline system performance.
[18] Based on either user defined parameters or assumptions developed by R. W. Beck. Refer to Input sheet for details. Costs may be zeroed out based on their relevance given certain user decisions
[19] Based on either user defined parameters or assumptions developed by R. W. Beck. Refer to Input sheet for details. Costs may be zeroed out based on their relevance given certain user decisions
[20] Same as line 6.
[21] Equal to 100% unless demand reduction is sourced from an intermittently available resource or project (example: solar generation).
[22] Only counts relevant costs based on user decisions in the Inputs sheet.
[23] Based on either user defined parameters or assumptions developed by R. W. Beck. Refer to Input sheet for details.
[24] Based on either user defined parameters or assumptions developed by R. W. Beck. Refer to Input sheet for details.
[25] Based on either user defined parameters or assumptions developed by R. W. Beck. Refer to Input sheet for details.
[26] Based on either user defined parameters or assumptions developed by R. W. Beck. Refer to Input sheet for details.
[27] All-in costs for the selected marginal generating unit that serves the last incremental part of demand.
[28] For utilities that purchase power through a third party, whereby costs are a "pass-through" to the utility
[29] Only counts relevant costs based on user decisions in the Inputs sheet.
[30] The difference between baseline losses and losses under the alternative system, valued at the market energy rate
[31] Based on allocation of losses for alternative system performance from the Inputs sheet.
[32] Based on allocation of losses for alternative system performance from the Inputs sheet.
[33] Peak demand growth rates for the baseline system (i.e., prior to the Program).
[34] Same as line 8.
[35] Based on user inputs.
[36] Represents the threshold below which any demand reduction would not be sufficient to avoid the next planned system improvement
[37] Benefits are calculated and assigned to the first year of a 3 year planning window. Equal to zero if threshold for demand reductions was met in the most recent three year planning window
[38] Distribution system improvements are needed for all new loads that come online for a system.
[39] First year costs assume some non-zero growth relative to the year prior to the Base Year
[40] Ongoing O&M represents an estimate related to both Transmission and Distribution costs in each year, as appropriate.
[41] Represents the application of the estimate of ongoing O&M for Transmission and Distribution system improvements (as a percent of plant value) to the total avoided costs (if any) in both categories in each year
[42] Market value of surplus energy may differ from market revenue potential of a specific marginal resource or the energy rate embedded in a specific tariff between a utility and their wholesale provider
[43] Based on total estimate of avoided energy.
[44] "Gross" Implies the sum benefits prior to accounting for the intrinsic costs of the Program being analyzed.
[45] Based on assumed discount rate in Inputs sheet.
[46] Based on user inputs.
[47] Based on user inputs.
[48] Based on user inputs.
[49] Only counts relevant costs based on user decisions in the Inputs sheet.
[50] Total program avoided costs (benefits) divided by total program costs; a ratio greater than 1.0 implies that benefits outweigh costs
[51] Benefit to Cost ratio over the life of the project, or the NPV of Gross Benefits divided by the NPV of Total Program Costs
[52] Total Program Benefits minus total Program Costs.
[53] Based on assumed discount rate in Inputs sheet.

RES Prog. #1

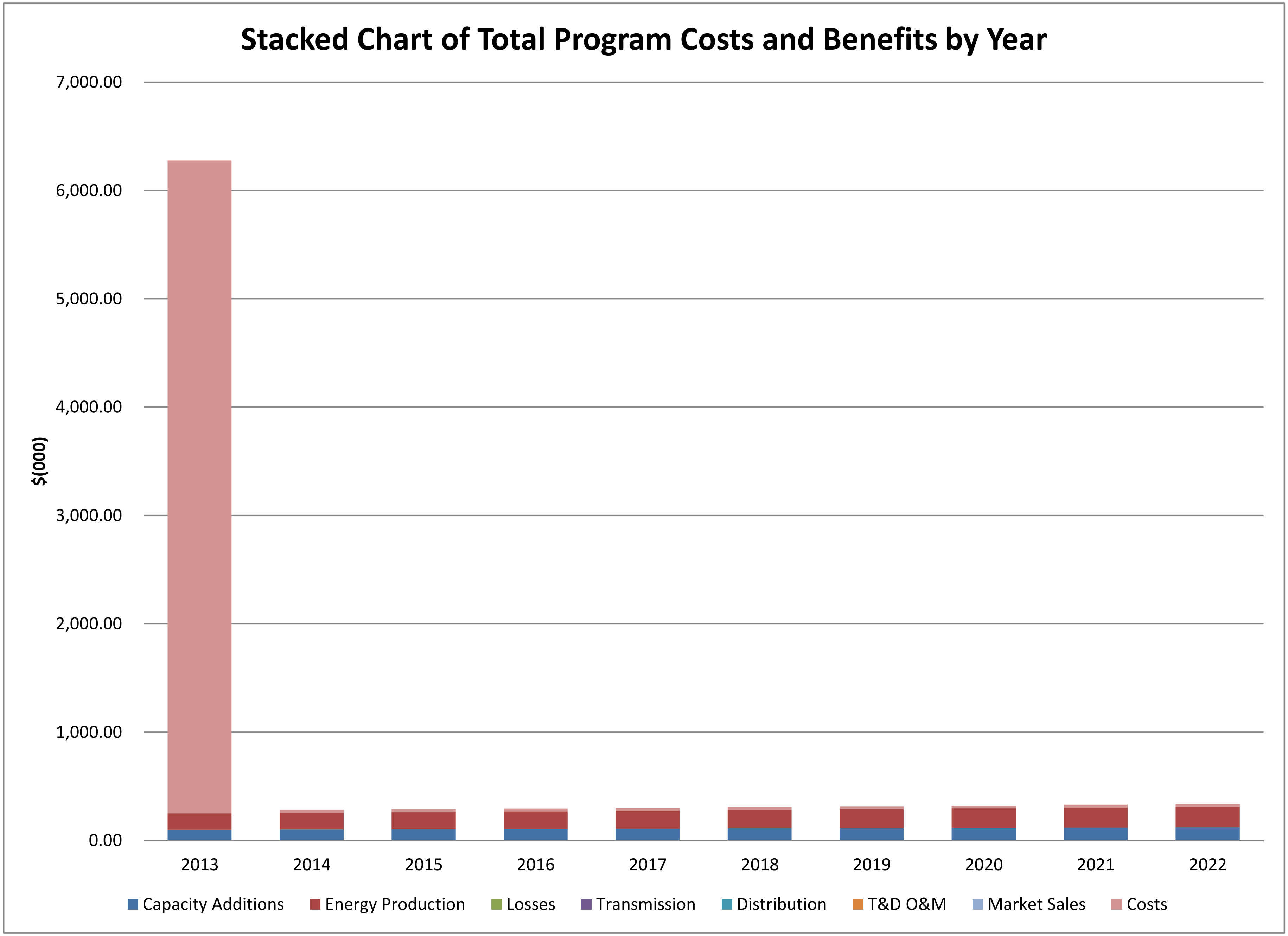
NPV ($000)

($3,793)

Summary of Net System Benefits by Year



	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Net System Benefits	(5,775.9)	230.1	236.2	242.5	248.9	255.5	262.3	269.2	276.3	283.6


Stacked Chart of Total Program Costs and Benefits by Year
7,000.00
6,000.00
5,000.00
4,000.00
3,000.00
2,000.00
1,000.00
0.00
$(000)
2013
2014
2015
2016
2017
2018
2019
2020
2021
2022
Capacity Additions
Energy Production
Losses
Transmission
Distribution
T&D O&M
Market Sales
Costs

EPRI - Demand and Energy Reduction Cost-Benefit Model

Summary of Avoided Costs and Program/Project Costs

(Nominal $)

Line	*Guam Power Authority: DSM_2012 - RES Prog. #2*		Units	Const.	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
	General Assumptions:													
1	Inflation	[1]	%	2.40%		2.40%	2.40%	2.40%	2.40%	2.40%	2.40%	2.40%	2.40%	2.40%
2	Discount Rate	[2]	%	5.25%										
	Projected Loads and Pricing:													
3	Forecasted Gross Energy for Load	[3]	MWh		1,664,029	1,672,870	1,688,316	1,699,590	1,706,988	1,707,460	1,710,423	1,713,391	1,730,525	1,747,830
4	Marginal Generation Energy Price	[4]	$/MWh		80.00	81.92	83.89	85.90	87.96	90.07	92.23	94.45	96.71	99.04
5	Forecasted Peak Demand	[5]	MW		272.5	279.1	285.4	286.8	286.0	284.6	284.2	287.0	289.9	292.8
6	Demand Price	[6]	$/kW-yr		350.00	358.40	367.00	375.81	384.83	394.06	403.52	413.21	423.12	433.28
	Projected Program Impacts:													
7	Projected Program Energy Reduction	[7]	MWh		91.0	91.0	91.0	91.0	91.0	91.0	91.0	91.0	91.0	91.0
8	Projected Program Peak Demand Reduction	[8]	MW		0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
9	Losses based on Historical Loss Percentage	[9]	MWh	6.95%	115,668	116,283	117,357	118,140	118,654	118,687	118,893	119,100	120,291	121,493
10	Load portion of Losses	[10]	MWh	75.0%	86,751	87,212	88,017	88,605	88,991	89,015	89,170	89,325	90,218	91,120
11	No-Load portion of Losses	[11]	MWh	25.0%	28,917	29,071	29,339	29,535	29,664	29,672	29,723	29,775	30,073	30,373
12	Losses based on Loss Percentage (Resulting from Program)	[12]	MWh	6.95%	115,668	116,283	117,357	118,140	118,654	118,687	118,893	119,100	120,291	121,493
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14	No-Load portion of Losses	[14]	MWh	24.9%	28,801	28,954	29,222	29,417	29,545	29,553	29,604	29,656	29,952	30,252
15	Loss Percentage Change	[15]	%		0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
16	Load portion of Losses	[16]	%		0.1%	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%
17	No-Load portion of Losses	[17]	%		-0.4%	-0.4%	-0.4%	-0.4%	-0.4%	-0.4%	-0.4%	-0.4%	-0.4%	-0.4%
	Avoided Capacity Additions/Purchases:													
18	Generating Unit Capital Costs	[18]	$/MW		2,140,000	2,191,360	2,243,953	2,297,808	2,352,955	2,409,426	2,467,252	2,526,466	2,587,101	2,649,192
19	Generating Unit Fixed O&M Costs	[19]	$/MW-yr		42,000.00	43,008.00	44,040.19	45,097.16	46,179.49	47,287.80	48,422.70	49,584.85	50,774.88	51,993.48
20	Pass-Through Demand Charge (for Purchases)	[20]	$/kW-yr		350.00	358.40	367.00	375.81	384.83	394.06	403.52	413.21	423.12	433.28
21	Dependable Capacity of Peak Demand Reduction	[21]	%	100.00%										
22	***Avoided Capacity Additions/Purchases Cost***	[22]	**$(000)**		**38.50**	**39.42**	**40.37**	**41.34**	**42.33**	**43.35**	**44.39**	**45.45**	**46.54**	**47.66**
	Avoided Energy Production/Purchase:													
	Marginal Resource Characteristics													
23	Heat Rate	[23]	btu/kWh	8,350										
24	Fuel Prices	[24]	$/mmBtu		17.96	18.40	18.84	19.29	19.75	20.23	20.71	21.21	21.72	22.24
25	Variable O&M Costs	[25]	$/MWh		5.00	5.12	5.24	5.37	5.50	5.63	5.76	5.90	6.04	6.19
26	Emissions Allowance Costs	[26]	$/MWh		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
27	*Marginal Resource Costs*	[27]	$/MWh		155.00	158.72	162.53	166.43	170.42	174.51	178.70	182.99	187.38	191.88
	Contract Characteristics													
28	*Tariff or Market Purchase Price*	[28]	$/MWh		55.00	56.32	57.67	59.06	60.47	61.92	63.41	64.93	66.49	68.09
29	***Avoided Energy Production/Purchase Cost***	[29]	**$(000)**		**14.11**	**14.44**	**14.79**	**15.15**	**15.51**	**15.88**	**16.26**	**16.65**	**17.05**	**17.46**
	Avoided System Losses:													
30	***Avoided System Losses Cost***	[30]	**$(000)**		**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**
31	Load portion of Losses Cost	[31]	$(000)		(9.25)	(9.53)	(9.84)	(10.15)	(10.44)	(10.69)	(10.97)	(11.25)	(11.63)	(12.03)
32	No-Load portion of Losses Cost	[32]	$(000)		9.25	9.53	9.84	10.15	10.44	10.69	10.97	11.25	11.63	12.03
	Avoided Transmission System Improvements:													
33	Load Growth (Organic)	[33]	%			2.4%	2.3%	0.5%	-0.3%	-0.5%	-0.2%	1.0%	1.0%	1.0%
34	Load Reduction (With Project or Program)	[34]	MW		0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11
35	Cost of Transmission Upgrades - Typical Growth	[35]	$/MW		1,500,000	1,536,000	1,572,864	1,610,613	1,649,267	1,688,850	1,729,382	1,770,887	1,813,389	1,856,910
36	Typical Load Growth Requiring Upgrades	[36]	MW	50.0										
37	***Avoided Transmission System Improvements Cost***	[37]	**$(000)**		**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**

EPRI - Demand and Energy Reduction Cost-Benefit Model

Summary of Avoided Costs and Program/Project Costs

(Nominal $)

Line	Guam Power Authority: DSM 2012 - RES Prog. #2		Units	Const.	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
	Avoided Distribution System Improvements:													
38	Capital Budget for Distribution System Improvements - Growth	[38]	$/MW		0	0	0	0	0	0	0	0	0	0
39	***Avoided Distribution System Improvements Cost***	[39]	**$(000)**		**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
	Avoided T&D Improvements O&M Costs:													
40	Avoided O&M Costs associated with Avoided T&D Improvements	[40]	$(000)		0	0	0	0	0	0	0	0	0	0
41	***Avoided O&M Costs:***	[41]	**$(000)**		**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
	Potential Power Market Sales:													
42	Market Value of Surplus Energy	[42]	$/MWh		0	0	0	0	0	0	0	0	0	0
43	***Surplus Energy Sales Value:***	[43]	**$(000)**		**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
44	***Total Gross Program Benefits***	[44]	**$(000)**		**53**	**54**	**55**	**56**	**58**	**59**	**61**	**62**	**64**	**65**
45	***Total Gross Program Benefits***	[45]	**NPV $(000)**		**$443**									
	Program Costs													
46	Rebate Costs per Customer	[46]	$		0	0	0	0	0	0	0	0	0	0
47	Rebate Customers	[47]	#		0	0	0	0	0	0	0	0	0	0
48	Project Costs	[48]	$(000)		46	26.0	26	26	26	46	26	26	26	26
49	**Total Program Costs**	[49]	**$(000)**		**46**	**26**	**26**	**26**	**26**	**46**	**26**	**26**	**26**	**26**
50	**Benefit to Cost Ratio**	[50]	**#**		**1.2**	**2.1**	**2**	**2**	**2**	**1**	**2**	**2**	**2**	**3**
51	**Benefit to Cost Ratio**	[51]	**NPV**		**1.9**									
52	***Net System Benefits***	[52]	**$(000)**		**7.1**	**27.9**	**29.2**	**30.5**	**31.8**	**13.7**	**34.6**	**36.1**	**37.6**	**39.1**
53	***Net System Benefits***	[53]	**NPV $(000)**		**$212**									

Line	*Guam Power Authority: DSM 2012 - RES Prog. #2*	Units	Const.	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022

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[1] Source: Blue Chip Economic Indicators Report, November 2010.
[2] Based on the most recent R. W. Beck standard assumption used to support power supply analyses.
[3] Total Retail Sales plus losses equals Gross Energy for Load. Gross Energy For Load is used to compute baseline and projected losses.
[4] Energy price for resources that are on the margin (or serve the last incremental portion of demand) in the market.
[5] Peak Demand represents annual non-coincident peak of the utility or the coincident peak of the utility with their wholesale provider, as appropriate.
[6] Demand price for wholesale power purchase contracts expected for utilities that purchase capacity from a third party.
[7] Total annual energy reduction resulting from a Project or a Rebate. Represents an estimate based on the specific characteristics of the Program, as appropriate.
[8] Total annual demand reduction resulting from a Project or a Rebate. Represents an estimate based on the specific characteristics of the Program, as appropriate.
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[10] Based on allocation of losses for baseline system performance from the Inputs sheet.
[11] Based on allocation of losses for baseline system performance from the Inputs sheet.
[12] Based on projected system performance resulting from the Program, as a function of baseline projected Gross Energy for Load. The difference in losses is valued at the market price for energy.
[13] Based on allocation of losses for alternative system performance from the Inputs sheet.
[14] Based on allocation of losses for alternative system performance from the Inputs sheet.
[15] Relative to baseline system performance.
[16] Relative to baseline system performance.
[17] Relative to baseline system performance.
[18] Based on either user defined parameters or assumptions developed by R. W. Beck. Refer to Input sheet for details. Costs may be zeroed out based on their relevance given certain user decisions.
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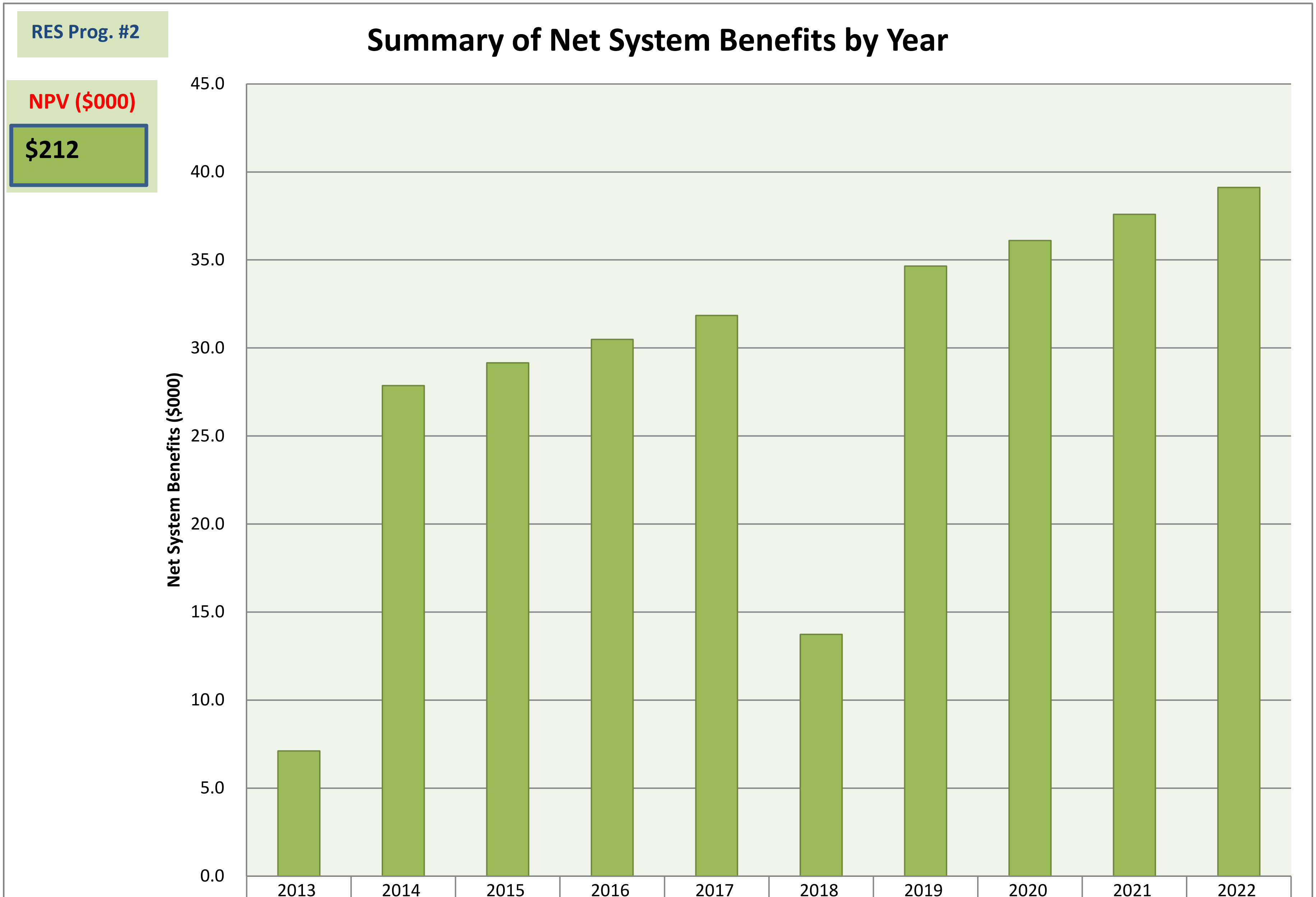
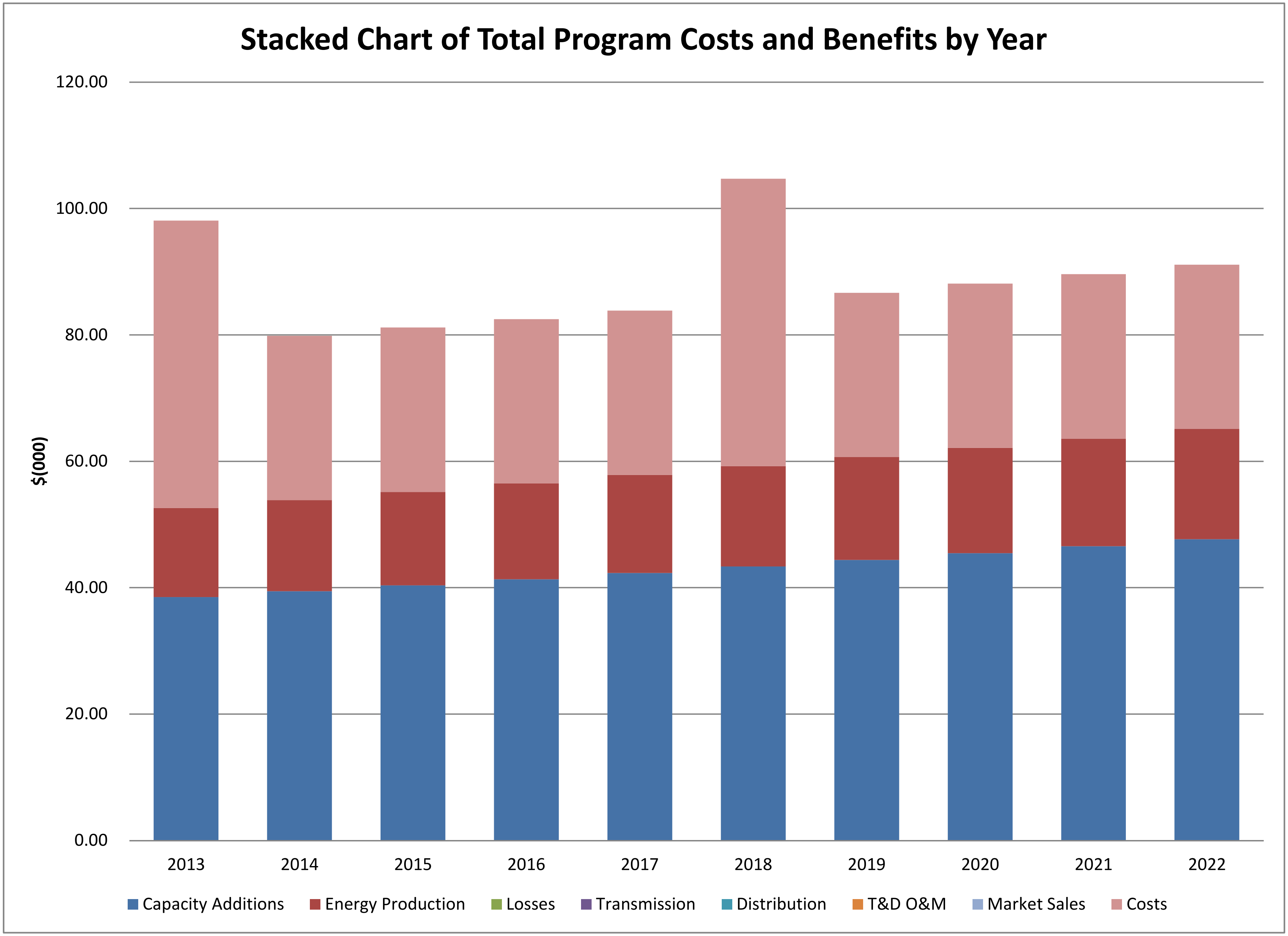
[30] The difference between baseline losses and losses under the alternative system, valued at the market energy rate.
[31] Based on allocation of losses for alternative system performance from the Inputs sheet.
[32] Based on allocation of losses for alternative system performance from the Inputs sheet.
[33] Peak demand growth rates for the baseline system (i.e., prior to the Program).
[34] Same as line 8.
[35] Based on user inputs.
[36] Represents the threshold below which any demand reduction would not be sufficient to avoid the next planned system improvement.
[37] Benefits are calculated and assigned to the first year of a 3 year planning window. Equal to zero if threshold for demand reductions was met in the most recent three year planning window.
[38] Distribution system improvements are needed for all new loads that come online for a system.
[39] First year costs assume some non-zero growth relative to the year prior to the Base Year.
[40] Ongoing O&M represents an estimate related to both Transmission and Distribution costs in each year, as appropriate.
[41] Represents the application of the estimate of ongoing O&M for Transmission and Distribution system improvements (as a percent of plant value) to the total avoided costs (if any) in both categories in each year.
[42] Market value of surplus energy may differ from market revenue potential of a specific marginal resource or the energy rate embedded in a specific tariff between a utility and their wholesale provider.
[43] Based on total estimate of avoided energy.
[44] "Gross" Implies the sum benefits prior to accounting for the intrinsic costs of the Program being analyzed.
[45] Based on assumed discount rate in Inputs sheet.
[46] Based on user inputs.
[47] Based on user inputs.
[48] Based on user inputs.
[49] Only counts relevant costs based on user decisions in the Inputs sheet.
[50] Total program avoided costs (benefits) divided by total program costs; a ratio greater than 1.0 implies that benefits outweigh costs.
[51] Benefit to Cost ratio over the life of the project, or the NPV of Gross Benefits divided by the NPV of Total Program Costs.
[52] Total Program Benefits minus total Program Costs.
[53] Based on assumed discount rate in Inputs sheet.



	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Net System Benefits	7.1	27.9	29.2	30.5	31.8	13.7	34.6	36.1	37.6	39.1


Stacked Chart of Total Program Costs and Benefits by Year
120.00
100.00
80.00
60.00
40.00
20.00
0.00
$(000)
2013
2014
2015
2016
2017
2018
2019
2020
2021
2022
Capacity Additions
Energy Production
Losses
Transmission
Distribution
T&D O&M
Market Sales
Costs

EPRI - Demand and Energy Reduction Cost-Benefit Model

Summary of Avoided Costs and Program/Project Costs

(Nominal $)

Line	*Guam Power Authority: DSM_2012 - COMM Prog. #1*		Units	Const.	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
	General Assumptions:													
1	Inflation	[1]	%	2.40%		2.40%	2.40%	2.40%	2.40%	2.40%	2.40%	2.40%	2.40%	2.40%
2	Discount Rate	[2]	%	5.25%										
	Projected Loads and Pricing:													
3	Forecasted Gross Energy for Load	[3]	MWh		1,664,029	1,672,870	1,688,316	1,699,590	1,706,988	1,707,460	1,710,423	1,713,391	1,730,525	1,747,830
4	Marginal Generation Energy Price	[4]	$/MWh		80.00	81.92	83.89	85.90	87.96	90.07	92.23	94.45	96.71	99.04
5	Forecasted Peak Demand	[5]	MW		272.5	279.1	285.4	286.8	286.0	284.6	284.2	287.0	289.9	292.8
6	Demand Price	[6]	$/kW-yr		350.00	358.40	367.00	375.81	384.83	394.06	403.52	413.21	423.12	433.28
	Projected Program Impacts:													
7	Projected Program Energy Reduction	[7]	MWh		7,004.8	7,004.8	7,004.8	7,004.8	7,004.8	7,004.8	7,004.8	7,004.8	7,004.8	7,004.8
8	Projected Program Peak Demand Reduction	[8]	MW		2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5
9	Losses based on Historical Loss Percentage	[9]	MWh	6.95%	115,668	116,283	117,357	118,140	118,654	118,687	118,893	119,100	120,291	121,493
10	Load portion of Losses	[10]	MWh	75.0%	86,751	87,212	88,017	88,605	88,991	89,015	89,170	89,325	90,218	91,120
11	No-Load portion of Losses	[11]	MWh	25.0%	28,917	29,071	29,339	29,535	29,664	29,672	29,723	29,775	30,073	30,373
12	Losses based on Loss Percentage (Resulting from Program)	[12]	MWh	6.95%	115,668	116,283	117,357	118,140	118,654	118,687	118,893	119,100	120,291	121,493
13	Load portion of Losses	[13]	MWh	75.1%	86,867	87,328	88,135	88,723	89,110	89,134	89,289	89,444	90,338	91,242
14	No-Load portion of Losses	[14]	MWh	24.9%	28,801	28,954	29,222	29,417	29,545	29,553	29,604	29,656	29,952	30,252
15	Loss Percentage Change	[15]	%		0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
16	Load portion of Losses	[16]	%		0.1%	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%
17	No-Load portion of Losses	[17]	%		-0.4%	-0.4%	-0.4%	-0.4%	-0.4%	-0.4%	-0.4%	-0.4%	-0.4%	-0.4%
	Avoided Capacity Additions/Purchases:													
18	Generating Unit Capital Costs	[18]	$/MW		2,140,000	2,191,360	2,243,953	2,297,808	2,352,955	2,409,426	2,467,252	2,526,466	2,587,101	2,649,192
19	Generating Unit Fixed O&M Costs	[19]	$/MW-yr		42,000.00	43,008.00	44,040.19	45,097.16	46,179.49	47,287.80	48,422.70	49,584.85	50,774.88	51,993.48
20	Pass-Through Demand Charge (for Purchases)	[20]	$/kW-yr		350.00	358.40	367.00	375.81	384.83	394.06	403.52	413.21	423.12	433.28
21	Dependable Capacity of Peak Demand Reduction	[21]	%	100.00%										
22	***Avoided Capacity Additions/Purchases Cost***	[22]	**$(000)**		**883.75**	**904.96**	**926.68**	**948.92**	**971.69**	**995.01**	**1,018.89**	**1,043.35**	**1,068.39**	**1,094.03**
	Avoided Energy Production/Purchase:													
	Marginal Resource Characteristics													
23	Heat Rate	[23]	btu/kWh	8,350										
24	Fuel Prices	[24]	$/mmBtu		17.96	18.40	18.84	19.29	19.75	20.23	20.71	21.21	21.72	22.24
25	Variable O&M Costs	[25]	$/MWh		5.00	5.12	5.24	5.37	5.50	5.63	5.76	5.90	6.04	6.19
26	Emissions Allowance Costs	[26]	$/MWh		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
27	*Marginal Resource Costs*	[27]	$/MWh		155.00	158.72	162.53	166.43	170.42	174.51	178.70	182.99	187.38	191.88
	Contract Characteristics													
28	*Tariff or Market Purchase Price*	[28]	$/MWh		55.00	56.32	57.67	59.06	60.47	61.92	63.41	64.93	66.49	68.09
29	***Avoided Energy Production/Purchase Cost***	[29]	**$(000)**		**1,085.74**	**1,111.79**	**1,138.48**	**1,165.80**	**1,193.78**	**1,222.43**	**1,251.77**	**1,281.81**	**1,312.57**	**1,344.08**
	Avoided System Losses:													
30	***Avoided System Losses Cost***	[30]	**$(000)**		**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**
31	Load portion of Losses Cost	[31]	$(000)		(9.25)	(9.53)	(9.84)	(10.15)	(10.44)	(10.69)	(10.97)	(11.25)	(11.63)	(12.03)
32	No-Load portion of Losses Cost	[32]	$(000)		9.25	9.53	9.84	10.15	10.44	10.69	10.97	11.25	11.63	12.03
	Avoided Transmission System Improvements:													
33	Load Growth (Organic)	[33]	%			2.4%	2.3%	0.5%	-0.3%	-0.5%	-0.2%	1.0%	1.0%	1.0%
34	Load Reduction (With Project or Program)	[34]	MW		2.53	2.53	2.53	2.53	2.53	2.53	2.53	2.53	2.53	2.53
35	Cost of Transmission Upgrades - Typical Growth	[35]	$/MW		1,500,000	1,536,000	1,572,864	1,610,613	1,649,267	1,688,850	1,729,382	1,770,887	1,813,389	1,856,910
36	Typical Load Growth Requiring Upgrades	[36]	MW	50.0										
37	***Avoided Transmission System Improvements Cost***	[37]	**$(000)**		**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**

EPRI - Demand and Energy Reduction Cost-Benefit Model

Summary of Avoided Costs and Program/Project Costs

(Nominal $)

Line	Guam Power Authority: DSM 2012 - COMM Prog. #1		Units	Const.	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
	Avoided Distribution System Improvements:													
38	Capital Budget for Distribution System Improvements - Growth	[38]	$/MW		0	0	0	0	0	0	0	0	0	0
39	***Avoided Distribution System Improvements Cost***	[39]	**$(000)**		**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
	Avoided T&D Improvements O&M Costs:													
40	Avoided O&M Costs associated with Avoided T&D Improvements	[40]	$(000)		0	0	0	0	0	0	0	0	0	0
41	***Avoided O&M Costs:***	[41]	**$(000)**		**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
	Potential Power Market Sales:													
42	Market Value of Surplus Energy	[42]	$/MWh		0	0	0	0	0	0	0	0	0	0
43	***Surplus Energy Sales Value:***	[43]	**$(000)**		**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
44	***Total Gross Program Benefits***	[44]	**$(000)**		**1,969**	**2,017**	**2,065**	**2,115**	**2,165**	**2,217**	**2,271**	**2,325**	**2,381**	**2,438**
45	***Total Gross Program Benefits***	[45]	**NPV $(000)**		**$16,589**									
	Program Costs													
46	Rebate Costs per Customer	[46]	$		0	0	0	0	0	0	0	0	0	0
47	Rebate Customers	[47]	#		0	0	0	0	0	0	0	0	0	0
48	Project Costs	[48]	$(000)		11,884	26.0	26	26	26	26	26	26	26	26
49	**Total Program Costs**	[49]	**$(000)**		**11,884**	**26**	**26**	**26**	**26**	**26**	**26**	**26**	**26**	**26**
50	**Benefit to Cost Ratio**	[50]	**#**		**0.2**	**77.6**	**79**	**81**	**83**	**85**	**87**	**89**	**92**	**94**
51	**Benefit to Cost Ratio**	[51]	**NPV**		**1.4**									
52	***Net System Benefits***	[52]	**$(000)**		**(9,914.0)**	**1,990.8**	**2,039.2**	**2,088.7**	**2,139.5**	**2,191.4**	**2,244.7**	**2,299.2**	**2,355.0**	**2,412.1**
53	***Net System Benefits***	[53]	**NPV $(000)**		**$5,125**									

Line	*Guam Power Authority: DSM 2012 - COMM Prog. #1*	Units	Const.	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022

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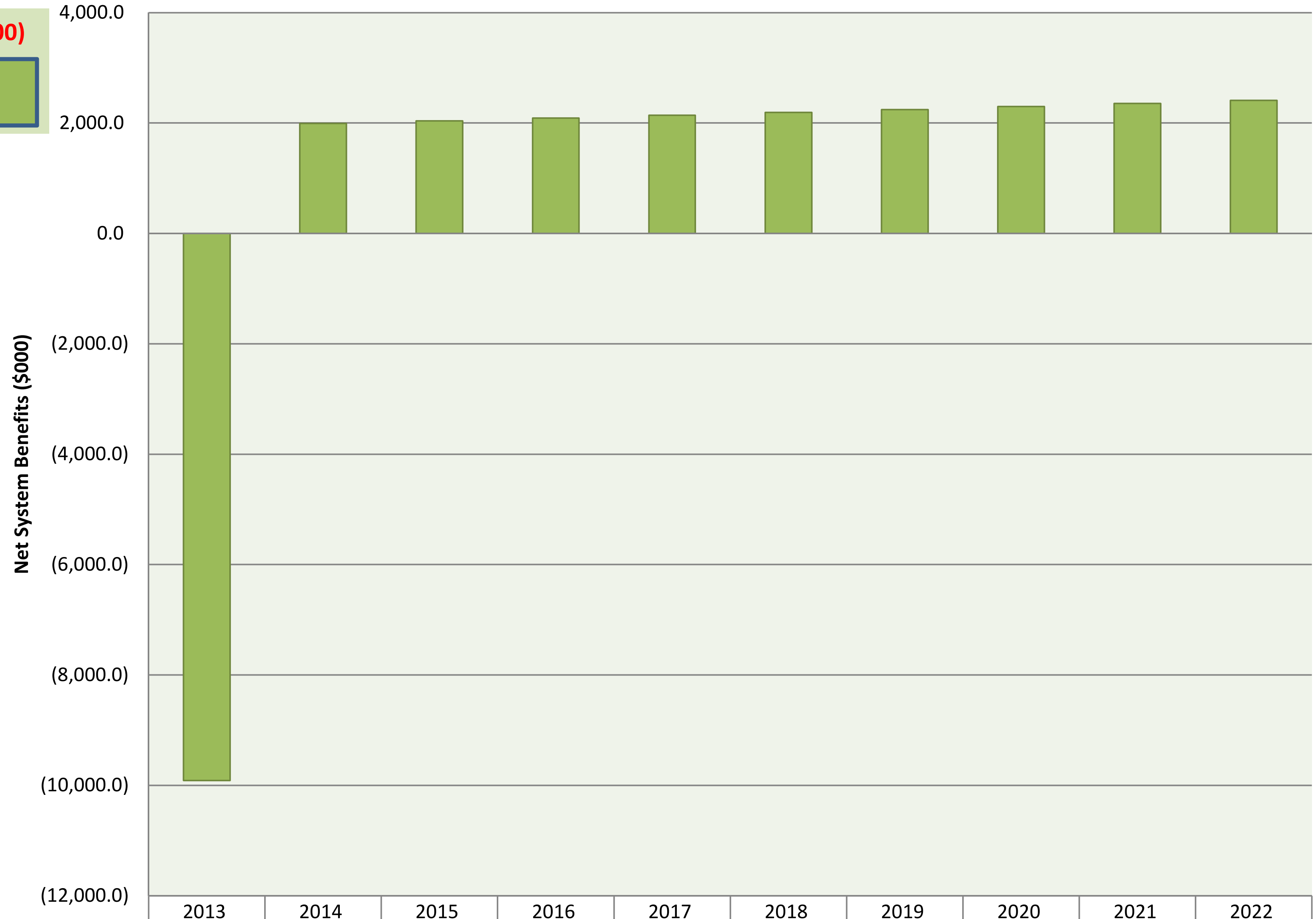
[52] Total Program Benefits minus total Program Costs.
[53] Based on assumed discount rate in Inputs sheet.

COMM Prog.

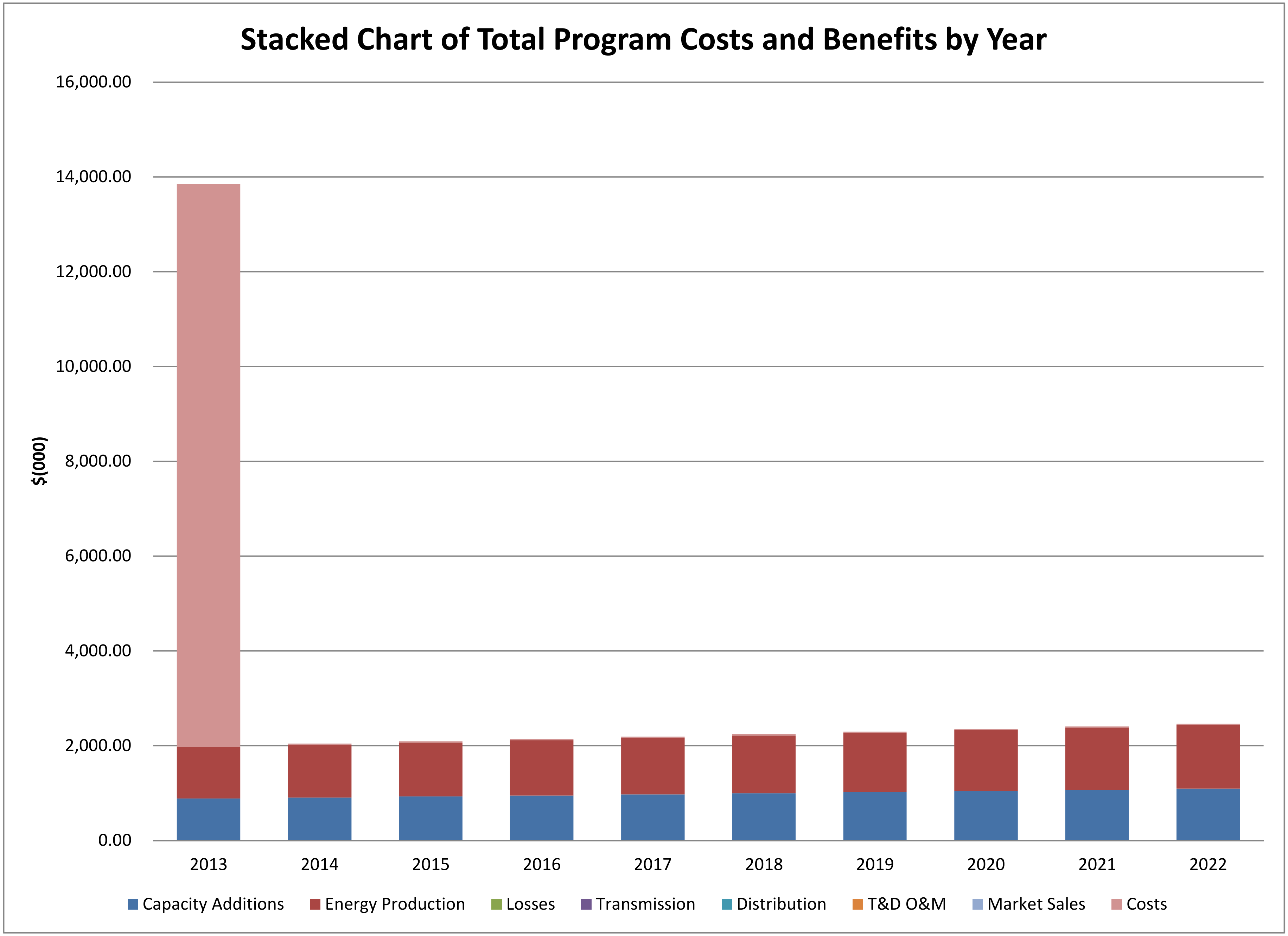
NPV ($000)

$5,125

Summary of Net System Benefits by Year



	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Net System Benefits	(9,914.0)	1,990.8	2,039.2	2,088.7	2,139.5	2,191.4	2,244.7	2,299.2	2,355.0	2,412.1


Stacked Chart of Total Program Costs and Benefits by Year
16,000.00
14,000.00
12,000.00
10,000.00
8,000.00
6,000.00
4,000.00
2,000.00
0.00
$(000)
2013
2014
2015
2016
2017
2018
2019
2020
2021
2022
Capacity Additions
Energy Production
Losses
Transmission
Distribution
T&D O&M
Market Sales
Costs

EPRI - Demand and Energy Reduction Cost-Benefit Model

Summary of Avoided Costs and Program/Project Costs

(Nominal $)

Line	*Guam Power Authority: DSM_2012 - COMM Prog. #2*		Units	Const.	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
	General Assumptions:													
1	Inflation	[1]	%	2.40%		2.40%	2.40%	2.40%	2.40%	2.40%	2.40%	2.40%	2.40%	2.40%
2	Discount Rate	[2]	%	5.25%										
	Projected Loads and Pricing:													
3	Forecasted Gross Energy for Load	[3]	MWh		1,664,029	1,672,870	1,688,316	1,699,590	1,706,988	1,707,460	1,710,423	1,713,391	1,730,525	1,747,830
4	Marginal Generation Energy Price	[4]	$/MWh		80.00	81.92	83.89	85.90	87.96	90.07	92.23	94.45	96.71	99.04
5	Forecasted Peak Demand	[5]	MW		272.5	279.1	285.4	286.8	286.0	284.6	284.2	287.0	289.9	292.8
6	Demand Price	[6]	$/kW-yr		350.00	358.40	367.00	375.81	384.83	394.06	403.52	413.21	423.12	433.28
	Projected Program Impacts:													
7	Projected Program Energy Reduction	[7]	MWh		350.0	350.0	350.0	350.0	350.0	350.0	350.0	350.0	350.0	350.0
8	Projected Program Peak Demand Reduction	[8]	MW		0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
9	Losses based on Historical Loss Percentage	[9]	MWh	6.95%	115,668	116,283	117,357	118,140	118,654	118,687	118,893	119,100	120,291	121,493
10	Load portion of Losses	[10]	MWh	75.0%	86,751	87,212	88,017	88,605	88,991	89,015	89,170	89,325	90,218	91,120
11	No-Load portion of Losses	[11]	MWh	25.0%	28,917	29,071	29,339	29,535	29,664	29,672	29,723	29,775	30,073	30,373
12	Losses based on Loss Percentage (Resulting from Program)	[12]	MWh	6.95%	115,668	116,283	117,357	118,140	118,654	118,687	118,893	119,100	120,291	121,493
13	Load portion of Losses	[13]	MWh	75.1%	86,867	87,328	88,135	88,723	89,110	89,134	89,289	89,444	90,338	91,242
14	No-Load portion of Losses	[14]	MWh	24.9%	28,801	28,954	29,222	29,417	29,545	29,553	29,604	29,656	29,952	30,252
15	Loss Percentage Change	[15]	%		0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
16	Load portion of Losses	[16]	%		0.1%	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%
17	No-Load portion of Losses	[17]	%		-0.4%	-0.4%	-0.4%	-0.4%	-0.4%	-0.4%	-0.4%	-0.4%	-0.4%	-0.4%
	Avoided Capacity Additions/Purchases:													
18	Generating Unit Capital Costs	[18]	$/MW		2,140,000	2,191,360	2,243,953	2,297,808	2,352,955	2,409,426	2,467,252	2,526,466	2,587,101	2,649,192
19	Generating Unit Fixed O&M Costs	[19]	$/MW-yr		42,000.00	43,008.00	44,040.19	45,097.16	46,179.49	47,287.80	48,422.70	49,584.85	50,774.88	51,993.48
20	Pass-Through Demand Charge (for Purchases)	[20]	$/kW-yr		350.00	358.40	367.00	375.81	384.83	394.06	403.52	413.21	423.12	433.28
21	Dependable Capacity of Peak Demand Reduction	[21]	%	100.00%										
22	***Avoided Capacity Additions/Purchases Cost***	[22]	**$(000)**		**35.35**	**36.20**	**37.07**	**37.96**	**38.87**	**39.80**	**40.76**	**41.73**	**42.74**	**43.76**
	Avoided Energy Production/Purchase:													
	Marginal Resource Characteristics													
23	Heat Rate	[23]	btu/kWh	8,350										
24	Fuel Prices	[24]	$/mmBtu		17.96	18.40	18.84	19.29	19.75	20.23	20.71	21.21	21.72	22.24
25	Variable O&M Costs	[25]	$/MWh		5.00	5.12	5.24	5.37	5.50	5.63	5.76	5.90	6.04	6.19
26	Emissions Allowance Costs	[26]	$/MWh		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
27	*Marginal Resource Costs*	[27]	$/MWh		155.00	158.72	162.53	166.43	170.42	174.51	178.70	182.99	187.38	191.88
	Contract Characteristics													
28	*Tariff or Market Purchase Price*	[28]	$/MWh		55.00	56.32	57.67	59.06	60.47	61.92	63.41	64.93	66.49	68.09
29	***Avoided Energy Production/Purchase Cost***	[29]	**$(000)**		**54.25**	**55.55**	**56.89**	**58.25**	**59.65**	**61.08**	**62.55**	**64.05**	**65.58**	**67.16**
	Avoided System Losses:													
30	***Avoided System Losses Cost***	[30]	**$(000)**		**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**
31	Load portion of Losses Cost	[31]	$(000)		(9.25)	(9.53)	(9.84)	(10.15)	(10.44)	(10.69)	(10.97)	(11.25)	(11.63)	(12.03)
32	No-Load portion of Losses Cost	[32]	$(000)		9.25	9.53	9.84	10.15	10.44	10.69	10.97	11.25	11.63	12.03
	Avoided Transmission System Improvements:													
33	Load Growth (Organic)	[33]	%			2.4%	2.3%	0.5%	-0.3%	-0.5%	-0.2%	1.0%	1.0%	1.0%
34	Load Reduction (With Project or Program)	[34]	MW		0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10
35	Cost of Transmission Upgrades - Typical Growth	[35]	$/MW		1,500,000	1,536,000	1,572,864	1,610,613	1,649,267	1,688,850	1,729,382	1,770,887	1,813,389	1,856,910
36	Typical Load Growth Requiring Upgrades	[36]	MW	50.0										
37	***Avoided Transmission System Improvements Cost***	[37]	**$(000)**		**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**

EPRI - Demand and Energy Reduction Cost-Benefit Model

Summary of Avoided Costs and Program/Project Costs

(Nominal $)

Line	Guam Power Authority: DSM 2012 - COMM Prog. #2		Units	Const.	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
	Avoided Distribution System Improvements:													
38	Capital Budget for Distribution System Improvements - Growth	[38]	$/MW		0	0	0	0	0	0	0	0	0	0
39	***Avoided Distribution System Improvements Cost***	[39]	**$(000)**		**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
	Avoided T&D Improvements O&M Costs:													
40	Avoided O&M Costs associated with Avoided T&D Improvements	[40]	$(000)		0	0	0	0	0	0	0	0	0	0
41	***Avoided O&M Costs:***	[41]	**$(000)**		**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
	Potential Power Market Sales:													
42	Market Value of Surplus Energy	[42]	$/MWh		0	0	0	0	0	0	0	0	0	0
43	***Surplus Energy Sales Value:***	[43]	**$(000)**		**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
44	***Total Gross Program Benefits***	[44]	**$(000)**		**90**	**92**	**94**	**96**	**99**	**101**	**103**	**106**	**108**	**111**
45	***Total Gross Program Benefits***	[45]	**NPV $(000)**		**$755**									
	Program Costs													
46	Rebate Costs per Customer	[46]	$		0	0	0	0	0	0	0	0	0	0
47	Rebate Customers	[47]	#		0	0	0	0	0	0	0	0	0	0
48	Project Costs	[48]	$(000)		46	26.0	26	26	26	46	26	26	26	26
49	**Total Program Costs**	[49]	**$(000)**		**46**	**26**	**26**	**26**	**26**	**46**	**26**	**26**	**26**	**26**
50	**Benefit to Cost Ratio**	[50]	**#**		**2.0**	**3.5**	**4**	**4**	**4**	**2**	**4**	**4**	**4**	**4**
51	**Benefit to Cost Ratio**	[51]	**NPV**		**3.3**									
52	***Net System Benefits***	[52]	**$(000)**		**44.1**	**65.8**	**68.0**	**70.2**	**72.5**	**55.4**	**77.3**	**79.8**	**82.3**	**84.9**
53	***Net System Benefits***	[53]	**NPV $(000)**		**$523**									

Line	*Guam Power Authority: DSM 2012 - COMM Prog. #2*	Units	Const.	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022

Footnotes (references to sources may be superseded by user adjustments to key inputs):

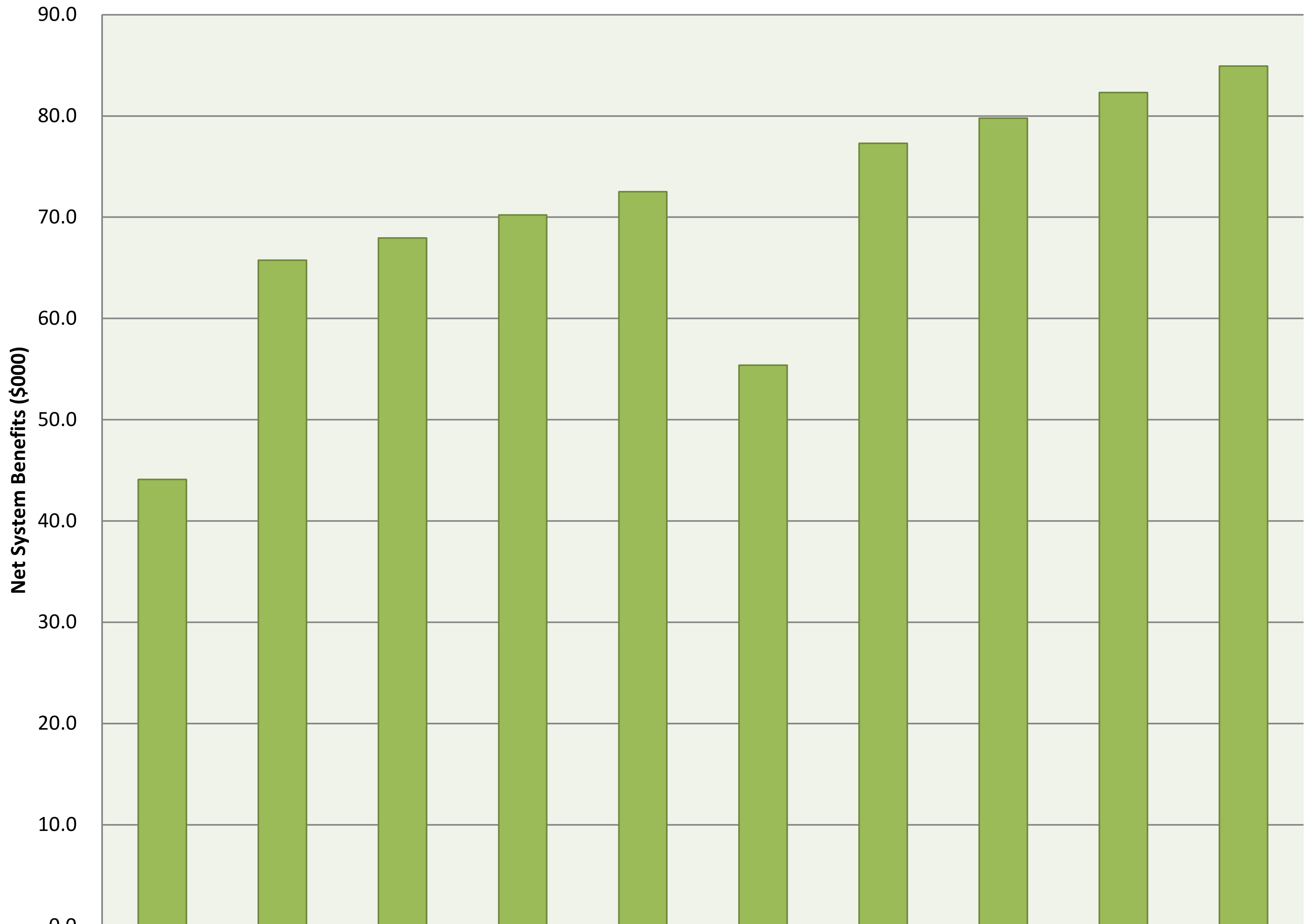
[1] Source: Blue Chip Economic Indicators Report, November 2010.
[2] Based on the most recent R. W. Beck standard assumption used to support power supply analyses.
[3] Total Retail Sales plus losses equals Gross Energy for Load. Gross Energy For Load is used to compute baseline and projected losses.
[4] Energy price for resources that are on the margin (or serve the last incremental portion of demand) in the market.
[5] Peak Demand represents annual non-coincident peak of the utility or the coincident peak of the utility with their wholesale provider, as appropriate.
[6] Demand price for wholesale power purchase contracts expected for utilities that purchase capacity from a third party.
[7] Total annual energy reduction resulting from a Project or a Rebate. Represents an estimate based on the specific characteristics of the Program, as appropriate.
[8] Total annual demand reduction resulting from a Project or a Rebate. Represents an estimate based on the specific characteristics of the Program, as appropriate.
[9] Projection of losses assuming baseline system performance and projected Gross Energy for Load.
[10] Based on allocation of losses for baseline system performance from the Inputs sheet.
[11] Based on allocation of losses for baseline system performance from the Inputs sheet.
[12] Based on projected system performance resulting from the Program, as a function of baseline projected Gross Energy for Load. The difference in losses is valued at the market price for energy.
[13] Based on allocation of losses for alternative system performance from the Inputs sheet.
[14] Based on allocation of losses for alternative system performance from the Inputs sheet.
[15] Relative to baseline system performance.
[16] Relative to baseline system performance.
[17] Relative to baseline system performance.
[18] Based on either user defined parameters or assumptions developed by R. W. Beck. Refer to Input sheet for details. Costs may be zeroed out based on their relevance given certain user decisions.
[19] Based on either user defined parameters or assumptions developed by R. W. Beck. Refer to Input sheet for details. Costs may be zeroed out based on their relevance given certain user decisions.
[20] Same as line 6.
[21] Equal to 100% unless demand reduction is sourced from an intermittently available resource or project (example: solar generation).
[22] Only counts relevant costs based on user decisions in the Inputs sheet.
[23] Based on either user defined parameters or assumptions developed by R. W. Beck. Refer to Input sheet for details.
[24] Based on either user defined parameters or assumptions developed by R. W. Beck. Refer to Input sheet for details.
[25] Based on either user defined parameters or assumptions developed by R. W. Beck. Refer to Input sheet for details.
[26] Based on either user defined parameters or assumptions developed by R. W. Beck. Refer to Input sheet for details.
[27] All-in costs for the selected marginal generating unit that serves the last incremental part of demand.
[28] For utilities that purchase power through a third party, whereby costs are a "pass-through" to the utility.
[29] Only counts relevant costs based on user decisions in the Inputs sheet.
[30] The difference between baseline losses and losses under the alternative system, valued at the market energy rate.
[31] Based on allocation of losses for alternative system performance from the Inputs sheet.
[32] Based on allocation of losses for alternative system performance from the Inputs sheet.
[33] Peak demand growth rates for the baseline system (i.e., prior to the Program).
[34] Same as line 8.
[35] Based on user inputs.
[36] Represents the threshold below which any demand reduction would not be sufficient to avoid the next planned system improvement.
[37] Benefits are calculated and assigned to the first year of a 3 year planning window. Equal to zero if threshold for demand reductions was met in the most recent three year planning window.
[38] Distribution system improvements are needed for all new loads that come online for a system.
[39] First year costs assume some non-zero growth relative to the year prior to the Base Year.
[40] Ongoing O&M represents an estimate related to both Transmission and Distribution costs in each year, as appropriate.
[41] Represents the application of the estimate of ongoing O&M for Transmission and Distribution system improvements (as a percent of plant value) to the total avoided costs (if any) in both categories in each year.
[42] Market value of surplus energy may differ from market revenue potential of a specific marginal resource or the energy rate embedded in a specific tariff between a utility and their wholesale provider.
[43] Based on total estimate of avoided energy.
[44] "Gross" Implies the sum benefits prior to accounting for the intrinsic costs of the Program being analyzed.
[45] Based on assumed discount rate in Inputs sheet.
[46] Based on user inputs.
[47] Based on user inputs.
[48] Based on user inputs.
[49] Only counts relevant costs based on user decisions in the Inputs sheet.
[50] Total program avoided costs (benefits) divided by total program costs; a ratio greater than 1.0 implies that benefits outweigh costs.
[51] Benefit to Cost ratio over the life of the project, or the NPV of Gross Benefits divided by the NPV of Total Program Costs.
[52] Total Program Benefits minus total Program Costs.
[53] Based on assumed discount rate in Inputs sheet.

COMM Prog.

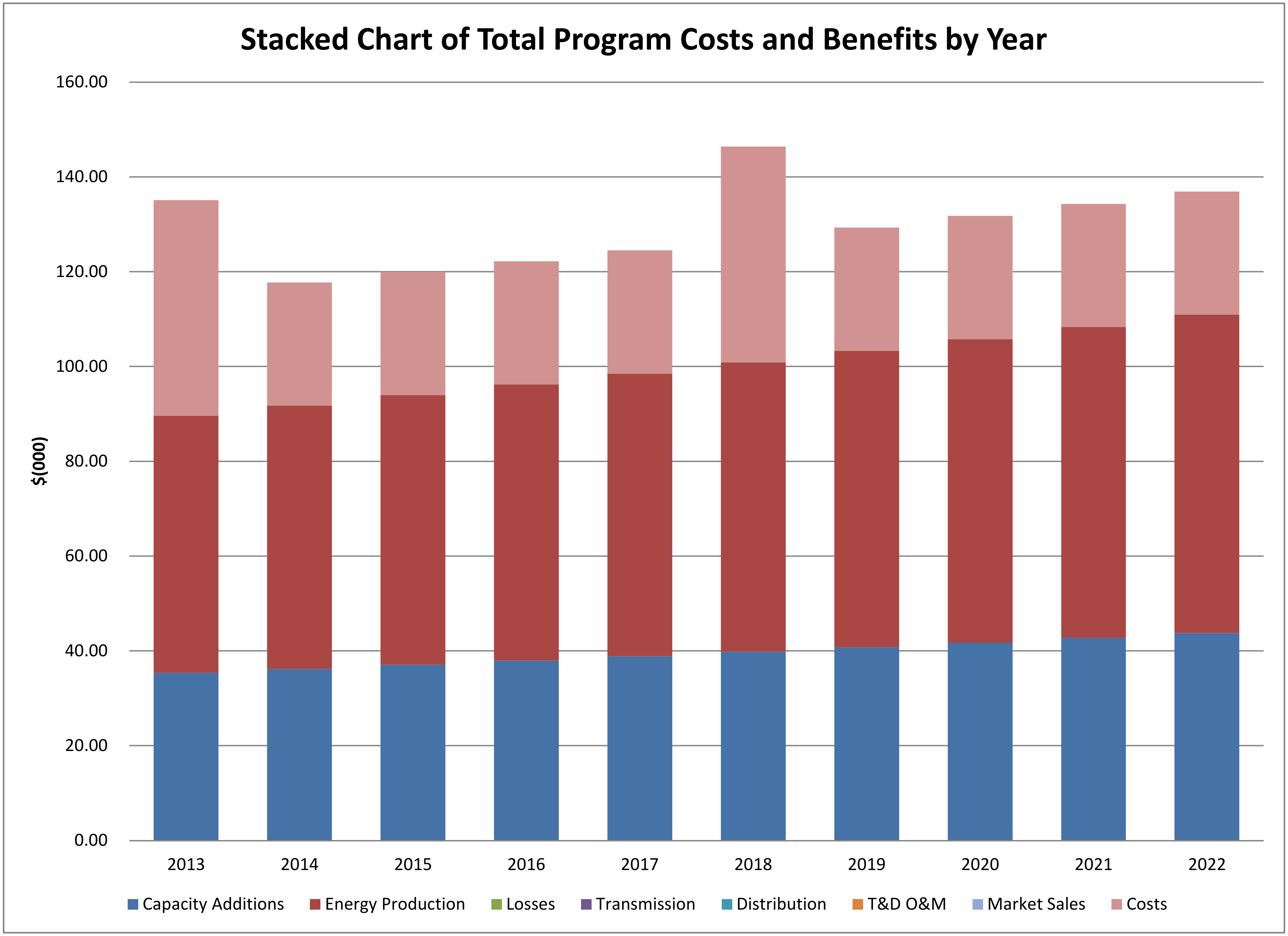
NPV ($000)

$523

Summary of Net System Benefits by Year



	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Net System Benefits	44.1	65.8	68.0	70.2	72.5	55.4	77.3	79.8	82.3	84.9


Stacked Chart of Total Program Costs and Benefits by Year
$(000)
160.00
140.00
120.00
100.00
80.00
60.00
40.00
20.00
0.00
2013
2014
2015
2016
2017
2018
2019
2020
2021
2022
Capacity Additions
Energy Production
Losses
Transmission
Distribution
T&D O&M
Market Sales
Costs

E IRP Strategist Scenario Analysis

IRP Strategist Scenario Analysis

Strategist by Ventyx is the optimization tool used to determine the most economical generation resource plan. The program evaluates operational performance and cost data of existing and new resources to meet forecasted demands and other constraints or planning assumptions. Planning assumptions include:

- Resource Options Availability: At what point in time can options be exercised?
- Number of Available Options: How many feasible options are allowed for consideration?
- Reserve Margin Requirements: How do unit retirements impact reliability?

This document identifies the planning assumptions and Strategist scenarios as well as the results from these scenarios.

1 Base Case

A base case is created to evaluate Present Value results from each Strategist scenario in screening scenarios for further evaluation. The following are assumptions used in developing the Base Case.

- **Study Period is 30 years.**
- **Fuel Forecast is Base Case.**
- **Load Forecast is the Baseline forecast.**
- **Includes recently contracted and pending contract for 35 MW of Renewable Energy from 2011 bid** (Quantum Guam Power and Pacific Green Resources). Both contracts are anticipated to start delivering renewable energy by end of FY2013.
- **Assumes capital costs for life extensions on existing units.** This assumption is made because the case evaluates an as is condition throughout the study period with no additional units and no change in fuel. Existing units would require capital investment in order to improve performance output and extend operating life.
- **Assumes capital costs for EPA compliance requirements (based on assumptions mentioned earlier).** Without a change in fuel and the introduction of new thermal units, upcoming compliance dates for EPA would need to be addressed. Capital costs for compliance without new resources are included.
- **No new resources, including renewable resources, or unit conversions are considered.**

From these assumptions the Base Case value for Present Value Utility Costs ($000) is $ 6,451,778. Present Value Utility Costs from each scenario will be compared against this value.

Reference No.	1A
Forecast	Baseline
PV Utility Costs ($000)	6,451,778
Variance from Base Case (CAPEX 1A)	**BASE CASE**
CAPEX	Yes
AQCS	**Yes**
Add New Resources	**NO**
QGP & PGR	Yes
SWAC	
Renewable Firming & Shaping Assumption	
Geothermal	

Figure 1 – Base Case

2 Modeling Assumptions

Several modeling assumptions are used in developing and evaluating scenarios which address compliance with upcoming EPA regulations and fuel diversification while considering the impact of military buildup projections. Upcoming EPA rules is a major factor as capital investment in excess of $400M for air quality control equipment would be required meet compliance requirements at the Slow Speed Diesel and the Steam power plants in the next few years. In addition to this there is still much uncertainty of military buildup which has significant influence on all load forecasts.

2.1 EPA Compliance

The following table summarizes compliance requirements and dates.

Table 1 – EPA Compliance Schedules

	EGU MACT	**RICE MACT**	**CT MACT**	**NAAQS**
Compliance Dates:	May 2015 + 2 Year Extensions	April 2013 + 2 Year Extensions	Triggered by PSD Requirements	June 2017
Units:	Steam Plants	Slow Speed Diesels/ Medium Speed Diesels	Combustion Turbines	All Units
Status:	Filed 1 Year Extension Request, Approval Pending	Filed 1 Year Extension Request, Approval Pending		

EPA compliance assumptions used in all scenarios include:

- **Delay of compliance for slow speed diesels (Cabras 3&4 and MEC 8&9) for conversion of plants to natural gas.** This assumption removes the capital costs required for the installation of scrubbers to reduce SO2 in exhaust due to residual fuel oil use which was modeled in the Base Case.

- **Delay of EGU MACT (Boiler MACT) and NAAQS compliance for steam plants (Cabras 1&2 and Tanguisson Power Plant) until LNG is available for plant conversion or plant retirement.**

- **All combustion turbines and medium speed diesels that are not converted to natural gas would comply by 2014.**

2.2 Demand Forecast & Reliability Planning

In Figure 2 below, the forecasts are graphed with compliance and new resource availability years highlighted.

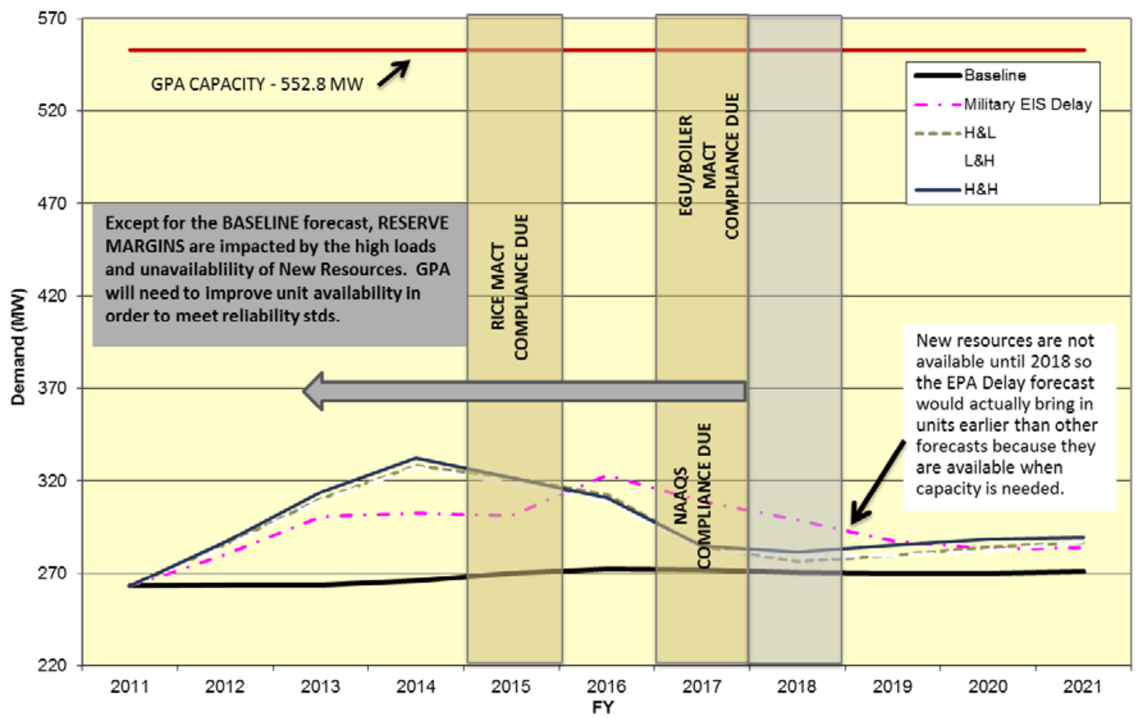


Figure 2 – Demand Forecasts, Compliance Schedules and New Resource Availability

Assumptions in demand and reliability include the following:

- **The baseline forecast shall be used to determine minimal requirements to meet future demand.** Until 2018, new firm resources would not be available to support peak demands in other forecasts. An evaluation of modeled scenarios against the EPA Delay forecast should also be done to show GPA should monitor military and industry growth to determine if pro

- **Capital investment for life extension and performance improvements, unless retired before 2014, are applied to existing units.** This assumption considers the other forecast peaks occurring before new resources are made available. Performance improvements and life extension costs are included starting from 2014 to ensure low operating costs and reliability through 2018.

- **Minimize unit retirements until new (firm) resources are available in 2018.** Although GPA has over 550 MW of capacity for loads, meeting reserve margin requirements for planned and forced outages would be difficult if military buildup accelerates and occurs before new resources are available.

2.3 Fuel Diversification Guidelines

In order to ensure fuel diversification, the following assumptions are used:

- **New Resources are not fuel oil fired units.** This is further supported by the strict new EPA rules for fuel oil units which would require air quality compliance and may delay permitting of new plants.

- **Unit Conversions are restricted as follows:**

    - Base load units would be first conversion. Peaking units would be evaluated after conversions.

    - Conversion of all units in single plant are done at same time. Strategist evaluates unit performance but this addresses construction schedule and fuel supply/inventory concerns as well.

    - Selection of unit conversions shall be based on lowest cost (total operating costs), but additional conversions maybe forced in order to meet LNG fuel usage requirements as mentioned earlier.

2.4 Renewables

A recent system impact study evaluating the interconnection of 35 MW of renewable energy resources determined that GPA's current spinning reserve would be adequate to accommodate the intermittent solar and wind operations. However, as GPA intends to expand its renewable portfolio, intermittency controls, whether through increased spinning reserves or energy storage, should be evaluated for any addition of solar or wind resources.

The following are the assumptions with renewable resources

- **Increase operational costs of solar and wind resource options to model increase of spinning reserve requirements.** This assumption is an initial attempt to address potential stability issues due to interconnection of intermittent renewable resources.

- **Consider feasibility of geothermal resource option**. GPA Geothermal is evaluated as a competitive option but geothermal potential has not been determined.
- **Limit additional renewables as they impact fuel consumption requirements for LNG.**

2.5 LNG Options

The following are assumptions for resources using natural gas which include existing unit fuel conversion and new resource options:

- **Construction of import terminal completion in 2018 sets the minimum year for natural gas resource options to be made available.**
- **Terminal costs, based on a loan payment schedule, are added as a fuel premium to LNG forecast using an assumption of 34,000 MBTU/day fuel usage.**

2.6 Other Assumptions

Other assumptions required include:

- Restrict selection of Small Modular Reactor (SMR) until after 2038 or in each scenario to ensure fuel usage requirements for natural gas usage are met.
- Exclude the Sea Water Air Conditioning demand side management (DSM) program in initial scenario since program requires business case analysis for PUC approval. Program should be evaluated later to determine impact on scenarios selected for further analysis.

3 Scenarios

3.1 LNG Scenarios

The following summarizes the overall assumptions for selected LNG Scenarios developed:

- Considers all LNG conversions as competitive options to lower overall costs.
- Considers reserve margin requirements in determining unit retirement scenarios.
- Considers retirement options to evaluate impact of capital costs for life extensions and EPA compliance costs but maintains minimum reserve margin requirements (~54%).
- Does not include small modular reactor due to fuel use requirements for LNG.
- Considers all renewable alternatives as competitive resources.
- Considers life extension costs initially to determine which of existing units would convert and then applies EPA compliance costs for comparison to Base Case.

The LNG scenarios developed are:

1. No Unit Retirements
2. Retire Marbo and Dededo Diesel in FY2012
3. Retire Marbo, Dededo Diesel, Dededo CT 1&2 in FY2012
4. Retire Marbo, Dededo Diesel, Dededo CT 1&2, Yigo in FY2012
5. Retire Marbo, Dededo Diesel, Dededo CT 1&2, and Yigo in FY2012 and Macheche in FY2018
6. Retire Marbo and Dededo Diesel in FY2012 and Tanguisson 1&2 in FY2018
7. Retire Marbo and Dededo Diesel in FY2012 and Cabras 1&2 in FY2018
8. Retire Marbo and Dededo Diesel in FY2012 and Cabras 1&2 and Tanguisson 1&2 in FY2018

3.2 SMR Scenario

The following summarizes the overall assumptions for selected SMR Scenarios developed:

- Assumes earliest availability is 2022 because of construction and permitting schedules.
- Assumes no LNG-fueled conversions or new resources are modeled due to restrictions on fuel use requirements.
- Assumes capital costs for EPA compliance is required due to protracted timing of SMR availability.

Since the SMR resource is not licensed and costs for this resource are still speculative, there is only a single scenario developed to evaluate how a delayed resource would be compared against the corresponding LNG scenario. The scenario is:

9. Retire Marbo and Dededo Diesel in FY2012 (SMR)

4 Results

Tables 2 & 3 below contain the initial results of the scenarios developed.

Table 2 – LNG Scenario Results (Initial Screening)

CASE	Retirement Units	PV Utility Costs ($000)	Present Value Variance (Savings) from Base Case ($000)
1	None	6,451,778	BASE CASE
2	Marbo, Dededo Diesel, Cabras 1&2	5,258,080	(1,193,698)
3	Marbo, Dededo Diesel, Tanguisson 1&2	5,311,525	(1,140,253)
4	Marbo, Dededo Diesel, Cabras 1&2, Tanguisson 1&2	5,241,317	(1,210,462)
5	Marbo, Dededo Diesel, Dededo CT 1&2, Yigo, Macheche	5,348,209	(1,103,570)
6	Marbo, Dededo Diesel, Dededo CT 1&2, Yigo	5,354,665	(1,097,114)
7	Marbo, Dededo Diesel, Dededo CT 1&2	5,360,709	(1,091,069)
8	Marbo, Dededo Diesel	5,388,596	(1,063,182)

Table 3 – SMR Scenario Results

CASE	Retirement Units	PV Utility Costs ($000)	Present Value Variance (Savings) from Base Case ($000)
1	None	6,451,778	BASE CASE
2	Marbo, Dededo Diesel (SMR Option)	5,478,235	(973,543)

4.1 LNG Results Evaluation

The following process was used to evaluate LNG scenarios:

- Run each scenario using minimum assumptions
- Select top scenarios with lowest Present Value Utility Costs to further test assumptions
- Test selected scenarios for the following:
    - Impact of increase operating costs of Solar and Wind resources to address intermittency controls.
    - Removal of Geothermal resource as an option due to pending feasibility study.
    - Include SWAC as a demand side management program which is an approximate equivalent of 12 MW capacity addition to test impact.

Figure 3 illustrates the modeling assumptions and testing sequence used for the top 3 cases.

Reference No.	1A	6A	6R-A (R40)	6RO-A (R40)	6ROS-A (R40)
Forecast	Baseline	Baseline	Baseline	Baseline	Baseline
PV Utility Costs ($000)	6,451,778	5,258,080	5,246,848	5,305,139	5,329,746
Variance from Base Case (CAPEX A)	BASE CASE	(1,193,698)	(1,204,930)	(1,146,639)	(1,122,032)
CAPEX	Yes	Yes	Yes	Yes	Yes
AQCS	YES	YES	YES	YES	YES
Add New Resources	NO	Yes	Yes	Yes	Yes
QGP & PGR	Yes	Yes	Yes	Yes	Yes
SWAC		No	No	No	YES
Renewable Firming & Shaping Assumption		Yes	NO	NO	NO
Geothermal		Yes	Yes	NO	NO

Apply compliance requirements to units that don't convert or retire

Evaluates Firming/Shaping Assumption Impact

Considers Geothermal Feasibility still pending

Evaluates the impact of Sea Water Air Conditioning (SWAC), ~12MW equivalent

Figure 3 – Modeling Assumptions

	6A	6R-A (R40)	6RO-A (R40)	6ROS-A (R40)
	Baseline	Baseline	Baseline	Baseline
	5,258,080	5,246,848	5,305,139	5,329,746
	(1,193,698)	(1,204,930)	(1,146,639)	(1,122,032)
	Yes	Yes	Yes	Yes
	YES	YES	YES	YES
	Yes	Yes	Yes	Yes
	Yes	Yes	Yes	Yes
	No	No	No	YES
	Yes	NO	NO	NO
	Yes	Yes	NO	NO
STRATEGIST RESULTS for ALTERNATIVE SELECTIONS by Fiscal Year:				
2017		PV(2, WIND(1)	PV(3), WIND(1)	PV(3), WIND(1)
2018	RETR, CLNG (1), C3L, C4L	WIND(1), RETR, CLNG (1), C3L, C4L	WIND(1), RETR, CLNG (1), C3L, C4L	RETR, CLNG (1), C3L, C4L
2019	GEOT, ML8, ML9	GEOT, ML8, ML9	ML8, ML9	ML8, ML9
2026		PV		
2027				
2028		PV		
2029				PV
2030			PV	PV
2031		PV		
2032			PV	
2033				
2034				
2035				
2036				CLNG
2037	CLNG		CLNG	
2038		CLNG		
2039				
2040				

Figure 4 – Case 2 (Cabras 1&2 Retirement) Results

The results indicate the following:

- Reduction of GPA's overall generation capacity.
- Reduction in overall costs.
  - Fixed costs - Reduced capacity requires less fixed costs.
  - Fuel costs – Renewable and LNG reduce total fuel costs.
  - Efficiency improvement – New combined cycle with better heat rates also lowers fuel costs.
- Maintains diversification.
- Meets or near minimum of the LNG fuel use requirements to cover cost of LNG import terminal and regasification infrastructure debt.
- Cases Contributes to Renewable Portfolio Standards goals.

4.2 SMR Results evaluation

The SMR unit is not available until 2022 due to permitting and construction requirements. LNG scenarios provide savings as early as 2018 due to fuel costs and in some cases due to addition of higher efficiency units.

The SMR scenario exceeds compliance dates for EPA air emissions regulations by 6-8 years. Since this modeled resource is not commercially available schedules are estimated and it is expected to cause concern with any discussions to delay compliance. In addition, because the modeled SMR is not currently licensed, actual commercial availability is uncertain.

SMR does prove to be a viable candidate as an alternative energy resource further out in about 20 or 30 years especially if GPA has not replaced units that were converted for natural gas use. This requirement would allow LNG infrastructure to be paid off and lessen requirements on LNG fuel or retire some of the units to save on fixed costs. GPA should continue to monitor and evaluate SMR as a potential resource in later years

4.3 Renewables

Renewables with low capacity factors (solar and wind) are selected by 2017. The firming and shaping costs do allow selection of these units through the study period. Figure 5summarizes the Case 2, Cabras 1&2 Retirement Scenario. In this case evaluation, the difference in savings with and without these assumptions indicate there may be $11 Million dollars that could be invested in energy storage or other stability projects.

Reference No.	6A	6R-A (R40)	6RO-A (R40)	6ROS-A (R40)
Forecast	Baseline	Baseline	Baseline	Baseline
PV Utility Costs ($000)	5,258,080	5,246,848	5,305,139	5,329,746
Variance from Base Case (CAPEX A)	(1,193,698)	(1,204,930)	(1,146,639)	(1,122,032)
CAPEX	Yes	Yes	Yes	Yes
AQCS	YES	YES	YES	YES
Add New Resources	Yes	Yes	Yes	Yes
QGP & PGR	Yes	Yes	Yes	Yes
SWAC	No	No	No	YES
Renewable Firming & Shaping Assumption	Yes	NO	NO	NO
Geothermal	Yes	Yes	NO	NO

Figure 5 – Case 2 (Cabras 1&2 Retirement) Renewable Assumption Test Results

Table 4 summarizes results from the top 3 cases in which renewable assumptions were tested.

Table 4 – Comparison of Initial Screening and Test Assumption Results

		Present Value Variance (Savings) from Base Case ($000)	
CASE	Retirement Units	Initial Screening Assumptions[1]	Test Assumptions[2]
1	None	BASE CASE	BASE CASE
2	Marbo, Dededo Diesel, Cabras 1&2	(1,193,698)	(1,204,930)
3	Marbo, Dededo Diesel, Tanguisson 1&2	(1,140,253)	(1,146,924)
4	Marbo, Dededo Diesel, Cabras 1&2, Tanguisson 1&2	(1,210,462)	(1,201,425)
5	Marbo, Dededo Diesel, Dededo CT 1&2, Yigo, Macheche	(1,103,570)	
6	Marbo, Dededo Diesel, Dededo CT 1&2, Yigo	(1,097,114)	
7	Marbo, Dededo Diesel, Dededo CT 1&2	(1,091,069)	
8	Marbo, Dededo Diesel	(1,063,182)	

[1] Initial screening assumptions include additional operation costs for intermittent renewable options (solar and wind) and the availability of geothermal potential.

[2] Testing assumptions evaluate results based on removal of initial screening assumptions.

Based on Case 2 (Cabras 1&2 Retirement Scenario), GPA's projection in meeting the Guam Renewable Portfolio Standards (RPS) as illustrated in Figure 6 below. The inclusion of renewable resources helps to meet RPS goals in the near future as well as help meet diversification strategy.

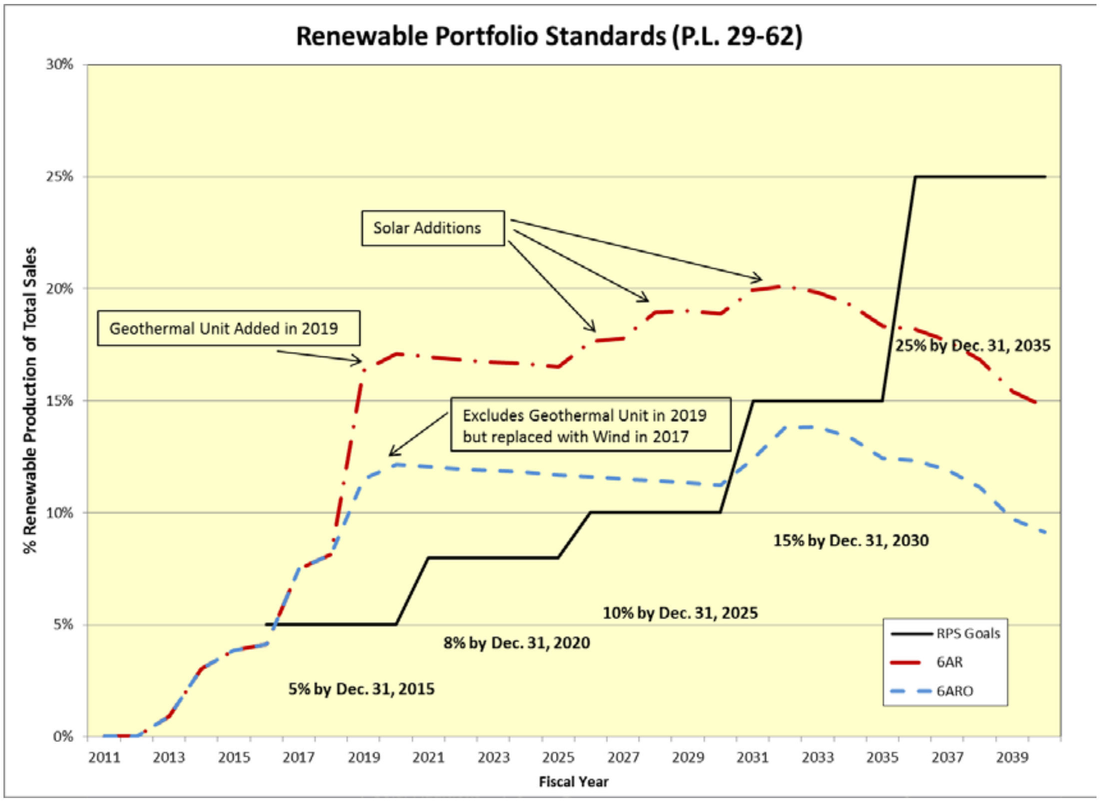


Figure 6 – Case 2 (Cabras 1&2 Retirement Scenario) and RPS Goals

Figure 6 shows how the removal of Geothermal pending feasibility impacts projected RPS projections. These units can be represent other renewable technologies, such as waste to energy, which have similar operating and cost assumptions.

5 Conclusions

Results indicate that conversion of LNG would provide over a $1Billion of savings throughout the study period.

- Results point towards LNG fuel as a viable option which:
  - Lowers overall costs over the study period; and
  - Addresses EPA air emissions compliance requirements near compliance dates.
- The addition of 40 MW for renewables (Phase II acquisition) will help lower costs and meet RPS goals.
- SMR may be a viable option in the distant future.

- Geothermal is a viable option along with LNG alternatives and as firm power and its potential for Guam may be worth investigating further. Other renewable technologies can replace the geothermal option which have the same or similar operating and costs.

- GPA should continue to evaluate efficiency improvements of existing units.

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