Quantification of Energy Efficiency in the Utilities of the U.S. Affiliate States (excluding US Virgin Islands)

Guam Power Authority (GPA)

Ordered by the Pacific Power Association (PPA)

Prepared by KEMA Inc.
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1. Executive Summary

KEMA's analysis of GPA's power system shows total losses of 12.39% consisting of:

- 5.36% in power station auxiliaries (station losses). Generally station losses are lower than 5%.
- 0.17% used by GPA in its own buildings. This unbilled usage cannot be considered to be a system loss. The power usage for own buildings should be accounted for and considered as part of GPA's operational costs.
- 6.36% in technical losses
- 0.50% in non-technical loss.

Technical and non-technical losses total 6.86%.

With non-technical losses being only 0.50%, GPA is "best in class". With a number this low, opportunities for improvement are limited. Also the figure for technical losses does not leave much room for further reduction in such a way that benefits are exceeding costs. Station losses in the power plants are somewhat higher than 5% which is considered as a not-to-exceed value at many electric utilities.

Each percentage of loss costs the utility at $2.19 per gallon of fuel about $ 2,800,000. It is estimated that when taking the following steps of process improvements, together with recommended investments of $8.9 million over 6 years, GPA can achieve savings of $ 3.5 million per year.

It is estimated that when taking the following steps of process improvements, together with recommended investments of $8.85 million over 6 years, GPA can achieve savings of $3.5 million per year.

1. Keep generating units running at highest operating efficiency.

2. Maintain optimized dispatching routine to provide highest production efficiencies.

3. Update specifications for distribution and power transformers to account for the cost of losses over the total lifetime (capital, losses and maintenance).

4. Add revenue-class meters to feeders and distribution transformers. This will also allow timely and accurate identification of non-technical losses from meter tampering, by-passing, or other theft.

5. Develop a methodology to optimize distribution transformer sizes to reduce no-load losses.

With these recommendations, it is estimated a net present value savings of $2.4 million over a period of 6 years is possible. Loss reductions would be as follows:

- Station losses (power plant auxiliaries): from 5.36% to 4.93%
- Technical losses: from 6.36% to 6.26%
- Non-technical losses: from 0.5% to 0.37%

2. Project Objectives

KEMA was asked by the Pacific Power Association (PPA) to conduct an energy efficiency study titled: "Quantification of Energy Efficiency in the Utilities of the U.S. Affiliate States (excluding US Virgin Islands)" for 10 Northern Pacific Island Utilities. This report summarizes the study results for Guam Power Authority (GPA) on the island of Guam.

Project objectives and deliverables:

1. Quantify energy losses in the power system.
2. Prepare an Electrical Data Handbook containing electrical characteristics for all high voltage equipment.
3. Prepare digital circuit model of the power system using EASY POWER, an established commercial package.
4. Prepare a prioritized replacement list of power system equipment to reduce technical losses.
5. Identify sources of non-technical losses.

2.1 Quantification of Losses

Losses are due to:

1. Power station losses
2. Transmission system losses
3. Distribution system losses.

All three categories of losses are quantified.

Improvement of generation efficiency will lead to fuel savings. The following is a list of quantified loss categories:

- Station Losses: Power Plant Auxiliary Loads
- Transmission & Distribution System Losses: These losses consist of:

- Technical losses: Summation of transformer core and copper losses, transmission line losses, primary distribution feeder losses, and secondary wire losses. The technical losses will become higher if the power factor in the system or in system parts is lower than the company's targeted power factor.
- Non-technical losses: Losses in this category are due to inaccurate meters, meter tampering or by-passing, theft, meter-reading errors, irregularities with prepaid meters, administrative failures, and wrong multiplying factors.

- Unbilled Usages – these are the energy consumptions in GPA's system, which are not billed. The unbilled usages should be accounted for and billed, or should otherwise be considered a financial losses rather than as a part of the non-technical losses. Possible usages that are unbilled can include:
  - Consumption of unbilled street lights.
  - Utility's own building usage.

Information received from GPA did not allocate any energy consumption to street lights. GPA's own usage was separately identified.

3. Data Gathering and Assessment of the Current Situation

The objective of the data gathering process is to collect information and understand the current situation of the power generation and distribution system in Guam.

3.1 Site Visit and Data Collection

Data was gathered during the site visit of March 2010. During the visit, we met with various people from power plants, T&D, metering, and billing departments, and we collected information on site. In addition, information on distribution transformer data and customer monthly consumption for each customer category, as well as the historical annual energy generation and consumption data were sent after our meetings.

It was very helpful that GPA provided transmission system models in PSLF format and distribution system models in SynerGee format. Loss data summaries were provided for the transmission and distribution systems. Metering data, secondary wire data, distribution transformer data, and monthly consumption data by customer categories (residential, commercial, and industrial customers) were also provided. This data was used to estimate system losses.

A summary of data received:

1. One line diagrams for transmission and distribution systems
2. Transmission system models in PSLF format
3. Distribution system models in SynerGee format
4. Distribution transformer summary
5. Loss summaries for the transmission system
6. Loss summaries per feeder for the distribution system
7. Metering data per feeder
8. Transmission line conductor data

9. Distribution feeder conductor data

10. Secondary conductor data

11. Number of customers and monthly consumptions by customer category

3.2 The GPA Power System

Generation

GPA has 10 power plants. The generators from Cabras, Piti, and Tanguiss serve base load. The remaining generators serve peak load. The generation mix is two steam turbines, five combustion turbines, one slow-speed diesel engine, and four medium-speed diesel engines. The system peak demand during 2008-2009 was 263 MW.

Transmission System

The transmission system has six (6) 115 kV transmission lines, thirty-one (31) 34.5 kV overhead lines, and fifteen (15) 34.5 kV underground cables. In addition, there are four (4) transmission lines at 34.5 kV, which are out of service. In total, there are sixty-four (64) power transformers at voltage levels of 115 kV, 34.5 kV, 13.8 kV, and 4.16 kV. Four (4) of 27 capacitor banks are in service under peak load condition.

Distribution System

The island of Guam is served by both overhead lines and underground cables of sixty three (63) primary feeders at 13.8 kV. These 13.8kV feeders are connected to 4759 single-phase pole-top and pad-mounted and 1041 pad-mounted three-phase distribution transformers. Under peak load condition, the utilization of the total installed distribution transformer capacity is 31%. Under peak load condition 31 out of 63 feeders are loaded between 30% and 40%, 21 feeders are loaded below 30%, while 9 feeders are loaded between 40% and 70% of the total installed distribution transformer capacity. There are only 3 feeders that appear to be more than 90% during the peak load condition, which are: P-246, P-400 and P-402.

Exhibit 3-1: Pad-Mounted Transformer

Exhibit 3-2: Revenue Meter

Fixed capacitors are also installed in the distribution system (150 kVAr capacitor banks).

System Condition Observed

The transformers observed during our visit appear to be in good condition. GPA is replacing their meters with new digital meters, which will accept pre-paid input and can communicate daily rate changes to the customers. During the site visit broken seals were not identified and GPA is aware of tampering and by-passing of meters, but irregularities are seldom found. The new system of automated meters will help improve the energy efficiency, demand response, and will reduce the impact of late or non-payment of the utility bills.

4. Grid Model and Calculation of Technical Losses

4.1 Estimates and Assumptions for Missing Data

KEMA made several assumptions (based on standard industry practices) for items which we did not receive data to quantify losses. These assumptions are:

The averaged power output for the past year (Fiscal Year 2009: Oct 2008-Sept 2009) is used to represent the annual energy production.

The maximum demand in the 2009 fiscal year is 263 MW. It was identified from the provided peak load case that this peak occurred on October 13, 2009, at 70.00 PM. We are assuming that this load flow case showed the typical daily load representing the peak load for fiscal year 2009.

The maximum MW demand per feeder during the fiscal year of 2009 was identified in the distribution loss summary as provided by GPA.

The typical value of no load and total losses for power transformers as derived from the loss curve[1] was used to calculate core losses of power transformers.

Typical loss data of no load and total losses from literature[2] were used to calculate distribution transformer core losses and copper losses.

Assumptions were made on typical type and size of the secondary service wires used for each customer category based on secondary line and cable data provided. Furthermore, assumptions were made for average wire lengths and for the general configuration of secondary wire connections, based on information provided by email. The secondary losses were estimated based on the average consumption for each customer category.

The effect of voltage drops through feeders was not considered in the loss estimations for distribution transformer losses and secondary wire losses.

[1] Areva Power Transformers Handbook (2008)

[2] Electric Power Distribution System Engineering, by Turan Gonen

4.2 Power System Model

GPA provided the power system model in 2 parts. The transmission system model in PSLF was provided in a series of hourly cases representing the peak load day of the evaluation period of 1 year from October 2008 to September 2009. This model included power plants, station transformers and power transformers as well as the transmission system. The distribution system model was provided as a SynerGee model dumped into Microsoft Access database files, together with a distribution system load and loss summary. In this model, primary feeders of the distribution system in Guam Island were modeled. The length of primary feeders and the connected load capacities were identified. It is KEMA's understanding that GPA has been successfully using, and will continue using, PSLF and SynerGee for system analysis. Therefore, KEMA is not providing a separate system model in Easy Power.

4.3 System Loss Estimation

System losses include technical losses and non-technical losses. Technical losses are quantified for the transmission system and the distribution system. Non-technical losses are calculated as follows:

Non-Technical Losses = Total Energy Generated – Total Energy Sold – Unaccounted Usage – Total Auxiliary Energy Used by the Power Plants – Total Technical Losses.

Historical statistics of generation output, power station usage, and unaccounted usage were provided by GPA.

Technical losses are estimated as follows:

Technical Losses = Transmission Line and Cable Losses + Power Transformer Losses + Primary Feeder Losses + Distribution Transformer Losses + Secondary Wire Losses

For the transmission system, technical losses consist of copper losses and core losses of station and power transformers, plus transmission line and cable losses. A power flow calculation was performed for the peak load scenario in PSLF to calculate the losses in MW under peak load condition. The case is provided for October 13, 2009, 7.00 PM. However, in the PSLF model, only resistances representing windings of power transformers were modeled, the resistances representing core losses were not modeled. Therefore, the power flow study results only provide the power transformer copper losses and transmission line losses, without addressing power transformer core losses. The estimation of power transformer core losses is shown in the table below:

Exhibit 4-1: Power Transformer Core Loss Estimation

FromBus	FName	Fkv	ToBus	ToName	Tokv	Circuit	online	MVA	FNominal	TNominal	R	X	core loss es
6002	VictrT43	0	2006	Vic345	35	1	0	1	0.5	34.5	0.0029	0.0576	0.0005
6001	VictrT42	0	2006	Vic345	35	1	0	3	0.5	34.5	0.0021	0.0429	0.0015
6003	VictrT44	0	2006	Vic345	35	1	0	3	0.5	34.5	0.0022	0.0437	0.0015
6004	VictrT45	0	2006	Vic345	35	1	0	3	0.5	34.5	0.0022	0.0434	0.0015
4201	NCS T47	4	2208	NCS345	35	1	1	4	4.2	34.5	0.0042	0.0841	0.002
4213	GIAT Trm	4	2217	GIA345B1	35	1	1	8	4.2	34.5	0.0035	0.0691	0.004
3207	PotsT110	14	2209	Pott345	35	1	1	4	13.8	34.5	0.0038	0.0758	0.002
3204	DededT55	14	203	DededDsl	4	1	1	5	13.8	4.2	0.0031	0.0627	0.0025
3204	DededT55	14	204	DededDsl	4	1	1	5	13.8	4.2	0.0031	0.0627	0.0025
3007	CldST132	14	2008	CldSt345	35	1	1	5	13.8	34.5	0.003	0.0609	0.0025
3001	Piti T7	14	2002	Pit345	35	1	1	8	13.8	34.5	0.0038	0.0756	0.004
3002	Piti T8	14	2002	Pit345	35	1	1	8	13.8	34.5	0.0038	0.0762	0.004
3104	RadBaT23	14	2103	RBa345B1	35	1	0	8	13.8	34.5	0.0033	0.0651	0.004
3105	RadBaT24	14	2103	RBa345B1	35	1	1	8	13.8	34.5	0.0033	0.0655	0.004
3202	HarmnT22	14	2219	Har345B1	35	1	1	8	13.8	34.5	0.0031	0.0615	0.004
3203	HarmnT44	14	2202	Har345B3	35	1	0	8	13.8	34.5	0.0031	0.0629	0.004
3003	TalofT80	14	2003	Tal345	35	1	1	10	13.8	34.5	0.0032	0.0639	0.005
3004	Apra T70	14	2004	Apr345	35	1	1	10	13.8	34.5	0.0032	0.0639	0.005
3005	OroteT11	14	2005	Oro345	35	1	1	10	13.8	34.5	0.0031	0.0628	0.005
3006	OroteT12	14	2005	Oro345	35	1	1	10	13.8	34.5	0.0032	0.0638	0.005
3012	OroteT13	14	2005	Oro345	35	1	1	10	13.8	34.5	0.0031	0.0629	0.005
3205	MarboT14	14	2204	Mar345B1	35	1	1	10	13.8	34.5	0.0031	0.0628	0.005
3101	Agana T9	14	2101	Aga345	35	1	1	12	13.8	34.5	0.0054	0.0601	0.006
3102	AganaT65	14	2101	Aga345	35	2	1	15	13.8	34.5	0.0034	0.0689	0.0075
3103	BarriT75	14	2102	Bar345	35	1	1	15	13.8	34.5	0.0034	0.069	0.0075
3106	TamunT50	14	2104	Tam345B1	35	1	1	15	13.8	34.5	0.0035	0.0709	0.0075
3108	TamunT51	14	2104	Tam345B1	35	1	1	15	13.8	34.5	0.0041	0.0829	0.0075
3107	TumonT60	14	2105	Tum345B1	35	2	1	15	13.8	34.5	0.0037	0.0749	0.0075
3109	TumonT61	14	2105	Tum345B1	35	1	1	15	13.8	34.5	0.0038	0.0769	0.0075
3204	DededT55	14	2203	Ded345B1	35	1	1	15	13.8	34.5	0.0035	0.0699	0.0075
3210	MacheT90	14	2211	Mac345B1	35	1	1	15	13.8	34.5	0.0038	0.0766	0.0075
3009	PulanT95	14	2011	Pul345	35	1	1	18	13.8	34.5	0.0041	0.0765	0.009
3011	UmatT120	14	2012	Uma345	35	1	1	18	13.8	34.5	0.0039	0.0776	0.009
3013	NimtzTXX	14	2015	NimitzSu	35	1	0	18	13.8	34.5	0	0.0766	0.009
3110	AnigT100	14	2106	Ani345B1	35	1	1	18	13.8	34.5	0.0041	0.0765	0.009
3113	SanVT122	14	2108	SV345B1	35	1	1	18	13.8	34.5	0.004	0.0749	0.009
3201	HarmnT21	14	2219	Har345B1	35	1	1	18	13.8	34.5	0.0039	0.0743	0.009
3211	PagaT115	14	2212	Pag345B1	35	1	1	18	13.8	34.5	0.0041	0.0761	0.009
3212	Yigo T30	14	2214	Yig345B1	35	1	1	18	13.8	34.5	0.004	0.0752	0.009
3213	GAA T105	14	2216	GAA345B1	35	1	1	18	13.8	34.5	0.004	0.0756	0.009
3208	AnderT15	14	2210	And345B1	35	1	1	20	13.8	34.4	0.0037	0.0748	0.01
3209	AnderT16	14	2210	And345B1	35	1	1	20	13.8	34.4	0.0037	0.0749	0.01
2201	Tan345B1	35	5201	TangoStr	2	1	1	3	34.5	2.4	0.0033	0.0651	0.0015
2001	Cab345	35	4001	CbrsStUp	4	1	1	5	34.5	4.2	0.003	0.0597	0.0025
2204	Mar345B1	35	205	Marbo CT	14	1	1	12	34.5	13.8	0.0038	0.0769	0.006
2014	Ten345	35	11	TenjoDsl	14	1	1	18	34.5	13.8	0.0038	0.0764	0.009
2201	Tan345B1	35	201	Tangui_1	14	1	1	18	36.1	13.8	0.0034	0.0687	0.009
2201	Tan345B1	35	202	Tangui_2	14	1	1	18	36.1	13.8	0.0028	0.0563	0.009
2203	Ded345B1	35	208	Ded CT#1	14	1	1	18	34.5	13.8	0.0039	0.0775	0.009
2203	Ded345B1	35	209	Ded CT#2	14	1	1	18	34.5	13.8	0.0391	0.0782	0.009
2214	Yig345B1	35	211	Yigo__CT	14	1	0	18	34.5	13.8	0.0037	0.075	0.009
2002	Pit345	35	15	TEMES	14	1	1	44	34.5	13.8	0.0051	0.1017	0.022
2001	Cab345	35	1001	Cab115EB	115	1	1	60	34.5	115	0.0031	0.0617	0.0225
2002	Pit345	35	1005	Pit115B1	115	1	1	60	34.5	115	0.0021	0.0802	0.0225
2101	Aga345	35	1101	Aga115	115	1	1	60	34.5	115	0.0076	0.0607	0.0225
2104	Tam345B1	35	1103	Tam115B1	115	1	1	60	34.5	115	0.0025	0.0788	0.0225
2219	Har345B1	35	1201	Har115B1	115	1	1	60	34.5	115	0.0075	0.0608	0.0225
2202	Har345B3	35	1201	Har115B1	115	1	1	112	34.5	115	0.003	0.1413	0.037333
1001	Cab115EB	115	12	Cabras_3	14	1	1	38	115	13.8	0.0043	0.0861	0.019
1001	Cab115EB	115	13	Cabras_4	14	1	1	38	115	13.8	0.0043	0.0866	0.019
1005	Pit115B1	115	16	MEC 8	14	1	1	56	115	13.8	0.006	0.121	0.021
1005	Pit115B1	115	17	MEC 9	14	1	1	56	115	13.8	0.0061	0.1212	0.021
1001	Cab115EB	115	1	Cabras_1	14	1	1	80	115	13.2	0.005	0.1	0.03
1001	Cab115EB	115	2	Cabras_2	14	1	1	80	115	13.2	0.0049	0.0986	0.03
											TOTAL CORE LOSS MW		0.617333

Due to a lack of specific transformer parameters, typical core loss data is derived from a loss curve[3] in the Exhibit below and is used to estimate core losses for the population of power transformers in GPA system. This could result in a large margin of difference between the estimated losses and the actual loss values. It is recommended for GPA to collect no load and load loss data for the power transformers in the future to improve the accuracy of loss estimation.

Exhibit 4-2: Power Transformer Typical Loss Curve

Figure from Areva Transformer Handbook (2008). As can be seen from the figure, the no-load loss percentage for transformers rating from 50 MVA to 150 MVA is approximately:

MVA	Core Loss kW	%
50	25	0.050
100	37.5	0.038
150	50	0.033

To estimate core losses for GPA, assuming that all power transformers are normally energized, see the table below.

<50 MVA	0.050%
50~100 MVA	0.0385
>100 MVA	0.033%

[3] Areva Power Transformers Handbook (2008)

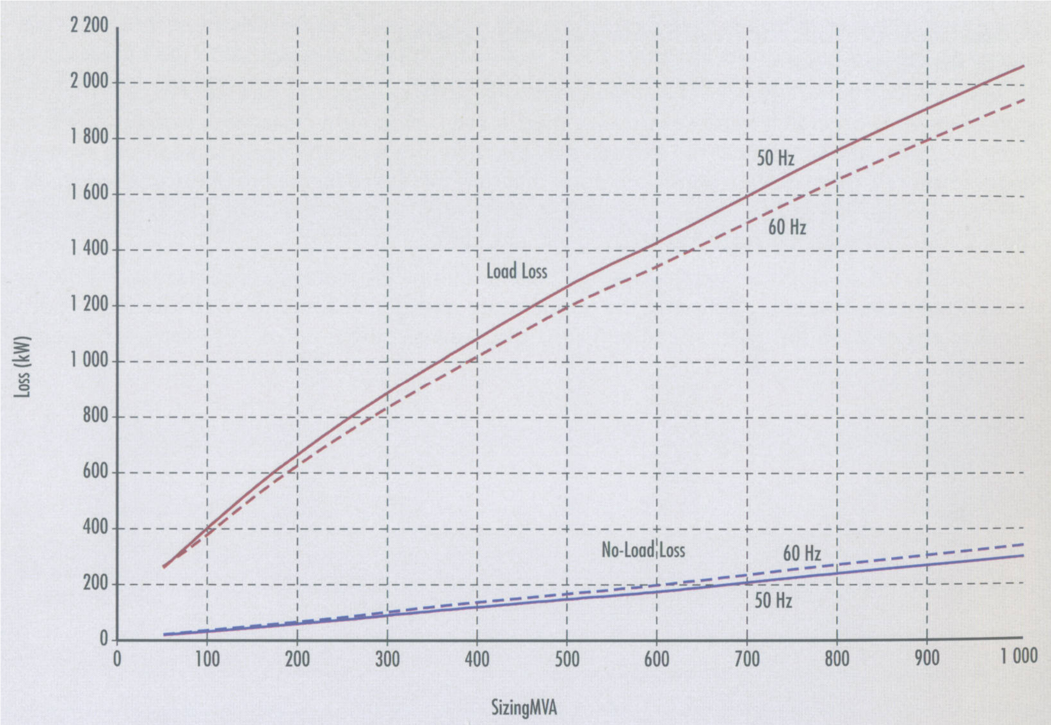

Fig. 3.4a – Typical Load and No-Load Losses Related to *SizingMVA*

For the distribution system, technical losses consist of primary feeder losses, distribution transformer core and copper losses, and secondary wire losses. Losses through primary feeders were provided by GPA in a distribution loss summary. All the other losses are part of the load and were estimated in the Exhibit below. Where information is not sufficient, assumptions were made to facilitate the estimation, and could result in a large margin of difference from the actual loss values.

Exhibit 4-3: Distribution Transformer and Secondary Losses

	Peak Demand Loss	Energy Loss
Core Loss	2.83 MW	24,800 MWh
Copper Loss	Ø 1.12 MW	5,792 MWh
Secondary Line Loss	3.65 MW	31,982 MWh
Distribution Transformer & Secondary Wire Total Loss	7.60 MW	62,573 MWh

Non-technical losses are calculated as the difference between total system losses and the technical losses. The total system losses are calculated as follows:

Total System Loss = Total Energy Generated – Total Energy Sold – Unaccounted Usage. (e.g., any non billed street lights and usage for GPA's buildings)

Technical Loss Estimation

To estimate the technical losses in MWh first the losses have been calculated in MW under peak load condition. This MW value is multiplied by the system loss factor and hours in a year to estimate losses in energy (MWh). Together with the system loss factor, the losses in MWh were estimated for the given period of time for which the loss factor was provided. For GPA, the period of time chosen was October 2008 to September 2009. For this 12-month period, annual energy losses were estimated using the following methodology.

Note that no-load loss is also called core loss and load-loss is also known as copper loss.

Exhibit 4-4: Loss Calculation Methodology

Element of Power System for which MW loss is to be calculated	MW loss calculation source and method	Energy losses (MWh) calculation method
Transmission line/cable and power transformer copper loss	Power flow study in PSLF - peak load case	Multiply MW loss with system average loss factor and 8,760 hours in a year
Power transformer core loss	Typical loss data derived from loss curve Transmission data from PSLF case	Core loss considered as constant loss. MW loss x 8760 hours in a year
Distribution feeder loss	Provided by GPA in DISTRIBUTION SUMMARY 02-12-10.pdf	Multiply MW loss for each feeder with loss factor for the respective feeder as provided in the same file and 8760 hours

Distribution transformer core loss and copper loss	Distribution transformer data provided in transformer sizes.pdf, Typical no-load loss and full-load loss from literature Distribution transformer utilization factor calculated based in data provided in DISTRIBUTION SUMMARY 02-12-10.pdf	Copper Loss: Multiply MW loss for each feeder with loss factor for the respective feeder as provided in the same file and 8760 hours Core loss is considered as constant loss. MW loss x 8760 hours in a year.
Secondary wire losses	Secondary wire data from Secondary Overhead Cable 600V.PDF and Secondary Underground Cable 600V.PDF Typical resistance data from literature Assumption on typical secondary wire size and configuration for each customer category Average MW consumption calculated for each customer category	Annual MWh loss is calculated based on average MW loss. Loss factor is not applied here.

In the distribution system, the utilization factor under peak load condition was calculated for the overall system, and was based on the per-feeder maximum load and the sum of connected kVA's provided by GPA. Similarly, the system-wise load factor and the loss factor under peak load condition are calculated based on the GPA provided load factors and loss factors for each of the feeders. Definitions of these factors are provided below:

- Utilization Factor UF
- Connected kVA

Sum of installed kVA's distribution transformers connected to the feeder.

- Load Factor LDF
- Loss Factor LSF

The relationship between LSF and LDF is

Where C varies from 0.15~0.3[4] C=0.2 is applied to estimate losses for GPA.

The summary of the losses are estimated in the following Exhibit.

Exhibit 4-5: Loss Estimation

Based on 2009 Data	kWh	% of generation	% of system consumption	Comments
Annual generation	1,854,061,583			
Annual station auxiliary	99,405,637	5.36%		
Annual system consumption	1,754,655,946	94.64%		
Annual energy sold (without unbilled usage)	1,624,382,893	87.61%	92.58%	
Unbilled usage - GPA own use	3,181,437	0.17%	0.18%	
System loss	127,091,616	6.85%	7.24%	
Technical loss	117,905,091	6.36%	6.72%	
Non technical loss	9,186,525	0.50%	0.52%	

[4] Electric Power Distribution System Engineering, by Turan Gonen

5. Electrical Data Handbook

As part of the project's scope of work, KEMA prepared an Electrical Data Handbook containing the electrical characteristics of the GPA power system high voltage equipment.

The Electrical Data Handbook can be found separately and in Appendix C.

6. Analysis of Technical and Non-Technical Losses

6.1 Generation Efficiency

The following information was provided by GPA for their generation resources:

Exhibit 6-1: GPA Generation Efficiency

GPA Generation:				
	Year Installed	NP Rating (MW)	Net Fuel Efficiency (kWh/Gal)	Gross Heat Rate (BTU/kWh)
RFO #6 - Baseload Units				
Cabras Unit #1	1974	66	12.56	10,923
Cabras Unit #2	1975	66	12.68	10,867
Tanguisson Unit #1	1971	26.5	10.20	13,171
Tanguisson Unit #2	1973	26.5	10.27	13,185
Cabras Unit #3	1995	39.3	16.09	8,646
Cabras Unit #4	1996	39.3	16.32	8,707
MEC Unit #8	1999	44	17.30	8,414
MEC Unit #9	1999	44	17.29	8,395
SUBTOTAL:		351.6	14.56	9,665
Diesel No. 2 - Peaking Units				
Dededo CT #1	1992	23	8.24	16,605
Dededo CT #2	1994	22	0.00	-
Macheche CT	1993	22	11.30	12,141
Marbo CT	1995	16	0.00	-
TEMES CT	1998	40	9.22	14,771
Yigo CT	1993	22	10.86	12,543
Dededo Diesel Plant	1971	10	12.21	11,076
Manenggon Diesel #1	1994	5.3	14.39	9,401
Manenggon Diesel #2	1994	5.3	14.42	9,387
Talofofo Diesel #1	1993	4.4	13.36	10,209
Talofofo Diesel #2	1993	4.4	14.72	9,263

Tenjo Unit #1	1993	4.4	14.31	9,537
Tenjo Unit #2	1993	4.4	14.54	9,383
Tenjo Unit #3	1993	4.4	14.47	9,433
Tenjo Unit #4	1993	4.4	14.51	9,408
Tenjo Unit #5	1993	4.4	14.53	9,392
Tenjo Unit #6	1993	4.4	14.53	9,628
SUBTOTAL:		200.8	12.37	11,040
Totals:		552.4	14.52	9,685
		Baseload		8,395
		Peaking		9,628
		CT		14,282
		MED DSL		9,485

The data given below for various generators is not for the fiscal year 2009 but for a rolling 12-month period:

Exhibit 6-2: Generation 12-Month Rolling Production Summary

	Gross Generation (kWh)	**Net Generation (kWh)**	**Fuel Consumption (Gals)**	**Net Fuel Efficiency (kWh/Gal)**
RFO #6 - Baseload Units				
Cabras Unit #1	332,157,900	306,217,782	24,374,260	12.56
Cabras Unit #2	239,674,800	221,915,910	17,498,068	12.68
Tanguisson Unit #1	72,247,500	65,209,150	6,394,429	10.20
Tanguisson Unit #2	81,619,800	74,258,687	7,231,911	10.27
Cabras Unit #3	240,611,384	224,858,766	13,976,555	16.09
Cabras Unit #4	240,639,030	229,726,588	14,076,450	16.32
MEC Unit #8	313,567,700	306,670,801	17,725,457	17.30
MEC Unit #9	298,053,200	290,486,910	16,803,516	17.29
SUBTOTAL:	1,818,571,314	1,719,344,594	118,080,645	14.56
Diesel No. 2 – Peak load Units				
Dededo CT #1	730,538	722,042	87,616	8.24
Dededo CT #2	0	0	0	0.00
Macheche CT	1,353,600	1,341,792	118,700	11.30
Marbo CT	0	0	0	0.00
TEMES CT	5,702,850	5,607,774	608,403	9.22

Yigo CT	910,800	896,112	82,514	10.86
Dededo Diesel Plant	90,100	88,026	7,208	12.21
Manenggon Diesel #1	964,944	942,934	65,520	14.39
Manenggon Diesel #2	981,072	958,974	66,513	14.42
Talofofo Diesel #1	845,280	832,607	62,330	13.36
Talofofo Diesel #2	691,920	681,546	46,290	14.72
Tenjo Unit #1	2,598,040	2,558,525	178,841	14.31
Tenjo Unit #2	2,593,440	2,554,543	175,636	14.54
Tenjo Unit #3	2,653,200	2,613,405	180,642	14.47
Tenjo Unit #4	2,750,400	2,709,148	186,750	14.51
Tenjo Unit #5	2,256,660	2,223,260	152,968	14.53
Tenjo Unit #6	1,683,360	1,699,954	116,972	14.53
SUBTOTAL:	26,806,203	26,430,641	2,136,903	12.37
Totals:	1,845,377,517	1,745,775,235	120,217,549	14.52
Baseload	98.55%	98.49%	98.22%	
Peaking	1.45%	1.51%	1.78%	
CT	8,697,787	8,567,719	897,233	
MED DSL	18,108,416	17,862,922	1,239,670	

GPA is using its base generating units to provide close to 99% of the energy. The newest units with highest efficiencies are being used most.

6.1.1 Power Plant Usage, Station Losses

The power plant usage from the measured values was 5.36% of the generated energy. This is a reasonable figure when so many generating resources are being used to provide the load.

Losses in the power plant auxiliaries should be controlled by optimizing the operation of fans, coolers, lights, etc for generating plant use.

7. Technical Losses

Exhibit 7-1: Technical Losses

Technical Losses			
Type of Losses	**Sub Total MWh**	**MWh**	
Distribution Transformer Core losses	24,800		
Distribution Transformer Copper losses	5,792	30,592	26%
Secondary wires	31,982		
Feeder Wires	21,205	69,084	59%
Transmission Losses	15,897		
Power Transformer Copper losses	12,822	18,230	15%
Power Transformer core losses	5,408		
Total =	117,905	117,905	100%
Core Losses Alone	30,208		26%

Technical losses in the transmission and distribution system comprise of two main parts – losses in wires and losses in transformers. Wires comprise of transmission lines, distribution lines, and secondary service wires connected to customer meters from the distribution transformers. Losses in transformers come from step-up transformers, substation transformers, (power transformers) and distribution transformers. There are two types of losses from transformers – core losses or no load losses (present as long as the transformer is energized) and load losses or copper losses (only present if the transformer is serving load). The table above illustrates that out of the total calculated technical losses, wire losses are majority (59%) and transformer losses are 41%. Out of the transformer total losses, core losses are majority (26%) vs. copper losses for transformers are 15%.

7.1.1 Transmission and Distribution Line Losses

Calculated line losses (transmission lines, distribution feeders and secondary wire losses) are 69,084 MWh out of 117, 905 MWh of total technical losses. Line losses are caused by the wire resistance which is inversely proportional to the size and depends on the type of conductor (copper and aluminum). With a larger size (diameter), the resistance is lower. Factors which can further lower the losses are using a mixture of fixed and switchable capacitors at selected locations or using larger wires for conductors, which can be justified by a cost/benefit analysis. GPA uses power factor correction capacitors and the overall system power factor is close to optimal.

Losses in low voltage service wires were estimated at about 31,982 MWh or 18% of the total technical losses. They are calculated based on assumptions regarding the load as average load through average wire lengths while using wire sizes provided to us by GPA for each category (Commercial, Industrial and Residential). A margin of error could be introduced by these assumptions. The GPA tariff system allows large industrial and commercial customers to be rewarded for keeping power factor as high as possible.

7.1.2 Transformer Losses

For GPA it is estimated that the total losses from distribution and power transformers are around 48,822 MWh per year. 30,208 MWh are core losses and 18,614 MWh are copper losses.

Sizes of the distribution transformers (peak load is calculated to be around 27% of the installed distribution transformer capacity) may be too large for the load and hence no-load losses (core losses) are relatively higher. The system database does not contain information for identifying which load is tied to which transformer, for this physical inspection should be performed.

7.2 Non-Technical Losses

9,187 MWh (0.5%) of the system losses (calculated from the energy delivered to the T&D system from generating plants) are classified as non-technical losses. This is a quite good figure. Loss causes could be old and inaccurate meters, tampering, incorrect meter multiplier factors, administrative errors, etc. Improving the meter accuracy figures by using new smart meters (already being implemented) will help in further reduction of these losses.

7.2.1 Unbilled Energy

3,181 MWh (0.17%) of the total energy is being used by GPA buildings. This is a very reasonable figure. There are opportunities available to reduce energy consumption through educating building occupants regarding energy efficiency.

7.2.2 Metering Losses

Old customer meters lose accuracy over time and may lower the amount of energy sold. New digital meters will improve the metering accuracy and will provide intelligence regarding tampering, if any.

Meters are read manually once a month.

Location of the customer meters should be tied to transformers which are connected, preferably through a Geographical Information System (GIS) in CIS (Customer Information System). Every year analyses should be performed to see which transformers can be replaced for proper loss reduction or because of overloading and general maintenance.

8. Options for Improvement

8.1 Power System Improvements/Modifications

Technical losses are unavoidable. KEMA does not expect that technical loss reduction efforts will result in substantial amounts of loss reductions based on the assessment, however reducing technical losses should continue to be an integral part of overall loss reduction strategy as well as in system planning and system operations for the following reasons:

- Electricity rates will continue to increase, particularly because of increasing fuel costs, which will change the cost-basis for evaluating many technical loss-reduction-related measures/programs
- Electrical equipment connections that are corroded or loose can cause heating, which results in higher losses, reliability and safety issues.
- Reducing technical losses is controllable per the results of this study.
- Priority should be given to equipment purchases that lead to lower losses

Many of the projects/programs that reduce technical losses, cannot be cost justified because of the large capital investment required. For projects and programs that are giving loss reduction benefits when considering total life costs is key to selecting those that will be most beneficial. GPA uses cost of losses over lifetime to evaluate costs of transformer purchases. The following formula is copied from GPA's standard specification E-004. Costs per kW of losses as shown below were based on assumptions of costs per kWh, the related fuel price, the interest rate, and expected loading of the transformer (for the load losses). This should be revised regularly.

From the GPA specification E-004:

No-Load	\$5,951/kW
Load Losses	\$3,813/kW

Losses = No-Load Losses (\$5,951) + Load Losses (\$3,813)

Total Owner Ship Cost (TOC) = Purchase Price + Losses

In addition to current efforts, GPA could improve the loss estimation in the following two areas:

Secondary circuits and service wires

GPA should consider using a targeted feeder program by creating an initial GIS map for secondary circuits (including customers and service wires). The map could be refined gradually to reflect the actual secondary circuit and service wires in the field. This would provide a solid basis for future technical loss evaluation.

Such a GIS map has an advantage that it can use customer consumption data to accurately estimate losses in secondary circuits and service wires.

Customer meters need to be associated with the respective transformer servicing the load. This can be done in a CIS system or using spreadsheet software to take loads from metering data and calculate transformer loadings. Properly sizing the transformers will have a significant impact on overall loss reduction (e.g., using smaller sizes).

Loss estimation in this part of the system is much more complicated and is affected by:

- Un-metered loads such as streetlights, illegal connections, etc
- Unknown exact lengths of are circuits/wires
- A load patterns are difficult to obtain for each customer unless AMI (Advanced Metering Infrastructure) is deployed

Nevertheless, creating such a GIS map will help GPA in better estimate losses.

Regularly Update the Loss Cost-Basis:

The loss cost-basis used to estimate lifetime cost of losses should take electricity rate increases into account. When rates are increasing at a slow pace, it may be acceptable to use current rates to calculate projected savings of technical losses over life spans of equipment (e.g. transformers) and other system parts. When the rates are fast increasing, using current rates will greatly underestimate the lifetime savings of reduced losses over a long term period.

As new equipment is installed and replaced the loss cost-basis should be accomplished to evaluate the impact of various alternatives, especially to understand the cost of lifetime equipment deployment. Once a new cost basis is established, it should be applied to the cost/benefit analysis of new equipment purchases immediately, such as pad-mounted and pole-mounted transformers. A new cost basis should also be used to re-evaluate projects/programs that can provide technical loss reductions to select the most beneficial programs.

Optimize distribution transformers

As core losses depend on size of transformers and GPA is using only 27% of the total installed capacity, there is an opportunity to decrease these losses. One lower size for distribution transformers will save 20% of core losses and two lower sizes can save about 35% of core losses for the distribution transformers (in total 8,646 MWh). The second option (two sizes lower) will load transformers to about 50% to 55% of the peak system load of 263 MW.

Recommendations:

a. Develop the load profile for each transformer and keep it updated once a year (a load profile for each distribution transformer implies that a meter per distribution transformer will be needed).

b. Develop proper transformer sizes for each location.

c. Optimize transformers, which can be optimized without capital cost investment (i.e., moving them to appropriate locations).

d. Develop a new transformer purchase plan based upon the standard sizing and least cost for lifetime cost, which includes capital investment and losses.

e. Replace transformers during emergency (during emergency the utility workers are already occupied with the emergency itself, in many cases) or during normal time based on the plan.

Optimize the Feeder Power Factor

GPA is managing the overall power factor of the system to a good level of 0.98 (from the GPA provided load flow case). The power factor of various sections of the feeders should be checked regularly (at least once a year) and always keep it above 0.9, preferably 0.95. The best location to correct the power factor is at the loads, especially at the induction motors terminals. GPA has a rate schedule like Schedule "P" for Large Service Power where penalty and incentives are applied to large power customers in order to keep the power factor at required level. This tariff should be periodically reviewed to analyze the effectiveness of the policy. Sometimes it requires more education for the customers to realize the benefit of power factor improvement. New AMI type meters will provide data daily, hourly, or every 15 minutes and as they can directly provide readings of the power factor, GPA will be able to take advantage of this information to further optimize system operations. The following information is provided for reference only as GPA is actively using the multi facet power factor improvement strategy.

Optimize Feeder Reactive Power Compensation

Shunt capacitor banks at 13.8 kV can be used to minimize the reactive load flow in the network to reduce losses. When operated for this purpose, there are two areas that should be considered.

1. **Determine the size of fixed and switched capacitors**

The compensation could use a mix of fixed and switched capacitors to achieve desired reactive power compensation.

The size of fixed capacitors should be determined by the minimum reactive power compensation requirement of a feeder. It is, however, not necessary to compensate the feeder at the minimum inductive reactive power level to 1.0 power factor, but should be as close as possible. From loss reduction point of view, the result will be the same if the compensated power factor has the same value regardless if it is leading or lagging. The actual size selection should also take the standard capacitor size that can be procured, and whether there are other feeder capacitors that are already installed, etc. into account.

The size of switched capacitors should be determined based on the load pattern of a particular feeder and the granularity of the power factor control. If the reactive power load of a feeder changes between two constant levels, then one large switched capacitor may be sufficient. These should be evaluated on a feeder-by-feeder basis.

In addition to power factor compensation, capacitors also affect the voltage profile along a feeder. When determining the capacitor sizes, in particular the switched capacitor bank sizes, this should also be verified to ensure voltage limits are not violated.

Switched capacitor control

Switching of capacitor banks can be controlled by any of the system variables or any derivatives of system variables. The common controls used are described below:

- Voltage Control: This is the most common type of control used to switch capacitors in or out of the circuit. They are switched in during low voltage conditions and switched off when the system voltage is high. This type of control is normally used where a drop of 3% or more of voltage occurs during full load. This type of control is not suitable in a tightly voltage regulated system where the voltage is held at constant values.
- Current Control: This control is used where the voltage control cannot be exercised. The capacitor current is excluded from the monitored current and this ensures that the capacitor will be brought on line during heavy load conditions.
- Current Compensated Voltage Control: This type of control is sensitive to voltage but is current compensated. The control acts as simple voltage control so long as the current is below a predetermined level. If current goes above the pre-determined level, the capacitors are brought on line by changing the calibration of the voltage elements. Hence, the capacitors remain in circuit so long as the current is above the pre-determined level. If the voltage starts to rise and becomes high enough to offset the calibration, the capacitor will be switched off. This is a sophisticated control and ensures that the capacitors are on line when they are most needed.
- Kilo VAr Control: This control operates in response to changes in the power flow. It has no significant advantage over current-compensated control and is usually more expensive.
- Time Control: This type of control is used when daily load patterns are predictable. Capacitors are switched in and out based on the time of day. This control is the least expensive; however, a disadvantage is that it cannot accommodate unusual system conditions such as a sudden loss of lines, etc. and will require manual intervention to switch the bank.

Selection of control type should be based on the load profile of a feeder.

8.2 Operational Recommendations

GPA has done an excellent job of keeping the system losses to a reasonable level. There is no specific recommendation for any improvements which have a significant cost/benefit impact. The following gives information for further consideration and can be of help with the continuous efforts to stay at the high performance level that has been reached.

8.2.1 Generation

Develop written operating procedures and plans to monitor the performance of operators and the plant based on those processes. Have enough spinning reserves in power producing systems to meet requirements during emergency outages. That is key to run the system most efficiently and reliable. System protection, voltage settings, power flow, and system stability analyses need to be updated regularly to adjust to changes and developments.

GPA is using economic dispatch concepts to provide power from the most efficient generating systems while meeting environmental commitments. Systems which provide the ability to view and act on real-time information can further reduce the losses in the system. Generating unit efficiency should also take into account the auxiliary power required to run the plants. To reduce auxiliary losses, utilize AC frequency drives for cooling water and fan motors and control automation to shut down areas which are not used.

8.2.2 Metering

Once GPA has implemented the installation of digital meters and will be able to analyze relevant information, calculations of losses will be more based on real time data to match the generation readings. This will provide information on how to operate the T&D system and gain more efficiency. Methodologies must be developed to measure distribution transformer load profiles either through software, which takes into account the customer meters on each of the transformers, or through physically measuring the load by installing demand type meters on the secondary side of each of the transformers. If meters are installed on the secondary side of the distribution transformers in areas where tampering of meters is suspected, this will help in inspecting customers connections and in reducing non-technical losses. Meters for each of the distribution transformers should also provide information for optimizing the transformer sizes to reduce no load losses.

8.2.3 Strategy for Reduction of Non-Technical Losses

1. Develop a process to randomly audit customer locations

2. Increase the effectiveness of revenue protection operations

GPA is advised to:

- Focus on the revenue recovery: When selecting targets for inspection, the potential of estimated amount of revenue recovery should be a major selection factor. With limited resources, selecting accounts with highest potential of revenue recovery and hit rate will be the most efficient use of the limited resources.
- Make operations less predictable: General industry experience shows that there are some sophisticated fraud activities that take advantage of the known pattern of revenue assurance operations. This should be countered with less predictable operations; e.g., occasional night inspections, computer generated daily target lists, and so on. This will help to increase the hit rate for the fraudsters and increase the deterrent effect of these operations.
- Prevent repeated fraud activities: Once a fraud is found, proper measures should be taken, depending on the type of fraud, to ensure that it won't occur again. Revenue Intelligence software (RI) will be a useful tool to help monitor an account after the problem is corrected and RI will issue a warning if problem resurfaces. However, RI alone will not be able to prevent offenders from repeated frauds.
- Prevent and curb internal collusion activities: One important aspect of effective revenue protection operation is to prevent and curb potential internal collusion. Internal collusion seriously undermines the effectiveness of revenue assurance process and efforts. One possible solution could be to bring in non-local inspection teams to conduct the critical revenue protection operations, such as auditing the largest accounts, under the direct control of GPA's management.

3. Employ right tactics for each group of customers

It is a fact that different types of customers have different needs for electricity, different usage patterns and different payment capabilities. A successful revenue assurance strategy should take this into account to develop corresponding tactics for each group of customers. In general, customers should be grouped based on their usage pattern and payment capabilities. Establishing typical usage pattern and payment capabilities for each group of customers will be one very important task of the Revenue Intelligence system and the results should be used as basis for employing the right tactics for each group of customers.

9. Per Item: Investments Needed, Expected Reduction of Losses, Payback Time

The following is our summary for savings and potential costs over a 6 year period of implementation:

Exhibit 9-1: Savings and Cost

	6 Yrs NPV of Savings and Cost		
NPV @ Cost of Capital	**Savings (NPV)**	**Cost (NPV)**	**Net (NPV)**
Non Technical Loss	$1,239,529	$0	$1,239,529
Technical Losses	$4,986,035	$3,964,347	$1,021,688
Auxiliary loss	$4,141,111	$4,000,000	$141,111
Total =	$10,366,675	$7,964,347	$2,402,328
Generator Efficiency improvement	1% improvement saves $2,800,000		

Financial assumptions are:

1. Cost will increase based upon inflation – 3% every year.

2. Cost of Capital is assumed to be 8%.

9.1 Recommendations

Recommendations are prioritized based on the cost and benefits. See spreadsheet with the Savings Model in Appendix C.

9.1.1 Reduction of Non-Technical Losses

Once meters are replaced with the digital meters with features on pre-payment and daily or weekly meter readings are taken, meter accuracy is improved 0.5 to1% of energy sold. Add new meters to the secondary sides of transformers and feeders at key locations for measuring transformer loads as well as auditing customers fed from each transformer. Make sure each customer is tied to the transformer and its meter in a database or a spreadsheet so that issues with tampering and transformer loading can be easily monitored. These improvements will lead to a small amount of savings of 2,756 MWh (0.17% of the energy sold) over 6 years and savings of $480,000 per year. Cost of new customer metering systems is not included in this initiative as this is already being planned or implemented by GPA. Cost of transformer meters is included in the next section.

9.1.2 Reduction of Technical Losses

In GPA's case, as far as losses are concerned there is not too much savings to be gained from modifying the system. Distribution transformers are utilized around 31% of their full capacity, there could be some savings from loss reduction by optimizing them with optimum sizes. Transformer optimizing should be considered a part of regular annual planning process. Optimizing distribution transformer sizes can be accomplished over a number of years as new transformers are purchased and replacements are warranted for various reasons.

Transformer right sizing criteria:

a. Determine proper sizes and specifications of distribution transformers needed for loads being served.

b. After determining correct sizes of the distribution transformers, determine the standard sizes and move them around to rationalize and optimize sizes at least 80% loaded to the maximum demand to transformer capacity.

c. As the transformers are reaching the end of life, replace them with right size transformer for the application. All transformers should be bought considering their lifetime costs.

d. Evaluate distribution transformers by applying the current cost of 1 kW of loss. For example, 1 kW of no load loss for 40 years of life at 8% cost of capital at $0.15 per kWh ($2.19 per gallon at 14.52 kWh per gallon and 3% increase in rise of cost of fuel per year) is $22,457. For a 10 year lifetime this figure will be $9,976.

e. Install meters on the secondary side of the distribution transformer.

Estimated cost for 7,000 new digital meters will be part of AMI installation ($2,850,000) and cost of moving transformers around is estimated to be $2,000,000. Estimated energy savings from these actions is 8,843 MWh (7.5% of 117,905 MWh of technical losses).

9.1.3 Reduction of Generation Auxiliary Losses

1. Develop manual processes to control operation of auxiliary equipment like cooling fans, exhaust fans and pumps, to run based on temperature sensing or other parameters to reduce energy consumption.

2. Automate manual processes using PLC controls to motor starters (cost not included – next step after process improvements and real time analysis and focus of energy consumption reduction is in place).

3. Apply Frequency Drives (costs not included).

Benefits from these actions are expected to be 8,946 MWh (9% of 99,406 MWh used by auxiliaries) over a period of 5 years (1% in the first year and 9% in the fifth year). Cost for this initiative is estimated to be $4 million.

9.1.4 Improving Generator Efficiencies

A 1% improvement in engine efficiency will result in savings of $2,800,000. GPA appears to have good management systems to continuously improve its performance. GPA also tracks daily statistics of generation activities and publishes them on the web. It is hard to keep the overall average efficiencies at higher levels without economic dispatch, written processes and regularly auditing processes in operations and maintenance.

Exhibit 9-2: Summary of Net Present Value Calculations on Loss Reduction Measures

Assumptions:				
Inflation	3%			
Cost of Capital	8.00%			
Cost of generation /kWh	$0.21			
Cost and Savings list	**Savings (NPV)**	**Cost (NPV)**	**Net (NPV)**	**Cash over 6 years**
Non Technical Savings:				
30% Non Technical Loss reduction over 6 years	$1,239,529		$1,239,529	
Technical Loss Savings:				
Meters for distribution transformers		$3,964,347		-$4,850,000
7.5% loss reduction over 6 years	$4,986,035		$1,021,688	
Auxiliary Losses				
AC frequency drives for motors and improving controls of auxiliaries		$4,000,000		-$4,000,000
9% loss reduction over 6 years	$4,141,111		$141,111	
Total =	$10,366,675	$7,964,347	$2,402,328	-$8,850,000

A. Data Request

Data Request

Inception Report

B. Electrical Data Handbook

C. Technical Loss Calculations and Financial Model for Options to Decrease Losses