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

Pohnpei Utilities Corporation (PUC)

Ordered by the Pacific Power Association (PPA)
Prepared by KEMA Inc.

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1. Executive Summary

KEMA's analysis of Pohnpei Utility Corporation (PUC) power system determined total losses of 18.66 % consisting of:

- 5.12% in power station auxiliaries (station losses), which is a relatively high amount of losses. Typically, station losses are lower than 5%.
- 1.94% in street lighting and usage for water and sewerage facilities. (If these revenues cannot be collected, street lighting should be considered a financial loss for PUC and not a system loss.
- Energy usage for water and sewerage facilities should be accounted for and allocated to the cost of service and not power system losses. However, if the costs are not allocated to service costs, they will remain a financial loss for PUC's power services and cannot be considered a power system loss.
- 5.94% in technical losses
- 5.66% in non-technical losses

Technical and non-technical losses total 11.6%.

Overall losses, including power plant usage total 16.72%.

Recommendations:
(Section 9 and the appendices contain detailed cost and benefit information.)

Total savings and costs for all loss reduction measures are summarized in the following table (exhibit 1-1)

:

Exhibit 1-1 – Savings and Cost

NPV @ Cost of Capital	6 Yrs NPV of Savings and Cost Summary **Savings (NPV)**	**Cost (NPV)**	**Net (NPV)**
Auxiliary loss	$254,373	$175,000	$79,373
Technical Losses	$410,534	$344,332	$66,202
Non Technical Loss	$783,367	$433,717	$349,649
Total =	$1,448,273	$953,049	$495,224
1% efficiency improvement in generation saves $81,000 per year. This based on the price of crude oil being $75 per barrel. At a price of $100 per barrel the savings of 1% efficiency improvement increase to $108,000 per year. This assumption can be influenced by fuel pricing effects related to creditworthiness of customers and transportation costs.			

A. Generation

1. Operate generating units at high efficiency. The engines should be properly maintained and operated near 80% of full rated output. Funding of on-going maintenance requirements is not included.

2. For every generating unit, add instrumentation to show efficiencies to operators (cost $175,000). Develop a process that provides regular reporting to management.

3. Train power plant operators on load forecasting and economic dispatch practices.

4. Include an economic dispatch module in future SCADA system plans.

5. Change and/or add meters to provide accurate real-time revenue-class generator outputs and auxiliary plant consumption statistics.

6. Develop manual processes to control the operation of fans (cooling fans, exhaust fans and pumps) to run based upon the temperature sensing or other parameters which will optimize the operation and reduce energy consumption.

7. Automate manual processes using PLC controls to motor starters (cost not included – this is considered a next step after process improvements and real time analysis as well as focus on energy consumption reduction is in place).

8. Apply Frequency Drives (cost not included)

Benefits from these actions are expected to be $350,000 over 6 years. Savings are produced by reducing auxiliary losses from 1,875 MWh to 1,500 MWh per year. Total cost of these initiatives (recommendations 5 through 7) is $175,000 over 6 years.

On **Generation Efficiency** the following has been identified:

Individual generation unit data was not provided but overall PUC data was given as shown below.

Exhibit 1-2 – Generation Efficiency

Generation Efficiency					
	2007	**2008**	**2009**	**6 mos. 2010**	**18 Mos. 2009 - 10**
kWh	38,333,400	36,106,000	36,003,600	20,012,500	56,016,100
Fuel Gals	2,683,412	2,512,777	2,625,760	1,483,785	4,109,545
kWh / gals	14.29	14.37	13.71	13.49	13.63

Due to lack of maintenance, which has lead to de-rating of the engines, generation efficiency lowered each year and it costs PUC $81,000 per year of fuel cost for each 1% drop in overall efficiency. From 2008 to 2009 the fuel cost increase was $369,000 due to an efficiency drop of 4.5%. Regular maintenance and optimizing the fuel injection system should bring the efficiency back to 14.3 to 14.5, which is close to the fuel efficiency of new engines of this size.

Increasing the efficiency from 13.49% (2010) to 14.5% would save $ 560,000 per year. With these savings maintenance costs could be covered, as well as replacement of deteriorated radiators.

Nanpil Hydro Plant

It is recommended to pursue funding of the Nanpil Hydro Plant's repair, making use of a business case showing the benefits of operating the hydro plant while saving on fuel costs to justify the initial costs for repair.

B. Distribution

1. Develop standard specifications for distribution and power transformers so purchases are based on reducing lifetime costs (costs of capital, losses, and maintenance). For example, the cost of 1 kW of core losses for 20 years at 22 cents per kWh of fuel cost (based on $ 3 per gallon of fuel) is $23,619 (NPV). For copper losses the NPV is estimated to be $12,920. These figures should be taken into account when evaluating bids for new transformers. (An example of transformer evaluation is provided in Appendix C).

2. Optimize distribution transformers ratings over a 4-to-6 year period by replacing them with transformers more closely matched to the load (lower losses).

3. Add revenue-class meters on feeders and distribution transformers to measure losses. Use these meters to check total loading on individual transformers. These meters can be avoided if customers are tied to distribution transformers in the Customer Information System. To reduce costs, meter only distribution transformers where there is an obvious occurrence of non-technical losses due to tampering, by-passing, or where total transformer loads are necessary. For transformer load profiling 20 to 40 recording meters could be temporarily installed and rotated. Transformer meter costs are included in Section C of this chapter.

4. Use an infrared camera to scan the power system equipment at least annually to find hot spots. These usually occur at connector points. Repair as necessary.

5. Require large customers to maintain the power factor above at least 0.85, preferably at 0.9. Install capacitors in the distribution system to maintain the system power factor above 0.95.

(Total cost of these initiatives is estimated to be $400,000 over 6 years.)

C. Metering, Billing, and Collection

Train a customer service staff member to audit metering and billing processes (including quality checks of billing system data such as multiplier factors, tariff categories applied to customers, functioning of red flags in the case of irregularities and utilizing transformer meters in suspected areas as well as initiating testing of meters and connections) and non-technical loss causes found by meter readers (meter tampering, by-passing, hook ups, etc).

(Total cost of estimated to be $490,000 over 6 years.)

Assign a senior staff member to be PUC’s Revenue Assurance Officer, responsible for PUC’s Loss Reduction Strategy, who will plan and initiate loss reduction programs and activities, keeps records of progress and successes, and reports to the General Manager. In sections 8.2.3 and 9.1.3 the ways of combating non-technical losses, under the leadership of the Revenue Assurance Officer, are worked out further.

2. Introduction

2.1 Project Objectives

KEMA Inc has been asked by the Pacific Power Association (PPA) to conduct a study called "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 covers the study results for PUC, Pohnpei.

Objectives of the project:

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

2.2 Quantification of Losses

Losses are due to:

1. Power station losses
2. Losses in the distribution system

All three categories are quantified below.

The following loss categories were identified:

- Station Losses: Power Plant Auxiliary Loads
- Transmission & Distribution System Losses:

- Technical losses: Summation of transformer core losses, transformer copper losses, transmission line losses, primary distribution feeder losses, and secondary wire losses. Technical losses will become higher as power factors drop below unity.
- Non-technical losses, Inaccurate meters, meter tampering or by-passing, theft, meter reading errors, irregularities with prepaid meters, administrative failures, and wrong multiplying factors

- Unbilled Usages: Energy consumptions not billed. Unbilled usage should be considered a financial loss rather than a non-technical loss. Unbilled usage is mostly for street lighting.

3. Data Gathering and Assessment of Current Situation

The data gathering process is to collect existing information and understand the current situation of the generation and distribution system in Pohnpei. KEMA visited Pohnpei in March 2010 and conducted meetings with management and staff. Visits were made to power plant Nanpohnmal, distribution facilities and overhead feeders. Mr. Andrew Daka of the PPA collected additional data in May 2010.

3.1 The PUC Power System

PUC owns two power plants: the Nanpohnmal diesel plant and Nanpil hydro plant (see specification in Appendix B).

There are three Caterpillar 3516 engines (1135 kW) and four Daihatsu 12DS32 (2500 kW) diesel generators in the Nanpohnmal power plant. Most diesel generators are de-rated at this time. The hydro plant has two Francis turbines made by Boving & Co. (650 kW and 1100 kW).

Due to a flooding in 2002 and un-restored foundation problems, the hydro plant is out of service. Customers are provided power at 240/120V, 208/120V or 480/277V through 450 distribution transformers. The system peak load is 6.3 MW with an average load factor below 0.63. Power factor is 0.9.

3.2 KEMA Data Request

Before we visited PUC Pohnpei, a data request was sent to PUC. (See Appendix A.)

3.3 Data Received

Data was entered into an Excel template per the following: Data Request, engine data, feeder data, meter data, distribution transformer data, power consumption data, the one line diagram, GIS data, and line loss data.

3.4 Site Visit

All data received is included in the Electrical Data Handbook. (Appendix B)

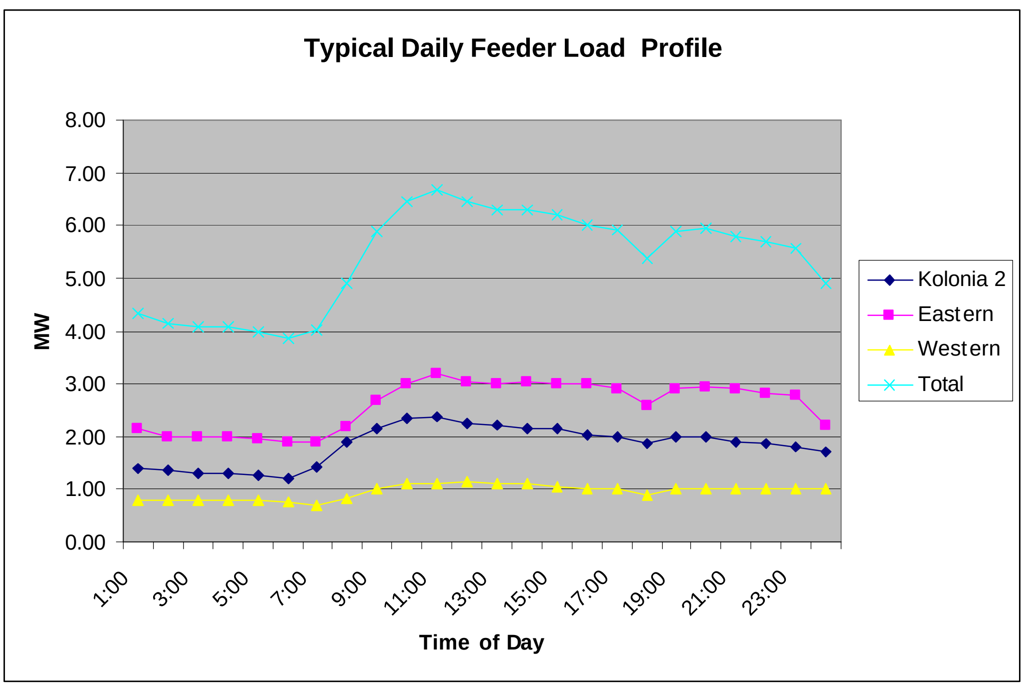
Site visits included the Nanpohnmal power plant, distribution department, and metering and billing department. Line and distribution transformer data was forwarded after the meetings. Power plant information from 2009 appeared to be the most complete for energy generated, load patterns, energy distributed, and energy used.

Data collected included:

1. One line diagram
2. Generator energy production logs, including fuel used.
3. Feeder load profiles
4. Substation and Transformer data
5. Distribution Feeder sizes and lengths
6. Metering Information

Load: Peak load is 6.3 MW with the average load of 4.2 MW (63% load factor). Power factor is 0.9.

Exhibit 3-1 – Typical Load Profile of 13.8 kV Feeders



Generators: There are three Caterpillar 3516 engines (1135 kW) and four Daihatsu 12DS32 (2500 kW) diesel generators in Nanpohnmal. Most diesel generators are de-rated at this time. The hydro plant (Nanpil) has two Francis turbines made by Boving & Co (650 kW and 1100 kW). Specific data is listed in the Data Handbook (Appendix B).

Transformers: There are 3 power plant step-up transformers (4.16 / 13.8 kV).

Exhibit 3-2 – Step-Up Transformer Data

PUC	**Substation Name**		**NAPOHNMAL**		
	Transformer Make		VANTRAN	AICHI	TAKAOKA
	Serial No.		89V5850	9122548	9348096
	Year of Manufacture			1992	1993
ELECTRICAL CHARACTERISTICS	**Rating (MVA)**		5	6.3	6.3
	Nr. of Phases		3	3	3
	Vector Group		YNd1	Yd1	YNd1
	Voltage (V)	**High**	13800/7970	13800	13800
		Low	4160	4160	4160
	Impedance (%)	**Z1**	5.75	5.68	5.58
		Z0			
	Losses (Watts)	**No Load**	8800[1]	10000	9000
		Full Load	42125	42000	42500
	Max. Current (A)	**HV**	220.9	264	204
		LV	693.9	874	874
TANK, CORE & OIL DETAILS	**Oil**	**Vol (Gals)**	900	740	925
		Weight (Lbs)		15211	14110
	WEIGHT (LBS)	**Net**	29000	30424	31306
		Core, Coil & TC		15213	17196
TAPS & TC DETAILS	**NO. of Taps**		5	5	5
	Tapchanger Type		NLTC	NLTC	NLTC
COOLING METHOD			ONAN	ONAN	ONAN
REMARKS			CAT 4, 5, and 6	Engine 7 & 8	Engine 9 & 10

1 Typical data from Electric Power Distribution System Engineering, by Turan Gonen

PUC has single phase and three-phase pole top transformers while some commercial customers have installed pad-mounted transformers, which are in good condition.

Distribution transformers are connected to 13.8 kV feeders. Overload rating for transformers is typically 71% or less.

Exhibit 3-3 – Typical Distribution Transformer Data

PUC	Impedance			Losses (watts)		Number of Transformers	Total kVA Installed
kVA	**Z%**	**R%**	**X%**	**No Load**	**Full Load**		
5	2.2	2.1	0.8	41	144	12	60
10	1.8	1.4	1.2	68	204	102	1020
15	1.7	1.3	1.2	84	282	158	2370
25	1.7	1.2	1.2	118	422	70	1750
37.5	1.7	1.1	1.3	166	570	36	1350
50	1.8	1.1	1.4	185	720	27	1350
75	1.7	0.9	1.4	285	985	16	1200
100	1.9	1.9	1.7	355	1275	5	500
200	2.4	1.1	2.2	544	2653	1	200
Total						427	9800

Feeders: The PUC system has 4 main distribution feeders. Majority of feeders are 13.8 kV overhead lines with the exception of underground cable.

Most lines and feeders look to be in good condition. Connectors and clamps should be infrared tested to identify hot spots and assess the condition of conductors showing signs of corrosion.

Exhibit 3-4 – Distribution Feeder

Capacitors: PUC provided information on the 3 capacitor banks but their rating was not clear.

Meters – There is a population of aging electromechanical meters with replacements occurring at a slow pace. Most meters are prepaid through Cash Power.

Exhibit 3-5 – Pre-Paid Meters and Remote Entry for Tokens

PUC is trying to upgrade these meters due to customers re-entering tokens in the prepaid meter.

There is a limited meter test facility. By request, customer meters are tested. During the site visits, broken seals are identified, alerting the staff to check for meter tampering and by-passing of meters, Irregularities are found monthly. Generator and feeder meters are not revenue-class.

Exhibit 3-6 – Meters by Customer Class

Metering Data	
As of April 2010	
Customer Type	**Number of Meters**
Small Commercial	86
Large Commercial Demand	24
Industrial Demand	2
Sub Total Commercial	**112**
Small Government	47
Large Government Demand	9
Industrial/Government. Demand	1
Sub Total Government	**57**
Residential	**172**
PUC	**28**
Small State	26
Industrial State	1
Sub Total State	**27**
CashPower	**6,194**
Total Mechanical Meters	**396**
Total CashPower Meters	**6,194**
Total Meters	**6,590**

Billing and Collection Processes: Meter reading and billing is done monthly but most of the meters are prepaid.

Reliability: Power delivery depends on availability of generation sets. During our visit one Daihatsu unit and one Caterpillar unit were waiting for spare parts. All engines are de-rated. There is currently no n-2 situation in place, while n-1 can hardly be met. Engine deteriorated radiators have garden sprinklers on them for extra cooling.

Exhibit 3-7 – Radiator Showing Sprinkler for Additional Cooling

T&D Maintenance: No maintenance is scheduled or performed in the substation. An overall maintenance management program covering all activities, (e.g., transformer oil sampling) is not in place. Due to heavy rain falls, feeders are covered with vegetation, which causes regular outages. For lines, there is a tree trimming schedule and a 24-hour crew for restoration.

4. Grid Model and Calculation of Technical Losses

4.1 Estimates and Assumptions for Missing Data

To quantify losses, the following assumptions were made:

1. The average power output over the past year (2009) was used for the annual energy consumption.

2. A typical value for power transformer no-load losses from literature(2) was used for the power transformers core losses.

3. Secondary service wire types and sizes were assumed, based on observations and common practices. Assumptions were made for average wire lengths and general structures based on assumed average customer consumption rates.

4. Loads were distributed based on the distribution transformer locations.

5. Loads were proportionally allocated to the kVA capacity for each feeder.

6. Estimated voltage drops through feeders were not considered in loss estimations. Actual voltage drops were calculated in the Easy Power system model.

4.2 Easy Power Model

Power plants, the substation transformers, and primary feeders were modeled in Easy Power. Feeder lengths and connected load capacities were identified based on the one line diagram and data provided by PUC. Load allocation is based on distribution transformer ratings connected to the feeders. Loads are modeled as lump-sum load connected to feeders or feeder sections. The exact location of load was not known. System peak load of 6.3 MW with a power factor of 0.9 was represented by applying a scaling factor of 0.714 to loads with a total 9800 kVA. Losses through the power transformers and the primary feeders were calculated in peak load condition using a power flow study.

The system one-line diagram in Easy Power is shown in Exhibit 4-1.

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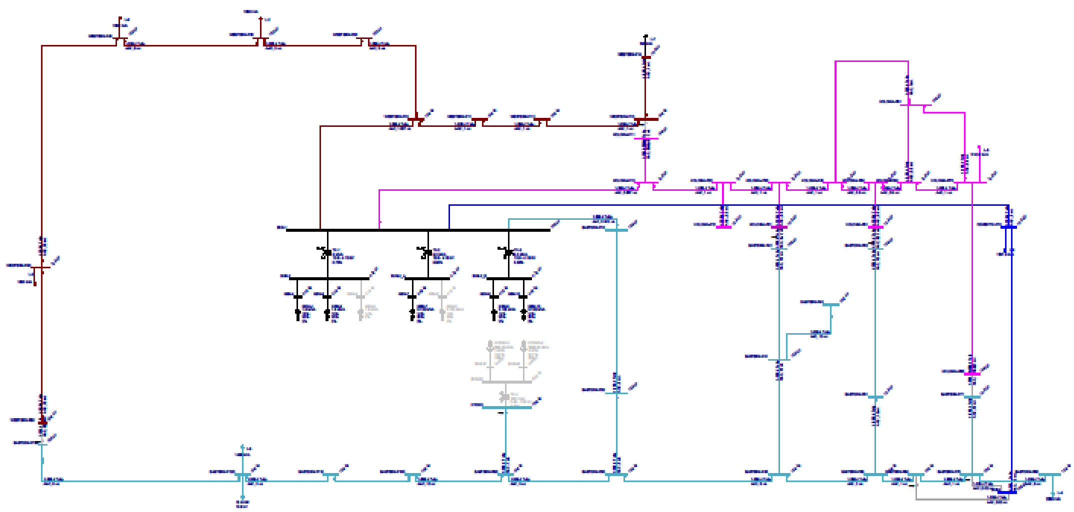
[2] Electric Power Distribution System Engineering, by Turan Gonen

Exhibit 4-1 – One Line Diagram



4.3 System Loss Estimation

System losses consist of technical and non-technical losses.

Technical losses: The sum of: primary feeders and power transformers, distribution transformers and secondary wires. Except for primary feeders and power transformer copper losses, all other losses were calculated in Excel sheets. Where information was not sufficient, assumptions were made to facilitate the estimation.

Non-technical losses: The difference between total system losses and technical losses; total energy entering the system from the power plants minus total energy sold.

For PUC, the unbilled energy usage came from the PUC buildings, water and sewage usage, and part of street lights. A summary of losses is provided in Exhibit 4-2.

Exhibit 4-2 – Loss Estimation

Based on 2009 Data	kWh	% of generation	% of system consumption
Annual generation	36,649,920		
Annual station auxiliary	1,875,208	5.12%	
Annual system consumption	34,774,712	94.88%	100.00%
Annual energy sold (without unbilled usage)	29,813,181	81.35%	85.73%
Unbilled usage - PUC, Offices, Water, Sewage and Street Lights	709,595	1.94%	2.04%
System loss	4,251,936	11.60%	12.23%
Technical loss	2,175,923	5.94%	6.26%
Non technical loss	2,076,013	5.66%	5.97%

5. Data Handbook

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

The Handbook can be found in Appendix B.

6. Analysis of Technical and Non-Technical Losses

6.1 Generation Efficiency

Individual generation unit data was not provided. Overall data was given as shown in Exhibit 6-1 below:

Exhibit 6-1 – Generation Efficiency

Generation Efficiency					
	2007	**2008**	**2009**	**6 mos. 2010**	**18 Mos. 2009 - 10**
kWh	38,333,400	36,106,000	36,003,600	20,012,500	56,016,100
Fuel Gals	2,683,412	2,512,777	2,625,760	1,483,785	4,109,545
kWh / gals	14.29	14.37	13.71	13.49	13.63

Due to lack of maintenance, which has lead to de-rating of the engines, the generation efficiency has lowered each year. It cost PUC $81,000 per year of fuel cost for 1% drop in efficiency. From 2008 to 2009 fuel cost increase was at least $369,000 due to an efficiency drop of 4.5%. Regular maintenance and optimizing the fuel injection system will bring the efficiency back to 14.5, which is close to the fuel efficiency of new engines of this size.

Going back from 13.49% (2010) to 14.5% would save $560,000 per year. Maintenance costs and replacement of deteriorated radiators would be covered.

6.1.1 Power Plant Usage, Station Losses

The power plant usage is 5.12% of the generated energy, which is consistent with industry norms. Since actual measurements are not performed using revenue-class meters, the real usage is not n at a sufficient accuracy.

Losses in plant auxiliaries can be controlled by paying attention to the operation of fans, radiators, lights, etc. Proper accounting or measurement of the energy being used, and optimization of fans and pumps, can reduce energy consumption.

6.2 Technical Losses

Technical losses are 5.94%. The overall utilization of distribution transformers is relatively high (71%).

Exhibit 6-2 – Technical Losses

Technical Losses			
Type of Losses	**Sub Total MWh**	**MWh**	
Dist Transf Core Losses	414		
Dist Transf Cu Losses	242	657	30%
Secondary wires	300		
Feeder Wires	922	1,222	56%
Power Transf Cu Losses	54	297	14%
Power Transf Core Losses	244		
Total =	2,176	2,176	
Core Losses Alone	658		30%

The above table demonstrates out of the total calculated overall losses, feeder and secondary wire losses account for the majority of them (56%). Transformer losses are 44%. More losses (69%) are in the long 13.8 kV feeder wires. Of the transformer losses, core losses are the major component (69%).

6.2.1 Distribution Line Losses

Feeder line losses are 42% of the 5.98% (2,176 MWh) technical losses, including 13.8 kV feeder losses, power transformer losses, distribution transformer losses and secondary service wires losses.

Exhibit 6-3 – Feeder Data

Feeder Data		
Type	**Length (approximate)**	
336.4 ACSR - Three phase lines	85	miles
1 & 2 Odd ACSR - Spurlines	37	miles
Total	122	miles
Capacitors	PUC has 3 capacitor banks all rated 15 kVAr.	

Some of the reasons for the relatively high line losses are the long distribution lines at 13.8 kV, a power factor of 0.9, and unbalanced load among different phases.

Low voltage service wire losses are estimated to be 300 MWh or 14% of technical losses. Assumption of typical size, length and connection of secondary wires were taken to quantify the losses due to lack of information on configurations.

6.2.2 Transformer Losses

Transformer losses are separated in two parts – no-load losses and copper losses. No-load losses are magnetizing losses which are present whenever the transformer is energized, independent of the load. Even an unloaded but energized transformer will have no-load losses. Copper losses are only present when load is present and are proportional to the square of loading relative to full load. For PUC, it total losses from distribution and power transformers are estimated to be 954 MWh per year. 658 MWh are core losses, and 297 MWh are copper losses.

Since the maximum load is 71% of the installed distribution transformer capacity, the distribution transformers seem to be sized appropriately. The system database did not contain information that matched loads to transformers, so this was done by physical inspection.

6.3 Non-Technical Losses

Of the total system losses, 5.66% is non-technical losses.

Possible sources include:

- Not accounting for the energy used by PUC offices, stores, workshops

- Identifying energy theft is left to meter readers or line men, which are part of the community and may not be open to bringing situations to management's attention.
- Meters are not tested and not working properly
- Customers can re-enter the token number. Upgrading the Cash Power system is on-going.
- Electro-mechanical meters are old and not working properly
- No regular procedure to check meter multipliers
- Organizationally, no one person who is responsible for loss reduction
- The billing system does not raise red flags for irregular consumption patterns

PUC has focused its attention to the reduction of the losses. Auditing and assignment of a Revenue Assurance Officer can contribute to reducing non-technical losses (see sections 8.2.3 and 9.1.3).

6.3.1 Metering Losses

About 400 out of 6,600 meters installed in PUC are electromechanical for commercial and larger customers with the remaining meters (residential) being prepaid meters. Due to problems with the Cash Power system and prepaid meters, there is currently no process to calibrate or test any of the meters. Meters used for generator outputs, main feeders, and auxiliaries are not revenue class. Meters also do not record maximum demand.

Processes: 400 meters are read manually once a month. Meter reading, billing, and collection processes are manual. Over 40% of the energy is sold to commercial and government entities.

Exhibit 6-4 – Electric Energy Sold by Category

Electric Energy Sold by Category		
Category	kWh	% sold
Commercial	7,466,803	24.46%
Government	5,373,567	17.61%
Residential	16,972,811	55.61%
Street lights + PUC (includes offices, water and sewerage consumption)	709,595	2.32%
Total =	30,522,776	100.00%

Prepaid meters do not have collection issues. Bill collection (e.g. payment behavior of certain clients) is not optimal, resulting in excessive amounts of receivables.

Customer meters should be tied to transformers, preferably through a Geographical Information System (GIS) in the CIS (Customer Information System). Every year analyses should be performed to see which transformers can be replaced for loss reduction, overloading issues, and general maintenance. It would be beneficial to add meters to the LV side of to capture transformer loadings and identify theft or tampering issues.

7. Other Issues

Power Generation: Most of the engines were running beyond the allowable time among maintenance intervals (major and minor overhaul). In the future, funds for on-going maintenance and replacement of aged generator sets will be needed to avoid a power crisis. PUC may be forced to have a third party own the hydro plant and provide power at a higher cost due to lack of funds for repair. Funding of the hydro plant's repair should be pursued, with a business case showing the benefits of operating the hydro plant while saving on fuel costs will justify the costs for repair.

Transmission lines, Feeders, Transformers and Loads: Developing a regular maintenance program for transformers, transmission lines, feeders, and cables is needed. Performing regular infrared scans (to identify hot spots and unnecessary technical losses) and oil testing (for monitoring power transformers' condition for reliability reasons) is recommended.

Meters need to be regularly tested to ensure revenue-class results. Processes for meter reading, verifying billing constants, collecting, auditing meter installations, and applying penalties for late payment will contribute to improvement of the performance and reduction of non-technical losses.

8. Options for Improvements

8.1 Power System Improvements/Modifications

Technical losses are unavoidable. KEMA does not expect technical loss reduction efforts to result in substantial amounts of loss reductions based on the assessment. Reducing them should continue to be an integral part of PUC's overall loss reduction strategy 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 loose can cause heating, which results in higher losses, loading to reliability concerns, and safety issues.
- 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 these projects/programs, giving loss reduction benefits a proper weight when considering total life costs is key to selecting those that will be most beneficial.

Distribution and power transformers make up 44% of the technical losses. Core losses are the majority of the losses. Over the life time the cost of losses represents a major cost relative to overall capital costs. The Distribution Department needs to better match transformer size to supplied load. If implemented, substantial savings are considered when based on the load.

Loss calculation is not a one-time event but needs to be considered when developing all utility processes (e.g. operational procedure, planning and engineering system expansions, purchasing materials, and defining revenue assurance measures). Loss estimation can be improved in the following two areas:

Secondary Circuits and Service Wires

PUC should consider using a targeted feeder program to create 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 more accurately estimate the losses in secondary circuits and service wires.

Customer meters need to be associated with the respective transformers servicing the load. This can be done in a CIS system or using spreadsheet software to take load from metering data and calculate transformer loading. 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 more complicated and is affected by:

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

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

Regularly Update Loss Cost-Basis

The loss cost-basis used to estimate lifetime cost of losses should take electricity rate increases into full account. When rates are increasing at a slow pace, it may be acceptable to use current rates to calculate projected savings over life spans of equipment (e.g. transformers) and other parts. When 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 old equipment replaced, the loss cost-basis should be evaluated. 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. The 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

Distribution transformers should be optimized to reduce losses. When the transformer sizes are appropriate for the load and purchased based on total lifetime cost, overall losses will be optimized. As optimized sizes cannot be realized in a single year, a multi-year replacement program should be set up:

1. 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, unless all customer loads connected to this transformer can be computed).

2. Develop proper transformer sizes for each location.

3. Optimize transformers which can be optimized without capital cost investments (e.g. by moving them to appropriate locations). Remember transformers can be overloaded for short durations.

4. Develop a new transformer purchase plan based on standard sizing while looking at least lifetime costs, which will include capital investment and losses. (An example transformer evaluation is included in Appendix C.)

Optimize Feeder Power Factor

Overall system power factor (PF) is 0.89. The power factor of feeder sections should be checked regularly (at least once a year) and actions should be taken to keep it above 0.9, preferably 0.95. The best location for corrective measures is at the loads, especially at inductor motor terminals. Develop a plan and tariff (or introduce a low power factor penalty) to make sure each larger commercial and government loads are at a minimum power factor of 0.9. If a customer does not improve its power factor to the required level, PUC should charge a penalty. Metering and billing should be coordinated with tariff and/or low power factor penalties.

Optimize Feeder Reactive Power Compensation

Shunt capacitor banks on 13.8 kV lines can be used to minimize reactive power flows in the network to help reduce the losses. When operated for this purpose, there are two areas that should be considered:

1. Fixed and Manually Switched Capacitors

Compensation can use a mix of fixed and switched capacitors to achieve desired reactive power compensation levels.

The size of <u>fixed</u> capacitors can be determined by minimum reactive power compensation requirements of a feeder. It is not necessary to compensate to 1.0 power factor, but should be as close as possible. From a loss reduction point of view, results will be the same regardless if the power factor is leading or lagging. The actual size selection should also take standard capacitor sizes into account that can be procured.

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 change between two constant levels, then one large switched capacitor may be sufficient. These should be evaluated on a feeder-by-feeder basis.

When determining capacitor sizes, in particular for switched capacitor banks, voltages should be verified to ensure voltage limits are not violated.

1. Automatically Switched Using Capacitor Controls

Automatic switching of capacitor banks can be controlled by a variety of system variables or derivatives of system variables. Common controls 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 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 pre-determined 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 capacitors are on line when they are most needed.

kVAr Control: This control operates in response to changes in the clover 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

8.2.1 Generation

Metering does not provide accurate coordinated readings. We recommend that the first step should be to install revenue-class metering (energy, fuel and other supplies) to accurately measure efficiency of each generator and dispatch them based on efficiency. Focus on efficiency improvement (developed processes for operators); real time display of engine efficiency helps operators run engines in the most optimum way. Minimum display of real-time information providing fuel use, lube oil usage, engine kWh production, auxiliary kWh usage, should be available. Objective of this is to improve the efficiency and reduce consumption in plant auxiliaries.

Generation efficiency dropped 5% in 2009 compared with previous years (13.71 from 14.37 kWh/ Gal). The cause should be investigated to correct the situation. Every 1% efficiency increase saves $81,000. Improving overall efficiency to 14.5 kWh/gal from 13.49 will save $560,000 fuel cost per year. Maintenance and replacement costs can be covered once these savings have been realized.

Pursue funding of the Nanpil Hydro Plant's repair by making use of a business case showing the benefits of operating the hydro plant while saving on fuel costs.

8.2.2 Metering

A procedure should be developed to test and calibrate meters before installation. This should include methodologies to test sample meters to assure accuracies.

Methodologies should be developed to measure distribution transformer load profiles either through:

1. Software, which takes into account the customer meters on each of the transformers or

2. Physically measuring the load by installing meters on the secondary of each transformer.

8.2.3 Strategy for Reduction of Non-Technical Losses

Considering there are 5.66% of non-technical losses, there are potential savings in this category.

In larger utilities with too high amounts of non-technical losses, one of the main areas in aligning a utilities' operation to Revenue Assurance is to implement a Revenue Assurance Process making use of an advanced Revenue Intelligence System. For conducting most efficient fraud prevention/detection and revenue operation audits with limited resources, an advanced Revenue Intelligence system is very helpful. Such a system can detect potential fraud based on information from multiple sources using advanced detection rules. It will vastly increase the hit rate and support a range of revenue assurance activities. These changes/processes should include:

- Implementation of a formal Revenue Assurance Process including an overall Audit Process.
- Implementation of Revenue Intelligence software to support Revenue Assurance oriented operations

However, for a small utility, implementation of a Revenue Assurance Department and implementation of Revenue Intelligence software requires a large investment and may have a large organizational impact.

A more pragmatic approach can be developed to locate non-technical losses and increase the effectiveness of revenue-protection operations.

PUC should consider the following:

1. Develop a program for checking old meters.

2. Train meter readers to identify tampering, by-passing, broken seals, hook ups.

3. Train a customer service staff member to audit metering and billing processes (including quality checks of billing system data such as multiplying factors, tariff categories applied to customers, functioning of red flags in the case of irregularities)

and non-technical loss causes found by meter readers, such as meter tampering or by-passing.

4. Select targets for inspection, also focusing on commercial customers. When selecting targets for inspection, the potential of the estimated amount of revenue recovery should be a major selection factor. When selecting accounts with highest revenues the recovery potential and hit rates will be the most efficient, particularly when only limited resources will be available.

5. Make operations less predictable. PUC's own experience may possibly show that there are sophisticated fraud activities that take advantage of known patterns of Revenue Assurance operations. This should be countered with less predictable operations (e.g. occasional night inspections, computer-generated random daily target lists, and so on). This will help to identify these fraudsters and increase the deterrent effect.

6. Prevent repeat fraud activities. Once a fraud is found, measures should be implemented to ensure it will not occur again.

7. 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 any revenue assurance process. One possible solution is to bring in non-local inspection teams to conduct critical revenue-protection operations, such as large account audits under the direct control of PUC's top management.

8. 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 patterns and payment capabilities. Establishing typical usage patterns and payment capabilities for each group is a very important task of Revenue Assurance. Results should then be used as the basis for employing right tactics for each group of customers.

9. Assign a senior staff member to be Revenue Assurance Officer, responsible for Loss Reduction Strategies, and who plans and initiates low reduction programs, keeps records of progress, and reports to the General Manager.

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

Exhibit 9-1 provides a summary of savings and associated costs over a 6-year implementation period.

Exhibit 9-1: Summary of Savings and Costs

Assumptions:				
Inflation	3%			
Cost of Capital	8.00%			
Cost of generation /kWh	$0.29			
Cost and Savings list	**Savings (NPV)**	**Cost (NPV)**	**Net (NPV)**	**Cash over 6 years**
Auxiliary Losses				
SCADA for generators and process improvement		$175,000		-$175,000
20% loss reduction over 6 years	$254,373		$79,373	
Technical Loss Savings:				
Infrascan camera and training		$100,000		-$100,000
Power factor improvement hardware installation and control.		$244,332		-$308,736
30% loss reduction over 6 years	$410,534		$66,202	
Non Technical Savings:				
Revenue Protection Department - Focus to analyze, audit and pursue issues with metering, including meter testing, billing and tampering. Developing processes, using check meters at distribution transformers and software to pin point losses in the system.		$433,717		-$490,228
60% Non Technical Loss reduction over 6 years	$783,367		$349,649	
Total =	$1,448,273	$953,049	$495,224	- $1,073,965

Detailed calculation of these numbers is provided in Appendix C called "Technical Loss Calculations and Financial Model for Options to Decrease Losses".

The summary of our recommendations is as follows:

1. Cost will increase based upon inflation of 3% every year.
2. Cost of Capital at 8% per year was assumed.
3. Emphasis should be placed on process improvements for purchasing, metering, billing, collection, and operations.
4. Technical and non-technical loss improvements will require investments totaling $1 million over 6 years. Losses will be reduced from 11.6% to less than 6.85%.
5. Generation auxiliary losses are a relatively small portion (5.12%) of overall losses. With process improvements and a $175,000 investment, it will be possible to provide real-time data and efficiency calculations to operators who can then operate the power plants, at maximum efficiencies (4.36%).
6. Every 1% improvement in engine efficiency will save $81,000. In chapter 8.2.1 efficiency of PUC's generators should be brought back to a level of 14.5 kWh/gallon by eliminating the arrears in maintenance and replacing radiators. PUC could set up a business case showing costs versus benefits of more than $0.5M fuel savings per year.
7. The costs of repairing the hydro plant can be calculated and evaluated against benefits of having this plant operational again, which will bring savings on fuel costs.

9.1 Recommendations

Recommendations below are prioritized according to costs and benefits. (See spreadsheet Savings Model tab in Appendix C.)

9.1.1 Reduction of Technical Losses

Distribution transformers appear to be loaded at 70% full capacity. Loss reductions are possible if transformer sizing more closely matches connected load. This could be done as part of an on-going transformer replacement program.

1. Power Factor Improvement:

The power factor of PUC is reasonable but it needs to be watched and a process should be developed to evaluate it at least once a year.

a. Acquire software for power factor analysis. (Cost of software and training $50,000)

b. Determine power factor of largest customers and require them to improve it over 0.85, preferably 0.90. This may require penalties or tariff changes. Add capacitors to improve the power factor if appropriate.

c. Determine what capacitor locations can be placed to improve the overall power factor to 0.95. (Overall power factor improvement costs are estimated to be $260,000 over a 6 year period.)

2. Transformer Right Sizing

a. Determine proper sizes and specifications of the distribution transformers needed for the loads to be served.

b. Distribution transformers should be sized to achieve 80% loading at maximum demand.

c. Transformers should be purchased based on lifetime costs (including NPV calculation for losses). For example, the cost of 1 kW of core losses for 20 years of a transformer's life at 22 cents per kWh of fuel cost (based on $ 3 per gallon of fuel) will be $23,619 (NPV). For copper losses NPV is dependent on transformer loading but is estimated to be $12,920. (See an example transformer evaluation in Appendix C).

No cost was allocated to this program.

3. Reduce Line Losses

Acquire an infrared scan camera and train PUC personnel on using it. (Cost of equipment and training $100,000).

Using an infrared camera is a necessary tool for identifying distribution loss issues. An infrared camera will identify hot spots from bad connections and overloading, and as a result, helps in detecting weak spots, prioritizing maintenance work and upgrading feeders. There is a potential energy savings by regularly identifying these maintenance issues and taking proactive correction measures.

Technical losses can be reduced from 5.94% to 4.43% in 6 years through process improvements for an estimated savings of $572,000. Cost of these initiatives is $400,000 over a 6 year period.

9.1.2 Reduction of Generation Auxiliary Losses

1. For every generating unit, add instrumentation to show efficiencies to operators (cost $175,000). Develop a process that provides regular reporting to management.

2. Develop procedures for economic dispatching of the generation units, based on load forecasting and operational preconditions.

3. PUC will implement SCADA in the future, a module for economic dispatching should be part of this system.

4. Prepare the cost/benefit analysis regarding cost of bringing generation efficiency to 14.5 kWh/gallon versus fuel savings.

5. Prepare the cost/benefit analysis regarding costs of repairing the hydro plant versus fuel savings.

6. Develop manual processes to control fan operation (cooling fans, exhaust fans and pumps) to run based on temperature sensing or other parameters to reduce energy consumption.

7. Automate manual processes using PLC controls to motor starters and frequency drives (cost not included).

8. Apply frequency drives where needed (cost not included).

The benefit of steps 1, 2, 5, 6, and 7 is estimated to be $350,000 over 6 years. Savings are produced by reducing auxiliary losses from 1,875 MWh to 1,500 MWh in 6 years. (See spreadsheet Savings Model tab in Appendix C).

Steps 3 and 4 depend on cost factors for maintenance, replacements, and repairs.

9.1.3 Reduction of Non-Technical Losses

Account for and highlight monthly financial losses associated with street lights and unaccounted energy use. Add new meters to transformer secondary sides and feeders at key locations for monitoring loads and customer usages. Procure meter testing equipment and train users to perform sample meter testing. Replace meters found to be out of specification. Make sure each customer is associated with its transformer and its meter (cost $490,000). Software can then be used to identify tampering and transformer issues loading.

It is not necessary to install meters on every transformer. Areas prone to excessive tampering or other theft issues or where loading profiles are unknown would be best locations. Temporary recording meters could be installed for a time period and be rotated to other locations. With this option, manpower costs associated with relocation need to be considered.

Add Revenue Protection measures as described in Section 8.2.3. Include a senior staff member accountable to the Revenue Assurance Officer.

Savings will come from focused attention to improved processes, and using tools like modern meters and systems. In the first year, it is reasonable to expect a 10% savings in non-technical losses, 60% after 6 years. Non-technical losses will drop to 2.42%. Savings will be $1 million, resulting in a NPV of $783,367.

Other Recommendations:

1. Develop a maintenance management program and written operational processes to repair and maintain the distribution system and provide related linemen training.
2. Keep up efficiency and reliability by funding maintenance for power plants and distribution operations. PUC should be self sustainable to keep up its technical and financial health.
3. Develop a testing program for revenue meters. The estimated cost of $200,000 is included in the non-technical savings plan

Appendices

A. Data Request

B. Data Received

Data Handbook

Pohnpei Engine Data

One Line Diagram

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

Technical Loss Calculations and Financial Model

Transformer Evaluation Example