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

Commonwealth Utilities Corporation of Saipan (CUC)

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

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1. Executive Summary

KEMA's analysis of the Commonwealth Utilities Corporation of Saipan (CUC) power system determined total losses of 28.75% consisting of:

- 4.73% in power station auxiliaries (station losses). Typically station losses in power stations of similar sizes are 5%.
- Street lighting – 0.98%: Should be accounted for and billed if these revenues cannot be collected, street lighting should be considered a financial loss for CUC and not a power system loss.
- Energy usage for water and sewerage activities – 7.93%: Should be 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 CUC's power services and cannot be considered a power system loss.
- 4.36% in technical losses.
- 10.75% in non-technical losses.

Technical and non-technical losses total 15.11%.

Overall losses, including power plant usage total 19.84%.

Recommendations:

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

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. Develop a generator dispatching routine to provide highest efficiency operation.
3. Change and/or add meters to provide accurate real-time revenue-class generator outputs and auxiliary plant consumption statistics.
4. Train power plant operators on load forecasting and economic dispatch practices. Include an economic dispatch module in future SCADA system plans.

(Total cost of these initiatives is estimated to be $1 million over 6 years.)

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 $23,161 (net present value). For copper losses (loading dependent) the net present value is estimated to be $12,609. These figures should be taken into account when evaluating bids for new transformers. (A transformer evaluation example is provided in Appendix C).

2. Add revenue-class meters on outgoing transmission lines, distribution 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 need due to tampering, by-passing, or where total transformer loads are necessary. For transformer load profiling, 50 to 100 recording meters could be temporarily installed and rotated. Transformer meter costs are included in Section C of this chapter.

3. Consider the impact of system losses when planning and designing the T&D system. Regularly evaluate the impact of losses due to low power factors and unused transformer capacities (minimizes excessive no-load losses).

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

5. Require large customers to maintain power factors above a minimum threshold of 0.85. Install capacitors on feeders and in substations to maintain system power factors above 0.95.

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

(Total cost of these initiatives is estimated to be $1.3 million over 6 years.)

C. Metering, Billing and Collection

1. Staff a Revenue Protection Department or empower a Revenue Assurance Officer responsible for reducing non-technical losses, who will execute a revenue assurance program that includes regular and un-announced program audits.

2. Replace customer meters with digital smart meters (or prepaid meters) for residential customers.

   (Total cost of these initiatives is estimated to be $11.5 million over 6 years.)

Recommended measures and actions under A, B, and C will cost $13.8 million over a period of 4-to-6 years, resulting in an estimated savings of $ 21 million (NPV of $14.8 million) with a reduction of:

- 0.4% for power plant losses (auxiliaries)
- 1% for technical losses
- 8% to 9% for non-technical losses
- Savings of $600,000 per year can be achieved for every 1% improvement in generation efficiency.

Total savings and costs for all loss reduction measures are summarized in the table below.

	6 Yrs NPV of Savings and Cost Summary		
NPV @ Cost of Capital	**Savings (NPV)**	**Cost (NPV)**	**Net (NPV)**
Auxiliary loss	$1,232,616	$1,000,000	$232,616
Non Technical Loss	$11,906,360	$9,412,326	$2,494,034
Technical Losses	$1,682,820	$1,254,994	$427,827
Total =	$14,821,796	$11,667,320	$3,154,476

1% efficiency improvement in generation saves $ 600,000 per year based on the price of crude oil being $75 per barrel. At a price of $100 per barrel the savings of 1% efficiency improvement $800,000 per year. This assumption can be influenced by fuel pricing effects related to credit worthiness of customers and transportation costs. In this report, economic dispatch of generators has been given highest priority.

2. Introduction

2.1 Project Objectives

KEMA was asked by 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 the 10 Northern Pacific Island Utilities. This report summarizes study results for CUC in Saipan, Mariana Islands.

Project objectives and deliverables:

- Quantify energy losses in the power system.
- Prepare an Electrical Data Handbook containing electrical characteristics for all high voltage equipment.
- Prepare digital circuit model of the power system using EASY POWER, an established commercial package.
- Prepare a prioritized replacement list of power system equipment to reduce technical losses.
- Identify sources of non-technical losses.
- 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 transmission system and
3. 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 be 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 consumption that is not billed should be considered a financial loss rather than a non-technical loss. Examples include the following:

  - Street Lights. Street lights need to be invoiced or be considered a financial loss.
  - Energy for water production, distribution and sewerage: Needs to be allocated to the cost of service for Water and Sewerage, or considered a financial loss.

• Unaccounted Usages: There were some usages which could not be accounted for, and represent potential savings if proper metering is made available.

3. Data Gathering and Assessment of the Current Situation

Data gathering process is to collect existing information and understand the current situation of the generation, transmission, and distribution systems. KEMA visited Saipan and conducted meetings with management and staff. Physical inspection was selectively done of power plants and transmission and distribution facilities, including transformer stations, mid-line breakers, distribution transformers, and overhead feeders.

3.1 The CUC Power System

CUC owns and operates three power plants in Saipan, all diesel engines. PP I consist of 7 engines varying from 7.27 MW to 13.04 MW, all supplying power at 13.8 kV. PP II consists of 6 2.5 MW EMD engines supplying power at 2400/4160V. PP IV consists of 2 Nordberg, 3 EMD and 4 Cummins generation units (ranging from 2.2 MW to 2.6 MW) supplying power at 2400/4160V.

Furthermore CUC operates power plants in the islands of Rota (installed capacity 5.0 MVA, peak load 2.7 MW) and Tinian (installed capacity 5 MVA, peak load 2.0 MW).

Power is distributed at 240/120V, 208/120V or 480/277V levels through distribution transformers ranging from 15 kVA to 750 kVA. System peak load is 42.0 MW with an average load factor below 0.71.

3.2 KEMA Data Request

A data request was sent to CUC prior to on-site meetings. (See Appendix A.)

3.3 Data Received

CUC provided a portion of the data prior to our on-site meetings which helped to facilitate the meetings.

3.4 Site visits

Additional data was gathered during the site visit of March 2010. Remaining data was forwarded after the meetings. (All data collected is the Data Book of Appendix B.)

Data collected:

1. One line diagram

2. Old system model report – Software DPA 4.1 as latest updated in the late 90s
3. Generator energy production logs including fuel and lube-oil used.
4. Substation and Transformer data
5. Transmission Lines' and Distribution Feeders' sizes and lengths
6. Metering Information

Load: Peak load is 42.0 MW with an average load of 29.87 MW. Power factor is 0.902.

Generators: There are three power plants in Saipan. Data for each plant is listed in the Data Handbook. All generating units use diesel fuel. Unit sizes vary from 2.2 MW to 13.04 MW.

Furthermore CUC operates power plants in the islands of Rota (installed capacity 5.0 MVA, peak load 2.7 MW) and Tinian (installed capacity 5 MVA, peak load 2.0 MW).

In 2009, Saipan suffered many outages due to insufficient generation as a result of poor maintenance in the prior years. The Department of the Interior (DOI) provided CUC with a grant to resolve the issues. Major overhauls were conducted in plants PP1 and PP2: Radiators were replaced; turbochargers and injection measure improvements were taken with Baileys in Australia. The number of outages was substantially reduced. Some distribution outages were caused by vegetation problems. Four (4) more engines still need to be overhauled and two new sets of radiators installed (CBM Australia).

Transformers: Most residential users are served by pole top transformers. Some commercial users are served by pad-mounted transformers. There are 15 station transformers 34.5/13.8 kV, varying in size from 1 MVA to 30/40/50 MVA capacity. Oil samples of this transformer population are not taken for condition assessments. Distribution transformers are connected to 13.8 kV feeders Routine maintenance procedures for the station transformers are not being followed; e.g., oil sample tests.

Aerial, Underground Transmission Lines and Feeders: 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.

Cables: Feeder 2 and Kiya 1 are underground. The important 34.5 kV transmission connection from the Power Plant 1 to the Chalan Kiya Substation is also underground. No issues were reported for these cable connections.

Exhibit 3-1: Three-phase 34.5 kV XLPE cable used for the connection between Power Plant 1 Substation to Chalan Kiya Substation

Meters: There is a population of aging electromechanical meters which are being replaced at a slow pace. There is a limited meter test facility. Meters are tested by customer request. During site visits broken seals were identified. CUC is quick to find meter tampering and by-passing. Monthly, irregularities are found. The reconnection fee is $75. Some large customers have their own generation, with a total load of 10 MW. Most are provided standby power, but no standby fee is charged. This can be considered a loss of return on investments. Prepaid meters were recently introduced and over 100 prepaid meters installed. It is CUC's intent to increase the number of prepaid meters.

Generator and feeder meters are not revenue-class meters.

Billing and Collection Processes: Meter reading and billing is performed monthly, making use of a CIS system (Customer Information System). The CIS does not automatically initiate red flags to identify irregularities, such as much lower than usual usage.

Reliability: After a period of blackouts and outages – mainly because of poorly maintained generator sets – reliability has improved substantially as a result of unit overhauls and replacements (radiators for example) in 2009. Except for four (4) generator sets, most are back to 80% of rated capacity resulting in system reliability returning to an acceptable level. Generation outages no longer occur. Distribution outages occur from time to time as expected on any power system.

T&D Maintenance: Time-based maintenance is performed in the substations. For lines, there is a tree trimming schedule. An overall maintenance management program covering all maintenance activities (e.g., power transformer oil sampling) is not in place.

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 1 year (2009) was used for the annual energy consumption.
2. A typical value for power transformer no-load losses literature1 was used for core losses. Distribution transformer losses were calculated based on no-load losses and load losses provided by CUC.
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 along the feeders based on feeder sections and assumed meter locations along the feeders.
5. The allocation of distribution transformers and loads were according to feeder sections shown on the one line diagram.
6. Load was allocated proportionally to the kVA capacities of the distribution transformers.
7. Estimated voltage drops through feeders were not considered in loss estimations. Actual voltage drops were calculated in the Easy Power system model.

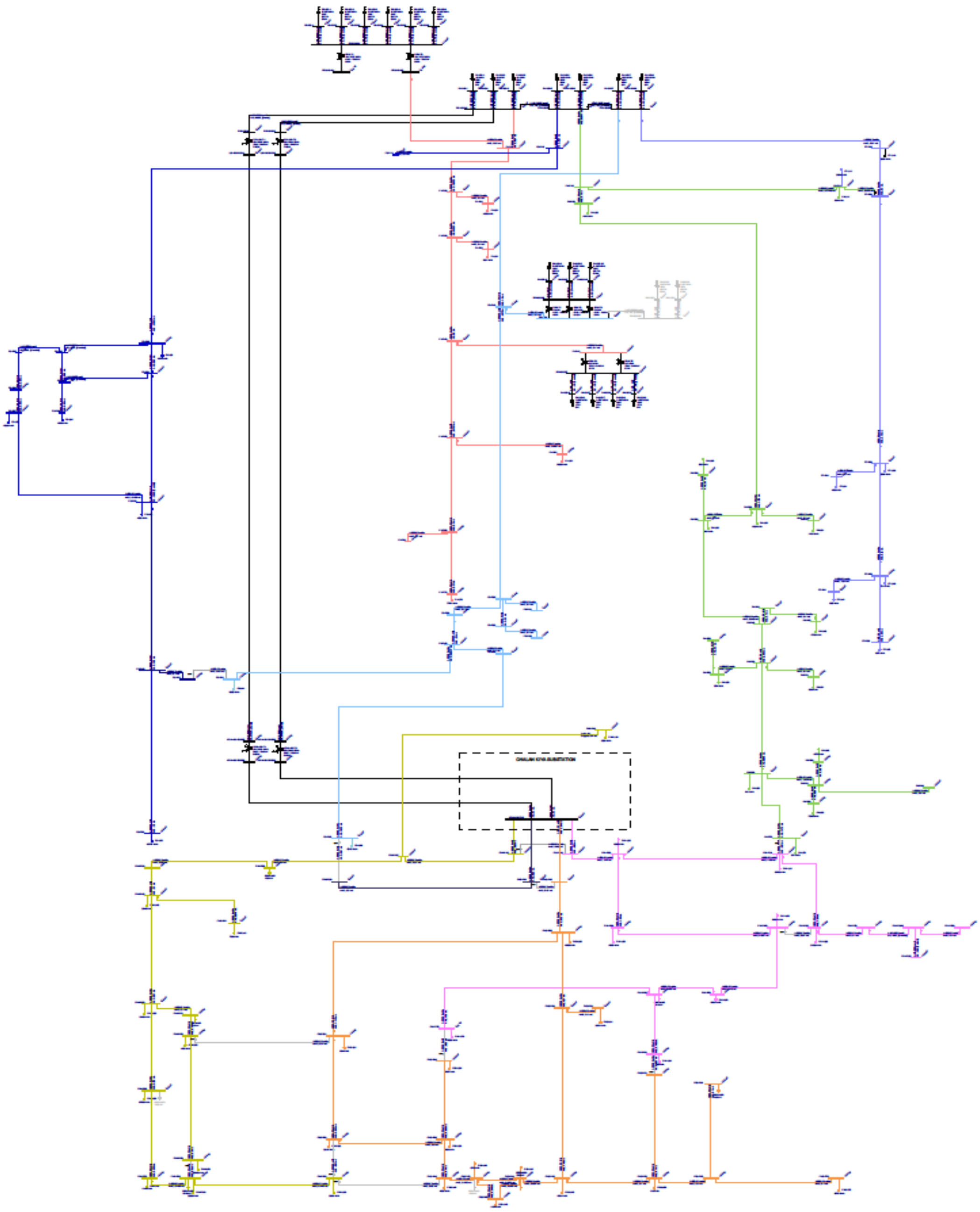
4.2 Easy Power Model

Power plants, transmission lines, and primary distribution feeders were modeled in Easy Power. Feeder lengths and connected loads were identified based on DPA model reports provided by CUC. Generators, power transformers, and capacitors were modeled based on data provided in response to the data request. Losses through the transmission system, primary feeders, and power transformers were calculated in a power flow study. Peak loads were estimated from the energy sold to customers and data collected from power plants. Since distribution transformers are not associated with customer meters, load allocation was based on transformer sizes for each of the feeders.

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

The system one-line diagram is shown in Exhibit 4-1 and included in Appendix D (PDF file which can be enlarged on the screen).

Exhibit 4-1: SAIPAN One Line Diagram



4.3 System Loss Estimation

System losses consist of technical and non-technical losses.

Technical losses: The sum of transmission line losses, primary feeders and power transformer copper losses, power transformer and distribution transformer core losses, distribution transformer copper losses, and secondary losses. Except for transmission lines, primary feeders and power transformer copper losses, all other losses were calculated in Excel sheets. Where information was not sufficient, assumptions (exact location of customers relative to their distribution transformer, load for each of the transformers, load on feeders, load per phase of feeder sections, power factor of the loads) were made to facilitate the estimation.

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

For CUC, the unbilled energy usage came from street lights, and water and wastewater system usage. A summary of the losses is provided in Exhibit 4-2.

Exhibit 4-2: Loss Estimation

Based on 2009 figures	MWh	% of generation	% of system consumption	Comments
Annual generation	274,675			
Annual station auxiliary	12,991	4.73%		
Annual total feeder load	261,684	95.27%	100%	Total feeder load should be approximately equal to system consumption.
Annual system consumption, including losses	261,684	95.27%	100%	
Annual energy sold	198,381	72.22%	75.81%	
Unbilled/unaccounted for usage	21,787	7.93%	8.33%	Water, waste water, street lights, others?
Total system losses	41,516	15.11%	15.86%	<- This is close to figures shown on CUC worksheets.

Technical losses	11,978	4.36%	4.58%	Actually, it could be higher due to unbalanced loads, higher lengths of service wires, etc. Estimated to be 5.0 to 5.5%.
Non technical losses	29,538	10.75%	11.29%	Could be lower due to technical loss being higher than calculated.

5. Electrical Data Handbook

As part of the project's scope of work, KEMA prepared an Electrical Data Handbook, containing electrical characteristics of CUC'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

Exhibit 6-1: CUC Engine Generator Efficiency 2009 in Power Plant 1

Efficiency - kWh/Gallon of Fuel												
	D/E 1	*D/E 2*	*D/E 3*	*D/E 4*	*D/E 5*	*D/E 6*	*D/E 7*	*D/E 8*	*PP II*	*PPIV*	*Aggreko (temporary power in 2009)*	Total
	14.34	14.57	13.79		14.92	13.30	13.41		10.89	12.86	14.19	13.90
PP 1								14.06				

Efficiency - kWh/Gallon of lube oil												
	D/E 1	*D/E 2*	*D/E 3*	*D/E 4*	*D/E 5*	*D/E 6*	*D/E 7*	*D/E 8*	*PP II*	*PP IV*	*Aggreko*	Total
	1,224	1,252	1,286		2,542	1,097	2,402	837	960	2,377		2,408
PP I								1,520				

Following a power crisis in 2008, a subsequent engine overhaul, Exhibit 6-1 summarizes available generation. Engine D/E 4 was decommissioned due to a crankshaft failure. D/E 8 was put on emergency stand-by due to broken foundation bolts.

Units D/E 1 and 5 (each 2.5 MW) are on standby, while D/E 6 has been decommissioned. D/E 2, 3 and 4 are under maintenance or waiting for parts.

From the point of view of efficiency, it is best to dispatch engines D/E 1, 2 and 5 before all others because they have highest efficiencies.

Plant PPIV is operated as an IPP (although owned by CUC, but operated by a private enterprise) with a “take or pay” contract, which forces CUC to purchase electricity regardless of efficiencies. In a situation like this, CUC should just dispatch its own engines in the most efficient way.

6.1.1 Power Plant Own Usage, Station Losses

The power plants are consuming 4.73% of the generated energy, which is consistent with industry norms. Since actual measurements are not performed using revenue-class meters, the real usage may differ from the estimated value.

The overhauls, including replacement of radiators, pumps and other auxiliaries will contribute to lower plant losses. Once all engine overhauls and replacements are completed, energy usage should be re-assessed to identify areas for further improvement.

6.2 Technical Losses

6.2.1 Transmission and Distribution Line losses

Calculated line losses are 39% of the 4.36% (11,978 MWh) technical losses. It is estimated only 17% of total technical losses come from low voltage service wires, which is low compared to other utilities.

One reason for low distribution line losses is the presence of 34.5 kV transmission lines, a relatively high power factor of 0.9 and low load compared to the wire size.

Line losses occur because of wire resistance, which is inversely proportional to the size and type of conductor. The larger the size (diameter), the lower the resistance. The same size wire made of copper will have lower resistance than aluminum. Raising the power factor above 0.9 will further lower some of the losses.

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 on unloaded but energized transformers there will be 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 CUC, total losses from distribution and power transformers are estimated to be 7,247 MWh per year. 4,032 MWh are core losses, and 3,245 MWh are copper losses.

The ratings of these transformers (the average load is calculated to be around 35% of the installed distribution transformer nameplate rating – assuming the ratings are at least equivalent to connected loads) may be too large for the load, resulting in higher no-load losses (core losses). The system database did not contain information that matched loads to transformers, so this was done by physical inspection.

Since core losses depend on transformer ratings, and since CUC is using only 35% of the total installed capacity (estimated at equivalent to the connected load) in a year, there is room to decrease these losses. Lowering distribution transformer ratings by one size will reduce losses by 20%; two lower sizes will reduce losses by 30%. The second option (two sizes lower) will load transformers 50% to 60% of the maximum system load of 42,000 kW.

Non-Technical Losses

Of the total system losses 10.75% is non-technical (not counting power usage for water, waste water and street lights, which we consider to be financial losses). Possible sources include:

- Not accounting for all energy used by CUC offices, stores or workshops
- Faulty photocells cause street lights to be operating 24 hours
- Identifying energy theft or irregularities is left to meter readers who 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
- Meters are old and not working properly
- No regular procedure to check meter multipliers
- Organizationally, no person assigned and responsible for developing and executing a loss reduction strategy
- Customer Information System does not raise red flags when irregular consumption is detected

6.2.3 Metering Losses

Customer meters are electromechanical. They have not been calibrated or tested for as long as they have been in service. Meters used for class generator outputs, transmission lines, main feeders, and auxiliaries are not revenue-class. Meters do not record maximum demand. Prepaid meters are slowly being introduced.

Processes: Most of the meters (14000) are read manually once a month. Meter reading, billing and collection processes are manual. Bill collection is not optimal, resulting in excessive amounts of receivables. Key to re-solving these issues is strong management and written implementation / enforcement policies.

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 identify which transformers can be replaced for loss reduction or because of overloading. It would be beneficial to add meters to the LV side to capture transformer loadings and identify theft or tampering issues. Current transformers (CT's) can be installed with the meters on the poles.

7. Other issues

Power Generation: It became apparent in 2008 that the key issue for CUC was keeping the generation units running. Most of the engines were running beyond the allowable maintenance intervals (major and minor overhaul). Funds became available in 2009 for overhauls and parts to bring the units back to running condition. In the future, funds for on-going maintenance and replacement of aged generator sets will be needed to avoid another power crisis. The technical health of the utility will depend on enough revenues being collected to cover maintenance costs. A cost of service study would quantify what tariffs would be necessary to be self sustainable. The gap between existing and desired conditions will become clear and measures can be taken to fill the gap (tariff increase, subsidies, securing some amount of grants per year, etc).

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 transformer conditions) is recommended.

Meters need to be regularly tested to ensure revenue-class results. Processes for collection, verifying billing constants, auditing meter installations, and applying penalties for late payment, are among the improvements needed to improve the performance and reduce the losses.

Revenue assurance will be addressed in Chapter 8.

8. Options for Improvements

8.1 Power System Improvements/Modifications

Technical losses are unavoidable. However, reducing them should continue to be an integral part of CUC's overall loss reduction strategy for the following reasons:

- Electricity rates will continue to increase with increasing fuel prices, 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, leading to reliability concerns 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 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.

Determining the accurate amount of technical losses is important to a loss-reduction program for determining the best investments and progress on distribution transformers and keeping the digital system model up to date are important improvement measures.

In addition to the above, loss reduction measures could be implemented in the following two areas:

Secondary circuits and service wires

CUC should consider using the GPS data for a targeted feeder 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 in that it can use customer consumption data to more accurately estimate 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 much more complicated and is affected by:

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

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

Regularly update loss-cost basis

The loss cost-basis used to estimate lifetime cost of losses should take electricity rate 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 projects. When rates are fast increasing, using current rates will greatly under estimate the life-time savings of reduced losses over a 15-20 year period.

As new equipment is installed and old equipment replaced, the loss-cost basis should be re-evaluated. Results can also be used to re-evaluate other large projects priorities.

Once a new cost basis is established, it should be applied to new equipment purchases immediately, such as pad-mounted and pole-mounted transformers. This will help to bring in immediate results without additional costs.

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

The size of distribution transformers should be optimized. When the transformer sizes are reduced two levels (50% of the sum of kVA's of distribution transformers) from the existing level, close to $ 280,000 per year in core loss savings can be realized. As optimized sizes cannot be realized in a single year, a multi-year replacement program should be set up:

a. Develop the load profile for each transformer and keep it updated once a year (a load profile for each distribution transformer implies a meter per distribution transformer will be needed, unless all customer loads connected to this transformer can be computed).

b. Develop proper transformer sizes for each location.

c. Optimize transformers which can be optimized without capital cost investments; i.e., by moving them to appropriate locations.

d. 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 factors

Data provided to KEMA included installed capacitor banks and an overall system power factor 0.9. The power factor of feeder sections should be checked regularly (at least once a year) and actions taken to keep it above 0.9, preferably 0.95. The best location for corrective measures is at the loads, especially at induction 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 power factor of at least 0.85. If less the customer does not improve to the required level, CUC 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 or 34.5 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:

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 fixed 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.

The size of switched capacitors can 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. This should be evaluated on a feeder-by-feeder basis. Determining sizes of switched capacitors requires further study, and more detailed information.

Capacitors also affect the voltage profile along a feeder. When determining capacitor sizes, in particular for switched capacitor banks, voltages should be verified to ensure voltage limits are not violated.

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 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 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.

Feeder Voltage Control

During the power flow study, attention is also paid to the voltage drop through primary feeders. The CUC distribution system has a few feeder sections where low voltages were observed, either due to long feeder sections or large connected load. Shunt capacitors are connected at some of the load centers. However, low voltages were observed at peak load levels. One way to keep the voltage at the end of the feeder within 5% of the nominal voltage is to adjust the tap position of 34.5/13.8 kV transformers at the beginning of the13.8 kV feeders. Increased voltages at the beginning of the feeder cause more losses since they are close to power source where the majority of load current is flowing. For long feeder sections, shunt capacitor banks or voltage regulators are recommended at load centers to correct local voltage drops and avoid increasing generator terminal voltages. By doing this, reactive power is reduced through the system to the generator, reducing current flow, voltage drop, and power equipment capacity needs. Since line losses are a function related to the square of the current flowing through the feeder, feeder losses will be reduced when the currents flowing through the conductors are reduced.

8.2 Operational Recommendations

8.2.1 Generation

Develop written operational procedures and plans for economic dispatch and monitoring of the performance of the plants and of individual generation units.

For reviewing the performance of generating units, the current metering in the power plant does not provide good coordinated readings. It should be mentioned that in 2009 about 2,698 MWh of energy has to be allocated to station losses of the temporary power by Aggreko rental gensets. We recommend that a first step should be to install revenue class meters (energy, fuel and other supplies) to accurately measure the efficiency of each generator and to be able to dispatch them based upon efficiency considering other operating constraints. Focus on efficiency improvement (which requires training and implementation of processes for the operators) and real time display of engine efficiency helps the operators to run the engines in the most optimal way. Minimum display of real time information providing fuel use, lube oil usage, generator kWh production and auxiliary kWh usage should be made available. The objective of all this is to improve generator efficiency and reduce consumption in plant auxiliaries.

8.2.2 Metering

A procedure should be developed to test and calibrate meters before they are installed. Methodologies must be established to test sample meters (based upon statistical sampling) such that their accuracy can be assured during the lifetime of the meters.

Meters to measure the generator output, auxiliary services and feeder output must be of revenue class accuracy.

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.

These meters can be installed while using current transformers (CT's) mounted on the pole or on the pad mounted transformers. It is not necessary to install these meters on all distribution transformers. Areas which are experiencing more tampering, or where transformers seem to be over loaded or under loaded may benefit from these installations. If customers are equipped with new digital meters and can be linked in a database or in the CIS to the distribution transformers, it may not be necessary to install these meters at the distribution transformers.

8.2.3 Strategy for Reduction of Non-Technical Losses

Considering there are 11.74% of non-technical losses, there are potential savings in this category.

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 operations, 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.

CUC should consider the following:

- Develop a program for checking old meters.
- Train meter readers to identify tampering, by-passing, broken seals, hook ups.
- 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.
- 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. With limited resources, selecting accounts with highest revenue recovery potential and hit rates will be the most efficient use of limited resources.
- Make operations less predictable. CUC's own experience may 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 list, and so on. This will help to identify these fraudsters and increase the deterrent effect.
- Prevent repeated fraud activities. Once a fraud is found, measures should be implemented to ensure it will not occur again.
- 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 CUC's top management.
- Employ rights 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.

- Assign a senior staff member to be Revenue Assurance Officer, responsible for Loss Reduction Strategies, and who plans and initiates loss 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: Savings and Cost

	6 Yrs NPV of Savings and Costs		
NPV @ Cost of Capital	**Savings (NPV)**	**Cost (NPV)**	**Net (NPV)**
Auxiliary loss	$1,232,616	$1,000,000	$232,616
Non Technical Loss	$11,906,360	$9,412,326	$2,494,034
Technical Losses	$1,682,820	$1,254,994	$427,827
Total =	$14,821,796	$11,667,320	$3,154,476
1% efficiency improvement in generation saves $600,000 per year based on the price of crude oil of $75 per barrel. At a price of $100 per barrel a 1% efficiency improvement will translate to $800,000 per year in savings. This assumption can be influenced by fuel pricing, creditworthiness of customers, and transportation costs.			

A summary of assumptions and recommendations follow. (Details are provided in Section 8.1)

1. An inflation of 3% per year was assumed.

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 $9 million to $12 million over 6 years. Losses will be reduced (including power station losses) from 19.85% to 10%

5. Generation auxiliary losses are a small portion (3.75%) of overall losses. Meter readings in power plants are not revenue class and may be higher than calculated from the data provided. With process improvements and a $1 million investment, it will be possible to provide real-time data and efficiency calculations to operators who can then operate the power plant, at maximum efficiencies.

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 Non-Technical Losses

Account and highlight monthly financial losses (i.e. street lights, water and sewage including unaccounted energy). Develop a regular meter testing program. Add prepaid digital meters as part of smart metering for customers. Add 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.

Procure meter testing equipment and train on use. Make sure each customer is linked to the transformer and its meter in a software tool that issues tampering and transformer loading can be easily monitored. Install distribution transformer meters on pad-mounted transformers or poles using current transformers. It is not necessary to install meters on every distribution transformer. Areas experiencing excessive tampering and where loading profiles are known will be best locations. This can also be accomplished by CIS applications linking transformers to customer meters. For transformer load profiling, 50 to 100 temporary recording meters could be installed on the transformers and relocated as needed.

Add Revenue Protection measures with high visibility reporting to the CEO through the Revenue Assurance Officer, with a focus on metering and billing policies and goals, audits of meter reading practices, of meter reading data processing and billing processes, of irregularities detected by revenue intelligence software and/or in the field, metering installations, meter accuracy, meter constants, multiplier factors, and tampering.

After year 1, 10% of non-technical losses will be saved; after year 6 80%. Non-technical losses will be reduced from 32,236 MWh to 6,447 MWh in 6 years. Savings in 6 years are expected to be $ 16 million, resulting in a NPV of $10 million.

9.1.2 Reduction of Generation Auxiliary Losses

When generating units are operating, they need fans, radiators, pumps and other equipment for auxiliary services. Manual processes to operate these equipments depend on having good procedures, but these procedures need to be designed with a focus on saving energy. Improvement measures could include:

1. Adding displays to show efficiencies of every generating unit to operators (cost $200,000). Develop a process to measure the efficiency of each generator and develop management reporting on generation efficiency. Instrumentation should

present real-time and accumulated fuel usage per generator, generator output (kW, kVAr, kWh, power factor), auxiliary power usage (kWh) and real-time displays of every generating unit's efficiency keeping historical records for analysis and dispatching purposes.

2. 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.

3. Automate manual processes using PLC controls to motor starters and frequency drives ($800,000).

Benefits from these actions are expected to be $1.7 million over 6 years. Savings are produced by reducing auxiliary losses from 10,293 MWh (3.75%) to 8,234 MWh (3.35%) in 6 years. (See spreadsheet Savings Model tab in Appendix C.)

9.1.3 Reduction of Technical Losses

1. Power Factor Improvement

The power factor of CUC 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 factors at largest customers and require them to improve it over 85% or improve it for them and charge it to customers. This may require penalties or tariff changes if improvements are not realized.

c. Add capacitors to improve the power factor (Estimated Cost of $300,000 over 6 years)

d. Determine where capacitors can be placed in the feeders for improving the overall power factor close to 95%. Make sure that a monitoring plan is part of this.

2. Transformer Sizing

a. Distribution transformers are loaded to 35% of full capacity. Loss reduction savings can be achieved by optimizing the ratings over a number of years as new transformers are purchased

b. Determine proper sizes and specifications of distribution transformers to better match served loads. Determine standard sizes and relocate such that each transformer is 80% loaded at maximum demand.

c. Exchange or replace with right size transformers over a 6-year period. Transformers purchases should consider total life time cost. For example, cost of 1kW of core losses for 20 years of transformer life at 22 cents per kWh of fuel cost (based on $3 per gallon of fuel) is $23,161 (NPV). Copper losses would be $12,609. (See Transformer Evaluation example in Appendix C).

Cost of right sizing of transformers is estimated to be $1,000,000.

3. Reduce Line Losses

Acquire an infrared camera and train to use. (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 of energy by regularly identifying these maintenance issues and taking proactive corrective measures.

These recommendations will lead to an expected technical loss reduction during the first year of 5% and 25% after 6 years. Technical losses will drop from 11,978 MWh to 8,384 MWh in 6 years with an expected savings of $2.8 million, resulting in an NPV of $2 million.

Exhibit 9-2: Present Value calculations

Assumptions:				
Inflation	3%			
Cost of Capital	8.00%			
Cost/KWh	$0.36			
Cost and Savings list	**Savings (NPV)**	**Cost (NPV)**	**Net (NPV)**	**Cash over 6 years**
Non Technical Savings:				
Replacing all meters. Adding feeder and transformer meters to pin point losses - specially non technical and technical losses		$7,698,697		-$9,235,457
Revenue Protection Department - Focus to analyze, audit and pursue issues with metering, billing and tampering. Developing processes, using check meters at distribution transformers and software's to pin point losses in the system.		$1,713,629		-$2,219,891
80% Non Technical Loss reduction over 6 years	$11,906,360		$2,494,034	
Technical Loss Savings:				
Infrared camera and training		$100,000		-$100,000
Right sizing of distribution transformers		$861,153		-$1,040,000
Easy Power software, power factor improvement hardware installation and control.		$293,841		-$151,500
30% loss reduction over 6 years	$1,682,820		$427,827	
Auxiliary Losses				
SCADA for generators and process improvement		$1,000,000		-$1,000,000
20% loss reduction over 6 years	$1,232,616		$232,616	
Total =	$14,821,796	$11,667,320	$3,154,476	- $13,746,848

Other Recommendations:

1. Develop a maintenance management program and written operational processes to repair and maintain the transmission and distribution systems and provide related linemen training.

2. Perform regular oil sampling and testing of all the power transformers.

3. Develop a testing program (bench test) for revenue meters. The estimated cost of $300,000 is included in the non-technical metering upgrade plan.

A. Data Request

Data Request.doc
Inception Report.doc

B. Data Book

CUC Data Handbook.xls

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

Technical Loss Calculations and Financial Model.xls

Transformer Evaluation Example.xls

D. Other Data

CUC One Line Diagram.pdf