Pacific Power Association

PACIFIC POWER UTILITIES

Benchmarking Report

2012

PREPARED BY THE PACIFIC POWER ASSOCIATION (PPA) WITH THE TECHNICAL SUPPORT OF THE PACIFIC INFRASTRUCTURE ADVISORY CENTRE (PIAC)

MARCH 2013

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MARCH 2013

This is a publication of the Pacific Power Association (PPA).

The report was prepared by Derek Todd (International Benchmarking Specialist) with input from Abraham Simpson (Regional Benchmarking Specialist) with overall support from the Pacific Infrastructure Advisory Centre (PIAC) based in Sydney, Australia and the Pacific Power Association based in Suva, Fiji. The work was project managed by Maria Corazon Alejandrino-Yap (Senior Research Officer, PIAC), with guidance and direction from John Austin (Manager, PIAC) and Andrew Daka (Executive Director, PPA).

PIAC operates under the Pacific Region Infrastructure Facility (PRIF) a multi-partner infrastructure coordination and financing mechanism for the Pacific region. The partners are the Asian Development Bank (ADB), the Australian Agency for International Development (AusAID), the New Zealand Ministry for Foreign Affairs and Trade (NZMFAT), the World Bank Group (WBG), the European Commission (EC) and the European Investment Bank (EIB). Financial support came from technical assistance grant TA 6522 REG, Establishment of PIAC.

PREFACE

It is with much pleasure that we release the 2012 Benchmarking Report. This presents the results of the second consecutive annual assessment of Pacific electricity utility performance. In addition to comparing performance over the last two benchmarking periods for the participating utilities, the work in 2012 included the preparation of a comprehensive *Benchmarking Manual* and significant site assistance.

The Pacific Power Association (PPA) appreciates the support provided by the Pacific Region Infrastructure Facility (PRIF), through its technical arm, the Pacific Infrastructure Advisory Center (PIAC) who worked with us closely to bring this benchmarking project to a successful conclusion.

Benchmarking is a tool used by similar organisations to compare their performances over a defined period of time. This tool is also used by individual organisations to evaluate their performance and target particular sections of their operations for performance improvement. Benchmarking utilises data collected over time to determine performance in key areas.

The PPA's aim is that this *Benchmarking Report* is used by its Member Utilities to formulate performance improvement programs that would benefit their respective organisations.

The Benchmarking process has involved the consultants making follow up visits to those utilities that needed added support not just in the data collections but to also hold discussions with key utility staff on all aspects of benchmarking. This is a step-up from the earlier exercise. Furthermore, a revised version of the 2002 *Benchmarking Manual* was issued for use in conjunction with the data collection.

The Board of the PPA has recognised the important role that benchmarking plays in utility operations and has given its support for the continuation of this exercise. A one day Benchmarking workshop organised by the PPA and PIAC during PPA's 21st Annual Conference in Port Vila, Vanuatu, provided an opportunity for the utility technical staff that are new to benchmarking to get to know it.

However, with current funding arrangements not being confirmed for the next round, the PPA is looking at options for sustained funding for future benchmarking exercises. A number of options are being considered including Member Utilities contributing to the cost of the annual benchmarking. The online submission of annual data by Members is also considered to reduce the costs involved.

The PPA wishes to thank everyone that contributed to this project and the production of this very important document; the PIAC team and its consultants, Derek Todd and Abraham Simpson; and also members of the PPA Benchmarking steering committee and all the Active Members Management and Staff.

Joaquin Flores
CEO, Guam Power Authority
Chair, Pacific Power Association
Hagåtña, Guam

Image courtesy of Pauline Muscat (PIAC)

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The Pacific Power Association (PPA) provided overall coordination and acted as the link between the ADB consultants and the participating PPA member utilities. PIAC facilitated while the PPA arranged support for Steering Committee meetings held in Port Vila, Vanuatu in July 2012 and in Auckland, New Zealand in March 2013. The exercise would not have been possible without the PPA's and PIAC's input and strong support.

The 22 participating utilities complied with repeated requests for information and clarification, extending in several cases into early 2013. Their commitment to improvement of the datasets to support this and future benchmarking efforts is to be commended. CEOs and other utility staff made helpful comments on the benchmarking questionnaire during the PPA Conference benchmarking workshop in July 2012.

The American Public Power Association (APPA) helpfully updated their series of "Selected Financial and Operational Ratios" for use as comparative indicators of performance for smaller USA-based Pacific-sized public utilities.

The draft and final report benefited from comments provided by Maria Corazon Alejandrino-Yap, John Austin and Pauline Muscat of the PIAC; Andrew Daka of the PPA; Martina Tonizzo and Anthony Maxwell of the ADB; Tendai Gregan of the World Bank (WB), and Solomon Fifita of the Secretariat of the Pacific Community (SPC).

Image courtesy of Pauline Muscat (PIAC)

Table of Contents

Preface ... i
Acknowledgments ... iii
Table of Contents ... v
List of Figures ... vi
List of Tables ... vi
List of Boxes ... vi
Abbreviations ... vii
Notes ... viii

Executive Summary ... ix

1 Introduction ... 1
1.1 Key Results and Objectives ... 1
1.2 Background ... 2
1.3 Summary Benchmarking 2001 to 2011 ... 2
1.4 Addressing Previous Recommendations ... 5
1.5 Process Improvements ... 6
1.6 Related Work in the Water Sector ... 8
1.7 Regional Context and Overview ... 8
1.8 Participants and Their Characteristics ... 9
1.9 Data and Other Information Used ... 10

2 Data and Indicators ... 11
2.1 Formulation of the Questionnaire ... 11
2.2 Proposed Indicators and Their Selection ... 12

3 Data Reliability Assessment ... 15
3.1 Introduction ... 15
3.2 Data Reliability Self Assessment ... 16

4 Results ... 19
4.1 Introduction ... 19
4.2 Generation Indicators ... 20
4.3 Delivery System Losses ... 27
4.4 Other Distribution Indicators ... 30
4.5 Financial Indicators ... 33
4.6 Other General Indicators ... 38
4.7 An Overall Composite Indicator ... 42

5 Comparing Results with Last Year and Other Studies ... 45
5.1 Comparing the 2002, 2011 and 2012 Benchmarking Results ... 45
5.2 Comparing Pacific Indicators to those of Other Small Island Utilities ... 46

6 Discussion and Lessons Learned ... 49
6.1 Discussion of Results ... 49
6.2 Lessons Learned ... 53

7 Recommendations ... 55
7.1 Towards Sustainable Benchmarking in the Pacific ... 55
7.2 Other Recommendations ... 59

Appendix 1: Lessons from International Benchmarking Experience ... 65
Appendix 2: PPA Utility Members in 2012 ... 69
Appendix 3: Regional Economic and Demographic Characteristics ... 71
Appendix 4: Participating Utilities and Characteristics ... 73
Appendix 5: Summary of Information and Data Used in 2012 Benchmarking Report ... 81
Appendix 6: Summary of Data Gaps in Utility Submissions ... 83
Appendix 7: Key Reports and Documentation Reviewed ... 85
Appendix 8: Key Persons Consulted ... 87
Appendix 9: Summary of Results of July 2012 Benchmarking Workshop ... 89
Appendix 10: Benchmarking Questionnaire Section 1 (General Information) ... 95
Appendix 11: Benchmarking Questionnaire Section 2 (Data Spreadsheet, Data Reliability) ... 199
Appendix 12: Data Tables ... 111

List of Figures

Figure 3.1 Reliability Grades Assessment by Key Data Component 16
Figure 4.1 Load Factor in 2011 (%) 20
Figure 4.2 Capacity Factor in 2011 (%) 21
Figure 4.3 Availability Factor in 2011 (%) 22
Figure 4.4 Generation Labour Productivity in 2011 (GWh/generation employee) 23
Figure 4.5 Labour Productivity in 2011 by Utility Maximum Demand (GWh/generation employee) 23
Figure 4.6 Specific Fuel Consumption in 2011 (kWh/litre) 24
Figure 4.7 Lubricating Oil Consumption Efficiency in 2011 (kWh/litre) 25
Figure 4.8 Forced Outages Reported for 2011 (%) 25
Figure 4.9 Planned Outages in 2011 (%) 26
Figure 4.10 Generation O&M costs in 2011 (US$/MWh) 27
Figure 4.11 Distribution Losses as Reported by Utilities in 2011 (%) 28
Figure 4.12 Losses for 19 Pacific Utilities as Reported by KEMA (2009–2010 operations) 29
Figure 4.13 Station Energy Use for Pacific Utilities as Reported by KEMA (2009–2010 operations) 29
Figure 4.14 Customers per Distribution Employee in 2011 30
Figure 4.15 Switchboard at the PPUC 31
Figure 4.16 Distribution Transformer Utilisation in 2011 (%) 31
Figure 4.17 SAIDI Interruptions in 2011 (minutes per customer) 32
Figure 4.18 SAIFI Interruption Frequency in 2011 (interruptions for customer) 32
Figure 4.19 Reported Average Selling Price in 2011 (US$/MWh) 33
Figure 4.20 Utility Cost Breakdown (%) 34
Figure 4.21 Debt to Equity Ratio in 2011 (%) 35
Figure 4.22 Return on Total Operating Assets in 2011 (%) 36
Figure 4.23 Return on Equity in 2011 (%) 36
Figure 4.24 Current Ratio in 2011 (%) 37
Figure 4.25 Debtor Days in 2011 37
Figure 4.26 Lost Time Injury Duration Rate (days per full time employee) 38
Figure 4.27 Lost Time Injury Frequency Rate (number of incidents per million hours) 39
Figure 4.28 Renewable Energy Generation in 2011 for all Grids (%) 39
Figure 4.29 Nadarivatu Hydroelectric Project, Fiji 40
Figure 4.30 Overall Labour Productivity in 2011 (customers per utility employee) 41
Figure 4.31 Composite Technical Indicator for 2011 43
Figure 4.32 Diesel Tank and Power Plant at the Electric Power Corporation (EPC), Samoa 43
Figure A3.1 Map of the Area Served by the Pacific Power Association 71
Figure A4.1 New Solar Operations at Tonga Power Limited (TPL) 75

List of Tables

Table A Key Indicators Compared for 2000, 2010 and 2012 Data x
Table 1.1 Addressing the Previous Learning 6
Table 1.2 Key Characteristics of Participants 9
Table 2.1 Key Benchmark Indicators (2000 & 2010) 12
Table 2.2 Additional Indicators or Information Added in 2011 Benchmarking 13
Table 2.3 Additional Cost Categories Added in 2012 Benchmarking 14
Table 3.1 Key Data Component Reliability Assessment Questions 15
Table 3.2 Grading Schema 15
Table 3.3 Aggregate Data Reliability Grade (2011) 16
Table 4.1 Utility Participation 19
Table 4.2 Utility Demand Side Management Efforts in 2011 41
Table 5.1 Key Indicators Compared for 2000, 2010 and 2011 Benchmarking Data 45
Table 5.2 Key Indicators Compared for Pacific and Other Small Utilities 47
Table 7.1 Indicative Calendar for Benchmarking 58
Table 7.2 Revised Pacific Regional Benchmarking Indicators and Goals for CEOs Consideration 62
Table A3.1 Economies and Populations of Independent Pacific Island Countries 71
Table A3.2: Economies and Populations of Pacific Island Territories or Dependencies 72
Table A4.1: Participating Utilities in 2002, 2011 and 2012 73
Table A4.2: Basic Information on Participating Utilities in 2011 74
Table A4.3: Utility Electricity Sales in 2011 (GWh) 75
Table A4.4: Gross Generation by Source - for all grids - in 2011 (MWh) 76
Table A4.5 Utility Transmission and Distribution Voltages (kV) 76
Table A4.6a: Utility Structures, Ownership, Policies, Regulation and Coverage 77
Table A4.6b: Utility Structures, Ownership, Policies, Regulation and Coverage 79
Table A6.1: Summary of Data Gaps in Submissions 83
Table A11.1: Key Data Component Reliability Assessment Questions 106
Table A11.2: General Reliability Evaluation 106
Table A11.3: Reliability Grading Guidance 106
Table A12.1: Data from Questionnaire Section 2, Data Reliability Self-Assessment 109
Table A12.2: Data from Questionnaire Section 2 (Additional Financial Data) 110
Table A12.3: Data from Questionnaire Section 2 (Generation) 111
Table A12.4: Data from Questionnaire Section 2 (Transmission) 112
Table A12.5: Data from Questionnaire Section 2 (Distribution, DSM, HR and Safety) 113
Table A12.6: Data from Questionnaire Section 2 (Financial Information) 114
Table A12.7: KEMA System Loss Data 115
Table A12.8: Calculation of Indicative Composite Technical Indicator 116

List of Boxes

Box 4.1 Technical Composite Indicator and Data Reliability 44

Abbreviations

ADB	Asian Development Bank
ADO, IDO	Automotive Diesel Oil; Industrial Diesel Oil (light petroleum fuels)
AGM	Annual General Meeting
APPA	American Public Power Association (of which PPA is a member)
AusAID	Australian Agency for International Development
BMEP	Brake Mean Effective Pressure
CAIDI	Customer Average Interruption Duration Index
CARICOM	Caribbean Community
CARILEC	The Caribbean Electric Utility Services Corporation
CEO	Chief Executive Officer
CROP	Council of Regional Organisations of the Pacific
DEA	Data Envelop Analysis
DSM	Demand Side Management (improved energy efficiency for customers)
EC	European Commission
Eurelectric	European Electrical Utility Association
Feed-in tariff (FIT)	Terms and conditions for private producer to sell renewable energy to the grid, typically varies by type of technology, and typically under a long-term contract
FTE	Full Time Equivalent
FSM	Federated States of Micronesia
GDP	Gross Domestic Product
GNP	Gross National Product
GST	Goods and Services Tax
GW, MW, kW	Gigawatt, Megawatt, kilowatt; (1 GW = 1,000 MW = 1,000 kW)
GWh, MWh, kWh	Gigawatt hours; Megawatt hours; kilowatt hours; (1 GWh = 1,000 MWh = 1,000,000 KWh)
HFO/IFO	Heavy Fuel Oil; Industrial Fuel Oil (heavy petroleum fuels)
HV	High voltage
ICT	Information and Communications Technology
IPP	Independent Power Producer, usually private sector
KEMA	Dutch consulting firm (and PPA Allied Member)
kV	kilovolt (1,000 volts)
MOU	Memorandum of Understanding
MVA	Megavolt ampere
NESIS	Network of Experts of Small Island System Managers (European utilities)
Net metering	RE incentive, usually allowing consumers to sell renewable-based electricity net of consumption from the grid at agreed price and duration
NZMFAT	New Zealand Ministry of Foreign Affairs and Trade
O&M	Operations and Maintenance
PIAC	Pacific Infrastructure Advisory Center
PICTs	Pacific Island Countries and Territories
PIFS	Pacific Islands Forum Secretariat
PIP	Performance Improvement Plan
PIPIs	Pacific Infrastructure Performance Indicators (PIAC)
PNG	Papua New Guinea
PPA	Pacific Power Association; also Power Purchase Agreement
PRIF	Pacific Region Infrastructure Facility
PV	Photovoltaic
PWWA	Pacific Water and Wastes Association
RE	Renewable Energy
RMI	Republic of the Marshall Islands
RoE	Return on Equity
RORA	Rate of Return on Assets
SAIDI	System Average Interruption Duration Index
SAIFI	System Average Interruption Frequency Index
SFC	Specific Fuel Consumption
SHS	Solar Home Systems (low voltage, usually direct current, photovoltaic systems)
SOE	State Owned Enterprise
SOPAC	Applied Geosciences and Technology Division of the Secretariat of the Pacific Community
SPC	Secretariat of the Pacific Community
T&D	Transmission and Distribution
USA	United States of America
USDOI	United States Department of the Interior
VAT	Value Added Tax
WBG	World Bank Group

Notes

1. Costs for 2011 utility operations were converted to US dollars using the average exchange rate from Table A19 of *Asian Development Outlook 2012* (Asian Development Bank, 2012) except French Polynesia from Oanda.com for average 2011 value.

2. The graphs in this report use a **black broken line** to mark out ***average*** values and a **red broken line** to mark out ***median*** values. Colour-coded labels are also included beside the graphs. **Red arrows** indicate the direction of improved performance for a particular indicator. **Blue arrows** indicate the direction of the trend between 2010 and 2011. **Blue diamonds** indicate the 2010 results. An indication of utility scale is provided via colour coding of results using the PPA Membership criteria: **Yellow** indicates annual peak load of less than 5MW (small); **Orange** indicates annual peak load of 5MW of greater and less than 30MW (medium); **Red** indicates an annual peak load of 30MW or greater (large).

3. Photos used in the chapter breaks in this report have been generously provided by Derek Todd, Cori Alejandrino-Yap, Tendai Gregan and the World Bank. All other images have been credited as they appear in the report.

EXECUTIVE SUMMARY

Annual benchmarking is a mechanism for better information collection and decision making within power utilities, and assisting the improvement of operational efficiency, service delivery and overall performance.

During 2012, 22 Pacific Island power utilities participated in the second of a programme of annual performance benchmarking studies. This year's benchmarking employed the same indicators established by the 2011 study – itself the first benchmarking assessment to be carried out in more than a decade.

Comparisons of the most recent results (for 2011 utility operations) with those of the previous study (for 2010 utility operations) were made, including those for the set of expanded indicators agreed as the baseline. The analysis was further extended to include a self-assessment of data reliability and more information on utility cost structure. Where possible, comparisons with international benchmarking studies of small and island utilities were updated.

The scope of the work in 2012 specifically addressed previous recommendations directed at improving the quality of information and the usefulness of benchmarking to participants. These recommendations were recognised in the design of the questionnaire and indicator set, the conduct of a benchmarking workshop for attendants of the Pacific Power Association (PPA) Conference Engineers Workshop in Vanuatu in July 2012, an updated benchmarking manual, and provision of funding for utility visits to assist in data validation and the development of performance improvement plans.

Annual benchmarking efforts continue to be coordinated by the PPA with financial assistance from development partners through the Sydney-based Pacific Infrastructure Advisory Center (PIAC) under an agreement between the PPA, PIAC and the Secretariat of the Pacific Community (SPC), which coordinates Pacific regional energy matters. All PPA members were invited to participate, with one additional confirmed participant increasing the benchmark group to 22 utilities.

Project Background

The information used in this report was provided by the 22 participating utilities through a two-part questionnaire similar to that used in 2011; modified to reflect feedback by utilities during the PPA Conference in July 2012, and to include a data reliability assessment and additional utility cost information.

The questionnaires were distributed to utilities by email, completed by designated benchmarking liaison officers, submitted by the utilities to the consultants, reviewed for consistency, and in most cases, resubmitted after amendment. The consultants made efforts to verify the validity and consistency of the data through site visits in the data validation phase of the work, written requests for clarification of apparent errors, dialogue with the utilities, and where possible, comparisons with recent development agency or utility reports.

The initial data request was made in July 2012 prior to the PPA Conference and the majority of initial responses were received by September. Clarifications were received during October and November, with late receipts from two utilities in December. All data validation and assistance visits during late 2012 resulted in changes to the dataset for the utilities concerned. A final draft report was completed in January 2013, reviewed by a project Steering Committee, and finalised in April 2013. One utility found it impossible to respond by the final reporting date, but has collected data which will be included in the next round of benchmarking.

Key Findings and Observations

In 2011, the Chief Executive Officers (CEOs) agreed that the identity of utilities could be revealed for most performance indicators, with exceptions for certain financial information some utilities considered to be sensitive. Anonymity has been retained on the same basis for the 2012 study. Table A compares the results of the 2012 exercise with that of the previous period and the initial benchmarking work undertaken in 2002.

Table A: Key Indicators Compared for 2000, 2010 and 2011 Data

Key Indicators (of 2002 report, with additional indicators in 2010 and 2011 shown)		2000 Results		Goals (2002)	International Best Practice (2002 report)	2010 Results		2011 Results	
		Average	Median			Average	Median	Average	Median
Generation									
Load factor (%)	↑ better	67	66	50-80	50-80	64	65	67	68
Capacity factor (%)	↑ better	34	33	> 40	35-65	32	31	36	37
Availability factor (%)	↑ better	93	97	80-90	10-65	98	100	82	80
Specific fuel oil consumption (kWh/ litre)	↑ better	3.8	3.7	4	Over 4	3.8	3.8	3.8	3.8
Lube oil consumption (litres/hour)	↓ better	3.5	2.0	3.2 - 3.5	No standard	-	-	-	-
Lube oil consumption (kWh/litre)	↑ better	N/A	N/A	N/A	No standard	1300	970	1084	937
Forced outage factor (%)	↓ better	7.9	3.2	3-5	0	0.9	0.1	7.9	6.0
Planned outage factor (%)	↓ better	4.3	3.9	3	3	2	~0 (?)	3.9	1.8
O&M (US$ per MWh)	varies	58	14	18		148 (?)	71 (?)	222 (?)	200 (?)
Renewable energy to grid (%)	varies	N/A	N/A	N/A	No standard	22% main grid (?)		26% of all grids (?)	
Transmission									
Transmission losses (%)	↓ better	8	N/A	5	5	?		?	
Distribution									
Customers/employee	↑ better	242	224	240	350	334	297	258	249
Transformer utilisation (%)	↑ better	18	18	30	50	19	21	18	19
Distribution losses (%)	↓ better	12 (?)	N/A	5	5	12? (10 replies)		14	10.7
SAIFI (interruptions/cust.)	↓ better	19	8	10	0.9	8.2 (?)	3.8 (?)	10.1 (?)	5.9 (?)
SAIDI (mins/customer)	↓ better	592	33	200	47	530 (?)	139	1020	583 (?)
Distribution O&M ($/km)	varies	2,478 (?)	-	800	167	?		?	
Corporate / Financial									
Debt to equity ratio (%)	↓ better	26	N/A	< 50	< 50	15	17	36	24
Rate of return on assets (%)	↑ better	- 16.8	-	> 0	> 10	9.2 (?)	1 (?)	-16 (?)	2.7 (?)
Current ratio	↑ better	3.1	1.3	>1:1	1:1	2.9:1	1.8	1.54:1	1.02:1
Debtor days (days)	↓ better	79	51	< 50	30	115	57	63	61
Labour productivity (c/FTE)	↑ better	N/A	N/A	N/A	Not defined	85	74	71	60
TECHNICAL COMPOSITE	↑ better	NA	N/A	NA	Not defined	2.80	2.75	2.71	2.72
Comment		20 utilities				20 utilities		21 utilities	

Notes: 1. n.a. = not available. 2. (**?**) = questionable result. 3. See Table 3.1 for definitions of the indicators.

Summarised observations concerning data quality based on utility self-assessments and data validation are as follows:

Data Reliability 2011

- Low reliability grades were afforded to evaluation of customer outages and impacts, reflecting known limitations in systems and processes in most cases.
- High confidence with financial information sources is at odds with the consultant's experience of populating the questionnaires, but explainable.
- Benchmarking liaison officers appeared to find the grading methodology relatively straightforward, and serious consideration was given to the self-assessment.
- Generally, utilities that had the benefit of site discussions and assistance in data collection by a member of the benchmarking team, assessed data reliability at lower levels than those that did not. This suggests that despite the guidance notes, more experience of higher or comparative levels of performance is required to objectively grade data reliability.

Briefly, comparisons between utility operations for 2010 and 2011 are as follows:

Comparisons 2010 to 2011

- In generation operations, load factor and capacity factor have exhibited improvements via small increases in utilisation. There has been no decline in specific fuel consumption overall, although individual utility movements exhibit significant variance.
- Availability of generating plant has decreased significantly, almost entirely because of improved information capture that takes into account de-rating, forced and planned outages. Outage indicators suggest that maintenance planning and implementation may have declined. Lubricating oil consumption suggests the same.
- Transmission and distribution (T&D) losses in all categories appear consistent for both time periods, with large variations in non-technical losses within utilities. Reporting issues for the latter make it difficult to conclude that performance has improved or declined. Loss evaluation continues to be a priority improvement area.
- Distribution transformer utilisation is essentially unchanged and remains low, suggesting that utilities are not properly sizing transformers (when they are ordered) and perhaps not maintaining them well. Distribution productivity, as measured by customers per distribution employee, has reduced significantly.
- Indicators of interruptions to supply (SAIDI and SAIFI) were mostly estimated, not measured, although many utilities are implementing improvements to systems for subsequent period data capture. It is likely that reported results reflect improvement in the capture of outages, not significantly worsening performance.
- Other than average debtor days, all financial indicators have worsened. The variances in reporting ranges for many of these measures distort the average results. This combined with the lack of consistent standards in the region mean financial indicators should still be considered indicative.
- The significant reduction in total labour productivity is of concern, as this is a relatively reliable measure in terms of data inputs.
- Renewable energy fed into all grids totalled 26 per cent of generation (22 per cent fed into the main grid in 2010). 17 of the 22 utilities remain almost entirely dependent on petroleum in 2011, with fuel costs accounting for up to 78 per cent of the cost of electricity provision in one case.
- There was, again, very limited reporting of utility efforts to assist customers to reduce electricity use via demand side programmes.
- The preliminary composite indicator was re-assessed using the same methodology as 2011, since no further confidence could be ascribed to other financial indicators as a justification for their inclusion in a revised composite. The average composite rating decreased from 2.80 in 2010 to 2.71 in 2011, consistent with the trend in the constituent technical indicators.

At the time of submission of the final report, an update to the benchmarking dataset of the Caribbean Electric Utility Services Corporation (CARILEC) benchmarking dataset is pending and no updated analysis is available from the Network of Experts of Small Island System Managers (NESIS).

The America Public Power Association (APPA) supplied updated core indicators for their association of 188 small public power companies in September 2012.

Nonetheless, comparisons of the updated 2011 data against currently available data indicate:

Comparing Pacific Results to Other Small Utilities

- The unfavourable gap between the Pacific and CARILEC in terms of load and capacity factor increased in 2012. Correction in the methodology for availability factor has brought the Pacific indicator back into line with CARILEC for that measure.
- Overall system losses and technical losses (as calculated, not measured, by KEMA in both regions) are almost identical for the PPA and CARILEC utilities. Non-technical losses are significantly higher in the Pacific system. Losses for the European-linked island utilities (NESIS members) are lower than those of the Pacific and the Caribbean.
- The small American cooperative utilities (APPA) which do not undertake expansive generation activities had higher average distribution productivity (higher customers per distribution employee, and lower distribution O&M costs/km) in 2006 than the PPA members did in 2011).
- Reported SAIDI and SAIFI customer supply interruption indicators are roughly 25 per cent higher for PPA members than CARILEC members, although reporting accuracy remains questionable.
- Both the median and average rate of return on assets is lower than that of CARILEC. Outliers distort the Pacific results significantly.
- The average household and commercial tariffs in the Pacific are higher than those of the Caribbean, but this is probably more the result of the calculations being made in different reporting years (2010 and 2008 respectively) rather than indicating a real difference.
- Overall labour productivity, measured by customers per Full Time Equivalent (FTE) employee, was very low for the PPA members in 2011, and is even lower in 2012 – at an average of only 71 compared to 135 for CARILEC members and 125 for the smallest utilities (under 100 GWh per year of generation) of the NESIS group. This constitutes a serious challenge to utilities in the Pacific region.

Summary of Recommendations

In addition to identifying areas of concern, a number of recommendations are made for follow-up activities to establish benchmarking on a sustainable footing in the Pacific, develop benchmarking practice and improve associated information or processes. These are summarised below.

Towards Sustainable Benchmarking

- Establishment of a clear annual calendar for benchmarking activities. Annual update with detailed comparative reports alternating with summary reporting every other year.
- Revised capture worksheets including multi-year analysis and automatic indicator calculation for next capture in 2012/2013, with functional specification for web-based implementation prepared for implementation in 2014.
- Timing and location of sub-regional workshops and conference workshops to be planned and budgeted for next five years, with other training delivery mechanisms to be considered.
- The PPA to operate as lead agency for benchmarking services, supplementing resources as necessary, with detailed estimates of service provision costs to be compiled as a basis for striking PPA member contributions from 2013.

Broad areas of concern for Pacific power utilities are summarised below. In general, trends since 2010 in the majority of the indicators that informed these concerns are unfavourable. In some cases, the unfavourable trend is associated more with data quality improvement than actual degradation in performance.

More specific performance improvement recommendations are included in Performance Improvement Plans (PIPs) prepared in conjunction with specific utilities to address one or more aspects of benchmarked performance. These were separately prepared and presented.

Broad Areas of Concern

- Levels of overall labour productivity appear to have dropped further for the benchmark group in 2011. Improved capture of information on Full Time Equivalent (FTE) employment may have contributed to this outcome. The previously recommended utility specific reporting into factors underpinning poor productivity should be progressed for use by the PPA and other agencies.
- While loss data has not been improved significantly as a result of this benchmarking update, regional loss-reduction programmes based on cost-effective improvements should continue, including discussions with PRIF partners on grant and loan assistance for implementation.
- There is a general lack of appreciation for the asset management discipline from asset design to end of life management. This exhibits itself most clearly in lack of systematic maintenance. It is recommended that specific utility support is supplemented with case studies covering key aspects of utility asset management.
- The level of reporting of safety incidents and other non-conformances appears either low or non-existent amongst many utilities. It is recommended that Pacific utilities or PPA subscribe to the safety specific newsletters of other industry associations and further develop safety improvement strategy and associated programmes.
- Varying financial standards and accounting regimes, coupled with a lack of transparency in financial data, limit the value of financial benchmarking. It is recommended that utilities consider revealing all financial data to improve comparative and other forms of analysis. It is also recommended that PRIF partners provide direct specialist financial support for future benchmarking updates, reviewing the design and scope of all financial measures and information.
- Reliability performance data continues to be highly questionable with few utilities making significant efforts to analyse customer perceptions and views. It is recommended that a study of key reliability improvement opportunities specific to Pacific utilities be prepared.

A number of process and questionnaire changes may be incorporated into the next benchmarking cycle in 2013 without the need for extensive resources. These are summarised below:

Process and Information Improvements

- The definitions and formulas for all indicators should be reviewed for accuracy, clarity, and relevance as useful indicators of performance for Pacific power utilities.
- The 2012 questionnaire adopted the recommendations made in 2011 for T&D losses, and separated station use, but did not separate non-technical losses. This adjustment should be completed in 2013 with comprehensive definitions of all loss components presented and clarified.
- It still may be possible to develop a reporting system to indicate the size and loading of individual generator engines, in order to distinguish between those with higher or lower design efficiencies.
- Revision of the specific fuel consumption indicator of fuel efficiency to a weight-based measure to more accurately reflect the energy content of different fuels could be considered.
- Reporting of utility based demand side management (DSM) initiatives was very poor, although the questionnaire was not significantly further developed for this purpose. More descriptive material may assist in defining the scope of such initiatives.
- While ensuring valid aggregate reliability performance measures is the highest priority, the extension of reliability performance reporting to make the distinction between generation, T&D outage contributions to SAIDI and SAIFI should be considered for the next period. The introduction of consistent fault cause classification could also be considered, including an agreed treatment of extreme events for reporting purposes.
- The usefulness of the overall composite indicator of utility performance should be considered again by CEOs in light of its update this year. It is recommended that the technical indicator be retained in its current form, and supplemented with a financial indicator if the data is considered to be reliable enough in the next cycle to support it.
- The CEOs should consider whether the introduction of a data reliability assessment measure is valuable and will contribute to enhancing data reliability, or whether it should be dropped for subsequent cycles.
- The regional goals for individual indicators were decided by the utility CEOs a decade ago. The trends in indicators in 2012 must provide some pause for thought before more ambitious targets are selected. Most could be considered stretch goals, but remain appropriate to the combined circumstances of Pacific utilities.
- In practice, there are major variances amongst utility performances, and the more significant targets are those selected by individual utilities as part of specific performance improvement plans. It is recommended that other general indicators be retained for 2013 and reviewed at the conclusion of the next cycle.

- The new *Manual of Performance Benchmarking for Pacific Power Utilities* was well received and will be useful for future benchmarking exercises. The benchmarking process material would benefit from update within the next few years.
- It is recommended that visits be made to at least some utilities to assist in the collection and initial analysis of data in the next cycle, possibly those that did not receive the benefit of visits by members of the consulting team in 2012.
- The consolidated summary worksheet developed this year will allow easier comparison of trends over time and comparisons among utilities. This will be managed and held in the PPA Office.

1 INTRODUCTION & BACKGROUND

1.1 Key Results and Objectives

The overarching goal of this benchmarking initiative is to help power utilities improve their performance and contribute to enhanced service delivery in the power sector. It is expected that continued benchmarking will result in:

Key Expectations

- Increased efficiency and improved performance of participating power utilities.
- Improved information followed by improved decision-making within power utilities.
- A better understanding of performance gaps in power generation, transmission and distribution across the Pacific.
- Enhanced capability and commitment of power utilities to gather and report information and to support a sustained system of performance benchmarking over time.[1]

At the conclusion of this project, which includes provisions for working with selected utilities to assist them develop and implement benchmarking performance improvement plans (PIPs[2]), the objective is to ensure:

Key Objectives

- The preparation of an updated *Benchmarking Manual*.[3]
- An updated summary and comparison of the benchmarking results, including trends between the previous benchmarking exercises and the recent results of similar island utilities and small utilities elsewhere.
- The identification of concerning measures and related recommendations, including information that assists the Government and development partners to direct and justify investment.
- Improved capacity of utilities to understand and obtain data on their operational performance.
- Further support and encouragement for Pacific utility accountability and progression.
- A realistic strategy to ensure sustainable benchmarking for power utilities in the region.

[1] From the Terms of Reference (TOR), Team Leader, 20th July 2012.
[2] PIPs for selected utilities will be prepared separately and are not included in this report.
[3] Pacific Power Association (PPA) and Pacific Region Infrastructure Facility (PRIF), *Power Benchmarking Manual* (September 2012).

The work also includes provisions to contribute to the Pacific energy sector database being developed by the Secretariat of the Pacific Community (SPC), and the Pacific Infrastructure Performance Indicators (PIPIs) for energy being developed by the Pacific Infrastructure Advisory Centre (PIAC).[4]

1.2 Background

Recent studies in the Pacific region have identified the poor quality of national and regional energy sector data as a constraint on the effective analyses of issues, limiting opportunities for improved decision-making and future performance improvement. This is true for the energy sector broadly and for the electric power sector in particular. There is limited reliable, consistent, up-to-date information on the technical and economic performance of the region's power utilities, and time-series data is lacking. This constrains attempts to prioritise and implement improvements.

In August 2010, the PPA, SPC, and PIAC signed a Memorandum of Understanding (MOU) to establish a sustainable benchmarking system for the power utilities of the Pacific Island Countries and Territories (PICTs). Within the Council of Regional Organisations of the Pacific (CROP), the PPA is the lead CROP agency responsible for electric power assistance activities, with 25 member utilities among the PICTs. The SPC signed the MOU as the lead CROP coordinating agency for energy and PIAC acted on behalf of the Pacific Regional Infrastructure Facility (PRIF).

This benchmarking initiative is linked to the Framework for Action on Energy Security in the Pacific – a policy and strategy for energy sector action at the regional level. Endorsed by regional leaders in 2010, it recognised the development of improved energy data as a high priority at both the national and regional level. Accordingly, data collected for this year’s and the previous 2011 benchmarking exercise was designed in part to provide selected power sector data for the SPC's initiatives to improve energy planning and policy formulation.

In total, 21 utilities participated in the 2011 benchmarking project. Performance comparisons established through benchmarking data over the decade to 2011 showed mixed results. However, it did serve to establish a baseline and identify the broad areas where performance improvement efforts should be focused. The key recommendations recognise that effort was required to improve: (i) the quality of benchmarking information, and (ii) how it was used to effect positive change. The 2012 benchmarking project was formulated to address these recommendations.

Similar to 2011, PRIF partners provided an oversight function to guide and monitor project implementation. The Project Steering Committee was chaired by the PIAC and comprised representatives from the SPC, PPA, PRIF partner agencies and CEOs of three PPA member power utilities. All 25 PPA member utilities (listed in Appendix 2) were eligible for participation in the benchmarking exercise.[5] In 2012, 23 utilities confirmed their participation, and 21 ultimately submitted data in satisfaction or partial satisfaction of the initial data request.

1.3 Summary of Benchmarking 2001 to 2011

(i) Pacific Power Benchmarking 2001

In 2001, the PPA and ADB carried out a benchmarking exercise based on 2000 data involving 13 PPA member utilities. This was intended to be the first of an annual series but no further benchmarking exercises were carried out. Several utilities reportedly continued to use the template developed in 2001 (later revised in 2003) for internal use.

The 2001 Pacific benchmarking survey used a series of indicators that were developed during a workshop with a number of PPA member CEOs, ADB staff and consultants. The bulk of the Pacific utilities were unfamiliar with the concept of benchmarking so the indicators chosen were basic, used data that most utilities could provide, were relatively easy to use, and suitable for future exercises with minimal modification. It was also agreed that the utilities would work toward a set of agreed goals for future benchmarking but that comparisons with ‘global’ standards were inappropriate.

Instead, there was an agreed ‘Pacific standard’: a “benchmark reference value for future planning and performance review.” It was understood that indicators might be added for future use as utilities became familiar with the concepts and more data was routinely collected. The template used in 2001, an Excel spreadsheet, was revised in 2003 to address

[4] These are covered and reported on elsewhere.
[5] Although only countries eligible for PRIF assistance can receive follow-up support

issues encountered during its earlier use. Amendments were made to clarify some concepts but the indicators themselves remained unchanged.

(ii) Pacific Benchmarking Stocktake 2010

A stocktake of lessons from infrastructure benchmarking in the Pacific was undertaken by PIAC in 2010. The PIAC stocktake identified the following likely difficulties, barriers and challenges:

Benchmarking Challenges

- **Data collection** is the paramount challenge and requires diligence and commitment from all participating utilities. Utilities may not be willing to put in the effort required if others are not involved in sufficient numbers.
- **Limitations** in the **availability and reliability of data** or considerable variation between utilities.
- Difficulties in agreeing on a **common set of performance indicators** and their definitions.
- Power benchmarking results are not entirely made public which does not help create the incentives for **improved efficiency expected** from such a program. **Confidentiality** caused an added capacity burden for utilities as consultants or donors must contact them directly for data each time a review is undertaken.
- Comparisons between utilities being influenced by the **different operating environment** that each one faces.
- **Variations** in the usefulness of an indicator to different utilities and also the likelihood of it being monitored.
- **Lack of appropriate incentives and accountability** for the various utilities to collect and report reliable performance data on a regular basis.
- **The cost of resources,** primarily in the form of staff time, is often considerable.
- There is a '**free-rider**' problem under which utilities may perceive that the benefits of benchmarking will be available to them even if they do not participate.

The stocktake also listed a number of requirements or characteristics of successful benchmarking:

Successful Benchmarking

- Benchmarking is a **long-term process** that requires much more than awareness raising and short-term assistance to build and sustain momentum. Therefore, to be effective as a management tool to monitor performance improvements through time, it should be undertaken long-term rather than as a discrete project leading to one-off results.
- Developing effective and sustainable benchmarking practices requires a **common commitment** to overcome constraints/barriers.
- Benchmarking needs to be **standardised** across sectors and as far as possible between sectors.
- Benchmarking makes little sense to a utility working in isolation; it is almost by definition a regional exercise requiring strong **regional leadership**.
- Benchmarking is useful only as one of the tools of an **overall improvement strategy**.
- It is of utmost importance that the collected data is **comparable**. Common definitions of data items, common data sources and measurement techniques are therefore critical.
- A benchmarking study can take many years to achieve a reasonable level of comparability, but **full comparability is not necessary** before significant benefits can be achieved.
- Successful benchmarking relies on a **culture** (and related systems) supportive of change and openness. It is essential that those undertaking analysis have full access to data and people across the organisation.
- **Top management support** is therefore necessary.
- The approach to analysis should be **action and value-oriented**. Work should be focused on issues which form a large proportion of the value chain.

The 'stocktake' paper also outlined a process for successful benchmarking. The following elements received particular emphasis:

Elements of Benchmarking Process

- A benchmarking project is never finished until **action plans** have been set in place and implemented to start using best practices and processes.

- While concise questionnaires are important in collecting data, they should be followed up with **face-to-face interviews** with the relevant managers where appropriate, and with **site visits** to see other participants, particularly those that are suspected to be good performers. More can often be achieved by visual observation than by detailed analysis.

(iii) Pacific Power Benchmarking 2011

The 2011 benchmarking exercise adopted the same basic indicators presented in the 2002 work, partly because the utilities had some familiarity with the approach but also to allow some longitudinal comparisons to be made (i.e. 2002 vs. 2010 performance). Additional indicators were added to include information about grid-connected renewable energy, utility energy efficiency efforts, electricity supply to grids from independent suppliers, and regulatory arrangements among others.

21 utilities, varying substantially in size, staffing, resources, customer base and geographical coverage, participated in the benchmarking project. The effort was coordinated by the PPA as Implementing Agency and managed and financed by the PIAC under an MOU between the PPA, PIAC and SPC, which coordinates Pacific regional matters.

The 2011 benchmarking was conceived as a baseline for a series of future benchmarking efforts to be carried out annually, as a mechanism to improve the pool of information available about the regions' utilities, and as a tool to assist utilities in the improvement of their technical and financial performance.

The performance comparison between 2000 and 2010 for Pacific utility participants revealed:

Performance Comparison Key Findings

- Indicators of generation performance were similar for both periods, suggesting no substantial improvement or decline in load factor, capacity factor or specific fuel consumption. Availability of generating plants improved slightly. Maintenance planning and its implementation may have worsened.
- Transmission and distribution losses reported by utilities were about the same for both periods. Because of issues in the reporting of system losses, it was difficult to conclude that performance had improved or declined, but results suggested that reporting of losses needed improvement.
- Distribution transformer utilisation is essentially unchanged since 2000, remaining very low, suggesting that utilities were not properly sizing transformers and perhaps not maintaining them well. Distribution productivity reported by utilities, measured by customers per distribution employee, had improved considerably.
- Indicators of interruptions to supply were probably estimated, not measured, for most utilities during both reporting periods. It was unclear whether performance has improved.
- Financial indicators were only indicative for both periods. Nonetheless, rates of return on assets, current ratios and debt/equity ratios all appeared to have improved. Timely collection of debt (debtor days) has worsened.

Of the performance measures newly introduced in 2011:

Assessment of New Measures in 2011

- Renewable energy contributions were overwhelmingly hydro-power, although 16 of the 21 participants remained almost totally petroleum dependent.
- Few end use energy efficiency initiatives were identified or reported on.
- The initial composite indicator of utility performance was considered indicative only, given data reliability limitations and that it was a first attempt at formulating such a measure.

Comparisons of the benchmark indicators shared by other island regions also revealed:

Regional Comparisons

- Load factors and capacity factors are considerably better for the Caribbean island utilities but the Pacific reported better reserve plant margins and generating equipment availability factors.

- Overall system losses and technical losses are almost identical for the Pacific and Caribbean utilities. However, non-technical losses (such as theft or bad metering) are significantly higher in the Pacific. System losses for the Network of Experts of Small Island System managers (NESIS) group of island utilities, part of the European utility association Eurelectric, are lower than those of the Pacific or the Caribbean.
- The average household tariff in the Pacific is roughly the same as the Caribbean considering the different reporting years. Commercial tariffs, however, seem to be somewhat higher in the Pacific.
- The small American cooperative utilities which usually purchase and then distribute power had the same average distribution productivity (customers per distribution employee) in 2006 as the PPA members did in 2010.
- Reported customer supply interruption indicators were similar for the Pacific and Caribbean but in both regions, reporting accuracy was questionable.
- Overall labour productivity, measured by customers per full-time equivalent (FTE) employee, is very low for the Pacific utilities: only 85 compared to 135 for the Caribbean and 125 for the smallest European island utilities. Low productivity suggests that Pacific utility staff generally require skill upgrading and could possibly benefit from more remote monitoring of isolated systems, which has become more cost-effective in recent years with improved communication and control systems.
- The rate of return on assets was higher for the Pacific than the Caribbean utilities but the very low median Pacific value suggests that Pacific results are not necessarily better.

1.4 Addressing Previous Recommendations

The 2011 benchmarking report made recommendations in three key areas for follow-up activities, the first area related to responses to measured performance; the second and third related to improvements in benchmarking. These are briefly described below. More detailed responses to proposed benchmarking process improvements are set out in Table 1.1 in Section 1.5.

(i) Broad Areas of Concern

> ***"Broad areas for improving Pacific power utility performance were identified as improving low labour productivity, reducing high non-technical losses, improving low levels of maintenance, improving outage indicators, improving knowledge of customer perceptions, and improving the effectiveness of life-line tariffs."***[6]

The 2011 report acknowledged that it is difficult to make specific recommendations for improvement to utilities without the level of practical understanding of utility operations, constraints and issues that comes with field visits and more extensive discussion. Nevertheless, of the broad areas of concern the following are noteworthy:

Broad areas of concern

- Low labour productivity is a fertile area for further analysis and consideration, including comparisons with other enterprises in the Pacific.
- System losses have now been the subject of a Pacific wide study and quantification that provides a good basis for improvement planning.[7]
- Knowledge of outages and their impact quantification is an important and well understood performance assessment area at the core of power delivery services. Investigating customer perceptions may be progressed via relatively inexpensive survey techniques.
- Infrastructure maintenance and life cycle asset management issues have been recognised across the Pacific and technical assistance procured by the ADB/PIAC to allow more comprehensive assessment.[8]

(ii) Improving the Quality of Information

> ***"Improving the quality of information in future benchmarking through more rigorous and better-defined performance indicators; improvement in the overall questionnaire; providing practical benchmarking training to utility staff; developing a new manual of performance benchmarking; and assisting utilities collect and analyse data for benchmarking".***

[6] Pacific Power Association (PPA) and Pacific Region Infrastructure Facility (PRIF), *Performance Benchmarking for Pacific Power Utilities* (2011), p.xx.
[7] KEMA, "Quantification of the Power System Energy Losses in Southern Pacific Utilities" (Pacific Power Association, 2011).
[8] CRMS Reference TA6522, "Infrastructure Maintenance Fellow" Consultant Recruitment, 42499-012 (7th August).

These recommendations were recognised in:

- The design of the questionnaire and indicator set for 2012;
- The conduct of a benchmarking workshop for attendants of the PPA Conference Engineers Workshop in Vanuatu in July 2012;
- Update of the benchmarking manual; and
- The provision of funding for limited utility visits to assist in data collection and validation.

(iii) Improving the Usefulness of Benchmarking

> ***"Improving the usefulness of benchmarking to utilities through practical training in benchmarking as an ongoing management tool for decision-making, use of Pacific utility staff for mentoring other utilities, consideration of performance-based employee contracts, and assistance to selected utilities for benchmarking performance improvement plans".***

The relevance of benchmarking to performance management and ongoing improvement was recognised in the design of the benchmarking workshop in July 2012, and funding provisions were made for assisting a number of utilities develop performance improvement plans during the 2012 Technical Assistance (TA) preparation. Although no mentoring activities were undertaken, performance based contracts are in use and under development within some Pacific utilities.

1.5 Process Improvements

A number of lessons for benchmarking in the Pacific were learnt during the course of the 2011 power benchmarking work. The key lessons and their treatment in this work are illustrated below in Table 1.1.

Table 1.1: Addressing the Previous Learning

Lessons Learned in 2011	Addressed in 2012 by:
In at least some utilities, CEOs apparently did not discuss the exercise and its priority with those given responsibility for data collection and reporting, and some staff did not put in sufficient time and effort to provide the most accurate available information. **This reduced the value of the resulting reports to utilities. Benchmarking success requires visible support and continuous leadership of the CEOs and allocation of adequate staff time and skills to obtain and report the data.**	▪ Obtaining to the greatest extent possible; shared and demonstrated support for the 2012 work by CEOs, (requiring commitments and demonstration during the PPA Conference management meetings and workshop sessions).
Although the 2011 questionnaire contained far more text to define and explain indicators than the earlier 2002 questionnaire, it nonetheless proved to be insufficient. More clarity is needed, supported by a benchmarking manual with calculations of practical examples.	▪ Revision of the questionnaire to include clarity and include expansion of indicator explanations. ▪ Updating and publication of the *Benchmarking Manual*.
Data collection is a key challenge, perhaps even more than those involved in this exercise realised at the outset, and requires diligence and commitment from all participating utilities. Lack of incentives and accountability for collecting and regularly reporting reliable performance data seems to be a contributing issue.	▪ Clear establishment of roles and early appointment of liaison officers. ▪ Introduction of a data reliability assessment tool to transparently quantify data reliability and incentivise improvement. ▪ Provisions for site visits to selected utilities to maintain momentum and provide essential assistance and training.

Lessons Learned in 2011	Addressed in 2012 by:
Benchmarking generally has both short-term objectives for the organisations undertaking it (improved delivery of selected services or operational processes) and medium-term objectives (institutionalised process of change, better capacity of staff to initiate change). **However, in the Pacific, it seems to be seen by senior staff of many utilities as primarily a mechanism for comparing their performance with regional peers, rather than a management tool for use within the utility. This reduces the value of benchmarking as a source of information for internal utility decision-making.**	▪ Including performance management elements in workshop training sessions, to sensitise staff use of benchmarking for improved decision making.
Training of utility staff to introduce – or reintroduce – benchmarking concepts and mechanisms would have been appropriate to improve the capacity of staff to provide appropriate data and improve the quality of results. **The lack of practical training exacerbated the difficulty in obtaining good data and resulted in more time being required to complete the work. Training would have made utility staff more aware of the use of benchmarking for improving utility performance.**	▪ Undertaking benchmarking workshop sessions during the PPA conference. ▪ Providing for site visits to selected utilities to maintain momentum and provide essential assistance and training.
'Reporting fatigue' – as consultants and the PPA request corrections to questionable data – can lead to inaccurate data, rendering the benchmarking system of limited practical use. Some utilities may have been burdened with unrealistic reporting requirements.	▪ Provisions for site visits to selected utilities to maintain momentum and provide essential assistance and training. ▪ Recognise and deal with problem areas early and realistically, considering data reliability assessment.
Data sources should be reliable and, ideally, cross-checked. In 2011, there were limited recent reports available for cross-checking.	▪ Use and source all recently completed authoritative reports, including Pacific wide loss studies, now complete.
For useful results, the cost of utility resources, primarily in the form of staff time, can be considerable, and this was probably underestimated during project design.	▪ Internal resources supplemented via selected utility visits. ▪ Establishing more convenient and sustainable model for update.
Visits to the utilities to assist staff locate data, assess its' accuracy, and perhaps collect some additional information, would have improved the reliability of results, although it would of course have added considerably to costs.	▪ Provisions for site visits to selected utilities to maintain momentum and provide essential assistance and training.
Although there were a series of discussions with utility staff during the PPA's Annual General Meeting (AGM) on preliminary results (the July draft report), there was no opportunity during a presentation to CEOs to get substantive feedback from them. More feedback may have improved the final reporting.	▪ Seeking feedback during the PPA conference and benchmarking workshop ▪ Including circulation of early draft results to encourage feedback and confirm utility contributions.
In the past there has been some sensitivity among some utilities regarding the public release of data or indicators that are considered sensitive. For the 2011 exercise, most indicators identify each utility. Experience elsewhere suggests that this is likely to improve the impact of benchmarking on utility service over time.	▪ Contributing to the SPC regional consultation on data sharing models, sensitive date handling and confidentiality. ▪ Rigorously complying with the agreed disclosure policy under the MOU to build confidence.

Additional general information relating to the experience of benchmarking elsewhere in the world can be found in Appendix 1.

1.6 Related Work

The Pacific Water and Waste Association (PWWA) also undertook a benchmarking exercise in 2011. Established and resourced in a similar way to the 2011 power benchmarking project, it generated a useful set of base data for the Pacific water sector across a range of performance indicators relevant to urban water businesses.

The study identified some issues in common with power delivery, for example, maintenance deficiencies and inadequate customer consultation on levels of service.

It was noted that the methodology for data reliability assessment used in the 2011 PWWA work was particularly suitable for use during the early stages of benchmarking programme development. It was subsequently modified for use in the assessment of power sector data in 2012. This is discussed in detail in Section 3.

Since the programmes for the Pacific water and power sector benchmarking TA consultancy assignments were contiguous in late 2012, the respective consulting teams assisted each other to the extent possible during site visits for data validation and follow-up. Several of the utilities involved manage both water and power services.

1.7 Regional Context and Overview

The PICTs have an estimated 2011 population of 10.0 million people living on 553,519 km^2 of land.[9] One country, Papua New Guinea (PNG), dominates, with over two-thirds of the population and occupying nearly 84 per cent of the land area. The geography of the region and the individual utility service areas poses extreme challenges for the delivery of affordable electricity of reasonable quality. There is a wide variation in populations, land areas, per capita Gross National Product (GNP), Gross Domestic Product (GDP), and recent economic growth rates per capita.

Recent per capita GNPs and GDPs in PICTs have averaged roughly US$3,000 and US$4,607 respectively. While global economic prospects remain weak, the Pacific economies have the advantage of being insulated from global market instability such as that arising from developments in the Eurozone. Expansion of the resource exporting economies of PNG (which accounts for approximately 60 per cent of Pacific GDP), Timor-Leste and the Solomon Islands; and strong growth in tourism In the Cook Islands, Fiji, Palau, and Vanuatu, lifted sub-regional growth to seven per cent in 2011. Yet, overall Pacific GDP growth is:

> "forecast to slow to 6.0 per cent and 4.1 per cent over the next 2 years due to lower resource export revenue, the winding down of infrastructure projects that stimulated growth in 2011 (Papua New Guinea, the Marshall Islands, and Vanuatu), lower international agricultural prices, and flooding impacts (Fiji)".[10]

As noted in 2011, it remains the case that "with slow economic growth in many PICs, governments may be reluctant to adjust power tariffs sufficiently to meet the actual cost of supply, and many already charge less than full cost".[11] All PICTs are highly vulnerable to the effects of high-cost petroleum fuels and fuel dominates the operating costs of most of the region's utilities.

PICT and Caribbean island utility benchmarking indicators are compared later in this report. When comparing PICT utilities with those in the Caribbean, it should be noted that average per capita GDP in the Caribbean region is about 4 times that of the PICs, suggesting that more resources are likely to be available to the Caribbean utilities for overall operations and maintenance (O&M).

Appendix 3 summarises the economic and demographic characteristics of the countries and territories in which the utilities that participated in this exercise operate.

[9] Secretariat of the Pacific Community (SPC), *Pacific Regional Information System*. http://www.spc.int/prism/.
[10] Asian Development Bank (ADB), *Asian Development Outlook – Highlights* (2012).
[11] PPA and PRIF, *Performance Benchmarking for Pacific Power Utilities*, p.9.

1.8 Participants and their Characteristics

All 25 PPA member utilities (listed in Appendix 2) were eligible for participation in the benchmarking exercise (although only countries eligible for PRIF assistance can receive follow-up support). Of the PPA's 25 member utilities, 22 participated in this update. Of these, 21 provided sufficient data to allow the calculation of a reasonable number of key performance indicators.[12]

Appendix 4 lists the participating utilities and illustrates their characteristics in a series of tables, summarised below for the utilities that submitted information.

Table 1.2: Key Characteristics of Participants

Ownership	19 of the 22 utilities that participated in the 2012 benchmarking exercise were 100 per cent government owned in 2011.
Scale	The utilities vary widely in terms of installed capacity (2 to over 550 MW), gross generation (3–1059 GWh), maximum demand (0.3–84.8 MW), customer base (about 900-155,000) and employees (20–1500).
Utility services	Seven of the 22 utilities that responded provided non-electricity services such as water supply, sewerage, and waste management and/or fuel sales. In some cases, some costs of these services are charged to electricity operations, or not adequately accounted for. This can lead to reported costs (and losses) that should be charged to the water, waste or sewerage operations. Utilities should better allocate costs among services to accurately reflect the actual costs of the services and clearly show subsidies or cross-subsidies where these exist.
Off-grid supply	Over half of the utilities have some responsibility for off-grid supply away from a main grid, usually stand-alone rural low-voltage DC photovoltaic systems but in some cases small diesel or hydro mini-grid systems. These remote systems often require considerable time and resources, without sufficient compensation to fully cover utility costs. For some utilities, governments have established artificially low users' fees for off-grid supply, imposing additional costs on the utility or resulting in poor operations and maintenance of the systems.
Boards	In general the government appoints most or all members of the utility board of directors but two of the utilities have no formal board.
Legislation	All but two utilities operate under formal power sector legislation (although some legislation is quite out-dated).
Regulation	Most of the utilities have no formal system of external regulation (technical or commercial) but commercial regulation exists (e.g. Fiji, PNG, and Vanuatu) or is under development or consideration in several PICTs (e.g. Samoa, Tonga). External regulators in other regions of the world often encourage or require a regular performance benchmarking programme. Most Pacific utilities are the only organisations in the country with technical knowledge of the power sector and are self-regulating technically, but with strong government influence on the level of tariffs.
Service obligations	Most utilities have no formal public service obligation.
Quality standards	Many utilities have some form of regulation of power standards (voltage fluctuations and/or frequency) but not all are enforced.
Private supply regulations	Only three of the 22 utilities have formal regulations for Independent Power Producers (IPPs) and utility Power Purchase Agreements (PPAs) with IPPs (with others under consideration), so some proposed IPP arrangements can be ad hoc and may be difficult to negotiate, limiting the potential for cost-effective independent supply.
Net metering or feed-in tariffs	Only six of the 21 utilities that responded have either net metering regulations or feed-in tariffs so it can be difficult for consumers or small businesses to legally provide power to the grid with clear rules, from renewable (or other) energy systems, such as household PV systems being installed or considered in some PICTs (and increasingly common outside of the Pacific).
Renewable energy goals	Most of the governments have established specific national goals and timetables for electrification through renewable energy. These tend to be very ambitious and many have been developed with little substantive utility input or serious consideration of practicality. They tend to be statements of broad intent.

[12] The NPC did not provide information by the reporting deadline, but are undertaking data collection for the period. The results will be incorporated in the next round of benchmarking.

Tariff determination	About half of the electricity tariffs are ostensibly established by the board of directors or external independent commissions. In practice, the governments have a very strong influence on – or in some cases effectively decide – tariff levels.
Charges to Consumers (tariffs)	It can be difficult to compare costs of supply on a consistent basis as some of the utilities pay import duty or tax on fuel and/or equipment, but others do not. Similarly, published tariff schedules do not always clearly indicate all charges to consumers. Some add government taxes and a range of other charges (e.g. insurance) to the bill, but others include these in the tariff schedule. Some tariffs indicate only a 'base charge' with additional fuel surcharges that often change frequently and can be difficult for consumers to understand or challenge.
Service coverage	The systems range from a single distribution voltage grid covering customers on only a single island to those covering many islands and dispersed rural communities with several main grids, a number of smaller isolated grids, and stand-alone systems. A few have national coverage but others (e.g. in the Federated States of Micronesia (FSM)) only cover specific states.

1.9 Data and Other Information Used

Supporting information within this report has been included in the Appendices.

The consolidated spreadsheet that summarises the data and data sources used to prepare this report is referenced in Appendix 5. The key data are those from the returned questionnaires. The associated data gaps are summarised in Appendix 6. In addition, a number of general reports on benchmarking were reviewed, as well as similar reports prepared for other small utilities or island utilities elsewhere in the world. These, and other materials used in this report, are listed in Appendix 7.

Appendix 8 lists key persons consulted during the study. Appendix 9 provides a brief summary of a benchmarking workshop for utility staff held in July 2012 in conjunction with the PPA's Annual Conference. Some information is extracted from Appendix 9 for the recommendations of this report.

Except where noted, the information used in this report was provided by the participating utilities through a questionnaire[13] (Appendix 10 and Appendix 11) prepared by the consultants, reviewed and subsequently modified and distributed to utilities by email. The questionnaires were completed by designated benchmarking liaison officers, submitted by the utilities to the consultants, reviewed for consistency, and in most cases resubmitted by utilities.

The consultants have tried to verify the validity and consistency of the data through site visits in the data validation phase of the work[14], written requests for clarification of apparent errors, dialogue with the utilities, and where possible, comparisons with recent development agency or utility reports.

The data sheets are attached as Appendix 12.

[13] The questionnaire is in two parts: (1) "PPA benchmarking 2012 - Intro & Section 1.doc" ; and (2) "PPA Benchmarking 2012 - Section 2 " . Section 1 covers background and basic utility information. Section 2 is for detailed data, the data reliability assessment and indicators.

[14] In Phase 1 of the work, D. Todd visited Nauru, Tuvalu and Fiji; A. Simpson visited Majuro, Ebeye, Kosrae, Pohnpei, Chuuk, Yap, Palau, Guam and the Solomon Islands; and PIACs Energy Sector Specialist, P. Muscat assisted in Kiribati, Tonga and Tuvalu.

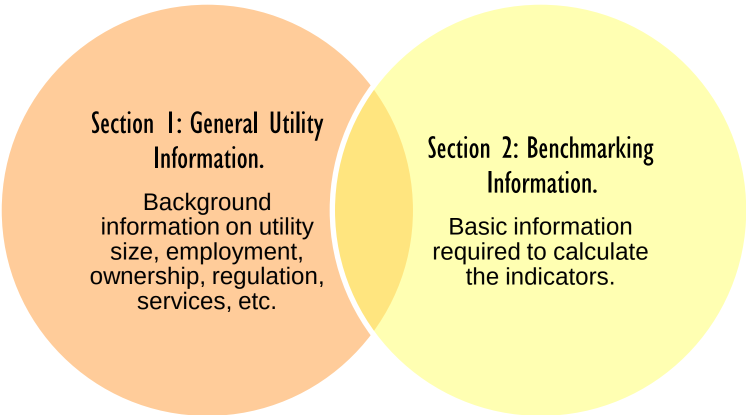
2 DATA & INDICATORS

2.1 Formulation of the Questionnaire

In designing the benchmarking exercise, it was considered desirable that the questionnaire be similar in basic structure to that deployed in 2011, although the format was revised to take into account the results of that work. In particular, the spreadsheet was simplified to separate data entry fields from indicator calculation fields and intermediate results. Colour coding was used to clearly indicate fields where data entry was necessary.

Instructions were provided via a separate explanatory document, which provided definitions and examples of typical calculations for each data point. The questionnaire and explanations have since been incorporated into the *Benchmarking Manual*. Clarifications were added to address lessons learned during the 2011 benchmarking report.

The benchmarking questionnaire was divided into two sections:



Web-based collection was not seriously considered for use as a result of the time-line for preparation of the questionnaire and related material in advance of the July benchmarking workshop. The participants were generally familiar with spreadsheet formats and their use and return for primary data input.

Workshop participants were requested to complete Section 2 as far as possible in preparation for exercises during the Engineer's Workshop on the 19th July, 2012. The potential future application of web-based platforms for data entry, storage and presentation is discussed in Section 8 of this report.

2.2 Proposed Indicators and their Selection

The indicators remained unchanged from 2010.

The criteria for deciding upon specific 2011 indicators were:

- Consistency with the 2010 set of indicators.
- Likely availability of the necessary data.
- Avoidance of undue cost and effort by the utilities.
- Suitability for measurement of important areas of performance.
- Consistency with the SPC national energy sector database and PRIF Pacific Infrastructure Performance Indicators (PIPIs).
- Flexibility to cope with expected changes in the coming years.

The indicator set that formed the basis of the initial data request is provided in Tables 2.1 and 2.2. The goals for future performance agreed in 2002 and associated average at that time are also illustrated.

Table 2.1: Key Benchmark Indicators (2000 and 2010).

Key Indicators* Used in 2002 report	Explanation or definition from the 2002 report	Average for 2002	Goals for future as agreed in 2002
Generation			
Load factor	Annual Generation (MWh) * 100 Peak generated load (MW) * Period hours (8,760)	67%	50-80%
Capacity factor	Annual Generation (MWh) * 100 Installed plant capacity (MW) * Period hours (8,760)	34%	> 40%
Availability factor	Installed plant capacity (MW) * hours (8,760) - MWh losses * 100 Installed capacity (MW) * Period hours (8,760)	93%	80%-90%
Specific fuel oil consumption (kWh / litre)	Units Generated / Fuel Used	3.79	3 - 4
Lube oil consumption (litres / hour)	Lubricants used (volume) Hours of operation	3.50	3.2 - 3.5
Forced outage	MWh out of service due to forced outages * 100 Installed plant capacity (MW) * Period hours (8,760)	7.93%	3-5%
Planned outage factor	MWh out of service due to planned outages * 100 Installed plant capacity (MW) * Period hours (8,760)	4.30%	3%
O&M cost per /MWh	Total operation and maintenance costs Electricity sent out to grid (MWh)		$18
Transmission**			
Reliability	Unplanned outage * 100 / Length of line	Not available	
Transmission Losses	Energy sent out - Energy sent to distribution system Energy sent to distribution system	8.02%	5%
Distribution			
Customers/employee	Average total number of customers Average no. of employees in distribution & consumer services	242	240

Key Indicators* Used in 2002 report	Explanation or definition from the 2002 report	Average for 2002	Goals for future as agreed in 2002
Reliability / km	No of unplanned outages * 100 / Total length of line		
Transformer utilisation	Total energy sold (MWh) * 100 / Distribution transformer capacity (MVA) * 8760 hr	18.14%	30%
Distribution Losses	Electricity sent out - electricity sold / Electricity sent out	12.34%	5%
SAIFI (interruptions/customer)	Total number of customer interruptions / Average total number of customers	19.00	10
SAIDI (hours/customer)	Total customer hours interrupted * 60 / Average total number of customers	592	200
Distribution O&M US$/km ***	Distribution operation and maintenance costs / Total circuit kilometres or miles	$2,478	$800
Corporate / Financial			
Operating ratio	Total operating expenses + depreciation / Operating revenue	186%	0%
Debt to equity ratio	Long term debt / (Equity + long term debt)	26.07%	<50%
Rate of return	Operating income / Average net fixed assets in operation	- 16.80%	> 0%
Current ratio	Current assets / Current liabilities	3:1	>1:1
Debtor days	Debtors at year end * 365 / Total revenue	79 days	< 50 days

Notes: 1. * Slightly edited from 2002 benchmarking summary report. Several indicators slightly renamed or formulas modified for clarity. 2. ** In effect 'transmission' refers only to the utilities with high-voltage supply above 33 or 34.5 kV. 3 . ***This was reported to be a questionable result in 2002.

The following indicators were added in 2011 and retained in 2012.

Table 2.2: Additional Indicators or Information Added in 2011 Benchmarking

Added indicator	What information it provides	Comment
Service coverage (electrification rate through the grid, %)	Population (i.e. residential connections) with utility-based electricity service / total population (i.e. total households) Comment: Most utilities will not have this information	SPC* PRIF** CARILEC***
Lifeline tariff ($ / kWh)	Lifeline Tariff for residential consumers $/kWh compared to average tariff Comment: Indicate savings for low-income consumers compared to the normal residential charge	SPC
Productive electricity use	Commercial & industrial electricity billed/total electricity billed	SPC
Regulation	Indication of extent of self-regulation (standards, tariffs, IPPS) or external regulation (government or independent commission)	SPC, CARILEC
Enabling Framework for Private Sector Participation	Existence of standard IPP / PPA arrangements	SPC
Private sector contribution	Total annual kWh supplied by IPP/Total kWh sent out Comment: May only be available for the main utility grid	SPC
Renewable energy	% of energy generated or sent out (in case of energy purchased from external IPPs) by renewable sources as follows: Biofuel, Wind, Solar PV, Hydro, Geothermal, Biomass/bagasse, Other Comment: biofuel to exclude any petroleum fuel content	SPC
Average generation cost ($ / MWh)	Total annual costs / gross energy entering the system (excluding power station auxiliary usage)	CARILEC
Average supply cost ($ / MWh)	Total annual costs / energy delivered to customers	CARILEC
Electricity charge (tariff by customer class) ($/kWh; $/kW)	Charge to consumer by consumer category (not just overall) Comment: preferably average for the year (2010), not latest charges	CARILEC
Power quality	Existence of a national standard for voltage and frequency fluctuations	CARILEC

Added indicator	What information it provides	Comment
Fuel used	For diesel systems, per cent of total generation which is light (IDO, ADO) and heavy petroleum fuel (HFO)	New
Demand side management	Budget if any for DSM; Full-time equivalent employees engaged in DSM; MWh saved by consumer from utility DSM initiative	New
Composite indicator	Overall indicator of utility performance	New
Lost Time Injury – duration and frequency	Average workdays lost/employee; and frequency of accidents	#

Notes: 1. * SPC indicates utility data SPC hopes to include in the Pacific energy sector database it is developing. 2. ** PRIF = PRIF energy indicator, which is part of a PRIF basic data set. 3. *** CARILEC = indicators in recent CARILEC benchmarking reports 4. # - injury rates were reported for 2002 and 2010. Inconsistent reporting standards have been used but the indicator retained.

Subsequent to the benchmarking workshop and consultation on the pilot template, the questionnaire was extended to include expanded operating expenditure breakdowns and a data reliability assessment. Several participants in the Benchmarking Workshop expressed a desire to further assess the breakdown of operating expenditure as an input into financial benchmarking information. After consultation with the PPA, it was agreed that additional questions would include the following key components of operating expenditure:

Table 2.3: Additional Cost Categories Added in 2012 Benchmarking

Cost Category	Component (expressed in US$, US$/kWh, %)
Fuel and Duty	Hydrocarbon Based Fuel & Lubrication Oil Expenditure Duty on Hydrocarbon Based Fuel & Lubricating Oil
Generation	Generation Operations & Maintenance Expenditure (excluding labour) Generation Labour Depreciation Generation Assets
Transmission and Distribution	Transmission & Distribution Operations & Maintenance Expenditure (excluding labour) Transmission/ Distribution Labour Depreciation Transmission & Distribution Assets
Overhead and Other Expenditure	Other Labour Expenditure (Customer Service, Head Office, Finance, HR, others) Other Duty/ Taxes Other Depreciation Other Expenditure

It was considered particularly useful by some CEOs to achieve a basis for comparison of duty and taxation regimes for fuel expenses – a major component of Pacific utility expenditure. The extended data request also required participating utilities to provide a self-assessed reliability grade for six key components of the primary data. This is described and presented with results in Section 3. Total labour productivity was also captured.

3 DATA RELIABILITY

3.1 Introduction

The benchmarking exercise required participating utilities to provide a self-assessed reliability grade for six key components of the primary data, as set out in Table 3.1. This was intended to help better understand data quality issues and encourage improvements in data reliability. Given the concerns over data quality, it was concluded that this was an effective means of sensitising participants to its significance and ensuring critical assessment of improvement opportunities. The general reliability expectations of each grade are also described below in Table 3.2.

Table 3.1: Key Data Component Reliability Assessment Questions

Question	Description
(i)	How is fuel consumption calculated or derived?
(ii)	How are generation quantities calculated or derived?
(iii)	How are customer outage impacts calculated or derived?
(iv)	How are network demands and capacity utilisation calculated or derived?
(v)	How is the number of connections or customers calculated?
(vi)	Where is financial information sourced from?

Table 3.2: Grading Schema

Question	Description	
A	Highly Reliable	Data is based on sound records, procedures, investigations or analyses that are properly documented and recognised as the best available assessment methods. Effective metering or measurement systems exist.
B	Reliable	Generally as in Category A, but with minor shortcomings, e.g. some of the documentation is missing, the assessment is old or some reliance on unconfirmed reports; or there is some extrapolation made (e.g. extrapolations from records that cover more than 50 per cent of the utility system).
C	Unreliable	Generally as in categories A or B, but data is based on extrapolations from records that cover more than 30 per cent (but less than 50 per cent) of the utility system.
D	Highly Unreliable	Data is based on unconfirmed verbal reports and/or cursory inspections or analysis, including extrapolations from such reports/inspections/analysis. There are no reliable metering or measurement systems.

Further guidance for each component was given in the detailed questionnaire (refer to Appendix 10) although a detailed specification was not intended. Self-assessments remain at least partially subjective as a result of variations in circumstances and scale. Visits to many of the participating utilities provided an opportunity for review and clarification of these self-assessments.

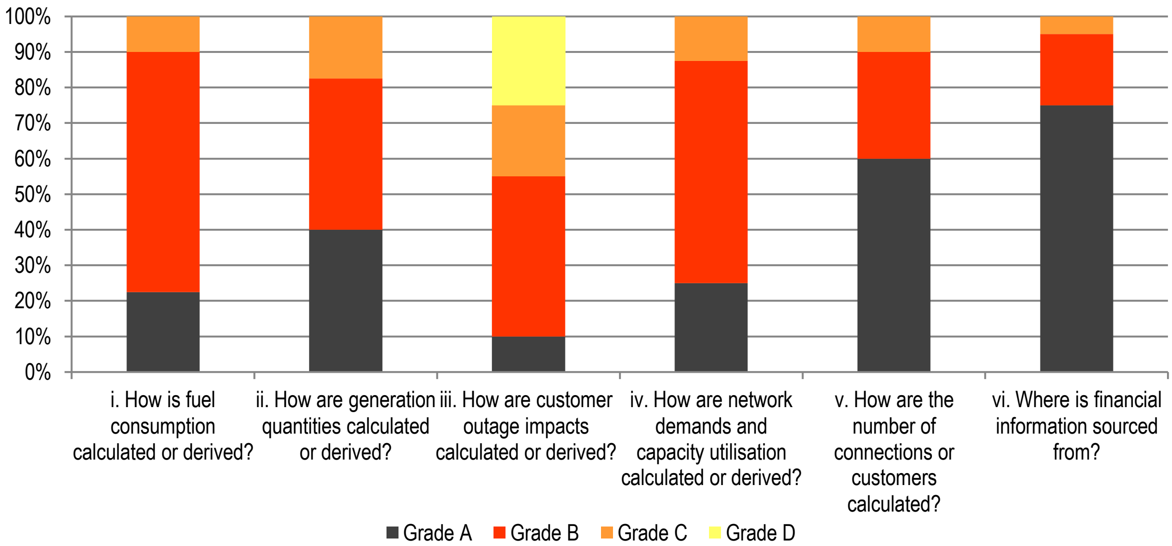
3.2 Data Reliability Self-Assessment

The purpose of the self-assessed data reliability grade is to better understand data quality issues and encourage improvements in data quality with time, in addition to improvements in measured performance.

While site visits were made to many utilities during the data collection phase of this work, the data accuracy and reliability self-assessments have not been subjected to a comprehensive or formal 'audit'. Advice in interpretation and possible grading was provided, but the intention was that utilities engage in the process and arrive at a self-assessment.

The general reliability expectations of each grade are presented in Figure 3.1. 'A' represents the most reliable data and 'D' represents the least reliable data. Detailed definitions for grades 'A' to 'D' for each key data component are presented in Appendix 10.

Figure 3.1: Reliability Grades Assessment by Key Data Component[15]



An aggregate data reliability grade was derived after quantifying and equally weighting the grade for each key component. The aggregate grade range covers D-minus to A-plus (or 12 categories) with aggregate assessments for 2012 ranging between C and A+ as illustrated in Table 3.3.

Table 3.3: Aggregate Data Reliability Grade (2011)

Aggregate Grade	Utility	Aggregate Grade	Utility
A+ **A** **A-**	ASPA, FEA, PNGP, UNELCO CUC, GPA, TPL KUA, PPUC, EDT	**C+** **C** **C-**	NUC
B+ **B** **B-**	KAJUR, EPC CPUC, YSPSC, TEC, SIEA PUB, MEC, PUC	**D- to D+**	(None in category)

[15] Excludes two of 22 utilities due to lack of data.

Some observations can be made concerning data quality from the self-assessments, data validation visits to selected utilities, and Figure 3.2 and Table 3.3 above:

Key Observations on Data Reliability

- The low reliability grades afforded to evaluation of customer outages and impacts is entirely consistent with experience. It reflects a lack of systems and processes that can assist in the evaluation of key aspects of power system reliability performance. Deficiencies in this area seemed well appreciated by utilities.
- The relatively high confidence with financial information sources is at odds with experience of populating the questionnaires. This is potentially a result of divided duties for questionnaire completion or may point towards a misperception of quality in financial data. Financial information may simply not be subject to the perception of uncertainty associated with other electrical system information.
- Benchmarking liaison officers appeared to find the grading methodology relatively straightforward, although in six cases, conjoint grades were allocated (i.e. AB, BC).This was indicative of serious consideration to the appropriate grade in each case.
- Generally, utilities that had the benefit of site visits and assistance in data collection by a member of the benchmarking team, assessed data reliability at lower levels than those that did not. This suggests that, despite the guidance notes, more experience of higher or comparative levels of performance is required to objectively grade data reliability. Anecdotally, benchmarking liaison officers also appeared to grade the key data components more harshly in their own areas of expertise (presumably because they have a better understanding of the issues that require resolution).

With an on-going commitment to benchmarking, it is crucial that the quality of information improves progressively. While the assessment tool undoubtedly remains somewhat subjective, its use has made sure that data reliability and accuracy has received more attention this year. Publication will lead to more careful scrutiny and evaluation of self-assessments by the participants in the next benchmarking cycle.

4 RESULTS

4.1 Introduction

This section provides performance results for 2011 operations in a series of graphs comparing the participating utilities. There is a brief explanation of the relevance of each indicator with both average and median[18] values, and a comparison of results to those of 2010 and a decade ago.

Where the text refers to the 'Pacific benchmark' or 'regional benchmark', these are the goals agreed to by utility CEOs in 2002 and discussed during mid-2012.[19] All quotations referring to the indicators for operational year 2000 are from the 2002 final report, while those referring to the 2010 operational year are from the 2011 report.[20] The format of this section closely follows the style of the 2011 report to aid comparison and understanding. The content of the 2011 report has not been formally quoted or referenced in this section on every occasion when results are restated for comparative purposes.

As shown in Table 4.1, the benchmarking study for utility operations during 2000 covered 20 utilities; the 2010 exercise covered 19; and that for 2011 covered 21 utilities (there were 22 participants in total but NPC[21] missed reporting deadlines). All utilities that participated in the work for 2010 reporting committed to do so for 2011, resulting in good coverage and an improved basis for comparison with the previous period.

An indication of utility scale is provided via colour coding of results using the PPA Membership criteria and as illustrated in Table 4.1. Yellow indicates annual peak load of less than 5MW (small); orange indicates annual peak load of 5MW of greater and less than 30MW (medium); red indicates an annual peak load of 30MW or greater (large).

Table 4.1: Utility Participation[16]

Abbreviation	2011	2010	2000
ASPA	√	√	√
CPUC	√	√	√
CUC	√	√	no
EDT	√	√	√
EEC	no[17]	no	√
EEWF	no	no	√
ENERCAL	no	no	√
EPC	√	√	√
FEA	√	√	√
GPA	√	√	√
KAJUR	√	√	√
KUA	√	√	√
MEC	√	√	no
NPC	√[19]	√	√
NUC	√	√	no
PNGP	√	√	√
PPUC	√	√	√
PUB	√	√	√
PUC	√	no	√
SIEA	√	√	√
TAU	√	√	√
TEC	√	√	no
TPL	√	√	√
UNELCO	√	√	√
YSPSC	√	√	no

The graphs in this report use a black broken line to mark out average values and a red broken line to mark out median values. Colour-coded labels are also included beside the graphs. Red arrows indicate the direction of improved

[16] See Table A4.1 for abbreviations and Appendix 4 for the characteristics of the participating utilities.
[17] The EEC initially expressed interest in participation, but did not respond to data requests.
[18] The 2002 report did not include any median values although some median values were estimated from charts in 2011.
[19] These targets were further discussed by member CEOs in 2012. Recommendations relating to these targets are presented in Section 8.
[20] PPA and PRIF, *Performance Benchmarking for Pacific Power Utilities.*
[21] NPC data was not received in time for inclusion in this report. The 2011 dataset is under preparation and will be included in the next reporting round.

performance for a particular indicator. Blue arrows indicate the direction of the trend between 2010 and 2011. Blue diamonds denote the 2010 results.

In the 2002 report, the average (arithmetic mean) values reported for all utilities were used for most indicators. To maintain consistency with 2010 reporting and mitigate the distortionary impact of 'outliers' on data comparisons, both the median (the middle value in the series) and average values, are presented.

For technical performance indicators, the utilities are identified by name. The financial indicators are not reported by utilities consistently and, in many cases, continue to be less accurate. Until consensus on the public disclosure of financial data is obtained, financial data will continue to be identified by an alphabetical code (A, B, C, etc.),[22] not utility names.

4.2 Generation Indicators

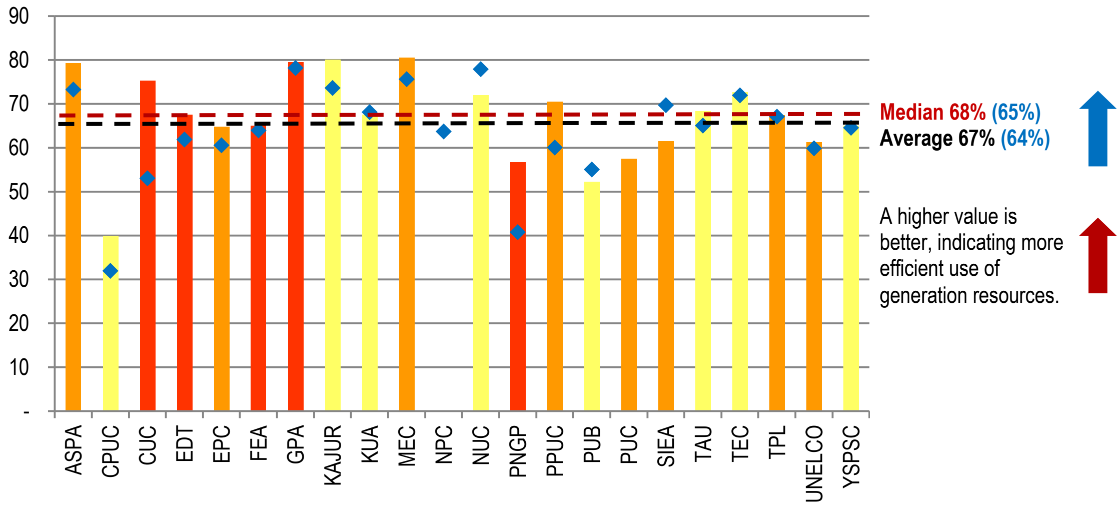
(i) Load Factor

Load factor (LF) measures the effectiveness of the use of utility generation resources. It is the ratio of system average power generated to peak power demand over a period of time. A lower LF indicates greater fluctuation in the use of generators throughout the reporting period, sometimes (but not necessarily) resulting in higher losses. A high LF implies a relatively flat demand for electricity and relatively constant utilisation of generators, transformers and related equipment operating at efficient levels.

In 2000, the load factor was rated as a "relatively good average [of] 67 per cent, compared to an international range of 65-80 per cent".[23] At the time, Pacific utility CEOs selected "a high benchmark of 80 per cent indicating that in future, demand management should play an increasingly important part in Pacific power sector policies."[24]

In 2010, the reported results were slightly lower than those of a decade ago. In 2011, the reported results have returned to the higher average of 67 per cent in 2000 as shown in Figure 4.1. Only three utilities report degradation in LF over the two most recent reporting periods.

Figure 4.1: Load Factor 2011 (2010) (%)



[22] There are gaps among the letters chosen as new letters are added for new participants. The code used for each utility has been provided to the CEO of that utility.
[23] Pacific Power Association (PPA) and Asian Development Bank (ADB). *Final Report Performance Benchmarking October 2002: Pacific Power Utilities* (Sydney, 2002), p. 5-1.
[24] PPA and ADB, *Pacific Power Utilities,* pp. 5-1.

(ii) Capacity Factor

Capacity factor (CF) is also an indicator of effectiveness in relation to the use of generation resources. It is a similar measure to LF. Where LF measures average power as a percentage of maximum demand, CF measures average power demand as a percentage of installed capacity.

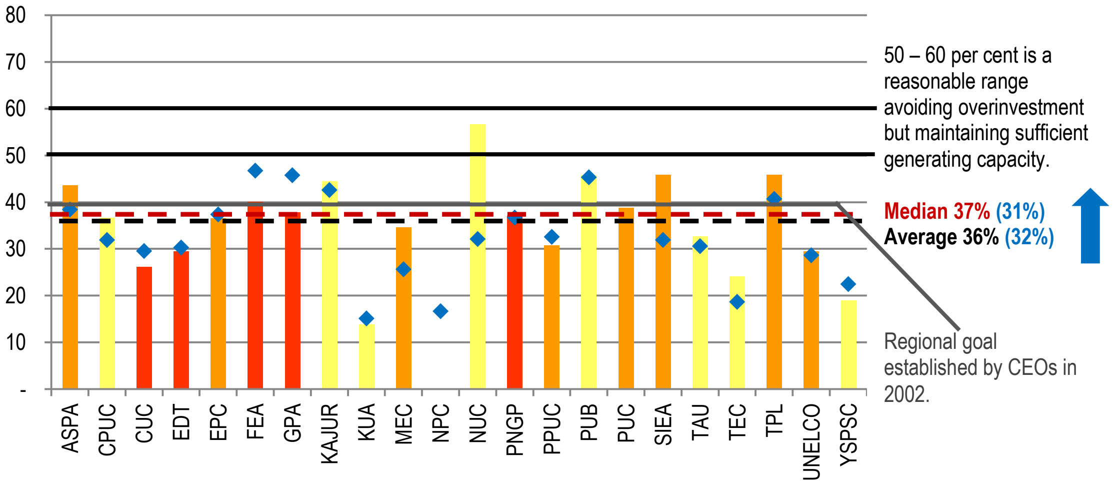
In 2011 the capacity factor improved to 36 per cent - slightly higher on average than a decade ago and 4 per cent better on average than for 2010.

A lower CF means that there is adequate reserve capacity to meet future load growth or demand when some generation is shut down for maintenance or down due to faults. It also suggests over-investment in generation capacity. A higher CF means demand is closer to available capacity, which can cause difficulties in scheduling maintenance of generating plants. Furthermore, available capacity may not meet future load increases. Improving the CF can require major capital investment in new generating plants. Utilities with a CF of nearly 1.0 tend to have an inadequate capacity to meet demand, which can result in power rationing.

For operations during 2000, the CF averaged at 34 per cent compared to a regional goal of 40 per cent and international best practice of 50-60 per cent, thus "reflecting … isolation, need for reserve margins and indivisibility of plant serving "pockets" of small loads. In 2010 the capacity factor averaged only 32 per cent."

In 2011, as shown in Figure 4.2, the CF improved to an average of 36 per cent (median 37 per cent) although there continued to be a wide variation in results. Significant increases in some utilities were offset by reductions in others. The CF for the majority of utilities is still under the regional goal of 40 per cent. The large increase in CF for the NUC was coincident with a period of reduced generation availability and inadequate capacity to meet demand.

Figure 4.2: Capacity Factor 2011 (2010) (%)



(iii) Availability Factor

The **availability factor** (AF) of a power plant is the amount of time it is able to produce electricity (taking into account outage times) over a specified period, divided by the installed capacity, times the length of the period.

The availability of a power plant varies depending on outages due to failure or maintenance. Plants that run less frequently (e.g. plants brought on line for meeting peak demand only) have a higher AF because they are generally in good operating condition. Plants that frequently experience breakdowns have a low AF.

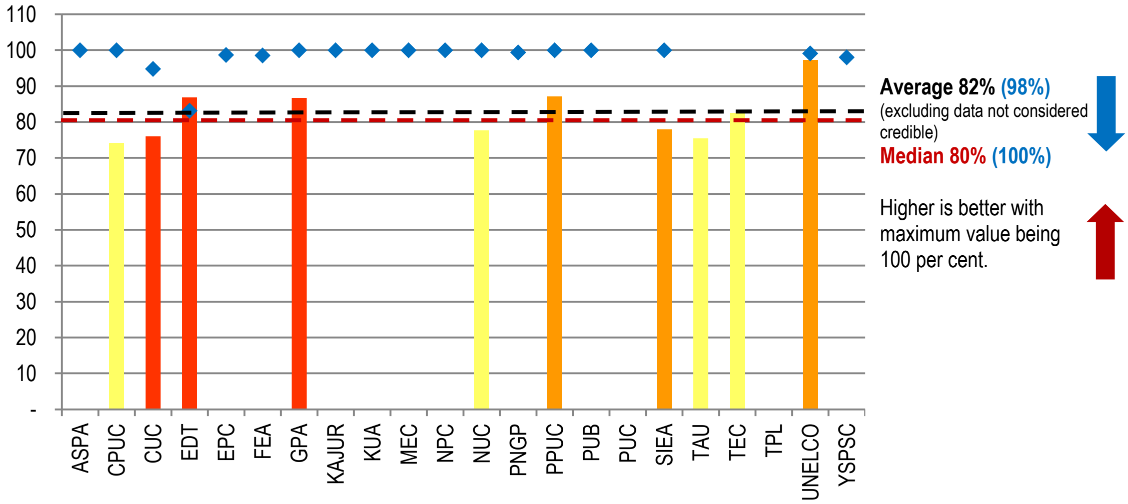
The 2011 average and median AF of 82 per cent and 80 per cent respectively, are significantly lower as a result of the change in methodology, but consistent with expectations and likely targets.

Thermal power stations generally have AF's between 70 per cent and 90 per cent. Newer plants, and those that are well-maintained, tend to have significantly higher AF's.

For utility operations during 2000, the reported availability of generating plant in the Pacific averaged 93 per cent "compared to the Pacific benchmark of 90 per cent and typical international practice of 65 per cent."[25] In 2010, the results reported by utilities averaged 98 per cent, but were not considered credible since they failed to take into account forced outages, planned outages and plant de-rating. In 2011, as far as possible, the AF was based on firm continuous capacity.

The 2011 average and median AF of 82 per cent and 80 per cent respectively, are significantly lower as a result of the change in methodology, but consistent with expectations and likely targets.

Figure 4.3: Availability Factor 2011 (2010) (%)



(iv) Generation Labour Productivity

Generation labour productivity is a measure of the services produced per employee, i.e. productivity of staff engaged to operate and maintain generating plants. It is a ratio of total electricity generation to the number of full-time equivalent (FTE) employees who operate and maintain the system's generating plant. For power utilities, the indicator of service has traditionally been the amount of electricity generated per employee, but this may change over time as Pacific utilities provide more energy efficiency services to customers.

In 2000, Pacific utilities generated about 3 GWh for each employee involved primarily in power generation (with a range of 0.5-10), compared to typically 22 GWh in larger utilities, which is considered to be international best practice. As noted in 2011:

> "the smaller utilities will tend to have lower generation productivity because of a low level of generated GWh but a high number of semi-skilled staff is required to operate and maintain the generating plant, regardless of utility size".[26]

It is worth restating that in 2002, the CEOs argued that this is not an appropriate indicator for comparing:

> "large base-load on mainland [utilities] … to island generation stations. However, considering the worldwide emphasis on productivity improvement in the power sector, there may also be opportunities in this regard in the Pacific."[27]

In 2010, the range was wider than that reported in 2002 but the average had declined to 2.7 GWh per generation employee, with the median of 1.2 even lower. The accuracy of FTE allocation to the generation function was questioned at the time, and concerns remain regarding the validity of the FTE count in 2011.

The reported productivity per FTE generation employee has apparently declined in the past decade, and continued to do so in 2011. Indicator variability and data reliability concerns remain.

The reported productivity per FTE generation employee has apparently declined further to 2.5GWh in the most recent reporting period.

[25] PPA and ADB, *Pacific Power Utilities,* p. 5-2.
[26] PPA and PRIF, *Performance Benchmarking for Pacific Power Utilities*, p.27
[27] PPA and ADB, *Pacific Power Utilities,* p. 5-2.

Figure 4.4: Generation Labour Productivity 2011 (2010) (GWh/generation employee)

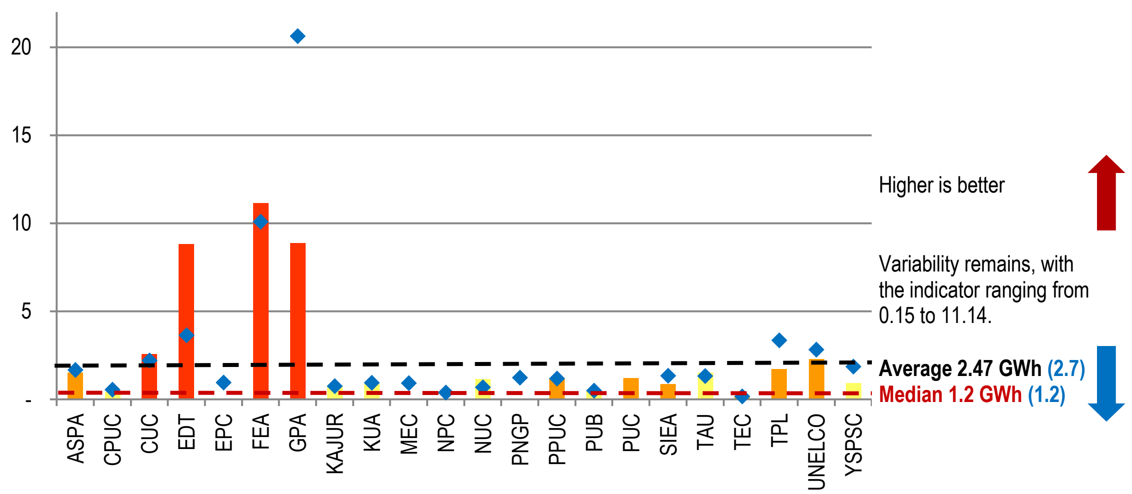
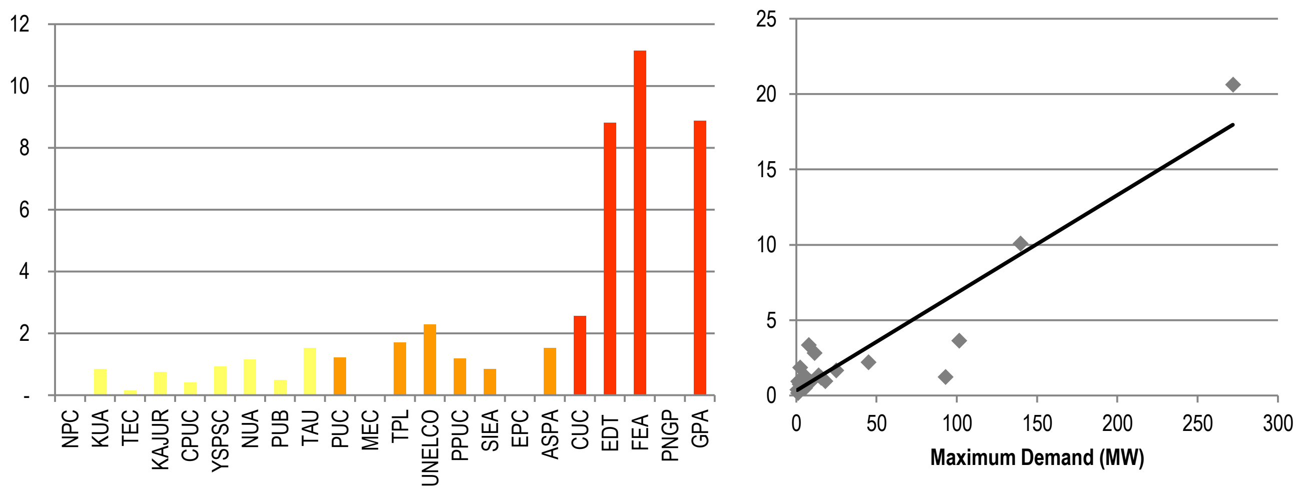


Figure 4.5 orders the results by increasing maximum demand in MW (left) and in the form of a scatter chart (right). For the latter, the best trend line fit appears to be linear, although the relationship is not strong. The generation productivity of the YSPSC, TPL and UNELCO, which stood out favourably relative to others in 2010 has decreased.

Figure 4.5: Labour Productivity 2011 by Utility Maximum Demand (GWh/generation employee)



It remains difficult to come to conclusions on the potential impact of economies of scale on productivity on the basis of this data.

(v) Specific Fuel Consumption

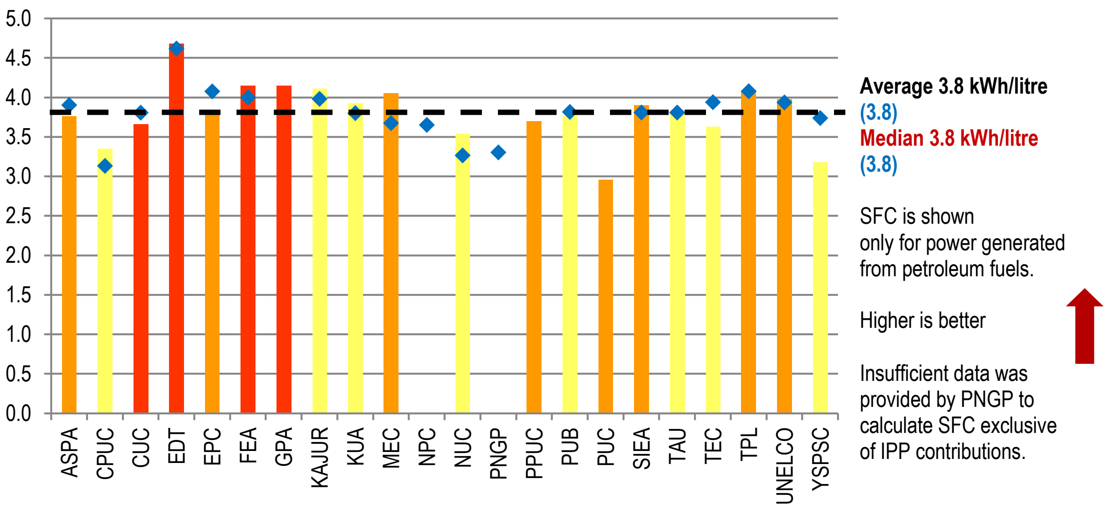
Specific fuel consumption (SFC) is a measure of the efficiency of fuel use for power generation, often reported in kWh/gallon or kWh/litre of fuel used. SFC is a key performance indicator because fuel accounts for the overwhelming bulk of generation costs in a typical PPA–member diesel based power utility. It refers to the efficiency of utility generation only – it does not include purchased energy from Independent Power Producers (IPPs).

Specific fuel consumption is a measure of the efficiency of fuel use for power generation. The average (and median) of 3.8 kWh has remained unchanged since 2002. Some variation in utility performance can be observed between 2010 and 2011.

In technical specifications, fuel efficiency is generally reported in kilograms (kg) or grams (g) of fuel per kWh of power produced, which takes into consideration the different densities and energy content of lighter and heavier petroleum fuels. The type of fuel used thus has a bearing on SFC.

For operations during 2000, it was reported that "Pacific practice … (average of 3.79 kWh per litre) is already close to … the Pacific benchmark of 4.0 kWh per litre indicating … good performance." [28] The average (and median) of 3.8 kWh per litre has remained unchanged since 2002, as illustrated in Figure 4.6. Some variation in utility performance can be observed between 2010 and 2011.

Figure 4.6: Specific Fuel Consumption in 2011 (2010) (kWh/litre)



It was noted in 2011 that:

> "Specific fuel consumption is only comparable for similar sized engines operating at similar loads, and with similar fuel. A large modern slow-speed or medium-speed engine with a high Brake Mean Effective Pressure (BMEP)[29] value generally has a higher SFC (about 30 per cent higher) than a small high-speed or low BMEP medium-speed engine at similar loads and with similar maintenance standards".[30]

The EDT and TPL – especially EDT – continue to stand out as the only utilities generating over 4.0 kWh per litre of fuel. The FEA, GPA and KAJUR report 4.0 kWh per litre (but, again, actual KAJUR efficiency is believed to be less). Engines using heavier fuel with high calorific values will normally have a higher SFC compared to lower density fuels.

The EDT and TPL – especially EDT – continue to stand out as the only utilities generating over 4 kWh per litre of fuel.

Subject to improvements in the quality and scope of data collection for this purpose, analysis of fuel efficiency could be further enhanced by accounting for engine type, size, operating conditions and fuel type. For Pacific utilities studied on behalf of the PPA by the Dutch consulting firm KEMA, the average SFC for 2009 or 2010 operations was 3.71 kWh per litre and the median was 3.66 kWh per litre. KEMA considered these values low.

Since most PICT utilities use small high-speed diesel generators, the benchmark values for 2011 are considered reasonable. New low and medium speed engines should achieve 4.0-5.0 kWh per litre.

(vi) Lubricating Oil Consumption[31]

Petroleum-fuelled generation efficiency can also be assessed via the number of kWh generated per litre of **lubricating oil consumed**, with the benchmark varying according to the size and condition of the engine. Lower lubricating oil efficiency can be attributed to poor maintenance, e.g. due to worn piston rings. It has been suggested that reasonable values are about 500–700 kWh per litre for a 1 MW engine and 1,000–1,300 kWh per litre for a 4–5 MW engine.

[28] PPA and ADB, *Pacific Power Utilities,* p. 5-3. A SFC of 3.79 kWh per litre is 4.512 kWh/kg at a specific gravity of fuel of 0.84 kg per litre. This is equivalent to 221.6 g per kWh.

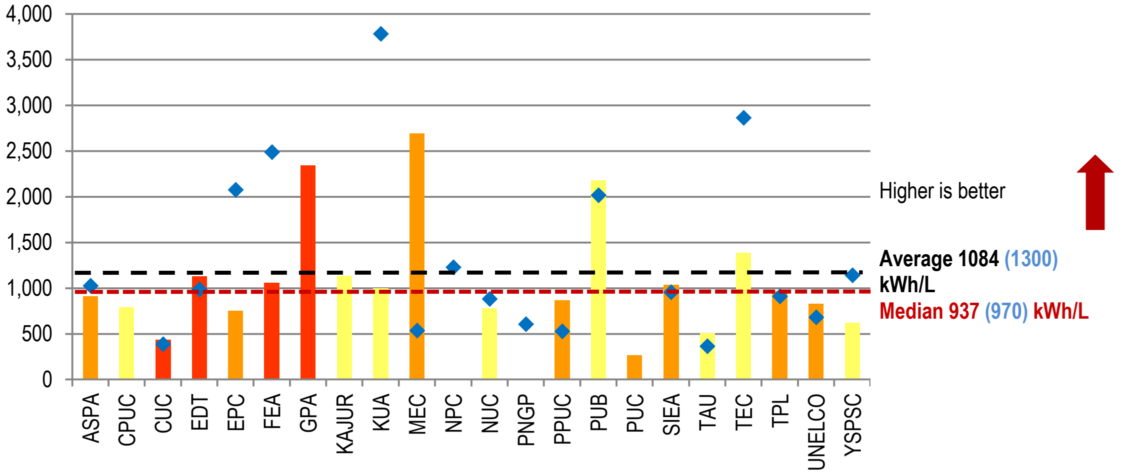
[29] BMEP is Brake Mean Effective Pressure, the average effective pressure of all stroke cycles. BMEP is a function of temperature of the gases in the cylinder.

[30] PPA and PRIF, *Performance Benchmarking for Pacific Power Utilities*, p.29

[31] For operations in 2000, the 2002 benchmarking exercise reported lubricating oil consumption for petroleum fuelled gensets in litres per hour. This was replaced with kWh per litre of lubricating oil in 2010.

In 2011, the average (Figure 4.7) was 1084 kWh per litre, with a median value of 937 kWh per litre, significantly lower than the 2010 values.

Figure 4.7: Lubricating Oil Consumption Efficiency in 2011 (2010) (kWh/litre)



(vii) Forced Outage

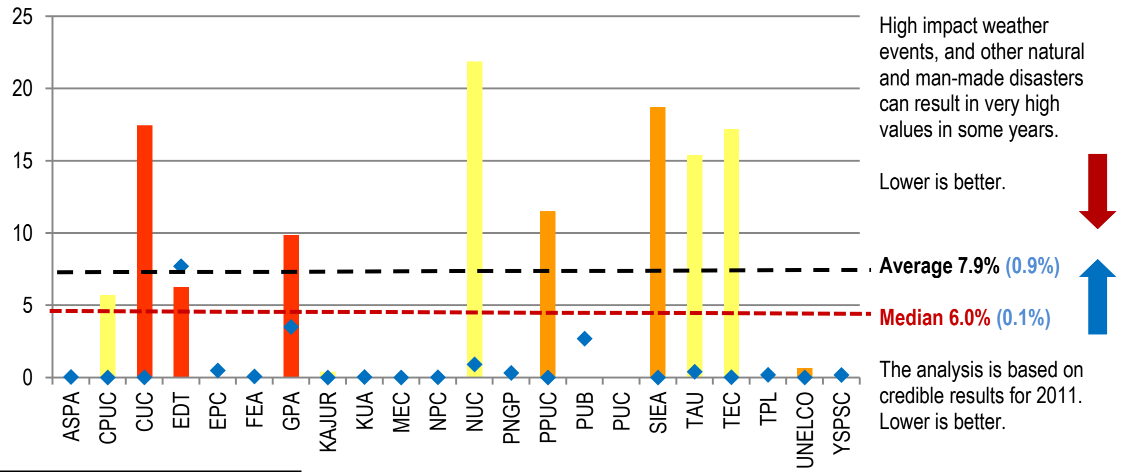
A **forced outage** is an unplanned outage (or generator downtime) that has been forced on the utility. It is total unplanned loss of generation capacity as a percentage of maximum available generation from installed capacity. Unplanned outages are attributable to problems with generators that compelled the utility to take them out of service.

As a result of reporting improvements, the 2011 average forced outage rate is a more realistic eight per cent, compared to one per cent in 2010. Information gaps remain.

In 2002, for operations during 2000, it was reported that "some improvement is required … regarding forced outage"[32] with an average of 7.93 per cent compared to a Pacific benchmark of five per cent. In 2010, the utilities reported average forced outage rates of less than one per cent and a median value under 0.1 per cent. Data for both indicators appeared questionable and no meaningful comparisons could be made.

Based on the utilities that submitted credible data, the average forced outage rate for 2011 is 7.9 per cent and the median is 6.0 per cent. All benchmarks measuring unplanned or forced outages are subject to significant variation in the Pacific, as a result of high impact weather events, natural disasters and man-made incidents. While the 2011 dataset is more realistic, significant information gaps remain, and future benchmarking comparisons would also benefit from analysis that accounts for high impact events.

Figure 4.8: Forced Outage Reported in 2011 (2010) (%)



[32] PPA and ADB, *Pacific Power Utilities*, p. 5-4.

(viii) Planned Outage

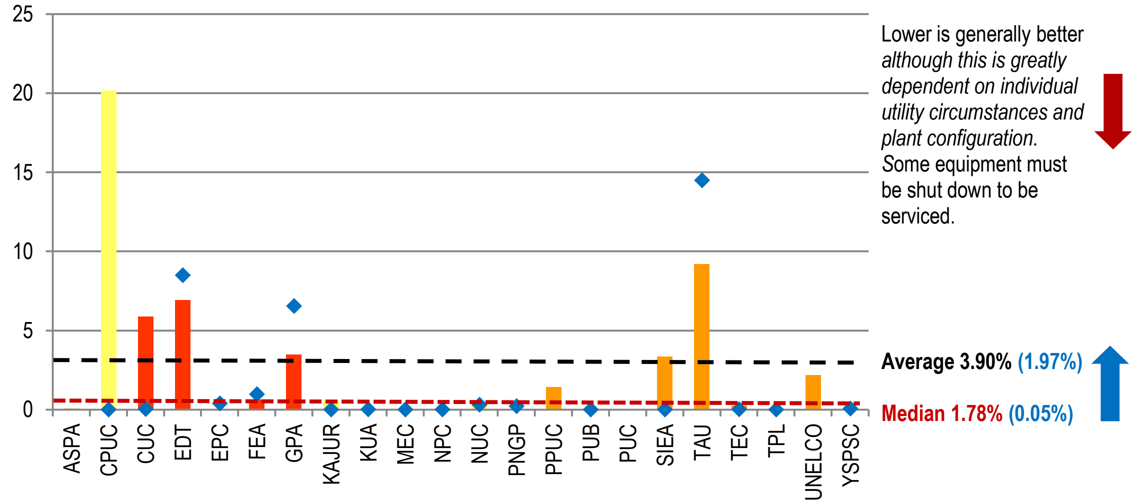
Planned or scheduled outages measure the proportion of downtime for planned maintenance or other activities requiring equipment to be shut down. It is a scheduled loss of generating capacity as a percentage of installed capacity to generate energy. In 2000, the planned outage rate was reported to be acceptable, averaging 4.3 per cent compared to the Pacific benchmark of three per cent.

In 2010, the reported average (Figure 4.9) was under two per cent, but the median was well under one per cent, which appeared to be far too low. It suggested that very little planned maintenance of generating equipment occurs in most of the Pacific utilities, often due to insufficient reserve capacity to allow the shutdown of generators due for scheduled maintenance, a lack of spare parts, or lack of funds for major contracted service work. When maintenance intervals are extended, the probability that generators may break down increases. The circumstances and plant configuration for each utility will have a major impact on the planned outage rate.

The reported average planned outage rate in 2011 has increased to 3.90 per cent, and the median to 1.80 per cent. This suggests improvement in maintenance scheduling, although eight of the 21 utilities either did not submit data or the data that was submitted was not credible.

The data and its limitations indicate that concerns remain, and that efforts to review maintenance regimes and their effectiveness continue to be appropriate.

Figure 4.9: Planned Outage in 2011 (2010) (%)

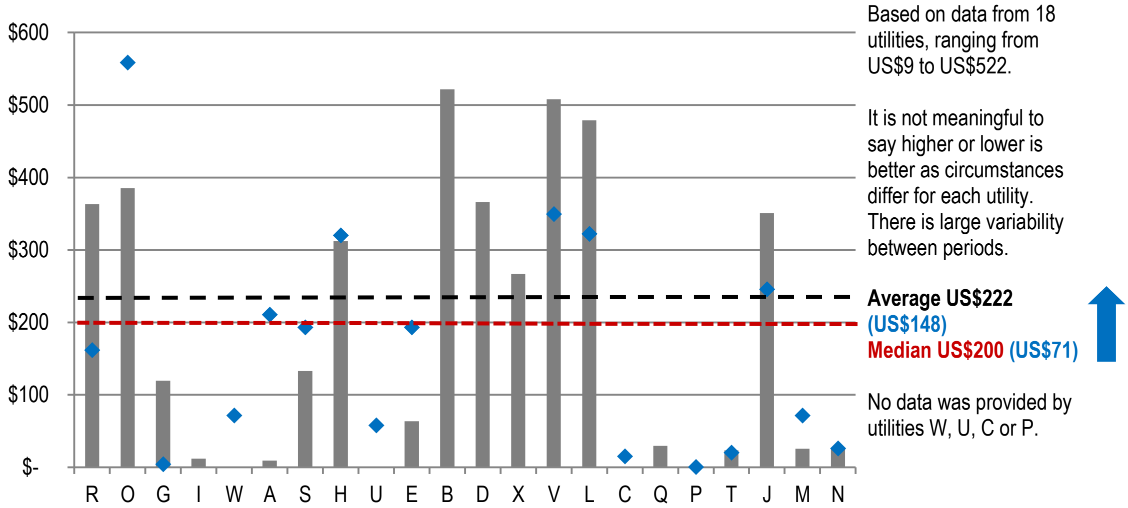


(ix) Generation Operations and Maintenance (O&M) Costs

The indicator used is the expenditure on O&M of generating equipment per MWh generated, expressed in US$. The 2002 report did not provide data on generation O&M expenditures but selected a benchmark of US$18 per MWh, excluding fuel and lubrication oil expenditures.

For operations during 2011, shown in Figure 4.10, the reported average was US$222 per MWh with a median of US$200. Note that some utilities did not want cost data to be made public so utilities are identified by alphabetic code, rather than the utility abbreviation (the codes assigned are not in the same order as the utility abbreviations or names). Comparisons with the 2010 dataset show a significant increase in both the indicator average and median. The large variability in results between 2010 and 2011 suggest there may be a lack of consistent allocation of costs or other financial data collection issues.

Figure 4.10: Generation and O&M Costs in 2011 (2010) (US$)



4.3 Delivery System Losses

(i) Losses (General)

In 2000, six participating utilities provided data for "transmission functions (defined as 33 kV and above)."[33] Reported transmission losses as a percentage of energy generated were typically around eight per cent (compared to a Pacific benchmark of five per cent). The 2002 report concluded that "there is scope in the Pacific to improve transmission line losses".[34]

In 2010, "comparable data for transmission losses was not provided for all five utilities. Some appeared to have reported transmission and distribution (T&D) combined and there were other inconsistencies in reporting".[35] Accurate loss evaluation proved to be difficult on the basis of benchmarking data collection:

> "Considering only combined T&D losses in 2010, Pacific utilities reported average T&D losses of nearly 21 per cent, a median value of 15 per cent, with some much higher. The data was considered only roughly indicative, as a result of varying treatment of loss categories, particularly station and certain financial losses".[36]

That analysis is not repeated here.

A recommendation to consolidate transmission and distribution losses for reporting purposes in 2011 was considered. On balance, the decision was to gather data as consistently as possible with the 2010 exercise, including transmission. Unfortunately, limited information on transmission losses was provided in 2011.

Reliance was again placed on the updated KEMA loss studies, which were completed in late 2011 for almost all benchmarking participants, to quantify loss components. The distinction between loss categories presented in 2010 is repeated below for the purposes of this discussion, and then followed by an update of the reporting of distribution system losses and the KEMA loss studies.

(ii) Distribution Losses

Distribution losses are those that occur from the HV substations to the consumer meters. For those PICT utilities without HV transmission grids, distribution losses are those from circuit breakers of feeders inside power plants to consumer meters. These losses are classified as technical and non-technical:

[33] PPA and ADB, *Pacific Power Utilities,* p. 6-1.
[34] PPA and ADB, *Pacific Power Utilities,* p. 6-1.
[35] PPA and PRIF, *Performance Benchmarking for Pacific Power Utilities*, p.33
[36] PPA and PRIF, *Performance Benchmarking for Pacific Power Utilities*, p.33

■ **Technical and Non-Technical Losses**

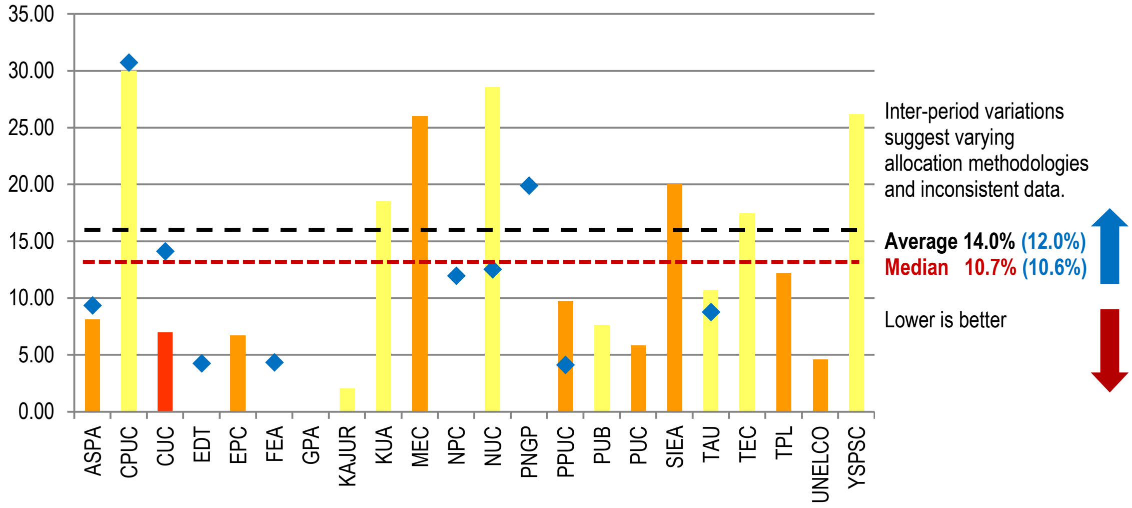
- Technical losses are mainly caused by imbalances in the distribution system and/or too high resistance in the system. These depend on distribution voltages, sizes and kinds of conductors or cables used, transformer types, condition and loading, and the wire sizes of service feeds to consumers' meters.
- Non-technical losses are those attributable to electricity used by a consumer but not paid for, including theft, computer programming errors, unmetered, metering errors, etc. This category should not include the use of electricity within the utility itself (power station use, other facility use), free provision of street lighting, or electricity provided to the water, waste management or sewerage section of the utility, but not paid for. These are financial, not non-technical, losses.

For utility operations in 2000, the report of 2002 stated that "Pacific distribution losses on average at 12 per cent are far too high (compared to the regional and international benchmark of five per cent)" and noted this as a priority area for improvement.[37] The reported distribution losses in 2010 remained high at 12 per cent, with a median value of 10.6 per cent.

In 2011, reported distribution losses for those utilities that provided data remained high at 14 per cent. Weak reporting and loss allocation variations make comparisons difficult.

The 2011 reported loss figures average 14 per cent with a median value of 10.7 per cent. Variations in the treatment and allocation of non-technical losses continue to make meaningful comparisons difficult.

Figure 4.11: Distribution Losses Reported by Utilities in 2011 (2010) (%)



(iii) The KEMA System Loss Studies[38]

Despite efforts to clarify the loss definitions in 2011, some inconsistencies remain in aspects of the reporting of losses by participating utilities.

The detailed KEMA loss studies undertaken during 2010 and 2011 for 19 Pacific utilities[39] provide data that helps distinguish between loss categories. Preliminary results for 2010 were reported for 17 utilities last year. The final results for delivery system losses, distinguishing between technical and non-technical losses, are presented in Figure 4.12. Internal power station use and financial losses are excluded.

Non-technical losses were higher on average than technical losses, averaging 7.3 per cent of electricity generated. Opportunities remain to reduce this level.

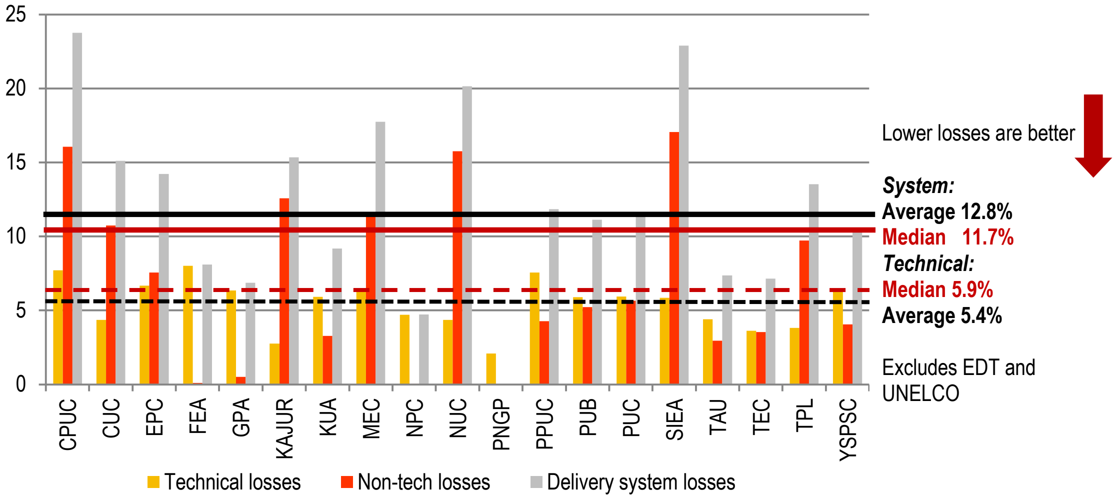
System losses during 2009 (northern utilities) and 2010 (southern utilities) vary widely, but averaged 12.8 per cent (median 11.7 per cent). Technical losses averaged 5.4 per cent with a median value of 5.9 per cent. The preferred performance range is towards the lower of three to five per cent.

[37] PPA and ADB, *Pacific Power Utilities,* p. 7-2.

[38] Pacific Power Association (PPA) and KEMA, *Quantification of Energy Efficiency in the Utilities of the South Pacific: Final Data Handbook and Final Report* (2012); Pacific Power Association (PPA) and KEMA, *Quantification of Energy Efficiency in the Utilities of the U.S. Affiliate States Excluding US Virgin Islands: Final Data Handbook and Final Report* (2010).

[39] The EDT and UNELCO were not part of the KEMA study report and work at the ASPA was postponed during a major re-build of its system

Figure 4.12: Losses for 19 Pacific Utilities Reported by KEMA (2009-2010 Operations (%)



Non-technical losses were higher on average than technical losses, averaging 7.3 per cent of electricity generated, with a median value of 5.4 per cent. There should be considerable opportunity to reduce this level. Finally, KEMA reports total losses (technical, non-technical, station use, provision to water and sewerage utility divisions, etc. combined) as 20.3 per cent on average and with a median of 19.3 per cent. While average and median values appear consistent between reported and evaluated system losses, there are major disparities for individual utilities. As noted earlier, the difference may be due to the different number of utilities covered and different ways of allocating non-technical losses, or in some cases, weak reporting.

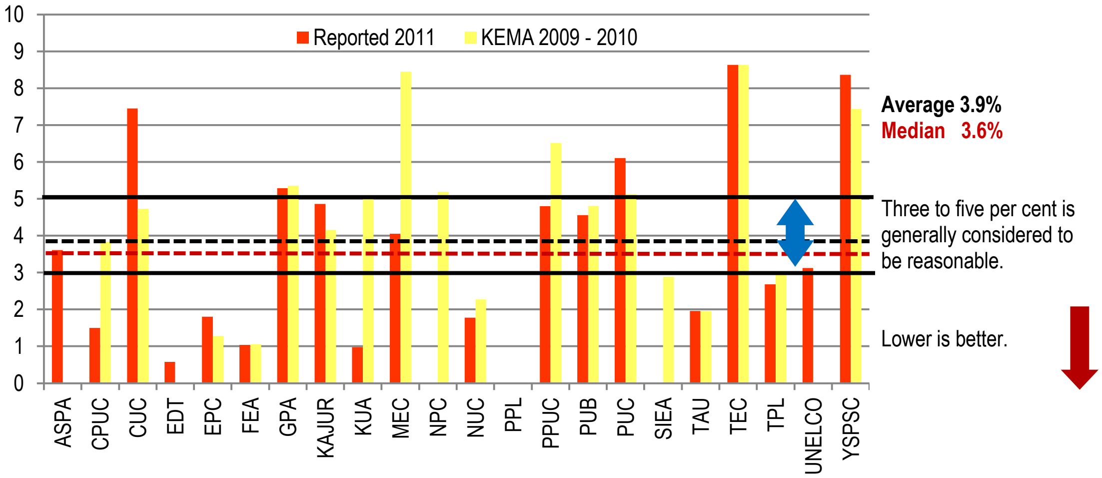
Finally it should be noted that the methodology adopted by KEMA is based on grid modelling and calculation, not actual metering. Since not all Pacific utilities have effective metering or reporting systems for losses, the KEMA loss study information is of significant value for guiding loss improvement initiatives. As metering systems develop, discrepancies between loss measurements and outputs derived from models should diminish.

(iv) Station Auxiliaries

A generating station's use of electricity is indicated by the percentage of MWh generation used internally for auxiliary systems. Three to five per cent is considered to be acceptable. The average reported value for 2011 was 3.9 per cent and the median was 3.6 per cent as shown in Figure 4.13. This compares to 4.5 and 4.8 per cent respectively for data assessed by KEMA for 2009 and 2010 operations.

The more significant discrepancies between reported Station Use and that assessed by KEMA for the previous operational period are difficult to reconcile. In some cases, the internal usage data has been sourced directly from the KEMA report, while in others lack of accurate metering leads to estimation and a high variance. It is difficult to conclude that overall station losses are reducing.

Figure 4.13: Station Energy Use for Pacific Utilities (2011 Reported and KEMA for 2009-2010 Operations) (%)



4.4 Other Distribution Indicators

(i) Customers per Distribution Employee

In 2000, there were on average 242 customers for each FTE utility employee working on distribution, which was considered by the report authors at the time to be good.

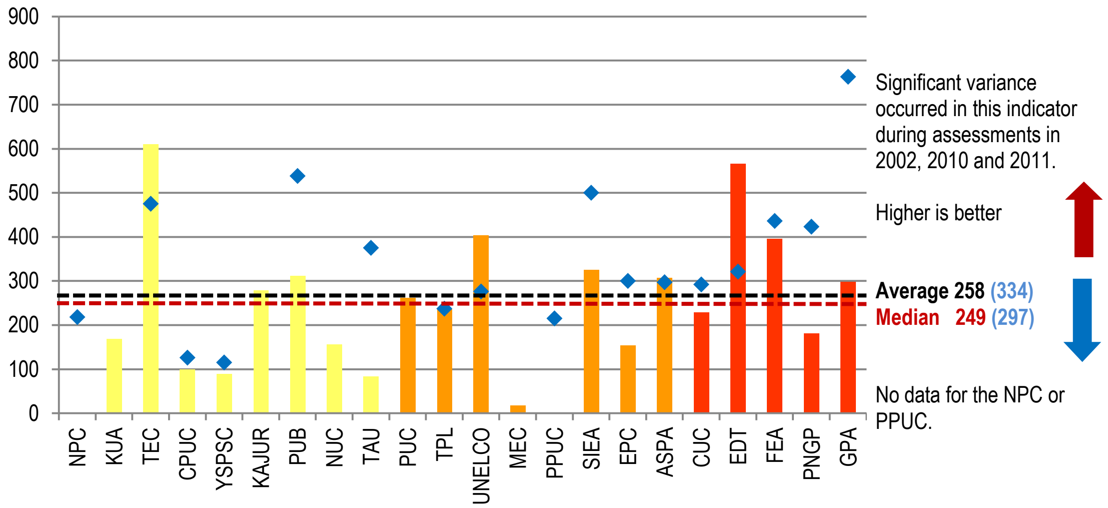
In 2010, the reported average was 334 and the median was 297, characterised as an impressive improvement of nearly 40 per cent for the average. It was also noted that Pacific utilities with higher total sales generally serve more customers per distribution employee.

Significant variance is evident in distribution productivity between 2002 and 2011, which is sensitive to assumptions in FTE allocation (particularly for smaller utilities).

Disappointingly, the 2011 data reverses that movement and the relationship between this measure and utility scale is less apparent. The 2011 average stands at 258 and the median is 249, as illustrated in Figure 4.14. This measure is particularly sensitive to the allocation of employees to the distribution function, and in the case of small utilities, a higher than average vacancy rate or reporting error could dramatically influence the result.

The benchmark survey did not require total labour hours (including contractors) to be taken into account for this indicator, whereas it was taken into account for total labour productivity (see Figure 4.30).

Figure 4.14: Customers per Distribution Employee in 2011 (2010)



(ii) Distribution Transformer Utilisation

This indicator measures the transformer average load against the transformer capacity in megavolt amperes (MVA), i.e. the energy used by customers connected to the transformers as a percentage of distribution transformer capacity. High utilisation implies an efficient capital expenditure process for investing in distribution transformer capacity to meet the demands of customers. This process takes into consideration demand, demand growth and contingency requirements to improve supply security and reliability.

In 2000, utilisation was low, averaging 18 per cent compared to a regional goal of 30 per cent. The report noted that “this can only be achieved in the long term because of the long lead times required to improve usage of capital assets.”[40]

In 2000, distribution transformer utilisation was low, averaging 18 percent compared to a regional goal of 30 per cent. No significant improvement was evident in 2010, and in 2011 the reported average is at the same level as 10 years ago.

In 2010, the reported average was 20 per cent, with a median value of 21 per cent, representing no significant improvement. Only the NUA exceeded the Pacific goal at that time. The 2011 data for the NUC (the successor corporatised entity) reflects both improvement in the capture of transformer data in a new asset register, and the inclusion of a significant number of under-utilised substation assets serving the remaining phosphate industry.

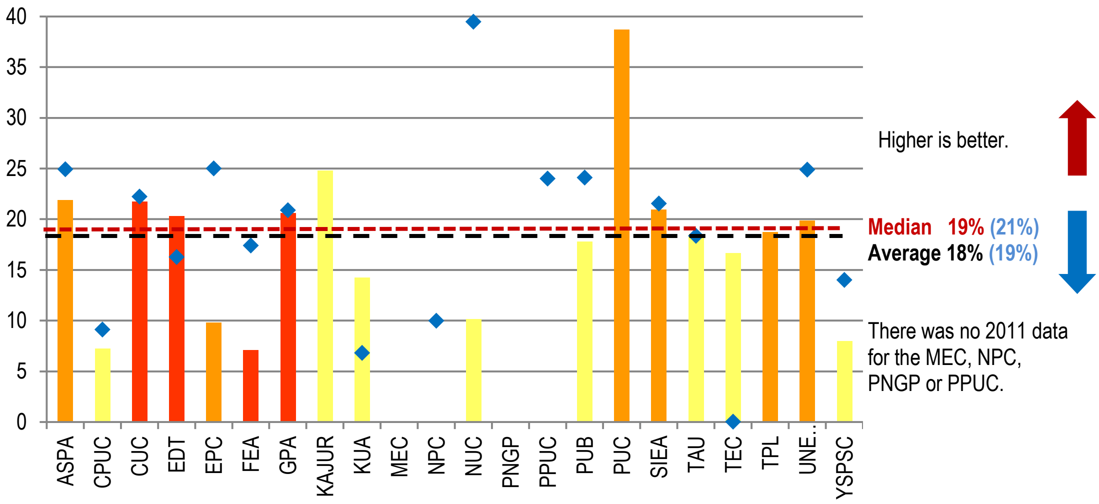
[40] PPA and ADB, *Pacific Power Utilities,* p. 7-1.

The reported average in 2011 has returned to 2000 levels of 18 per cent, with a median of 19 per cent. This is partly as a result of the adjustment to the NUC, but also reductions in utilisation for seven other utilities who have reported data for both periods. Only the PUC now exceeds the target.

Figure 4.15: Switchboard at the PPUC

Image courtesy of Derek Todd.

Figure 4.16: Distribution Transformer Utilisation in 2011 (2010) (%)



(iii) Interruption Duration

The System Average Interruption Duration Index (SAIDI) is an internationally recognised reliability indicator measuring the average duration of interruptions per customer within a measurement period (typically one year). In the 2002 report, SAIDI was considered to be:

> "a priority area for improvement considering that current performance is not good (average of 592 minutes per year compared to [the] Pacific benchmark of 200) and customers typically rank reliability of supply as very important."[41]

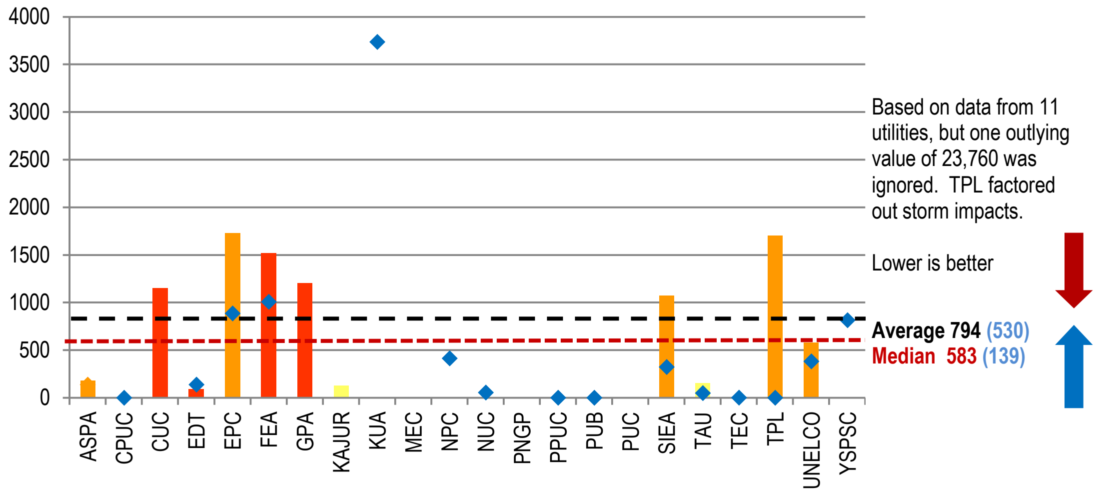
In 2010, the reported average was 530 minutes (with one very high value ignored) with a median of only 139 minutes, well within the Pacific goal of 200. It was noted at the time, however, that "within PICT utilities, SAIDI tends to be estimated or only measured in part, so the reported results for some utilities were unlikely to be indicative of actual performance".[42]

In 2011, the reported average is 794 minutes (again with one very high value ignored) and a median of 583 as shown in Figure 4.17. The validation of data via utility visits by members of the consulting and PIAC team confirmed, firstly, that previously reported performance was unlikely to be accurate for many utilities, and secondly, sought to provide estimates of reliability measures for the last period. Credible reporting data was sourced for 11 utilities, although improvements are

[41] PPA and ADB, *Pacific Power Utilities,* p. 7-2.
[42] PPA and PRIF, *Performance Benchmarking for Pacific Power Utilities,* p. 39.

possible for most. The weak reporting of forced outages (Figure 4.8) also affects the calculation of SAIDI and System Average Interruption Frequency Index (SAIFI) (see Figure 4.18) further suggesting that reported outage data is unlikely to be reliable.

Figure 4.17: SAIDI Interruptions in 2011 (2010) (minutes per customer)

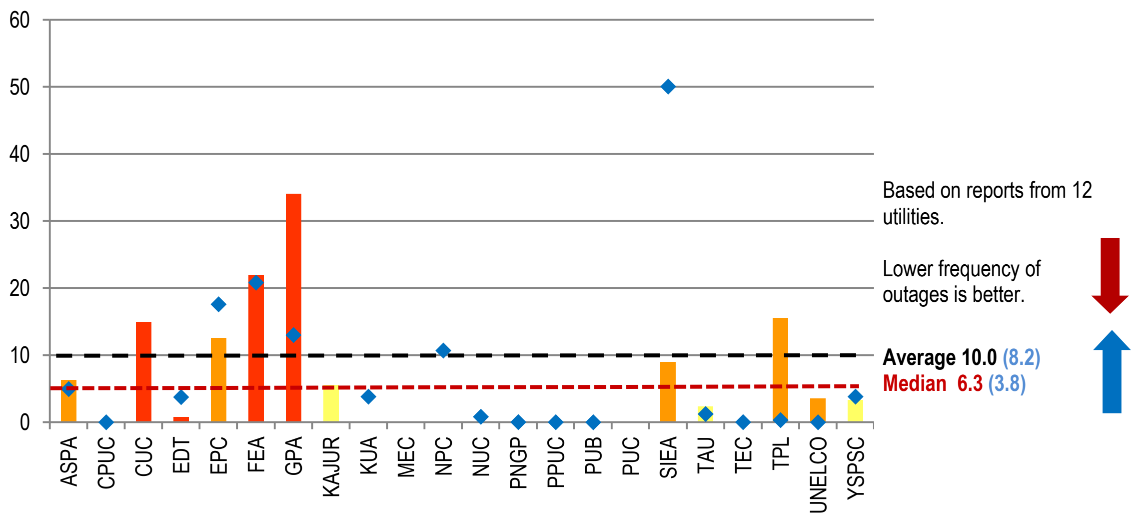


Although the *Power Benchmarking Manual* set out in some detail the calculation of SAIDI (and SAIFI), it became apparent that the capture of SAIDI data within the benchmarking spread-sheet was not easily understood. Improved benchmarking measure definition is also required to ensure consistent treatment of extreme events, short duration outages, 'planned' outages that involve limited customer notification, and LV outages. The most significant factor, however, was lack of capture of basic outage timing and customer impacts, without which even simple reliability measures are impossible to assess. It should be noted that several larger utilities, including the FEA, have implemented detailed processes for capture of reliability performance data. Data confidence and reliability is higher in these cases.

(iv) Interruption Frequency

The SAIFI is also used as a reliability indicator, measuring the average number of interruptions per customer. In 2000, the reported average was 19 compared to a regional benchmark of 10 and international best practice of 0.9. For 2010, reported data suggested that SAIFI had dropped to about eight with a median of less than four interruptions per customer per year. As with SAIDI, SAIFI tends to be estimated by utilities or only partly recorded so the reported improvement may not have reflected actual changes in performance. Reporting issues affecting SAIDI calculations also affect SAIFI, since they rely on the same datasets and the timely recording of outages and customer impacts. In 2011, reported SAIFI for those 12 utilities with credible data, increased to an average of 10.0, with a median of 6.3.

Figure 4.18: SAIFI Interruption Frequency in 2011 (2010) (interruptions per customer)



The relative movements of SAIDI and SAIFI between 2010 and 2011 suggest that the average duration of an outage, for an affected customer, has increased from 69 to 79 minutes.

4.5 Financial Indicators

(i) Financial Indicators: General Comments

For some of the following financial indicators, utilities have requested that data not be made public. As such, alphabetic codes are used in place of utility abbreviations. The codes have been adjusted as a result of the increase in participation and do not match those for the previous benchmarking report.

It should be noted that financial reporting is in many cases not indicative of actual utility costs. In some PICTs, equipment and services provided by donor grants are not included or costed in the asset base. Some utilities use accounting methods and principles that are in accordance with recognised international standards, while others have not yet commenced doing so. Some utilities provide independently audited accounts but others do not. Of those that do, at the time of writing, a number of the accounts on which these indicators are based have either not been subjected to audit or have not yet been approved. The basis for asset valuations also varies significantly amongst utilities, if they are in fact performed.

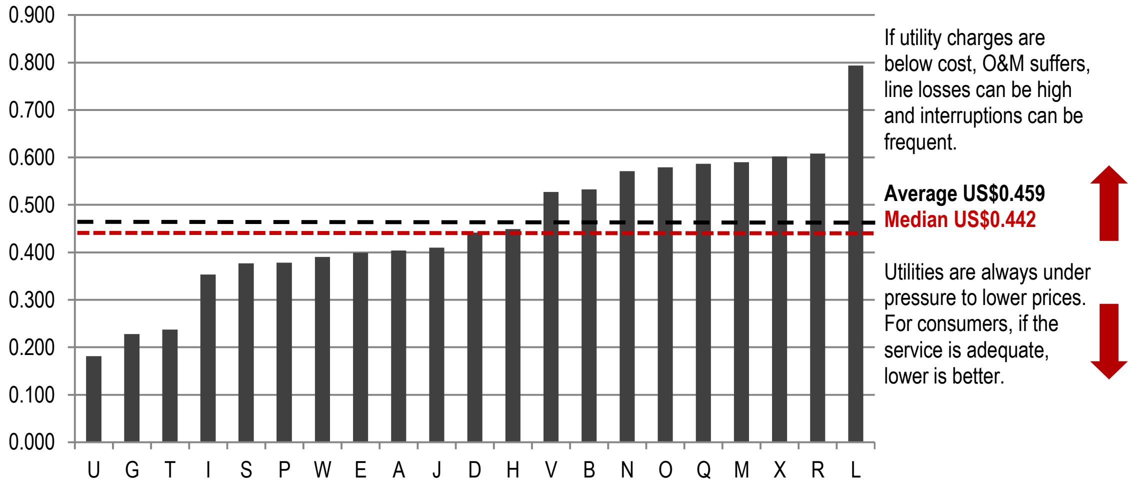
In general, the financial data should be considered indicative only. Financial data in this report has been converted to US dollars.

(ii) Price of Electricity

In the 2002 report the average selling price of electricity to all consumers was US$0.154 per kWh, ranging from US$0.03 to US$0.42. In 2010, the reported average selling price was US$0.394 per kWh with a median value of US$0.38 and range from US$0.07 to US$1.00 (un-inflated). As illustrated in Figure 4.19,[43] the 2011 reported average is US$0.459 per kWh with a median value of US$0.442 and range from US$0.18 to US$0.79.

As previously noted, “the price charged by a utility does not, of course, necessarily correlate with costs for the same utility. Most Pacific utilities charge consumers less than the full cost of supply”.[44]

Figure 4.19: Reported Average Selling Price in 2011 (¢/kWh)



[43] The data for 2010 is not illustrated since the utility coverage is somewhat different between the two years.
[44] PPA and PRIF, *Performance Benchmarking for Pacific Power Utilities,* p.40

(iii) Tariff Analysis

An effort was made in 2010 to compare the electricity charges of different utilities to different consumer classes through an evaluation of costs for representative households (200kWh per month) and commercial enterprises (500kWh per month). This was intended to overcome the difficulty associated with comparisons given variances in surcharges, taxes and other charging mechanisms and subsidies within tariffs. The 2010 analysis was qualified as indicative because of inconsistent tariff periods and difficulty in tariff interpretation.

Reportedly in 2010, households consuming 200kWh per month paid on average US$0.39 per kWh (median US$0.41), and small commercial customers consuming 500kWh per month paid on average US$0.44 per kWh (median US$0.47). These rates were significantly higher than the evaluated average selling price as a result of inconsistencies in the time period and within the utility samples.

The analysis was also extended in 2010 to review lifeline tariff consumption and savings for the seven utilities that have such a structure. They varied significantly in impact on low income families and perceived effectiveness.

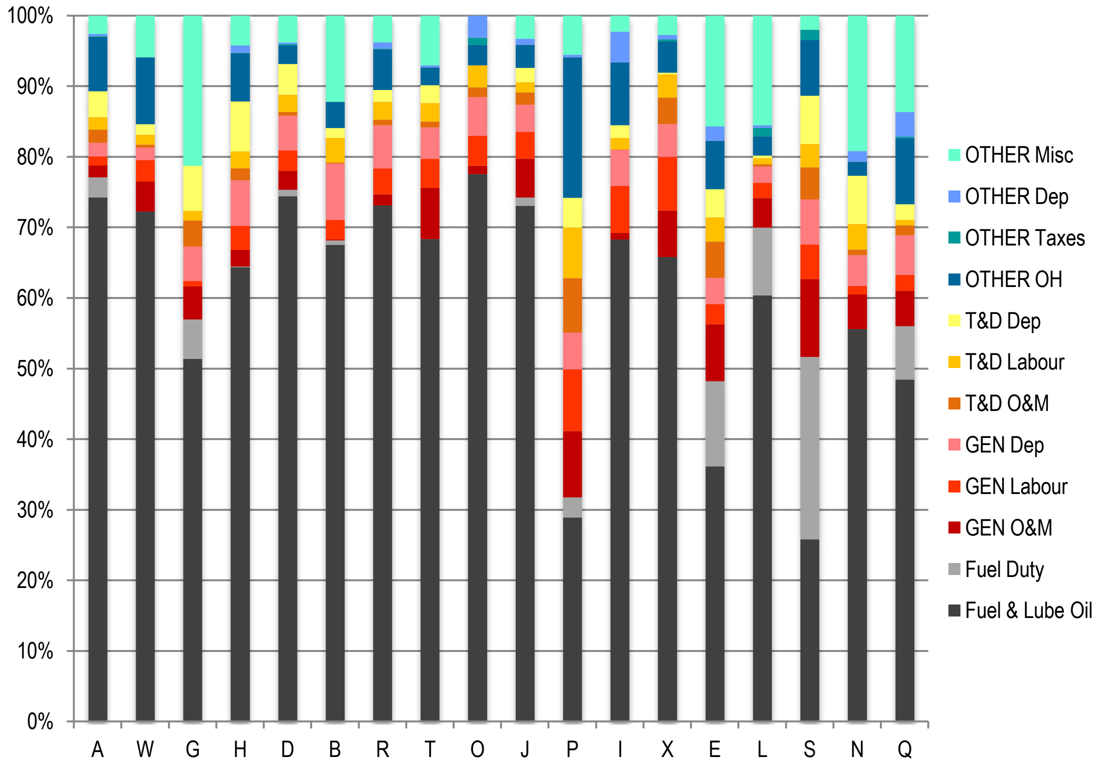
Insufficient data was initially received from utilities to update this analysis. A limited set of data was subsequently collected, most of which did not relate to the 2011 benchmarking time period, and which was of little comparative value. Reporting difficulties and inconsistencies suggest that this will be a useful area for more detailed financial assessment in the next benchmarking round.

(iv) Cost of Electricity

The 2012 benchmarking survey sought a more detailed breakdown of key utility costs to assess and report on overall cost structure. The cost categories for which information was collected included hydrocarbon based fuel and lubrication costs, duty on fuel and lubricating oil, generation O&M, labour and deprecation, transmission and distribution O&M, labour and depreciation, and other overhead expenditure, duty, taxes and miscellaneous costs.

The percentage contributions of each component are presented for the utilities that reported sufficient data in Figure 4.20 below.[45]

Figure 4.20: Utility Cost Breakdown (%)



[45] Analysis of actual costs was undertaken, but not disclosed in the final report in accordance with the agreed treatment of financial data.

Other than the fact that fuel and lubricating oil costs dominate, as expected, with fuel duty regimes varying significantly, cost structures will vary with system topology, fuel mix and the other characteristics of the service area, customer base and organisational structure. Fuel and related duty accounts for between 32 per cent and 78 per cent of total costs for the reporting utilities for the period, with a median of 65 per cent.

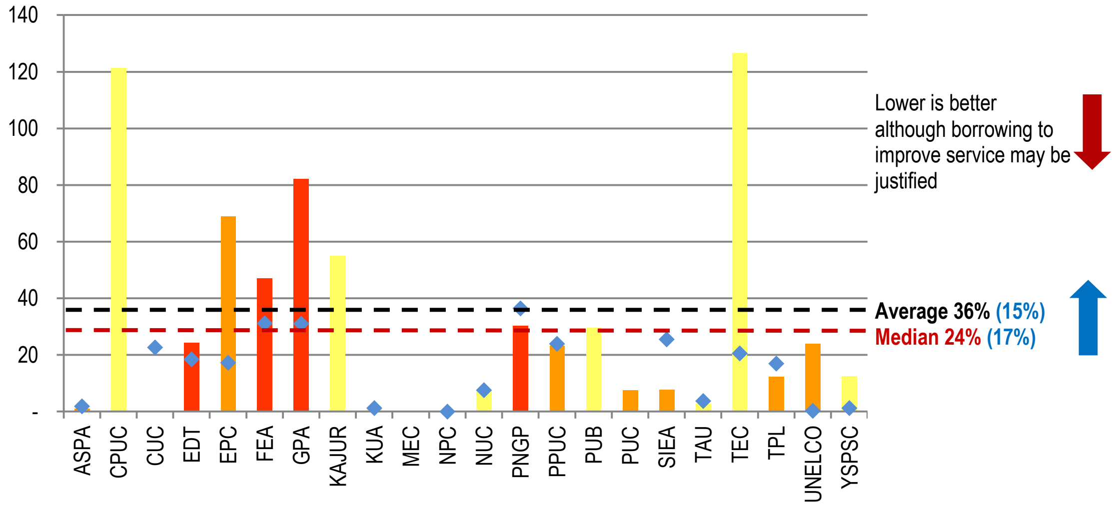
(v) Debt to Equity Ratio

For 2011, the reported debt to equity ratio increased to an average of 36 per cent from 15 per cent in 2010. The 2011 median ratio is 24 per cent and for most, debt levels remain relatively low.

The indicator used for the level of utility debt is the ratio of long term debt to equity, plus long term debt, expressed as a percentage. In 2000, Pacific utilities generally had low levels of debt, with an average ratio of 26 per cent compared to a regional and international benchmark of a maximum of 50 per cent.

In 2010, the reported debt to equity ratio declined to an average of 15 per cent (median 17 per cent). The 2011 reported ratio increased significantly as a result of both increases in debt ratios for many, and the inclusion of data for the relatively highly geared CPUC and KAJUR. The average in 2011 is 36 per cent and the median 24 per cent as shown in Figure 4.21.

Figure 4.21: Debt to Equity Ratio in 2011 (2010) (%)



(vi) Rate of Return on Assets

The Rate of Return on Assets (RORA) is the ratio of operating income to the average value of net fixed assets in operation. The 2002 report stated that:

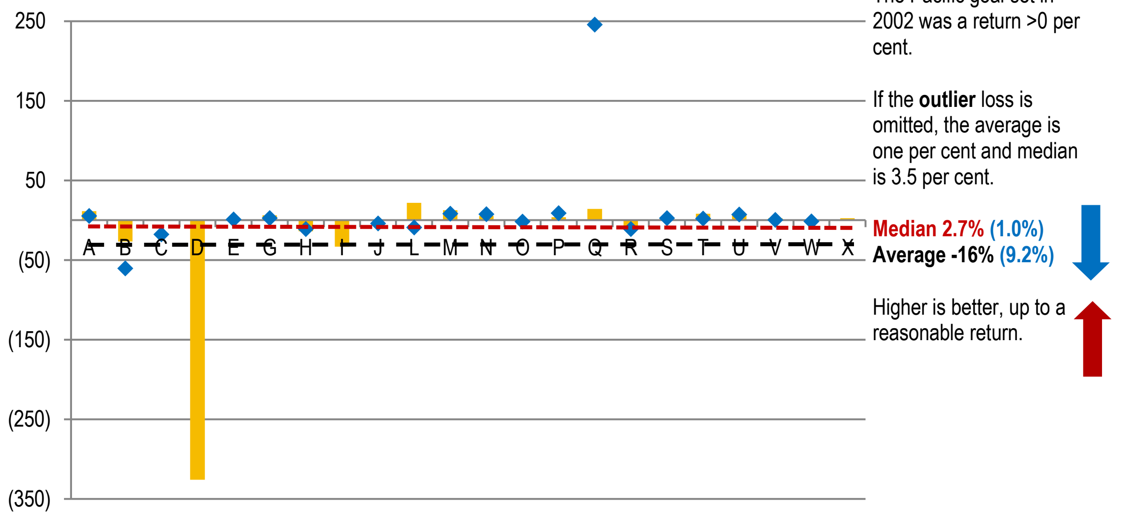
> "generally, Pacific power utilities do not earn commercial rates of return (the Pacific average is minus 16 per cent compared to typical commercial returns of plus 10 per cent). Commercial development is a potential area for improvement in the Pacific."[46]

The reported rate of return on assets in 2000 was skewed greatly by the extreme results of one utility. The median value was about four per cent (positive) and this is probably more indicative than the average of typical utility performance a decade ago.

In 2010, the average reported return was nine per cent (skewed upwards by one very high reported value) but with a low median of only one per cent. In 2011, as shown in Figure 4.22, an extreme loss again skewed the average reported return to -16 per cent, with a median of 2.7 per cent. Excluding the outlier, the average return is one per cent with a median of 3.5 per cent.

[46] PPA and ADB, *Pacific Power Utilities,* p. 8.1.

Figure 4.22: Return on Total Operating Assets in 2011 (2010) (%)



(vii) Return on Equity

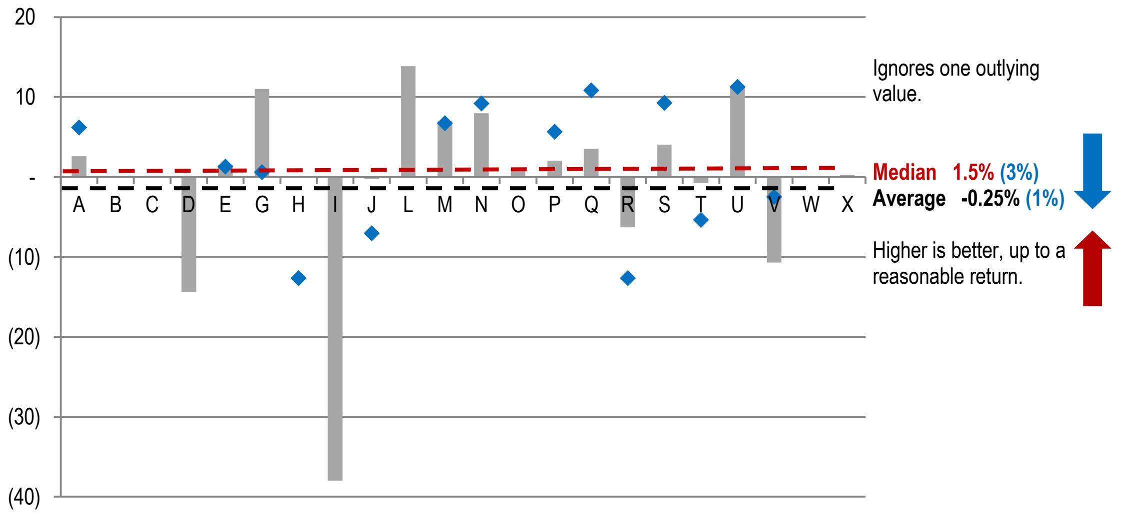
Return on equity (RoE) measures financial returns on owners' funds invested, where:

average owners funds = contributed equity + reserves + retained profits/losses.

This indicator was calculated in 2002 but not provided in the 2002 report. In 2010, the reported return on equity – which covered a slightly different set of utilities than Figure 4.24 – was eight per cent with a median value of six per cent, with considerable variation among utilities. Ignoring one outlier dropped the average and median to one per cent and three per cent respectively.

Very similarly in 2011 as illustrated in Figure 4.23, if outlier 'B' (100 per cent) is ignored, the average and median of 4.8 per cent and 1.8 per cent respectively, drop to minus 0.25 per cent and 1.5 per cent.

Figure 4.23: Return on Equity in 2011 (2010) (%)

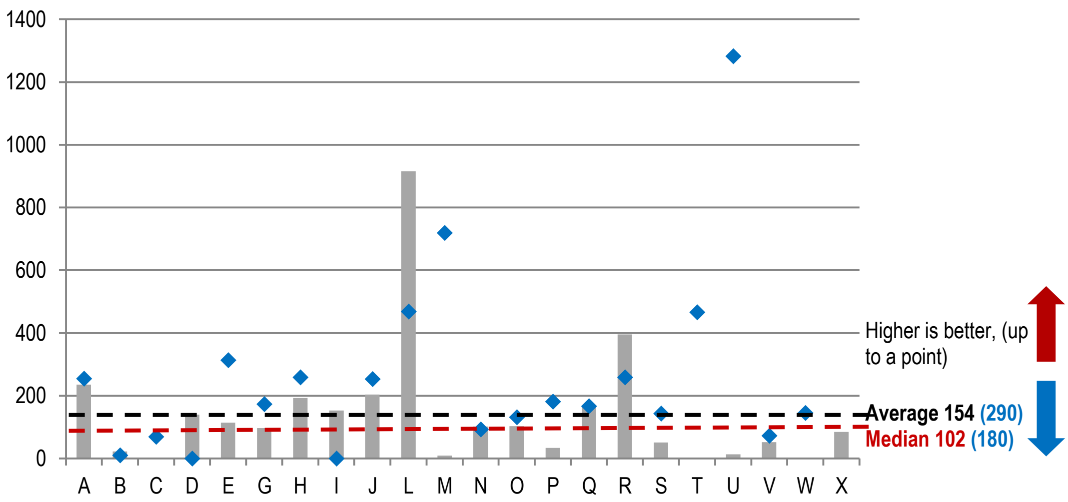


(viii) Current Ratio

The current ratio (current assets divided by current liabilities, expressed as a percentage) measures the ability of business to pay its creditors within the next 12 months, i.e. the ability of the utility to meet its current liabilities from current assets.

For 2000, it was reported that generally, “Pacific power utilities have adequate liquidity indicating probably grant support and effective rate recoveries (Pacific average is 327 per cent compared to Pacific benchmark of 100 per cent).”[47] As for other indicators, however, the results were skewed by the extremely high reported ratio of one utility. If the outlier is ignored, the average in the earlier 2002 benchmarking report was 214 per cent with a median of 105 per cent. For 2010 the average was slightly higher at 290 per cent, with a median of 180 per cent.

Figure 4.24: Reported Current Ratio in 2011 (2010) (current assets/current liabilities)



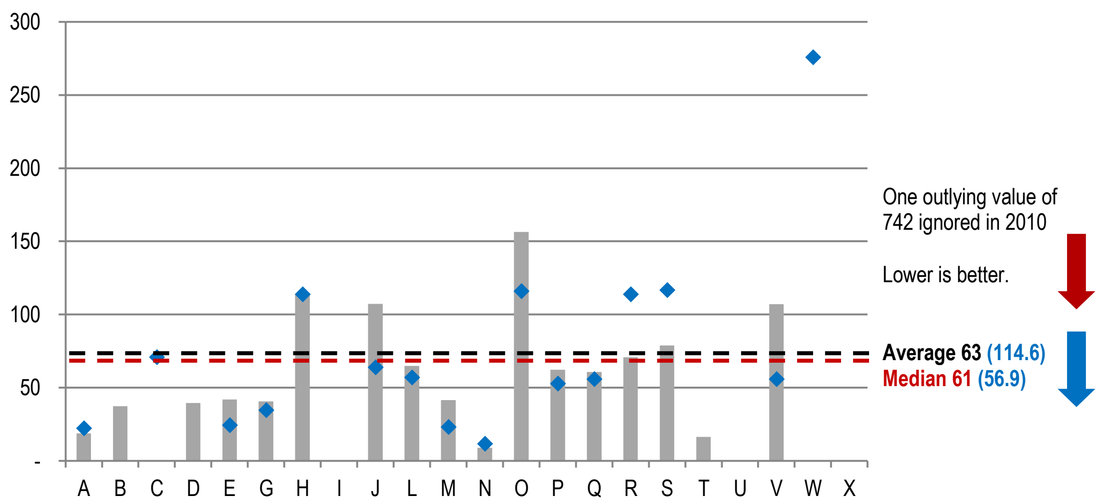
In 2011, as illustrated in Figure 4.24, the reported average current ratio has reduced significantly to 154 per cent, with a median value of 102 per cent.

(ix) Debtor Days

This indicator measures how long it takes, on average, for the utility to collect debts. In 2000:“generally, revenue collection [was] good with a few exceptions making the average worse than the benchmark (Pacific average is 79 days compared to the Pacific benchmark of 50).”[48] In 2002, the median value was about the same as the benchmark of 50 days.

The average in 2010 was considerably higher at 115 days, while the median remained at 57 days. In 2011, the average measure has dropped to 63 days, with a median of 61 days. Only four utilities in total have debtor day values in excess of 100 days.

Figure 4.25: Reported Debtor Days in 2011 (2010) (days)



[47] PPA and ADB, *Pacific Power Utilities,* p. 8-2.
[48] PPA and ADB, *Pacific Power Utilities,* p. 8-2.

4.6 Other General Indicators

(i) Lost Time Injury Duration Rate

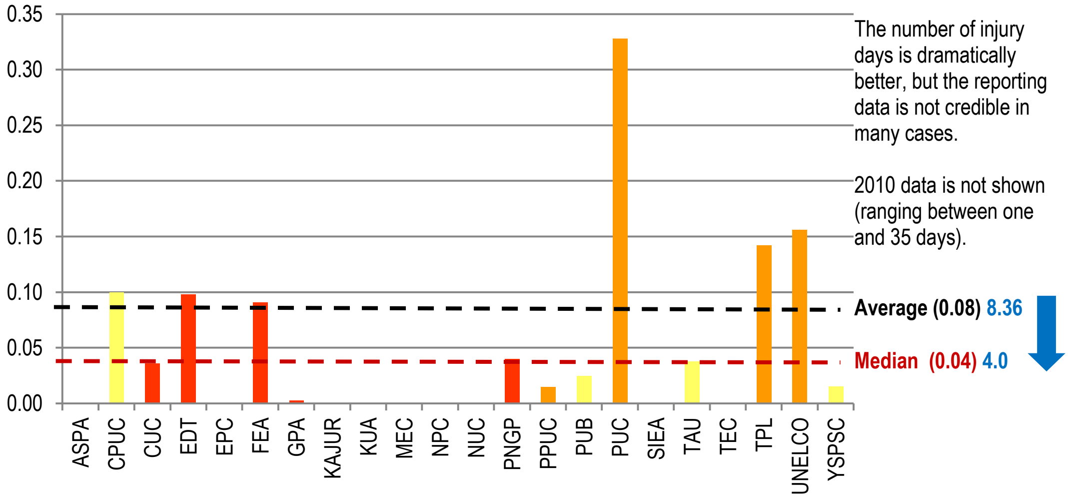
The 2002 report suggested an average of about 500 workdays lost to injuries for each utility and that several utilities "could well benefit from pro-actively managing duration of absences caused by accidents."[49] In 2010, only 10 utilities reported data. With one very high outlier report omitted, the average lost time due to injuries was about eight days per employee with a median of four.

In 2011, the **Lost Time Injury** (LTI) definition was refined based on the Australian Standard AS18851. This broadly means an incident where an employee is absent from work for one day or one shift due to injury incurred during the course of their work. The indicator **Lost Time Injury Duration Rate** (LTIDR) measures the average number of days or shifts lost to injury for employees (excluding contractors) during the reporting period.

As shown in Figure 4.26, the LTDIR for the 13 utilities that submitted information in 2011 was 0.08 days with a median value of 0.04 days. It would be pleasing to conclude that incident rates have decreased by two orders of magnitude in the Pacific, but safety records are not sufficiently robust to support this contention. Underreporting or reporting errors are suspected to have contributed significantly to this reduction.

The amendment to the LTI definition may also have contributed to these results. Discussion with utility management revealed that some utilities may have effectively over-reported injury data in the previous period, treating all incidents (however minor) as LTIs.

Figure 4.26: Lost Time Injury Duration Rate in 2011 (2010) (days per FTE employee)

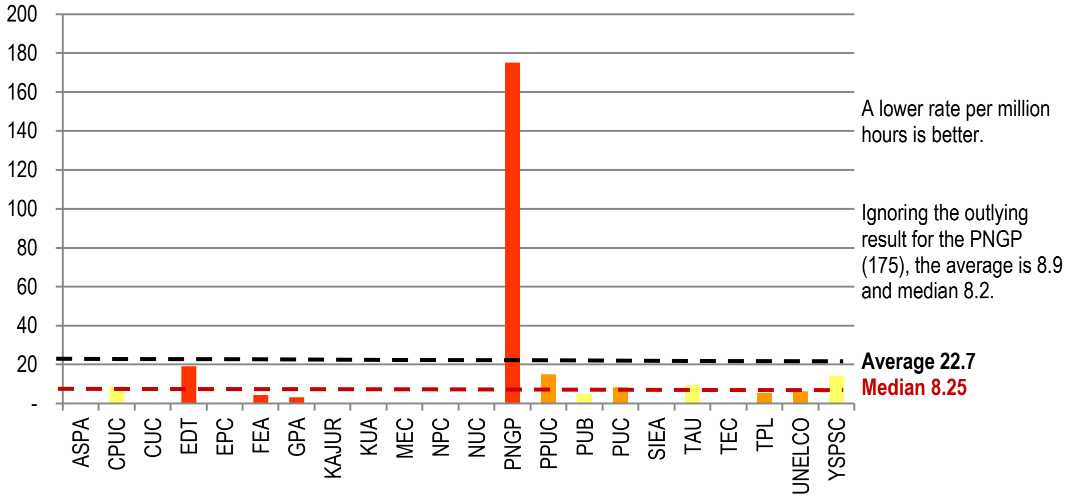


(ii) Lost Time Injury Frequency Rate

This indicator measures the number of Lost Time Injuries for each one million hours worked. The reported frequency of accidents resulting in lost days in the 2002 report was an average of about 2.5 per million hours, per utility, with a wide range. Two utilities (not the same ones as for injury duration) were far in excess of the others. The 2002 report noted that "some utilities appear to have a high frequency of accidents which generally may not be severe; i.e. duration and frequency do not appear to be greatly correlated".[50]

[49] PPA and ADB, *Pacific Power Utilities,* p. 9-1.
[50] PPA and ADB, *Pacific Power Utilities,* p. 9-1.

Figure 4.27: Lost Time Injury Frequency Rate in 2011 (number of incidents per million hours)



No chart was prepared in 2010 as few utilities reported data and the rates that were reported seemed excessive. The need for improved reporting for future benchmarking was identified.[51] As shown in Figure 4.27, the reported average LTIFR for the 12 utilities that submitted information in 2011 was 22.7 per million hours, with a median of 8.3 million hours. The average of 22.7 is equivalent to approximately 4.5 incidents per 100 employees, which is of the same order of magnitude as the rate of 3.0 incidents/100 employees reported by CARILEC in 2008.[52] This allows more confidence to be afforded to the LTIFR measure than the LTIDR reported above, although reporting coverage and overall data reliability remains low.

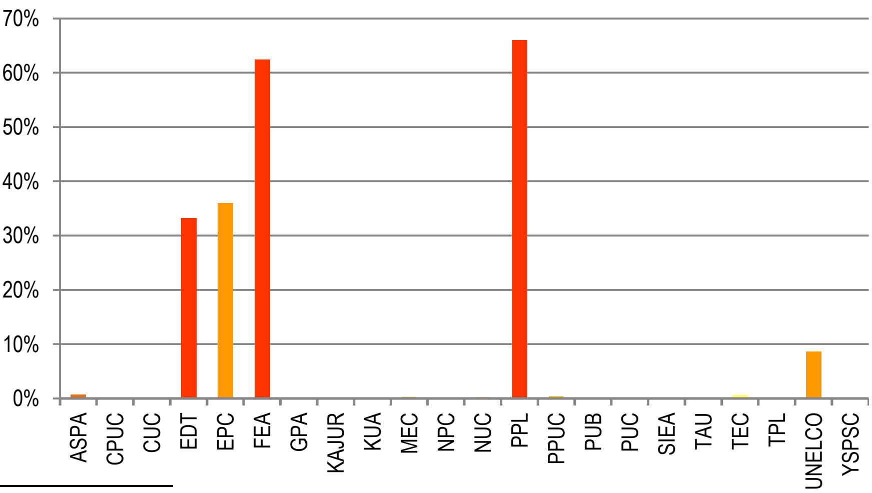
(iii) Renewable Energy to Grid

An indication of the renewable share of energy generation for the main grid of each utility was provided in 2010.[53] On that basis, renewable energy accounted for 22 per cent of generation, 97 per cent of which was from hydropower and concentrated in the EDT, EPC, FEA and PNGP. Small amounts of other renewable sources, including solar PV, wind, bio-energy and bio-fuel generation were also reported. Renewable generation shares were not covered in the 2002 report.

Figure 4.28 illustrates the shares of renewable energy for all grids. As a result of the increasing use of renewable sources on smaller islands, and an increase in hydro generation in Fiji, the total renewable energy share is slightly higher than that reported last year for only the main grids, at 26 per cent.

Renewable energy accounted for 26 per cent of generation in all grids, 97 per cent of which was from hydropower. 17 of 22 utilities still rely on petroleum fuel for 98 per cent of electricity demand.

Figure 4.28: Renewable Energy Generation in 2011 for all Grids (%)



[51] PPA and PRIF, *Performance Benchmarking for Pacific Power Utilities*, p.47
[52] Caribbean Electric Utility Services Corporation (CARILEC) and KEMA, *Benchmark Study of Caribbean Utilities (Fifth Update – Year 2008).* Final Report (Anonymous Version, April 2010).
[53] PPA and PRIF, *Performance Benchmarking for Pacific Power Utilities*, p.47

The majority of renewable energy continues to come from the larger hydro facilities (see Figure 4.29), and 17 of the 22 participating utilities still provide 98 per cent or more of electricity from petroleum fuel.

This indicator is likely to demonstrate significant variability from year to year, depending on the availability and output of hydro generation (which dominates the measure), the extent of reporting of the contribution of small renewable installations, and the treatment of the contributions of IPPs. Non grid connected renewable energy is presently omitted from these figures.

Renewable installations that have been commissioned recently and which did not contribute energy in this reporting period include one MW solar PV installations in both Tonga and American Samoa.

Figure 4.29: Nadarivatu Hydroelectric Project, Fiji

Photo courtesy of the Pacific Power Association.

(iv) Demand Side Management

As noted in the previous benchmark update:

> "[T]here is likely to be an increase in the future in DSM services to large consumers, small businesses and households. DSM services entail utility involvement in efforts to assist customers to reduce electricity consumption or change the pattern of demand in ways that could benefit the utility, such as reducing the rate of growth of maximum demand or shifting loads to different times of day".[54]

Table 4.2 summarises the responses received from utilities in 2010 and 2011 to benchmark questions on the scope and investment in demand side activities.

[54] PPA and PRIF, *Performance Benchmarking for Pacific Power Utilities,* p.49

Table 4.2: Utility Demand Side Management Efforts in 2011 (2010)

Response from utilities	No of utilities reporting	Comments
No response	15	DSM section of questionnaire left blank
No DSM staff or N/A	5	As above
Some Full time DSM staff	4 (4)	Between 1 and 3 staff (either one or two staff)
Budget for DSM	4 (5)	Ranges from $0-$82,000 ($0-75,000)[1]
Savings made in 2010	2 (1)	600 to 5000 MWh (1 MWh)

Notes: 1. Average = US$60,000 (US$35,000)

Five utilities reported that they have no DSM activities and four reported that they have between one and three staff members assigned to DSM with budgets ranging from US$32,000-$82,000. Two utilities reported significant savings through DSM efforts.

Again, the conclusion that there is likely to be more DSM activity than utilities reported is reasonable. Many were involved in donor-supported and/or government DSM efforts, and several discussed these initiatives with benchmarking consultants without explicitly reporting any information.

It is likely that respondents are having difficulty in quantification of the budgets, resources and savings associated with DSM, and are as a result, making limited returns. Modification of the benchmarking questionnaire may help in future periods.

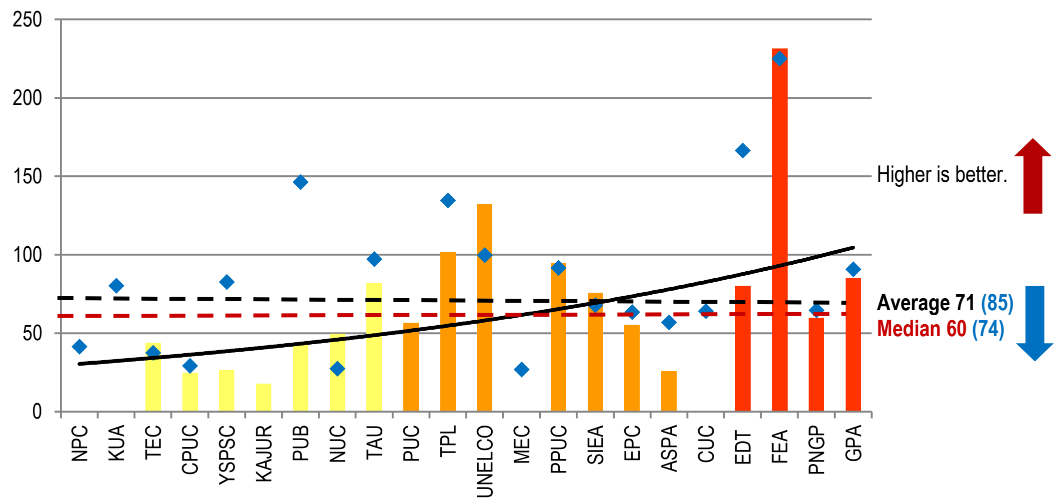
(v) Overall Labour Productivity

The 2002 report did not include an indicator of overall labour productivity, measured by the number of customers per total FTE utility employee. In 2010, there were on average 85 customers per employee, with a median value of only 74, and the observation was made that "productivity appears to be quite low compared to similar sized island utilities elsewhere".[55]

The 2011 data, illustrated in Figure 4.30, indicates a reduction in average labour productivity to 71 customers per FTE employee, with a median of 60. Of those utilities that stood out as above average for their size in 2010, assessed by total generation, only the labour productivity of the FEA continues to appear high.

Overall, the significant reduction may be associated with the reporting of higher FTE numbers, assessed using paid hours inclusive of contractor inputs. While this is likely to have resulted in a more consistent and valid assessment, data issues remain. Not all respondents, for example, have excluded labour hours for staff engaged in capital projects. Data for FTE utility employees was unavailable for four utilities.

Figure 4.30: Overall Labour Productivity in 2011 (2010) (customers per FTE employee)



[55] PPA and PRIF, *Performance Benchmarking for Pacific Power Utilities*, p.49

4.7 An Overall Composite Indicator

An overall composite indicator of utility performance was developed in 2011. Data limitations meant that it was not possible to include financial data in the composite. Even for technical data, there were significant gaps in the data submitted by some utilities.

A simple indicator that equally weighted generation efficiency, capacity utilisation, system losses and overall labour productivity was derived, with quantitative score ranging from 2.2 to 3.8 (on a scale up to 4.0). Overall, this was considered to be a valid assessment of technical performance, although not necessarily a good measure of overall performance for the utilities involved. The omission of financial data in particular was perceived as a significant limitation.

The Steering Committee canvassed views on the composite indicator in July 2012, concluding that the approach was worthy of development and requesting that the PIAC further develop the composite index. The difficulties associated with the range of accurate indicators were appreciated at the time, with the expectation that data improvement would allow a more comprehensive approach reflective of all aspects of utility performance.

Composite indicators generally require a more balanced mix of indicators across key aspects of utility performance, including financial and key service criteria (like supply reliability) and more mature and accurate benchmarking data. Based on the information available, it is not considered timely to introduce financial criteria to the composite indicator:

Key Issues in Composite Indicator Development

- The reliability of financial data is not perceived to have improved sufficiently to allow inclusion of a meaningful financial measure in the composite.
- The qualitative data reliability assessment has emphasised the need for more work to be done across all key measurement and data systems to support benchmarking, including those underpinning technical performance.
- There is no obvious extension of the composite beyond the relatively robust set of technical measures adopted in 2010. For example, it would still be premature to attempt inclusion of SAIDI or other customer-focussed measures until they are more systematically gathered and can be compared meaningfully.
- Care is needed in interpretation of simple composite indicators, since results reflect the interaction of a large number of utility-specific factors (regardless of the number of key components).
- There are advantages in update of the composite to reflect 2011 performance, allowing at least an aggregate assessment of the relative development of technical performance amongst the benchmark group.

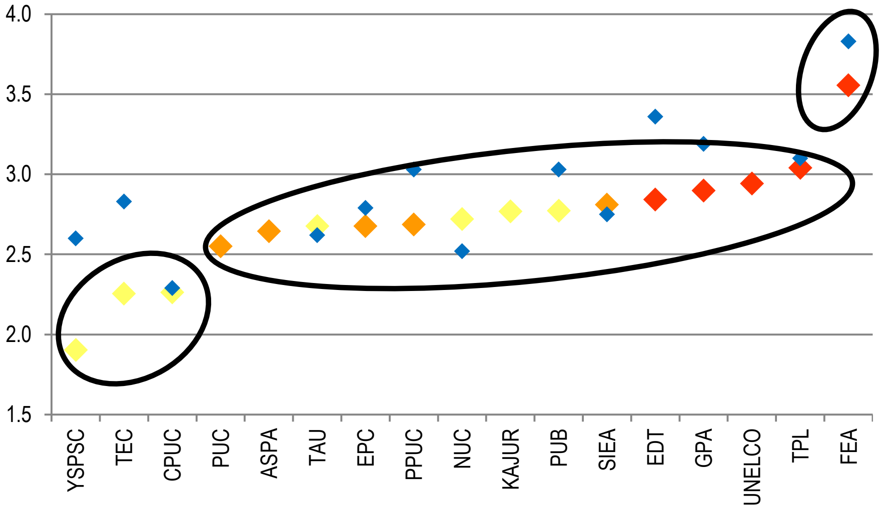
For 2011, the preliminary composite indicator has been reassessed based on the same four equally weighted components identified in 2010, namely:

Components of Composite Indicator (Maximum score 4.0)

- **Generation efficiency:** specific fuel consumption (25 per cent)
- **Efficient utilisation of assets:** capacity factor (25 per cent)
- **System losses:** delivery system losses (25 per cent)
- **Overall labour productivity:** customers per full time utility employee (25 per cent)

Results are summarised in Figure 4.31 and Table 4.3. The composite provides a rough indication of technical performance appropriate to the level of data reliability and benchmarking maturity in the Pacific. The ‘average’ data reliability grade, denoted by the composite grade based on the quantified average across the four data classes presented in Table 4.3, is also shown for the updated composite indicator. Ten of the 19 utilities were grouped within a fairly narrow band with a score of 2.5 to 3.0, with three utilities scoring lower and two higher. The scores for 2010 are also shown, illustrating some movement in rankings and distribution.

Figure 4.31: Composite Technical Indicator for 2011 (2010) (maximum value of 4.0)



The average composite rating for the utilities for which it was calculated decreased from 2.80 in 2010 to 2.71 in 2011. The median decreased from 2.75 to 2.72. This is consistent with the general trend of the movements in technical indicators presented in this updated analysis.

Steering Committee discussion of the draft results in March 2013 revealed some concern over the validity of the relative performance evaluation, but also revealed a very good understanding of the factors underlying the ranking system and the impact of each component. There was also general acknowledgement that the 'conversation was worth having', since it went to the core of utility performance and characteristics. While there was no strong consensus, at the very least, it was felt that retention of the composite indicator was required to keep it on the improvement agenda.

It is proposed that the constitution of the composite indicator continues to be reviewed as the validity of the dataset improves. Improvements in data quality may also permit more sophisticated approaches to relative performance evaluation in future.

Figure 4.32: Diesel Tank and Power Plant at the Electric Power Corporation (EPC), Samoa

Good performance at the EPC has led to its enhanced plant capacity.
Photo courtesy of Cori Alejandrino-Yap (PIAC)

Box 4.1: Technical Composite Indicator and Data Reliability

While there is no proposition to widen the set of measures in the composite, it is desirable to reveal the underlying data reliability assessment scores to provide the 'context' for a composite assessment. This dimension of performance is sufficiently important at this stage of benchmarking development in the Pacific to deserve emphasis. Some commentators suggested that a correlation between data reliability and the composite score is discernible, although the self-assessment methodology makes this too subjective to be particularly meaningful.

Overall Ranking	Utilities and Aggregate Data Reliability Grading Score	Score (Maximum of 4.0)
Higher	FEA (A+)	3.4+
Medium	TPL (A) , UNELCO (A+), GPA (A), EDT (A-) , PUB (B-), KAJUR (B+), NUC (C), PPUC (A-) EPC (B+), TAU (no assessment), ASPA (A+), CUC (A), SIEA (B), PUC (B-)	2.5 – 3.1
Lower	CPUC (B), TEC (B), YSPSC (B)	1.9 - 2.3

Notes: 1. Insufficient data for the PGNP, KUA, NPC, MEC and CUC so these utilities are excluded. **2.** No data reliability self-assessment has been completed for TAU at the time of writing. 3. The data reliability aggregate grade can vary from D- to A+

5 COMPARING RESULTS

5.1 Comparing the 2000, 2010 and 2011 Benchmarking Results

Table 5.1 compares the average results of the current exercise (based on 2011 data) with that of the previous period (based on 2010 date), and the initial benchmarking work of 2002 (based on 2000 data).

Table 5.1: Key Indicators Compared for 2000, 2010 and 2011 Data

Key Indicators (of 2002 report, with additional indicators in 2010 and 2011 shown)		2000 Results		Goals (2002)	International Best Practice (2002 report)	2010 Results		2011 Results	
		Average	Median			Average	Median	Average	Median
Generation									
Load factor (%)	↑ better	67	66	50-80	50-80	64	65	67	68
Capacity factor (%)	↑ better	34	33	> 40	35-65	32	31	36	37
Availability factor (%)	↑ better	93	97	80-90	10-65	98	100	82	80
Specific fuel oil consumption (kWh/ litre)	↑ better	3.8	3.7	4	Over 4	3.8	3.8	3.8	3.8
Lube oil consumption (litres/hour)	↓ better	3.5	2.0	3.2 - 3.5	No standard	-	-	-	-
Lube oil consumption (kWh/litre)	↑ better	N/A	N/A	N/A	No standard	1300	970	1084	937
Forced outage factor (%)	↓ better	7.9	3.2	3-5	0	0.9	0.1	7.9	6.0
Planned outage factor (%)	↓ better	4.3	3.9	3	3	2	~0 (?)	3.9	1.8
O&M (US$ per MWh)	varies	58	14	18		148 (?)	71 (?)	222 (?)	200 (?)
Renewable energy to grid (%)	varies	N/A	N/A	N/A	No standard	22% main grid (?)		26% of all grids (?)	
Transmission									
Transmission losses (%)	↓ better	8	N/A	5	5	?		?	
Distribution									
Customers/employee	↑ better	242	224	240	350	334	297	258	249
Transformer utilisation (%)	↑ better	18	18	30	50	19	21	18	19
Distribution losses (%)	↓ better	12 (?)	N/A	5	5	12? (10 replies)		14	10.7
SAIFI (interruptions/cust.)	↓ better	19	8	10	0.9	8.2 (?)	3.8 (?)	10.1 (?)	5.9 (?)
SAIDI (mins/customer)	↓ better	592	33	200	47	530 (?)	139	1020	583 (?)
Distribution O&M ($/km)	varies	2,478 (?)	-	800	167	?		?	

Key Indicators (of 2002 report, with additional indicators in 2010 and 2011 shown)		2000 Results		Goals (2002)	International Best Practice (2002 report)	2010 Results		2011 Results	
		Average	Median			Average	Median	Average	Median
Corporate / Financial									
Debt to equity ratio (%)	↓ better	26	N/A	< 50	< 50	15	17	36	24
Rate of return on assets (%)	↑ better	- 16.8	-	> 0	> 10	9.2 (?)	1 (?)	-16 (?)	2.7 (?)
Current ratio	↑ better	3.1	1.3	>1:1	1:1	2.9:1	1.8	1.54:1	1.02:1
Debtor days (days)	↓ better	79	51	< 50	30	115	57	63	61
Labour productivity (c/FTE)	↑ better	N/A	N/A	N/A	Not defined	85	74	71	60
TECHNICAL COMPOSITE	↑ better	NA	N/A	NA	Not defined	2.80	2.75	2.71	2.72
Comment		20 utilities				20 utilities		21 utilities	

Notes: 1. n.a. = not available **2.** (**?**) = questionable result **3.** See Table 3.1 for definitions of the indicators

5.2 Comparing Pacific Indicators to those of Other Small Utilities

There was reportedly some doubt about the value of international benchmarking at the inception of the 2011 work. “Some Pacific utility staff questioned the value of comparing PICT indicators to those considered to be international best practice, which generally apply to large, well-resourced utilities in richer countries”.[56]

Consensus was that comparisons should not stray too far. Accordingly, for 2011, an attempt was made to compare Pacific performance to those utilities that share PICT characteristics: small, remote locations and (for most utilities) extreme dependence on petroleum fuel. An appropriate benchmark set continues to be the following group of small island utilities:

Comparison to Other Small Island Utilities

- ***Benchmark Study of Caribbean Utilities, Final Report Sixth Update – Year 2009):***[57] This update has been prepared for the CARILEC but not yet received for comparative purposes at the date of submission of the final report. 21 Caribbean island utilities are expected to have participated. Like the PICTs, the CARILEC members rely overwhelming on petroleum fuel and are small, remote utilities. In general, they have higher electricity coverage and better maintenance budgets than PPA members and the countries have considerably higher per capita GDPs. As there have now been six Caribbean regional benchmarking exercises from 2002 to 2009, the utilities are increasingly familiar with the approach so data collection and reporting are probably better than in the Pacific.
- ***Small Island Systems Second Benchmarking Report of the Network of Experts of Small Island System Managers (NESIS)***. The last benchmarking report was prepared in 2009,[58] based mostly on 2006 data and covering island utilities associated with the European utility association, Eurelectric. The study covers 17 utility groups operating in 73 islands. The 17 groups include GDF-SUEZ Energy Services within which EDT Polynésie Française, EEC Nouvelle Calédonie, EEWF Wallis et Futuna and UNELCO Vanuatu were included as one group. Also included were utilities of high-income islands such as Malta, Jersey, Guernsey, Cyprus and the Isle of Man. Nonetheless, like utilities of the PICTs, these are mostly small, remote, high-cost, petroleum-dependent operations. Upon investigation, this has not been updated recently, although a university joint venture is expected to work with NESIS on an update in 2013.
- ***Selected Financial and Operational Ratios 2009***[59] of the APPA was included as the coverage separates indicators for its smaller Pacific-sized member utilities from the larger ones. Of the 188 utilities participating, 82 per cent have less than 50,000 customers and 54 per cent less than 20,000. However, half of the utilities do not generate electricity (and 70 per cent generate 10 per cent or less of energy supplied to customers). The indicators are of limited comparative value for that reason.

[56] PPA and PRIF, *Performance Benchmarking for Pacific Power Utilities*, p. xx.

[57] Caribbean Electric Utility Services Corporation (CARILEC) and KEMA, *Benchmark Study of Caribbean Utilities (Sixth Update – Year 2009),* Final Report (Anonymous Version, 2011) – requested via the PPA but not yet received.

[58] Network of Experts of Small Island System Managers (NESIS), *Small Island Systems Second Benchmarking Report of the Network of Experts of Small Island System Managers – 2004, 2005, 2006 Data* (14 April 2009).

[59] American Public Power Association (APPA), *APPA Selected Financial and Operating Ratios of Public Power Systems, 2010 Data* (November 2011).

Table 5.2 attempts to compare Pacific performance with other small utilities using results from recent benchmarking reports for them. However, there were fewer common indicators available than expected. Some of these are only indicative as the definitions of some indicators differ. Averages were used (CARILEC & NESIS) where median values were not available. Observations that arise from Table 5.2 are covered in Section 7 of this report.

Table 5.2: Key Indicators Compared for Pacific and Other Small Utilities

Indicator	Pacific (Average & Median)		CARILEC (Average)	NESIS (Average)			APPA (Median)
Data for operational year	2011		2008[60]	2006			2010
No. of participating utilities	22 (but limited data for 2)		21	17 groups; 73 islands			188
Utility characteristics	Most small, remote & oil dependent; most 100% govt-owned. Range of 900 - 150,000+ customers, with median of 8,300		Most small, remote & oil dependent; much higher GDP/capita than PICs; Govt, private & mixed ownership	EU-linked; much higher GDP/capita than PIC;; Govt, private & mixed ownership. Islands are listed in 3 categories below.(14 of 21 PICTs<100 GWh)			US public-owned; typically generation < 10% of supply; 82% have < 50,000 customers
Generation	**Average**	**Median**		**> 1000 GWh**	**< 1000 GWh**	**< 100 GWh**	
Load factor (%)	67	68	74.2				57.1
Capacity (utilisation) factor (%)	36	37	42.4				
Reserve plant margin (%)	114	91	60.5				
Availability factor (%)	82	80	82.9				
Fuel consumption (kWh / litre)	3.8	3.8					
Lube oil use (kWh / litre)	1084	937					
Forced outage factor (%)	7.9	6.0					
Planned outage factor (%)	3.9	1.8					
O&M (US$ per kWh)	222	200					
Transmission& Distribution Losses*							
System losses (%)	12.8	11.6	13	9.7	6.9	9.0	
T & D technical losses (%)	5.4	5.9	6				
Non-technical losses (%)	7.3	5.4	3				
Distribution							
Customers/employee	258	249					313
Unplanned outages / km	72	19					
Transformer utilisation (%)	18	19					
Distribution losses (%)	14	10.7					3.98
SAIFI** (see note 3)	10.1	5.9	6.38				
SAIDI**(min/year/customer)	794	583	580	176	77	309	
Distribution O&M (US$/km)	5846	4648					5,773
Distribution O&M (US$/kWh)	(?)	(?)					0.071
Corporate / Financial / Misc							
Debt to equity ratio (%)	36	24					
Rate of return on assets (%)	-16	2.7	6.4				
Current ratio	1.54:1	1.02:1					2.41
Debtor days	63	61					
Gen. cost (US$/kWh)***	(?)	(?)	0.264	0.126	0.169	0.274	
Tariff (US$/kWh) household + commercial	0.39 0.47	0.41 0.44	0.366 0.387				0.094 0.092
Customers/employee (total)	67	56	135	278	167	125	
Work incidents/100 employees	4.5	(?)	3.0				2.1

Notes: **1.** *From KEMA supply side loss reports. **2.** **PICT data are comparable to the region's total system losses and presumably wrongly reported **3.** SAIFI & SAIDI: Data insufficient for benchmarking & some are inconsistent for CARILEC (and probably PICTs). **4.** ***Generation costs for NESIS & APPA include purchased electricity; NESIS costs based on €1.0 = US$1.25 in 2006. **5.** +PICTs based on 200 kWh per m for households, 500 kWh per m commercial; CARILEC 100 & 2000 respectively. **6.** (**?**) indicates data may not be sufficiently reliable for meaningful comparisons.

[60] Awaiting update including data for 2009 from CARILEC.

6 DISCUSSION & LESSONS LEARNED

6.1 Discussion of Results

This is the second of the annual benchmarking exercises that the PPA intends to continue to carry out with support from development partners. Key discussion points from the 2012 benchmarking exercise are summarised below.

(i) Questionnaire Design

The 2012 questionnaire was revised to take into account comments regarding usability in 2011. The framework for the template and its indicators was based on the 2011 questionnaire (itself based on the 2001 questionnaire with 2003 revisions) as a starting point; then modified to distinguish between data to be entered, intermediate data and output measures. The questionnaire retained the style and format of the 2011 model, which was expected to be familiar to most utilities.

The PPA conference in July 2012 presented an opportunity early in the work to familiarise the benchmarking participants with the questionnaire, the benchmarking process and obtain their input. In the process of working through sample exercises with benchmarking liaison officers and other participants, adjustments were made to several questions within the survey. Feedback was received that the utilities "found the new format simpler, less confusing and more user-friendly". The benchmarking workshop was declared a success and commitments to resourcing the data collection were made by the organisations involved.

Mirroring the experience of the 2011 benchmarking team, numerous exchanges took place between the participants and regional consultant to explain and clarify questionnaire use. Some of the misunderstandings related to 'visual' aspects of the spreadsheet and the different approach from the previous year. Keeping it simple and removing the complexity of output measure calculation also 'lost' visibility of those results for the user. In other words, being removed one step from the ultimate output measures makes it more difficult to appreciate and understand the calculations, and therefore more likely that errors will be made. While ample supplementary material was prepared to inform and educate the users on the data entry spreadsheet, including a comprehensive *Benchmarking Manual*, the spreadsheet itself remains the primary tool and focus of data completion.

There was little need to reiterate background material in Section 1. A better approach may have been to present the data in the spreadsheet and require any changes to be made by edits.

Subsequent clarifications complicated matters, as did the issue of a supplementary request. While handled transparently with clear instructions, multiple versions of spreadsheets inevitably result in data inconsistency and version management problems. This was the case for a number of respondents.

These observations on the treatment of spreadsheet completion touch, to some extent, on the perceived ownership of the benchmarking data. The means by which the utilities themselves become owners, not handlers, designers or simple respondents to data requests, is crucial.

(ii) Data Collection

At the time of inception it was anticipated that some utilities, despite a strong interest in benchmarking and a willingness to devote resources to the work, would be unable to collect sufficiently reliable data for practical use. This conclusion was reached in consultation with previous participants and consultants involved with the work.

It is tempting to expect utilities, in the second year of a benchmarking exercise, to be able to provide reasonably good data without any additional training or the need for on-site assistance. The presumption of continuity is often thwarted in the Pacific, as competent staff members are transferred to other more immediate priorities, or change roles, or employment. Appointing benchmarking liaison officers and engaging with them during the PPA workshop was a useful strategy.

Again, it proved difficult to obtain reliable, consistent and reasonably complete data through email and telephone exchanges. For some utilities, it appeared that the time period allocated (i.e. four months) was insufficient to collate the necessary information, while for others, the information appeared to be unavailable. In general, though not universally, site visits quickly ascertained whether the latter was the case. Unfortunately it is also apparent that many benchmarking representatives do not know where to find information within their own organisations.

Follow up visits to utilities were essential to advance the completeness of the questionnaires, and generally resulted in very good engagement with senior management and technical staff.

(iii) Resubmissions of Data, Site Visits and Quality of Results

Data gaps and inconsistencies were assessed, and brief requests sent to utilities indicating specific omissions and data requiring clarification. This resulted in a second round of submissions from about half of the utilities with some improvements. Subsequent site visits involving the benchmarking consultants resulted in further improvement in the data provided from several utilities.

Importantly, site visits for data validation purposes also provided the opportunity to establish where serious gaps in data were, and where possible and if there was sufficient time, to propose reporting systems or other steps to fill them in subsequent annual benchmarking cycles.

One utility failed to respond as a result of resourcing issues, but at the date of this final report was continuing to capture data for the period for inclusion in the next benchmarking update. Three utilities failed to submit data for major sections of the questionnaire, compromising the data reliability assessments. Nevertheless, review of gaps in reporting against last year’s review suggests a better response overall.

(iv) Cross-Checking Data

Staff members of the PRIF partners and others were asked to provide any recent PICT power sector studies that might provide additional data or allow checking of data submitted.

The most useful source was the KEMA series of supply side loss studies – supported by the European Commission (EC), the United States Department of the Interior (USDOI) and the New Zealand Ministry for Foreign Affairs and Trade (NZMFAT) – which was completed in 2012 to provided information on losses (technical, non-technical, and station auxiliary use) for 19 utilities for 2009 or 2010 operations.

(v) Perceived Value of Benchmarking to the Utilities

During the 2012 PPA Annual General Meeting (AGM), CEOs had what was characterised as a dynamic exchange and expressed strong support for continuing benchmarking. It provided a strong platform for improvement, discussion of successful initiatives between peers, and afforded guidance for effective action planning.

Individual utilities reported on specific initiatives that had been prompted by benchmarking results in the previous period, including reliability performance reporting systems, the initiation of customer surveys and targeted analysis of individual generating plant efficiency. Others provided strong support for benchmarking as a good means of sensitising those in other jurisdictions, including regulators, to the unique challenges faced in the Pacific.

The same positive perception was expressed by attendees at the benchmarking workshop and the Steering Committee meeting in March 2013.

(vi) Comparison of the 2010 and 2011 Results

Comparison of utility operations for 2010 and 2011 is relatively straightforward, although as discussed in Section 5, data inconsistencies make comparisons difficult in some cases. In summary:

2010 vs. 2011 Results

- In generation operations, load factor and capacity factor have exhibited improvements via small increases in utilisation. There has been no decline in specific fuel consumption overall, although individual utility movements are more significant. (The fuel consumption data were still aggregates for each utility since there was insufficient information on generator sizes and loading to determine whether they operated within efficient ranges for their sizes).
- Results for availability of generating plant have decreased significantly, but this is almost entirely due to improved information capture that takes into account de-rating, forced and planned outages. Outage indicators suggest that maintenance planning and implementation may have declined. Lubricating oil consumption suggests the same.
- T&D losses in all categories appear consistent for both time periods, with large variations in non-technical losses within utilities. Reporting issues for the latter make it difficult to conclude that performance has improved or declined. Loss evaluation continues to be a priority improvement area.
- Distribution transformer utilisation is essentially unchanged and remains low, suggesting that utilities are not properly sizing transformers (when they are ordered) and perhaps not maintaining them well. Distribution productivity, as measured by customers per distribution employee, has reduced significantly.
- Indicators of interruptions to supply (SAIDI and SAIFI) were mostly estimated, not measured, although many utilities are implementing improvements to systems for subsequent period data capture. It is likely that reported results reflect improvement in the capture of outages, not significantly worsening performance.
- Other than average debtor days, all financial indicators have worsened. The variances in reporting ranges for many of these measures distort the average results. Combined with the lack of consistent standards in the region, this means financial indicators should still be considered indicative.
- The significant reduction in total labour productivity is of concern, as this is a relatively reliable measure in terms of data inputs.

(vii) Comparing Pacific Results with Those of Other Small Utilities

Comparable indicators for small island utilities remain limited to CARILEC, NESIS and, to a lesser extent, the APPA. At the time the final report was submitted, an update to CARILEC's benchmarking dataset is pending and no updated analysis is available from NESIS. The APPA supplied updated core indicators for their association of 188 small public power companies in September 2012.

Nonetheless the following observations can be made:

Comparing Pacific Results to Other Small Utilities

- The gap between the Pacific and CARILEC utilities in terms of load and capacity factor increased in 2012. Load factors and capacity factors are considerably better for the Caribbean island utilities (CARILEC members) than the PPA members. Correction in the methodology for availability factor has brought the Pacific indicator back into line with CARILEC for that measure.
- Overall system losses and technical losses (as calculated, not measured, by KEMA in both regions) are almost identical for the PPA and CARILEC utilities. Non-technical losses are significantly higher in the Pacific system. Losses for the European-linked island utilities (NESIS members) are lower than those of the Pacific and the Caribbean.
- The small American cooperative utilities (APPA) which do not undertake expansive generation activities had higher average distribution productivity (higher customers per distribution employee, and lower distribution O&M costs/km) in 2006 than the PPA members did in 2011.
- Reported SAIDI and SAIFI customer supply interruption indicators are roughly 25 per cent higher for PPA members than CARILEC members, although reporting accuracy remains questionable.
- Both the median and average rate of return on assets is lower than that of CARILEC. Outliers significantly distort the Pacific results.
- The average household and commercial tariffs in the Pacific are higher than those of the Caribbean, but this is probably more the result of the calculations being made in different reporting years (2010 and 2008 respectively) rather than indicating a real difference.
- Overall labour productivity, measured by customers per FTE employee, was very low for the PPA members in 2011, and is even lower in 2012 – at an average of only 71 compared to 135 for CARILEC members and 125 for the smallest utilities (under 100 GWh per year of generation) of the NESIS group. This constitutes a serious challenge to utilities in the Pacific region.

(viii) Recent Indicators and Performance

Indicators introduced in 2011 were compared to performance in the last period, and a measure of data reliability introduced.

Recently Introduced Indicators

- Renewable energy fed into all grids totalled 26 per cent of generation (22 per cent fed into the main grid in 2010). 17 of the 22 utilities remain almost entirely dependent on petroleum in 2011, with fuel costs accounting for up to 78 per cent of the cost of electricity provision in one case.
- There was, again, very limited reporting of utility efforts to assist customers to reduce electricity use via demand side programmes. The way in which information is captured on this subject requires rethinking, as undoubtedly there is more activity than is being reported.
- Data reliability assessments for six key data components were assessed, with PPA utilities receiving aggregate grades of between C- and A+ for data reliability. It is important that data quality is perceived as significant by participants.
- The additional cost breakdown data presented in Section 4.5 (iv) illustrated the expected variation in the cost structures of the participating utilities. More useful analyses of actual costs have not been presented in accordance with current agreements on anonymity of key financial data.
- The composite indicator was updated, the average reducing from 2.80 to 2.60 between 2011 and 2012. Composite scores ranged from 1.90 to 3.60. Results remain indicative, with no grounds to expand the scope of the composite indicator, or adopt more sophisticated approaches to relative performance evaluation,[61] until data is more reliable and benchmarking in the Pacific more mature. This should be reviewed annually.

Commentators and evaluators have suggested that consideration be given to further analysis of Pacific utilities by scale, similar to the analysis undertaken in the most recent update of the PWWA benchmarking work.[62] The water companies were analysed in three water utility size classes – small, medium and large – on the basis that comparisons would be more meaningful for utilities of the same scale.

[61] Lending agency commentators observed that, amongst other methods, Data Envelop Analysis ("DEA") may be a useful technique for relative efficiency evaluation in future. The method has the advantage that it can take into account multiple inputs and outputs while also allowing for efficiency variations based on scale. DEA has also been relatively widely used for the regulatory analysis of public and private utility efficiency. Results remain highly sensitive to selection of inputs and outputs, and therefore the quality of the underlying data.

[62] Pacific Water and Wastes Association (PWWA), *Pacific Water and Wastewater Utilities Benchmarking Report* (2012).

Based on the distribution of results for power indicators amongst small, medium and large Pacific utilities, which suggest that factors other than scale economies are significant, the value of this approach remains uncertain. This approach will, in the long term, result in some customisation of the benchmarking approach to utilities of different scale, the split potentially being somewhat arbitrary. If this can be accomplished in reporting without losing a coherent benchmarking group, it would be worthy of consideration. The decision would be best taken at the commencement of a new benchmarking cycle.

For the purposes of this report, the scale classification of all utilities using the PPA Membership criteria has been revealed on most graphs where possible. No detailed segmented analysis has been attempted.

(ix) Follow-up Including Performance Improvement Plans (PIPs)

It is worth again stressing two key learning points associated with historical benchmarking programmes:

- A benchmarking project is never finished until action plans have been set in place and implemented to start using best practices and processes; and

- While concise questionnaires are important in collecting data, they should be followed up with face to face interviews with the relevant managers where appropriate, and with site visits to see other participants, particularly those that are suspected to be good performers. More can often be achieved by visual observation than by detailed analysis.

This was achieved to a greater extent in 2012 with provisions for visits to selected participating utilities to assist in both data collection and validation, and the ongoing development of performance improvement action plans in the last phase of the work.

Performance improvement visits were focused on addressing the benchmarking findings and identifying productive areas for utility specific assistance. The point was made in last year's report that "initial follow-up assistance to utilities to help them develop PIPs should be focussed, practical and address areas of improvement that the utilities have themselves identified, rather than try to improve overall utility performance, which can be a huge undertaking".[63]

This is the philosophy used during site visits, working with selected utilities[64] on their most significant needs and priorities for short-term follow-up assistance relevant to the benchmarking results. Performance improvement planning outputs were documented separately from this report.

6.2 Lessons Learned

When this benchmarking exercise began, an attempt was made to apply the large number of lessons associated with the 2011 programme, in addition to those learned from benchmarking experiences in other small utilities (both power and water) in relatively remote less-developed countries. Further lessons have been recognised during the 2012 benchmarking process:

Lessons Learned
▪ The perception of ownership of the data and its potential use means everything. At the simplest level, this means entrusting more of the meaningful dataset to the users and utilities, revising the spreadsheet model to accommodate multiple years data, including future data, and ensuring it is a coherent tool in itself without reference to disparate supplementary material)
▪ Benchmarking data collection programmes can span months, meaning momentum is lost without sustained leadership and commitment from utilities to an established programme. Deadlines for data collection were established in this case on three separate occasions, and in some cases more. The effects of delays in data submission are significant. A clear, fixed and annually consistent programme for benchmarking updates should be established as part of the benchmarking strategy, highlighting deadlines and requiring commitment to them. Consulting assistance should be contracted early where it is a significant part of the work and there are other inflexible milestones (such as the PPA Conference).

[63] PPA and PRIF, *Performance Benchmarking for Pacific Power Utilities*, p. xx.
[64] PIAC's Energy Specialist, P. Muscat assisted the PUB, TPL, and TEC in preparation of Performance Improvement Plans in late 2012. The Team Leader, D. Todd, assisted the SIEA, PPUC and CPUC in February and March 2013.

7 RECOMMENDATIONS

7.1 Towards Sustainable Benchmarking

The PPAs governing mission is to enable access to electricity for all the people of the Pacific Islands region; supporting the PICT power utilities in the provision of high quality, secure, efficient and sustainable electric services.

Amongst the key strategic objectives that are identified in the PPA Strategic Plan,[65] the ongoing benchmarking initiative directly addresses the provision of improved information systems for the evaluation of performance; and indirectly addresses other objectives. The latter related objectives include all those that rely on, or involve, mutually beneficial information sharing and collaboration, institutional development, and specific improvement planning.

The following sections of this report reviews the key considerations for the sustainable continuation of benchmarking led and resourced by the PPA and its members over the medium term. Utilities necessarily have long planning cycles, but in the context of the delivery of benchmarking services to its members, five years is considered a reasonable term for satisfaction of this objective.

(i) Frequency of Benchmark Reporting and Analysis

The PPA Strategic Plan identifies and confirms the need for an annual update of benchmarking in order to help utilities track their progress and evaluate their performance. It is expected that annual reporting will encourage utilities to use benchmarking for regular internal management reporting, and not as an occasional snap-shot of performance.

The July 2012 Steering Committee meeting confirmed that annual update was considered appropriate. Alternatives are potentially available, but longer periods between updates (say, every two years) are not consistent with a five year objective. More regular update of detailed comparative reports and information than annually is not tenable, although utilities may choose to capture information within their internal management systems monthly or quarterly.

Preparing detailed comparative reports is an onerous task for annual completion. Consideration should be given to preparation of a detailed report every two years, and a summary report in the intervening periods. The summary report would include indicators and graphical comparisons, without detailed analysis or commentary.[66]

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[65] Pacific Power Association (PPA), *Pacific Power Association Strategic Plan* (July 2011 – June 2016) approved 26th July 2011.

[66] This is increasingly the kind of approach adopted for regulatory disclosure purposes in other jurisdictions, where regulatory costs are analysed in detail and the disclosure regime needs to be economically justifiable.

Recommendation

- Annual update, with detailed comparative reports prepared every other year. The format of a summary report needs to be developed, and summary information should be compiled and presented for the next reporting year (for 2012 data).

(ii) Data Collection and Online Platform

Benchmarking data is presently collated via email returns of questionnaires prepared in Excel. The issues associated with this mechanism were reviewed in Section 7 and several improvements are possible.

Summary worksheets for data capture and analysis need to be prepared in a form that is easily extended in future. Individual worksheets should be revised for use in the next period to reveal and automatically calculate indicators, and include the indicators already captured. This will allow participants to more easily understand the basis for indicator calculation and performance changes.

Web-based implementation of benchmarking is a more effective tool for data capture, presentation and reporting. Advantages include improved data quality with error checking, convenient data entry and management of time-series data, flexible and immediate feedback and reporting, multi-level security and 24/7 access. Implementation itself needs to consider hosting responsibilities, although there are many providers that can provide adequate service levels, both in Fiji and elsewhere.[67] Good data structure is paramount, requiring the user to be very clear regarding the functional specification and development. Despite some sensitivity, the benefits of a high level of disclosure, aiding in the understanding and communication of significant benchmarks, are well understood by most public organisations. Higher levels of disclosure will result in benchmarking improvement.

Based on the current maturity of Pacific benchmarking, it is recommended that a least one more reporting cycle is undertaken before web based implementation is considered. This will provide time to refine the data structure, prepare more detailed estimates of hosted and other solutions and clarify the internal resources that PPA will require for administration. The latter will be minimal for a well implemented solution, or where consulting resources are used to manage the system.

Recommendations

- **For the next annual capture (2012 data):** revise capture worksheets to include 2010 and 2011 indicator results for convenient reference; automatically calculate new indicators and reveal workings to users; and include the background information from the previous year (for minor edit).

- Revise 2010 dataset for inclusion in consistent summary worksheets or 2011 (to be undertaken as part of this assignment). Include template for 2012 data for convenient annual update in next cycle.

- Prepare functional specification for web-based implementation based on current data-structure and reporting in 2013, with expectation of implementation in 2014. The focus for the next five year period will be progressive improvement of data reliability, assessed in each cycle.

- PPA members conduct the collection and presentation of benchmarking data in an open and transparent manner. (Ownership by the utilities means they will always have the final say on what information will and will not be made publicly available).

[67] The PPA is presently implementing a new website. Of the various options available, development of this platform to accommodate benchmarking data is possible, as is subscribing to a similar solution to that implemented at CARILEC by KEMA (potentially in a joint arrangement). The PPA has recently sought and received a formal offer from KEMA for that purpose.

(iii) Benchmarking Training and Workshops

The PPA generally undertakes several technical workshops per annum, one in conjunction with management workshops and meetings at the annual PPA Conference. There is an expectation that performance benchmarking training and workshops will continue to be valuable and feedback from participants bolsters that contention.

It was originally anticipated that a Northern Pacific regional workshop be undertaken as part of this work, but this was ruled out because of the cost, and also as a result of good attendance at the annual conference workshop. The basis for sub-regional workshops, however, given the cost of travel and flight schedules in the Pacific, is a good one.

It is expected that future workshops will be run to take into account the location of the PPA conference, and also the nature and timing of benchmarking reporting for the year. More detailed sessions including management could be undertaken after release of detailed comparative reports, generally at the conference venue, with annual workshops undertaken in either the Northern or Southern Pacific.

Budgets should take into account the cost of conference and sub-regional workshops and should be prepared well in advance as an element of the cost of effective benchmarking.

The conduct of ‘webinars’ (seminars using the internet, including video conferencing or presentation delivery) or other web-based training may also now be a more realistic option for those utilities with good internet connectivity.

Recommendation

- Consider the timing and location of sub-regional workshops in advance of the benchmarking programme for the next five year period, preparing budgets for attendance costs and taking into account the PPA conference location.

(iv) Resourcing and Costs

Development partner agencies have limited resources and competing priorities for assistance with activities, requiring utilities to bear greater responsibility for ensuring continuation of benchmarking.

Participants were not specifically canvassed on the value that they attribute to benchmarking and how much they would be willing to contribute to this initiative annually, either via PPA subscriptions, or separately. PWWA member surveys established that the relatively low value of US$500 to US$1,000 per annum was considered reasonable, while CARILEC utilities reportedly pay between US$1,500 and US$2,500 per annum to support benchmarking in the Caribbean. The latter contribution does not include funding of the initial cost of CARILEC’s website infrastructure for benchmarking data capture, built with donor assistance for about US$60,000[68] and administered by KEMA.

Pacific CEOs have confirmed that cost sharing of the benchmarking activity is supportable, particularly if benefits are realised. The expectation of a number of members of the PPA is that such an investment would be recovered many times over.

It would be advantageous for buy-in for all members to contribute via the established PPA subscription method, after agreeing the development of annual contributions to match a share of benchmarking costs (to increase over the five year period). The PPA is in the fortunate position that the majority of their members are already engaged with the benchmarking process, meaning the output has more value for all. It would still be beneficial to expand the scope of benchmarking to include those few utilities that have not yet participated.

[68] Excluding annual maintenance of approximately US$10,000.

Recommendations

- That the PPA, as lead agency, works closely with its development partners and other regional organisations to provide benchmarking as a service to its member, and seek funding to assist it to do so.
- That estimates of the costs of benchmarking activities, including the further implementation of a web-based data capture system, consulting assistance, regional and sub-regional workshop conduct, and supplementary reporting be compiled. The order of magnitude of these costs is likely to be $100,000 per annum.
- Contact non-participants with a programme update and with a view to future involvement.
- That PPA members be canvassed and acceptable benchmarking contributions implemented by way of subscriptions (prior to next subscription period), aiming to contribute up to 25 per cent of the annual costs in 2013, increasing with the value of the service in subsequent years as functionality and value is added by the PPA (expanded scope of web-based services and benchmarking assistance). PPA's members will be asked to contribute to supplementary activities, including regional workshops.
- That the PPA considers supplementing resources, at least part-time, to administer benchmarking process improvement and manage the next update.

(v) Annual Calendar and Programme

An established annual schedule for benchmarking activities is an important part of ensuring sustainability. It will also serve to reinforce deadlines and ensure analysis can be completed in a timely fashion.

While calendar year data is preferred, the only practical standard benchmarking periods for comprehensive technical and financial indicator derivation match the accounting year used by participating organisations. Since financial years differ for the benchmark group, including calendar years for some, and balance dates of 31st March and 30th June for others, the analysis periods are not contiguous.

While it will not suit all participants, it would make sense to commence the next cycle early. The process will still be fresh in the minds of participants, abbreviated reporting could be prepared, and it would allow some engagement on the 2012 provisional results at the July PPA Palau conference (if considered desirable). The more significant detailed 2011 results, proposed programme for the future and any significant elements of PIPs should be covered in Palau. This is a challenging but potentially beneficial programme.

Table 7.1: Indicative Calendar for Benchmarking

Month(s)	Summary of Activities	2013 to 2016
April	Begin work planning and initiate data collection.	
May	Data entry and returns by utilities.	2013 – 2015: Email spreadsheet 2015 onwards: Web based entry (Implementation of web system in 2014/15)
June	Utility follow-up and clarification.	
July	PPA Conference: Management presentations, PIP feedback. Benchmarking programme focus as required.	2013: Koror (Palau)
August	Complete data validation and analysis.	
September	Preparation of draft report.	
October	Sub-regional workshops (subject to budgetary provisions): Action planning and PIPs.	2013: Southern utilities: technical workshop. 2014 – 2016: Location either alternating North or South based on Conference attendance and coverage.
November	Prepare Final Benchmarking Report.	2013 and 2015: Summary 2014 and 2016: Detailed

(vi) Maintaining Engagement: Other Possibilities

Other means of maintaining interest and engagement in benchmarking may include:

- Adoption of utility awards based on either benchmarking performance, improvement, or other criteria that involve exemplary work based on benchmarking data. These could be awarded in several classifications at the PPA Annual Conference.
- Involvement of well recognised benchmarking practitioners and utilities from other jurisdictions in regional workshops and conferences.
- Regular PPA newsletter updates during the key parts of the benchmarking information preparation cycle, including key information, lessons and observations.

Recommendation

- That the potential for improvements in benchmarking engagement be considered in relation to all related activities undertaken by PPA.

7.2 Other Recommendations

The following sets out recommendations for the consideration of the utility CEOs, the PPA and development partners arising from the experiences of the 2012 benchmarking exercise, in addition to those associated with the benchmarking sustainability strategy presented in Section 8.1.

(i) Broad Areas of Concern for Pacific Power Utility Performance

More specific performance improvement recommendations are included in Performance Improvement Plans prepared in conjunction with specific utilities to address one or more aspects of benchmarked performance. These are separately prepared and presented.

The following areas of concern repeat some of the conclusions of the 2011 benchmarking. Given that the trend in the majority of the indicators informing these concerns is unfavourable, this is unsurprising. Again, it should be noted that improvements in data quality have an impact on observed trends.

Broad Areas of Concern

- **Low labour productivity.** Levels of overall labour productivity appear to have dropped further for the benchmark group in 2011, although improved capture of information on Full Time Equivalent employment numbers may have had an impact. Last year's recommendations centred on research and investigation of the factors underpinning poor productivity within utilities and other SOEs in the region, consolidating any learning into a utility specific report for use by the PPA and other agencies. This is a wide ranging issue for which this seems a good first step. It should be undertaken if not already progressed. A particular aspect that might merit investigation would be the extent to which modern SCADA and communication systems can alleviate issues for remote systems.

  One commentator asked the question, "what lessons can be learnt from the more productive utilities?"; saying "a detailed understanding of how crews are set up and operate might help". A number of invitations were extended by utilities with high performance rankings to others during the course of this work. Formalisation of these arrangements would be most beneficial.

  Another utility CEO identified the need to deepen the technical skills of senior management teams as a crucial success factor for Pacific utilities.

- **High non-technical losses.** While data in this area has not been improved significantly as a result of this benchmarking update, the opportunities have been well documented in KEMAs completed loss studies. Regional loss-reduction programmes based on cost-effective improvements should continue, including discussions with PRIF partners on grant and loan assistance to specific utilities for implementation. Non-technical loss reduction opportunities are likely to be more immediately implemented in many cases than technical loss reductions involving changes in asset design or operation.

- **Poor life-cycle management and appreciation of asset management.** There is a general lack of appreciation for the asset management discipline from asset design to end of life management. This potentially exhibits itself most clearly in lack of systematic maintenance, an issue that was highlighted in the 2010 report and resulted in recommendations for case study preparation.

  The fundamental problem of maintenance deferral because of lack of funds remains, despite the inherently high cost and risks of this practice. In the words of one utility CEO, "the issue of maintenance is both technical and fiscal – if utility income is insufficient to cover all costs, maintenance will be the first to suffer – establishing proper fiscal management is essential. This does not get the right level of attention". Progress has been made on this front, with several case studies completed or under preparation, emphasising the economics of maintenance for release in the Asset Management publication due in April 2013.

  It is recommended that consideration be given to expanding the use of case studies to cover other utility asset-management issues, including for example, demand forecasting and service level assessment.

- **Lack of attention to safety and incident reporting.** The level of reporting of safety incidents and other non-conformances appears either low or non-existent amongst many utilities. Insufficient analysis or investigation of this has been performed to come to conclusions, but it would appear that most Pacific utilities have relatively immature safety management systems.

  The next cycle of benchmarking should provide more guidance to respondents on safety statistics. It is recommended that Pacific utilities or PPA subscribe to the safety specific publications of other industry associations in New Zealand or Australia to promulgate safety information and alerts. Safety specific strategy and associated programmes appear to require further development.

- **Financial Data Disclosure and Review.** The difficulties associated with varying financial standards and accounting regimes have been discussed elsewhere in this document. The impact of these variations, and the policy of anonymity for financial data, means that financial benchmarking data prepared during this period is not as robust as that associated with the technical benchmarks. Other commentators have questioned the choice of financial indicators and the need to disclose all cost data to allow more meaningful analysis of profitability. In particular, the difference between tariffs and variable costs "would show the margin (if any) that [the] utilities can use to make capital investment out of their own resources".

  It is recommended that utilities consider revealing all financial benchmarking data as a means of furthering performance improvement and the quality of comparative benchmarking and financial analysis. It is also recommended that PRIF partners consider providing specialist direct financial support for future benchmarking updates, undertaking a more comprehensive review of the design and scope of financial benchmarks.

- **Poor knowledge of outages and customer experience.** The SAIDI and SAIFI indicators of the duration and frequency of customer outages continue to be highly questionable, although practical recommendations implemented during data validation visits afford confidence (in at least some cases) that the quality of this data can be improved quickly without major investments. Improved reliability statistics are essential for appropriately targeted investments for reliability improvement.

  It is recommended that a study of key opportunities for reliability improvement specific to the Pacific utility experience be prepared, highlighting the range of causes and mitigating investments. This should also consider customer perceptions of outages, since these will guide preferred solutions to the same extent as hard outage data.

The costs of carrying out the above recommendations, possible sources of funding, responsibility for action, and priorities, have not been addressed. However, these could be considered when the PPA Secretariat discusses the themes, findings and recommendations of this report with their directors, and subsequently advises the PIAC of initiatives that might form the basis for collaboration with the PRIF regarding future support and assistance at a regional level and to specific utilities.

(ii) Improving the Quality of Information in Future Benchmarking

Indicators and analysis continue to be defined and undertaken in a way that allows consistent comparisons between reporting periods. This also reduces the reporting burden on utilities. It is recommended that a number of changes be made to improve the quality and accuracy of future reports. Many of these can be easily incorporated into the next benchmarking cycle in 2013 exercise without the need for extensive resources.

Improving the indicators and questionnaire

The indicators and questionnaire format should be carefully reviewed by the PPA and CEOs to agree on changes to make it more user-friendly and improve the resulting data. Specific recommendations for consideration follow.

Improving Indicators and Questionnaire

- **General.** The definitions and formulas for all indicators should be reviewed for accuracy, clarity, and relevance as useful indicators of performance for Pacific power utilities. They should be modified as required.
- **Losses.** The 2012 questionnaire adopted the recommendations made in 2011 for transmission and distribution losses, and separated station use, but did not separate non-technical losses. This adjustment should be completed in 2013. Comprehensive definitions of all loss components should also be presented and clarified.
- **Genset sizes.** It still may be possible to develop a reporting system to indicate the size and loading of individual generator engines, in order to distinguish between those with higher or lower design efficiencies. Part of this work was effectively undertaken in reporting detailed engine sizes for the purposes of forced outage and de-rating reporting in 2011. CEOs should consider whether loading and fuel use information can be readily provided for multiple units. A significant amount of additional data would still be required.
- **Energy efficiency.** Reporting of utility based DSM initiatives was very poor, although the questionnaire was not significantly further developed for this purpose. As national interest in improved energy efficiency is likely to grow in the Pacific, and more resources are expected to be available to improve the efficiency of energy use, an improved method of reporting energy efficiency efforts should be developed. More descriptive material may assist in defining the scope of such initiatives.
- **Specific Fuel Consumption.** Specific fuel consumption, as noted within the 2012 benchmarking manual, is normally specified as a weight based measure to account for variations in the specific gravity and energy content of fuel types. The data specification used in 2012 was consistent with the previous year, requiring utilities to provide volumetric fuel usage data at the standard 15 degrees C. While the use of a consistent specification aids intra-period comparisons, it also results in distorted efficiency reporting. Revision of the indicator may be warranted or at the very least, an adjusted comparison for those who use Heavy Fuel Oil could be undertaken.
- **Composite indicator.** The usefulness of the overall composite indicator of utility performance should be considered again by CEOs in light of its update this year. Should the methodology associated with the technical indicator update and results prove unsatisfactory, then it is most unlikely that inclusion of financial measures will improve matters. It is recommended that the technical indicator is retained in its current form, and supplemented with a financial indicator if the data is considered to be reliable enough in the next cycle to support it.
- **Reliability Performance.** The extension of reliability performance reporting to make the distinction between generation, transmission and distribution outage contributions to SAIDI and SAIFI should be considered for the next period. Few utilities report separately in this way at present, but it is a logical extension of reliability performance reporting. The introduction of consistent fault cause classification could also be considered, including an agreed treatment of extreme events for reporting purposes. The priority should initially be on reporting valid aggregate SAIDI and SAIFI performance.
- **Data Reliability Assessment.** The CEOs should consider whether the introduction of a data reliability assessment measure is valuable and will contribute to enhancing data reliability, or whether it should be dropped for subsequent cycles. This amendment was made late in the process of completing the adjustments to the questionnaire.
- **New indicators.** Consider whether new indicators suggested by various commentators should be added, and if so carefully define them and how they are to be measured, e.g.:
    - Emissions from power plants, and if so, should this be restricted to carbon dioxide or include others such as sulphur and nitrogen oxides;
    - Consumer perceptions of the quality of service provided by the utilities have not yet been included. This requires effort in consultation with customers and consistent measures to be evaluated.
    - One utility CEO suggested the use of service order fulfilment (aged in the same way as debtors, for example) as a useful proxy measure of customer service performance.

- **Pacific regional targets for specific indicators.** The regional goals for individual indicators were decided by the utility CEOs a decade ago. They were reconsidered and discussed in mid-2012 with differing opinions on what was achievable and appropriate. No firm recommendations for changes were made in 2011 and the information in Table 7.1 was still considered a starting point for consideration by CEOs.

  The trends in indicators in 2012 must provide some pause for thought before more ambitious targets are selected. Most could be considered stretch goals, but remain appropriate to the combined circumstances of Pacific utilities. SAIDI and SAIFI are the exception, where the realisation of annual SAIDI-minutes of 100 is considered a long term goal. It is recommended that the more realistic 200 minute SAIDI and SAIFI of 10 is re-adopted (excluding the impact of extreme events).

  In practice, there are major variances amongst utility performances, and the more significant targets are those selected by individual utilities as part of specific performance improvement plans. It is recommended that other general indicators be retained for 2013 and reviewed at the conclusion of the next cycle.

Table 7.2: Revised Pacific Regional Benchmarking Indicators and Goals for CEOs' Consideration and Confirmation

Key Indicator	Goals for future agreed by CEOs in 2002	International Best Practice (2002 report)	Reported Results in 2011 (Median)	Reported Results in 2012 (Median)	Goals for future
Generation					
Load factor	50-80%	65-80%	65%	68%	70-75%
Capacity factor	> 40%	35-65%	31%	37%	60%
Availability factor	80%-90%	10-65%	100%	80%	Overall: 60% New plant: >70%
Reserve margin		30 – 60%	91%	Not used	60%
Lubricating oil (kWh/litre)	-	-	970	937	~1 MW: 500-600 ~4-5 MW:1000-1300
Specific fuel consumption medium speed 750 rpm (kWh / l)	4.0	4.5	3.6-3.8 *	3.8-3.8 *	> 4.0
Forced outage	3-5%	3%	0.1%	6.0%	3 – 5%
Planned outage factor	3%	3%	0.05%	1.8%	3 – 5%
O&M cost per MWh	$18	-	$71	$200	Report but no goal**
Transmission & Distribution (T&D)					
Transmission Losses	5%	5%	n.a.	n.a.	< 10% T&D combined
Delivery system losses **Technical** **Non-technical**			 5.9% 5.2%	 5.9% 5.5%	 < 5% < 3 %
Station auxiliary use	None	-	4.8%	3.6%	< 5.0%
Customers/distribution employee	240	350	297	330	300
Distribution transformer utilisation	30%	50%	21%	19%	< 50%
Distribution losses	5%	5%	12%(?)	10.7%(?)	Combine with T** losses
SAIFI	10	0.9	3.8	5.9	6-10
SAIDI	200	47	139	583	200 #
Distribution O&M US$/km	$800	$167	-	-	Report but no goal***
Corporate / Financial					
Debt to equity ratio	<50%	< 50%	17%	24%	20-30%
Rate of return on assets	> 0%	> 10%	1%	2.7%	10%
Current ratio	>1:1	1:1	1.8	1.02:1	2:1 – 3:1
Debtor days	< 50 days	30 days	57	61	< 30 days
Customers / total employees	None	-	74	60	>100 (?)

Notes: 1. * Median differs according to source (questionnaires or KEMA) **2.** ** T= Transmission losses **3.** *** Or possibly goal using constant $. The old indicators not mentioned in this table remain unchanged but CEOs should consider them as well **4. (?)** questionable result 5. # excluding extreme or unusual events.

The Benchmarking Manual

The updated *Manual of Performance Benchmarking for Pacific Power Utilities*[69] was well received and will be useful for future benchmarking exercises. The practical examples of calculations of indicators were found to be particularly useful to the utilities. The questionnaire and explanatory notes have been included. The process material (taken from the

[69] PPA and PRIF, *Power Benchmarking Manual*.

original *Manual)* is somewhat dated, since the scope of the update did not include sufficient time or resources to undertake a comprehensive revision. This material would benefit from update within the next few years.

Visits to Utilities for Data Collection

It is recommended that visits be made to at least some utilities to assist in the collection and initial analysis of data in the next cycle, possibly to those that did not receive the benefit of visits by members of the consulting team in 2012.

PRIF Requirements

Where the PRIF partners arrange power sector technical assistance grants or loans, they should continue to consider including the collection of specific benchmarking data in their covenants, provide financial support for the data collection, and provide all reports electronically to the PPA. In return, the development partners should have access to PPA data.

PPA Database

The consolidated summary worksheet developed this year will allow easier comparison of trends over time and comparisons among utilities. The data for the 2011 benchmarking will form the baseline. This will be managed and held in the PPA Office.

APPENDIX

Appendix 1

Lessons from International Benchmarking

This Appendix is excerpted from the PPA's (with ADB/PIAC support) 'Inception Report: Performance Benchmarking for Pacific Power Utilities' (September 2012).

Global benchmarking experience was canvassed in preparation for the 2011 benchmarking exercise, including information from long running projects for developing country utilities undertaken by the World Bank and the ADB, and other studies in South Asia and Africa.

The conclusions remain valid and important to keep in mind while ensuring a sustainable approach is established for the Pacific utilities. An interesting early conclusion of the World Bank (WB) was that the existence of regular performance benchmarking, if the indicators are clear and data are made publicly available, improves the quality of utility performance through pressure from the public and other stakeholders, a conclusion supported by a recent ADB study (ADB, 2010). The WB report lists "the requirements for effective benchmarking: choosing indicators that are unambiguous and verifiable, consistent with long-term incentives for good performance, and easy for the public to understand."

The power of public disclosure of comparable information has been proven in other jurisdictions, including in New Zealand, where the adoption of an information disclosure regime is a major part of the light-handed regulatory model for power utilities. This has arguably led to significant performance gains, as a wide range of disclosed performance benchmarks and detailed asset management information has been assimilated by participants in the industry, and been subjected to analysis by regulators and customers alike.

Later analysis (WB, 2009) concluded that 'no one model fits all' for improving service provision. However, it suggests that the existence of a regulatory agency, regardless of whether utility ownership is public or private, has a significant positive impact on utility performance, as long as the agency is transparent, accountable and free of political interference. Although few PICT utilities currently operate under external regulation, this is changing. Regulators have specific data needs but developing the habit of regular data collection may help prepare utilities for this eventuality.

Lessons learned from benchmarking in Uganda (IPPP, 2006) include the following:

- "Operators do not necessarily want internationally accepted indicators to benchmark against. As a matter of fact most would prefer **home grown indicators** that they can easily identify with;
- It is important to agree on an **acceptable number of indicators** with the target stakeholders;
- The target stakeholders **need to be consulted** at each and every stage to make the indicators acceptable to them; and

- Stakeholders should not be burdened with reporting requirements**. 'Reporting fatigue'** can easily lead to stakeholders furnishing false data hence rendering the entire benchmarking system useless!"

These conclusions apply to all benchmarking exercises. Power utilities, despite often having similar service goals, are faced by a broad range of institutional, geographical, social, economic, technological and other circumstances. The desire for truly relevant local indicators needs to be balanced against comparability with practice elsewhere, something that is required to target improvement and critically examine alternatives. "Reporting fatigue" could be considered to be closely allied to "consulting fatigue". It will always be desirable for participants to take as much ownership of delivery of long term benchmarking programmes as possible, and as soon as possible.

In a concept study of power sector benchmarking for a number of South Asian countries, USAID (2004) concluded that "the difficulty in obtaining reliable data for this project cannot be understated. Without participation from key stakeholders in the region, the methodological framework will remain conceptual with little real-world value or regional specificity."

For a benchmarking database to be truly valuable and commercially worthwhile, the input data should have the following characteristics:

- **Accessibility**: "It must be possible to access the data for multiple [utilities] within resource constraints

- **Reliability:** The data must be good quality and based on confirmable facts, with a reasonable level of assurance that it has not been fabricated or misrepresented;

- **Consistency**: Definitions of the metrics being reported must be consistent across sources and across [utilities] to assure that the data are comparable.

- **Replicability**: Data sources and the means of acquisition should be standardised to support periodic updates that indicate changes in benchmark metrics over time."

These characteristics require good programme design; careful consideration of data storage and modelling, and ongoing quality assurance effort.

Other lessons from reviews of power utility benchmarking (ADB, 2007; ADB, 2010; CEPE, 2007; ERGEG, 2010; USAID, 2006; WB, 2005) include the following:

- Data should be available at realistic and reasonable levels of cost and effort, and sources should be reliable and, ideally, **cross-checked**;

- Comparability of the indicator measured **over time** is an important criterion; an indicator should be consistent in definition, measurement method and data assembly;

- Differences in accounting standards and inflation, as well as conversions using exchange rates and purchasing power parities, tend to reduce the usefulness of time-series and cross-country data conversion into a single monetary unit;

- Benchmarking should have both short-term objectives (improve delivery of selected services or operational processes) and medium term objectives (institutionalise a process of change, build capacity of staff to initiate change, and establish **a sustainable exchange process** on experience among network members);

- Factors for benchmarking success include visible support and **continuous leadership** of senior officials and executives, allocation of adequate staff time and skills, willingness to accept and implement change and try new approaches;

- A series of regular benchmarking is far more valuable than a one-off exercise. **Repeated observations** of a utility over time allows a better understanding of utility-specific issues;

- The regular monitoring of relevant indicators and comparative benchmarking can encourage the sharing and implementation of good practices through **peer pressure** mechanisms;

- Key financial performance indicators should preferably be those used internationally, rather than utility specific; and

- For comparability among utilities, there needs to be a minimum agreed level of **fundamental data transparency** and a minimum common level of data released for publication.

The distinction between short term, medium term and long term benchmarking objectives is particularly important. While benchmarking in the Pacific is in its early stages, the development of a strategy that reconciles varying objectives and guides future effort is an important part of this project.

It continues to be appropriate to focus on similar efforts in other island regions and other relatively small systems. The most relevant benchmarking has been undertaken by:

- the American Public Power Association (APPA) benchmarking specifically for its smaller member utilities;
- Caribbean island utilities, through the work of the Caribbean Electric Utility Services Corporation (CARILEC), the PPA's counterpart in the Caribbean; and
- the island utilities that are members of the Network of Experts of Small Island System Managers (NESIS), a subgroup of the European utility association Eurelectric, who felt that benchmarking needs to be tailored to their specific needs.

Appendix 2

PPA Member Utilities in 2012

Updated 1 December 2012.

AMERICAN SAMOA POWER AUTHORITY
P O Box PPB, Pago Pago,
American Samoa 96799
Tel: 1 (684) 699 3040 Fax: 1(684) 699 3052/ 3049
Email: andras@aspower.com
CEO: Ms. Andra Samoa
Website: www.aspower.com

ELECTRIC POWER CORPORATION
P O Box 2011, Apia, Samoa
Tel: (685) 65 400/ 22 261 Fax: (685) 23 748
Email: leiat@epc.ws
CEO: Mr. Tologata Tile Leia Tuimalealiifano
Website: www.epc.ws

CHUUK PUBLIC UTILITY CORPORATION
P O Box 910, Weno, Chuuk, FSM 96942
Tel: (691) 330 2400/ 2401 Fax: (691) 330 3259 or 2777
Email: mwaite_cpuc@mail.fm
CEO: Mr Mark Waite

ENERCAL (Societe Neo-Caledonenne D'Energie)
87,av.Du General De Gaulle, BP, C1
98848 Noumea, New Caledonia
Tel: (687) 250 250 Fax: (687) 250 253
Email: jbegaud@canl.nc
CEO: Mr. Jean Begaud

COMMONWEALTH UTILITIES CORPORATION, SAIPAN
P O Box 501220 CK, 3rd Floor, Joeten Dandan Building, Saipan,
MP 96950-1220
Tel: 1 (670) 235 7025 through 7032 Fax: 1 (670) 235 5131
Email: alan.fletcher@cucgov.net
CEO: Mr. Alan Fletcher

FIJI ELECTRICITY AUTHORITY
Private Mail Bag, Suva, Fiji Islands
Tel: (679) 322 4310 Fax: (679) 331 1074
Email: hasmukh@fea.com.fj
CEO: Mr. Hasmukh Patel
Website: www.fea.com.fj

ELECTRICITE DE TAHITI
BP 8021, Faaa, Tahiti, French Polynesia
Tel: (689) 86 77 86 Fax: (689) 83 44 39
Email: herve.dubost-martin@edt.pf or edt@edt.pf
CEO: Mr. Hervé Dubost-Martin,
Website: www.edt.pf (in French)

GUAM POWER AUTHORITY
P O Box 2977, Agana, Guam 96910
Tel: +1 (671) 648 3225
Fax: +1 (671) 646 3290
Email: jflores@gpagwa.com
CEO: Mr. Joaquin Flores
Website: www.guampowerauthority.com

ELECTRICITE ET EAU DE CALEDONIE
15 rue Jean Chalier PK4
BP F3 – 98848 NOUMEA CEDEX
New Caledonia
Tel: (687) 46 35 28 Fax: (687) 46 35 10
Email: francois.guichard@eec.nc
CEO: Mr. Francois Guichard

KOSRAE UTILITIES AUTHORITY
P O Box KUA, Kosrae, FSM 96944
Tel: (691) 370 3799 / 3344 Fax: (691) 370 3798
Email: kua@mail.fm
CEO: Mr. Fred Skilling

ELECTRICITE ET EAU DE WALLIS ET FUTUNA
BP 28 - 98600 - Mata-Utu
Wallis and Futuna Islands
Tel: (681) 72 1501 Fax: (681) 72 2215
Email: pascal.louvet@eewf.wf
CEO: Mr. Pascal Louvet

KWAJALEIN ATOLL JOINT UTILITY RESOURCES
P O Box 5819, Ebeye, Marshall Islands 96970
Tel: (692) 329 3799/3798 Fax: (692) 329 6722
Email: romeo.afred@yahoo.com
CEO: Mr Romeo Alfred

MARSHALLS ENERGY COMPANY P O Box 1439, Majuro, MH Marshall Islands 96960 Tel: (692) 625 3827/3828/3829/3507 Fax: (692) 625 3397/5886 Email: dpaul@mecrmi.net CEO: Mr. David Paul Website: www.mecrmi.net	**PUBLIC UTILITIES BOARD** P O Box 443, Betio, Tarawa, Kiribati Tel: (686) 26 292 Fax: (686) 26 106 Email: ceo.pub@tskl.net.ki CEO: Mr. Kevin Rouatu
NAURU UTILITIES CORPORATION Aiwo District, Nauru Mobilel: (674) 557 4000 Fax: (674) 444 3521 Email: Tom Tafia or ceoutilities@naurugov.nr CEO: Mr Tom Tafia	**SOLOMON ISLANDS ELECTRICITY AUTHORITY** P O Box 6, Honiara, Solomon Islands Tel: (677) 39 422 Fax: (677) 39 472 Email: n_nicholls@siea.com.sb CEO: Mr. Norman Nicholls Website: www.siea.com.sb
NIUE POWER CORPORATION P O Box 198, Alofi, NIUE Tel: (683) 4119 Fax: (683) 4385 Email: gm.npc@mail.gov.nu CEO: Mr. Speedo Hetutu, General Manager	**TE APONGA UIRA O TUMU-TE-VAROVARO** P O Box 112, Rarotonga, Cook Islands Tel: (682) 20 054 Fax: (682) 21 944 Email: atimoti@electricity.co.ck CEO: Mr. Apii Timoti
PALAU PUBLIC UTILITIES CORPORATION P O Box 1372, Koror, Palau 96940 Tel: (680) 488 3870/72/77 Fax: (680) 488 3878 Email: kji@ppuc.com CEO: Mr. Kione J Isechal	**TONGA POWER LIMITED** P O Box 429, Nuku'alofa,Kingdom of Tonga Tel: (676) 27 390 Fax: (676) 63 202 Email: jvanbrink@tongapower.to CEO: Mr. John van Brink
PNG POWER Ltd P O Box 1105, Boroko 111, National Capital District, Papua New Guinea Tel: (675) 324 3111 or 324 3332 Fax: (675) 3250 008/3877 Email: tkoiri@pngpower.com.pg CEO: Mr. Tony Koiri	**TUVALU ELECTRICITY CORPORATION** P O Box 32, Funafuti, Tuvalu Tel: (688) 20 352/358 Fax: (688) 20 351 Email: mafaluloto@gmail.com CEO: Mr. Mafalu Lotolua
POHNPEI UTILITIES CORPORATION P O Box C, Kolonia, Pohnpei, FSM 96941 Tel: (691) 320 2374 Fax: (691) 320 2422 Email: pucgm@mail.fm CEO: Mr. Robert Hadley Website: www.puc.fm	**UNELCO VANUATU LIMITED** P O Box 26, Port Vila, Vanuatu Tel: (678) 22 211 Fax: (678) 25 011 Email: unelco@unelco.com.vu Managing Director: Mr Philippe Mehrenberger
YAP STATE PUBLIC SERVICE CORPORATION P O Box 667, Colonia, Yap, FSM Tel: (691) 350 4427 Fax: (691) 350 4518 (Power plant) Email: faustinoyangmog@yspsc.fm CEO: Mr. Faustino Yangmog	

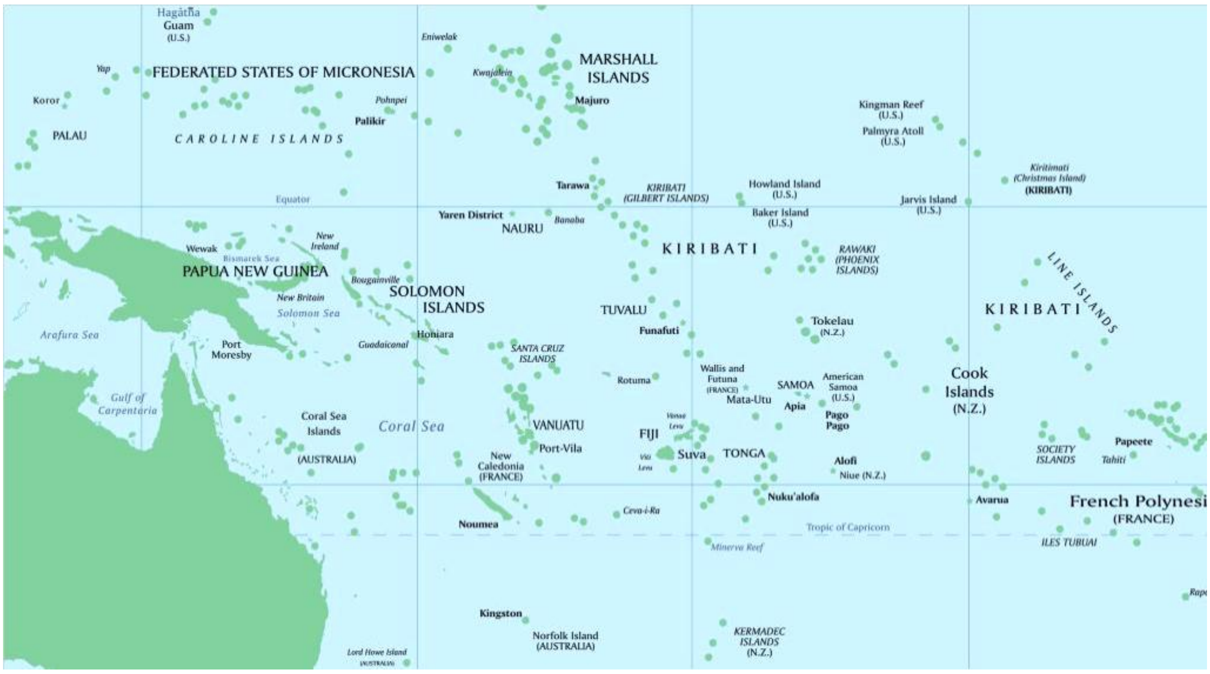
Appendix 3

Regional Economic and Demographic Characteristics

The tables in this Appendix have been updated from the 2011 Benchmarking Report.

Figure A3.1 shows the Pacific Island Countries and Territories in the region served by the Pacific Power Association.

Figure A3.1 Map of the Area Served by the Pacific Power Association



Source: Applied Geosciences and Technology Division of the Secretariat of the Pacific Community (SOPAC), *Member Countries* (2012), http://www.sopac.org/index.php/member-countries.

Tables A3.1 and A3.2 summarise some economic and demographic characteristics of the countries and territories in which the utilities that participated in this exercise operate.

Table A3.1 Economies and Populations of Independent Pacific Island Countries

Country	Population Mid-2011	Land area km²	GNP per capita US$ (2009)	GDP per capita		GDP growth rate per capita		Current account balance % GDP (2012)	High exposure to fuel price rises
				US$	Year	% 2011	%2012		
Cook Isl.	15,576	237	n.a.	11,917	2010	-0.8	3.4	-2.2e	√
Fiji	851,745	18,273	3,840	3472	2010	0.0	1.3	-1.6p	√
Kiribati	102,697	811	1,830	1,664	2011	0.1	3.5	-10p	√
RMI	54,999	181	3,060	3130	2008	0.0	5.4	1.4e	√
FSM	102,360	701	2,500	2889	2010	n.a.	1.0	0.4e	√
Nauru	10,185	21	n.a.	7121	2009	1.9	4.8	0.6e	√
Palau	20,643	444	6,220	10,692	2011	n.a.	4.0	-2.3e	√
PNG	6,888,297	462,840	1,180	2700	2012	6.2	7.5	-1.2p	√
Samoa	183,617	2,785	2,840	3706	2011	2.7	1.0e	-7.3e	√
Solomon Islands	553,254	30,407	n.a.	1181	2009	5.2	6.0	6.0e	√

Country	Population Mid-2011	Land area km²	GNP per capita US$ (2009)	GDP per capita		GDP growth rate per capita		Current account balance % GDP (2012)	High exposure to fuel price rises
				US$	Year	% 2011	%2012		
Tonga	103,682	650	3,260	4394	2011	0.2	1.3e	3.0e	√
Tuvalu	11,206	26	n.a.	4002	2011	-0.5	1.2	10.0e	√
Vanuatu	251,784	12,281	2,620	3022	2008	1.2	3.0	0.0e	√
PIC average				*4,607*		*1.5*	*3.7*		
CARICOM average				*11,632*	*various*				

Notes: 1. *e* = estimated. 2. n.a. = not available. 3. p = projection. 4. Utilities from all above PICs above participated in 2011 benchmarking.
Sources: 1. Asian Development Bank (ADB), *Asian Development Outlook* (2011). 2. ADB, *Pacific Economic Monitor* (2012). 3. GNPs from ADB; GDPs from Secretariat of the Pacific Community (SPC), (2012). 4. SPC, Populations from Pacific Island Populations: Estimates and Projections (2011). 5. CARICOM GDPs sourced from CIA, *The World Factbook* (2011), https://www.cia.gov/library/publications/the-world-factbook/geos/xx.html.

The Pacific territories and dependencies (Table A3.2) have far higher GDP/capita than the independent PICs, and consumers can presumably afford higher electricity charges.

Table A3.2: Economies and Populations of Pacific Island Territories or Dependencies[1]

Dependency or Territory	Population Mid-2011	Land area km²	GDP per capita	
			US$	Year
American Samoa	66,692	199	7874	2007
Guam	192,090	541	23134	2007
Niue	1,446	259	11985	2009
Northern Mariana Islands	63,517	457	16494	2007
New Caledonia	252,331	18,576	37,993	2008
French Polynesia	271,831	3,521	21,071	2006
Wallis & Futuna	13,193	142	12,640	2005
Average			*18,741*	

Sources: 1. Asian Development Bank (ADB), *Asian Development Outlook* (2011). 2. ADB, *Pacific Economic Monitor* (2012). 3. GNPs from ADB; GDPs from Secretariat of the Pacific Community (SPC), (2012). 4. SPC, Populations from Pacific Island Populations: Estimates and Projections (2011). 5. CARICOM GDPs sourced from CIA, *The World Factbook*, (2011), https://www.cia.gov/library/publications/the-world-factbook/geos/xx.html.

[1] French Polynesia was designated as an overseas territory, in 2003 became an overseas collectively (*collectivités d'outre-mer* or *COM*) and in 2004 an overseas country inside the French Republic (*pays d'outre-mer au sein de la République*, or POM), with considerable autonomy but without a legal modification of its status.
New Caledonia was also an overseas territory but gained a special status (*statut particulier* or *statut original*) in 1999, with New Caledonian citizenship and a gradual transfer of power from France to New Caledonia itself.

Appendix 4

Participating Utilities and their Characteristics

The tables in this Appendix have been adapted and updated where relevant from the 2011 Benchmarking Report.

Table A4.1: Participating Utilities in 2002, 2011 and 2012

Utility abbrev.	Utility Name	Country / Territory	Participated in 2012 benchmarking?	Participated in 2011 benchmarking?	Participated in 2001/2002 benchmarking?
ASPA	American Samoa Power Authority	American Samoa *	√	√	√
CPUC	Chuuk Public Utility Corporation	Fed States of Micronesia (FSM)	√	√	√
CUC	Commonwealth Utilities Corp., Saipan	Commonwealth of N Marianas *	√	√	No
EDT	Electricite de Tahiti	French Polynesia *	√	√	√
EPC	Electric Power Corporation	Samoa (SAM)	√	√	√
FEA	Fiji Electricity Authority	Fiji (FIJ)	√	√	√
GPA	Guam Power Authority	Guam *	√	√	√
KAJUR	Kwajalein Joint Utility Resources	Marshall Islands (RMI)	√	√	√
KUA	Kosrae Utilities Authority	Fed States of Micronesia (FSM)	√	√	√
MEC	Marshall Energy Company	Marshall Islands (RMI)	√	√	No
NPC	Niue Power Corporation	Niue	No response in time for reporting, but continuing to capture 2011 data	√	√
NUC	Nauru Utilities Corporation	Nauru (NAU)	√	√	No
PNGP	PNG Power Ltd.	Papua New Guinea (PNG)	√	√	√
PPUC	Palau Public Utilities Corporation	Palau (PAL)	√	√	√
PUB	Public Utilities Board	Kiribati (KIR)	√	√	√
PUC	Pohnpei Utilities Corporation	Fed States of Micronesia (FSM)	√	No	√
SIEA	Solomon Islands Electricity Authority	Solomon Islands (SOL)	√	√	√
TAU	Te Aponga Uira O Tumu -Te-Varovaro	Cook Islands (COO)	√	√	√
TEC	Tuvalu Electricity Corporation	Tuvalu (TUV)	√	√	No
TPL	Tonga Power Limited	Tonga (TON)	√	√	√
UNELCO	UNELCO Vanuatu Limited	Vanuatu (VAN)	√	√	√
YSPSC	Yap State Public Service Corporation	Fed States of Micronesia (FSM)	√	√	No
EEC	Electricite et Eau de Caledonie	New Caledonia *	No	No	√
EEWF	Electricite et Eau de Wallis et Futuna	Wallis & Futuna *	No	No	√
ENERCAL	Societe Neo-Caledonenne D'Energie	New Caledonia *	No - expressed early interest but did not respond to data requests	No	√
VUI	Vanuatu Utilities & Infrastructure Ltd	Vanuatu (Santo)	No - not PPA member; recently established & did not express interest.	No	No

Notes: 1. Abbreviations in parenthesis (e.g. FSM) are ADB designations . 2. * indicates not an ADB or WB member

A4.1 The Participating Utilities

All 25 PPA member utilities (listed in Appendix 2) were eligible for participation in the benchmarking exercise (although only countries eligible for PRIF assistance can receive follow-up support). Of the PPA's 25 member utilities, 22 participated in this update, as shown in Table A4.1 above. Of these, 21 provided sufficient data to allow the calculation of a reasonable number of key performance indicators.

A4.2 Utility Characteristics

As Table A4.2 illustrates, the utilities vary widely in terms of installed capacity (2 to over 550 MW), gross generation (3–1059 GWh), maximum demand (0.6–263 MW), customer base (about 900-150,000) and employees (20 – 1500).

Clearly, performance indicators would be expected to vary widely, even if each utility is managed equally well. With such a wide range of utility sizes, very small or very large values can distort the average. For example, the average installed capacity is 81 MW but the median (or middle) value is only 19 MW.

Table A4.2: Basic Information on Participating Utilities in 2011

Utility	Installed Capacity	Gross Generation Excludes IPPs	Maximum Demand	Minimum Demand	Customers	Employees
	(MW)	(MWh)	(MW)	(MW)	(Number)	(FTE)
ASPA (A .Samoa)	41.8	154,991	22.5	16.2	12,067	471
CPUC (Chuuk, FSM)	2.4	7,701	2.2	1.2	1,544	62
CUC (Saipan)	125.9	186,685	43.5	31.7	14,333	198
EDT (Tahiti)	271.2	666,137	114.6	49.6	81,866	1020
EPC (Samoa)	35.6	109,029	20	8.7	39,922	721
FEA (Fiji)	217.97	801,206	146.7	84.8	155,322	671
GPA (Guam)	552.8	1,059,094	263	145	52,333	614
KAJUR (Ebeye, RMI)	3.6	14,022	2	1.55	1397	78
KUA (Kosrae, FSM)	5.4	6,504	1.1	0.5	2,591	23
MEC (Majuro, RMI)	18.6	61,730	8.75	6.5	4832	-
NPC (Niue)	2.1	3,000	0.6	0.3	870	21
NUC (Nauru)	4.45	22,077	3.5	2	2,291	46
PNGP (PNG)	369	854,146	196	42	91,022	1,523
PPUC (Palau)	30.3	77,011	12.6	9.9	6,423	68
PUB (Kiribati)	5.5	21,826	4.8	1	4,941	112
PUC (Pohnpei, FSM)	9.8	33,241	6.6	2.5	6,910	122
SIEA (Solomon Islands)	20.6	83,810	15.4	12.8	2,895	206
TAU (Cook Islands)	10.1	28,870	4.8	3.3	4,422	54
TEC (Tuvalu)	3.2	6,572	1.3	0.6	2,502	57
TPL (Tonga)	13.8	52,391	9.2	3.7	20,498	202
UNELCO (Vanuatu)	23.9	60,632	11.3	2.9	10,998	83
YSPSC (Yap, FSM)	8.1	13,446	2.4	1.8	2,125	80
Average	***80.7***	***196,551***	***40.6***	***19.5***	***23,732***	***327***
Median	*18.6*	*60,632*	*9.2*	*3.7*	*6,423*	*117.0*

Notes: 1. Data in Tables A4.2 through A4.6 was provided by the utilities. However some data provided were inconsistent (or reported differently in different parts of the questionnaire) so data in other tables may differ. 2. Blank = not available from data submitted

Figure A4.1 New Solar Operations at Tonga Power Limited (TPL)

1.2MW solar panel power plant at TPL, Tongatapu.
Photos courtesy of Pauline Muscat (PIAC).

Tables A4.3 and A4.4 illustrate the differences amongst the utilities. Table A4.3 indicates that about 30 per cent of sales are to households, 32 per cent to commerce, 22 per cent to industry and 16 per cent to other consumers including government.

Table A4.3: Utility Electricity Sales in 2011 (GWh)

Utility	Household	Commercial	Industry	Other (include govt)	Total
ASPA (A. Samoa)	41.8	37.1	22.4	25.4	126.7
CPUC (Chuuk, FSM)	1.1	2.9	0.0	0.97	4.9
CUC (Saipan)	65.9	117.1	0.0	43.3	226.4
EDT (Tahiti)	207	98.9	282.2	16.9	605.0
EPC (Samoa)	26.5	39.0	5.3	18.9	89.7
FEA (Fiji)	225.3	332.0	193.0	-	750.2
GPA (Guam)	520.5	259.5	307.7	563.4	1651.1
KAJUR (Ebeye, RMI)	5.9	3.9	-	-	9.8
KUA (Kosrae, FSM)	2.0	1.4	0.3	1.5	5.2
MEC (Majuro, RMI)	15.9	18.7	-	9.3	43.8
NUC (Nauru)	8.1	5.5	0.8	1.1	15.5
PNGP (PNG)	130.7	448.5	164.3	34.8	778.3
PPUC (Palau)	19.9	25.6	-	21.3	66.8
PUB (Kiribati)	7.1	3.0	6.6	-	16.7
PUC (Pohnpei)	17.1	7.0	-	4.6	29.4
SIEA (Solomon Islands)	7.3	27.4	5.5	8.6	48.8
TAU (Cook Islands)	10.9	10.6	6.2	-	27.7
TEC (Tuvalu)	2.1	1.6	-	1.4	5.0
TPL (Tonga)	27.0	17.6	-	-	44.6
UNELCO (Vanuatu)	18.9	13.7	22.9	0.2	55.6
YSPSC (Yap, FSM)	2.6	4.2	-	2.3	9.1
*% of total **	*30%*	*32%*	*22%*	*16%*	*100%*

Notes: 1. * Calculated only for utilities that provided sales by customer category. 2. The definition of 'commercial' differs by utility: some include government sales within commercial. 3. Blank cells = not categorised or available from utility data provided.

For the participating utilities (Table A4.1), 75 per cent of generation is from petroleum fuels (light and heavy fuel combined). About 26 per cent of all utility generation is from renewable energy sources, overwhelmingly through hydroelectric power.

Table A4.4: Gross Generation by Source - *for all grids* - in 2011 (MWh)

Utility	Distillate ADO / IDO**	Heavy fuel HFO / IFO***	Hydro	Wind	Solar PV	Biomass & Biofuel	Total	% RE+
ASPA (A. Samoa)	153,910	-	-	-	1,081	-	154,991	0.7
CPUC (Chuuk, FSM)	-	7,701	-	-	-	-	7,701	0.0
CUC (Saipan) *	186,685	-	-	-	-	-	186,685	0.0
EDT (Tahiti)	132,034	352,264	181,313		489	-	666,137	27.2
EPC (Samoa)	73,773		35,248		8		109,029	32.0
FEA (Fiji) *	256,220	83,540	456,469	4,977		35,978	837,184	59.4
GPA (Guam)	29,872	1,801,036	-	-	-	-	1,830,909	0.0
KAJUR (Ebeye, RMI)	14,022	-	-	-	-	-	14,022	0.0
KUA (Kosrae, FSM)	6,504	-	-	-	-	-	6,504	0.0
MEC (Majuro, RMI)	61,730	-	-	-	-	-	61,730	0.3
NUC (Nauru)	22,026	-	-	-	51	-	22,077	0.2
PNGP (PNG)	334,542	153,184	672,084	-	-	-	1,159,810	58.0
PPUC (Palau)	76,677	-	-	-	334	-	77,011	0.4
PUB (Kiribati)	21,826	-	-	-	-	-	21,826	0.0
PUC (Pohnpei)	33,241	-	-	-	-	-	33,241	0.0
SIEA (Solomon Islands)	83,810	-	-	-	-	-	83,810	0.2
TAU (Cook Islands)	28,870	-	-	-	-	-	28,870	0.0
TEC (Tuvalu)	6,531	-	-	-	41	-	6,572	0.6
TPL (Tonga)	52,391	-	-	-	-	-	52,391	0.0
UNELCO (Vanuatu)	55463	-	-	4,295	67	806	60,632	8.5
YSPSC (Yap, FSM)	13,430	-	-	-	16	-	13,446	0.1
Total	*1,643,557*	*2,397,725*	*1,345,114*	*9,272*	*2,087*	*36,784*	*5,434,578*	
% of total	*30.2%*	*44.1%*	*24.8%*	*0.2%*	*0.04%*	*0.7%*	*100%*	*25.6%*

Notes: 1. Total is for entire utility generation. Blank spaces = zero. 2. Data as reported by the utilities; for some (e.g. PPUC, TAU) there may be some unreported PV 3. * Excludes CUC power purchases of 99,545 MWh; includes FEA biofuel purchases; includes PNGP power purchases of 163,510 MWh. 4. ** ADO/IDO = Automotive Diesel Oil; Industrial Diesel Oil (light petroleum fuels). 5. *** HFO/IDO = Heavy Fuel Oil; Industrial Fuel Oil (heavy petroleum fuels). 6. + RE = Renewable Energy

All of the utilities generate power, transmit it through grids of various voltages (see Table A4.5) and distribute to customers. A few purchase relatively small amounts of electricity but most generate nearly all of the power fed into the grids. Table A4.6a and Table A4.6b summarises information about utility ownership, the range of services provided, policies, power sector legislation, national goals for electrification through renewable energy, regulations that encourage (or at least permit) private supply to the grid, and the extent of coverage of each utility's electrification services

Table A4.5 Utility Transmission and Distribution Voltages (kV)

Utility	Transmission	Distribution	Frequency (Hz)
CUC * (Saipan)	34.5	13.8	60
EDT (Tahiti)	30, 90	11; 14; 20	50
EPC (Samoa)	22; 33	6.6; 22	50
FEA (Fiji)	33; 132	11	50
GPA (Guam)	110 & above	13.8	60
RMI & FSM **	None	13.8	60
NPC (Niue), NUC (Nauru), PUB (Kiribati), TAU (Cook Isl.), TEC (Tuvalu), TPL (Tonga)	33	11	50
PPUC (Palau)	34.5	13.8	60
UNELCO (Vanuatu)	None	5.5	50

Notes: 1. * In Rota & Tinian, 13.8 kV distribution only. 2. ** RMI = MEC and KAJUR; FSM = PUC, CPUC, KUA & YSPSC.

Table A4.6a: Utility Structures, Ownership, Policies, Regulation and Coverage

Utility	Govt ownership	Provides non-electric services? y or n?	If yes, type	Non-grid or rural supply	Govt / Cabinet appoints board?	Electricity legislation?	External regulation? Technical?	Commercial?
ASPA (American Samoa)								
CPUC (Chuuk, FSM)	100%	Yes	Water supply & sewerage	Standalone PV & SHS *	Yes	CPUC Act 1996	No	No
CUC (Saipan)	100%	Yes	Water; waste management	No	No	Public Law 4-47 enacted by Legislature	Yes both: Commonwealth Public Utility Commission	
EDT (Tahiti)	99.99% private	No	N/A	A few mini-grids; no obligation to develop more	No but represented by Energy Ministry	No	SEM is technical regulator Tariff set by Concession formula negotiated every 5 years	
EPC (Samoa)	100%	No	N/A	Grid extension, standalone PV and PV mini-grid (Apolima)	Yes	Yes, various Acts 1972-2010	Regulator created under Electricity Act of 2010 but not yet implemented	
FEA (Fiji)	100%	No	N/A	Rural grid extensions only	Minister for Utilities	Yes	Not at present but Govt regulation anticipated	
GPA (Guam)	100%	No	N/A	Single grid	General public	Public Law 9-189, May 1968	Regulated by Guam Public Utilities Commission; follow national standards & policies.	
KAJUR (Kwajalein, FSM)								
KUA (Kosrae, FSM)	100%	No	N/A	Single grid; Kosrae is all rural	Governor, legislature	Yes, state law Nov 1991	No	No
MEC (Majuro, RMI)	100%	Yes	fuel sales	Manage rural PV	Yes	Yes	No	No
NPC (Niue)	100%	No	N/A	Rural grid extensions only	No board	No, part of Public Works	No	No, only Cabinet
NUC (Nauru)	100%	Yes	Water, fuel	N/A	No board	Yes, June 2011	Planned	Planned
PNGP (PNG)	100%	No	N/A	Rural grid extensions only		Yes. Electricity Industry Act and ICCC Act	Independent Consumer and Competition Commission (ICCC)	
PPUC (Palau)	100%	No	N/A	Standalone PV & diesel systems; grid-connected PV	No	Yes	No	No
PUB (Kiribati)	100%	Yes	Water supply & sewage	Standalone PV & SHS	Yes	Public Utility Act 1997, revised 1998	No	No
PUC (Pohnpei)	100%	Yes	Water supply & sewerage	Diesel, Standalone PV	Yes	Yes	Yes	Yes
SIEA (Solomon Islands)	100%	No	N/A	Diesel, Hydro, Standalone & SHS	Yes	Electricity Act 2007, State Enterprises Act 2009	Yes	No
TAU (Cook Islands)	100%	No	N/A	Diesel & solar PV on Pukapuka	Yes	Yes	No	No
TEC (Tuvalu)	100%	No	N/A	Standalone PV, diesel & SHS	Yes	Electricity Act 1991, Public Enterprises Act 2010	No	Yes - National energy Policy
TPL (Tonga)	100%	No	N/A	Standalone PV, Diesel and SHS	Yes	Electricity Act 2007	Electricity Commission 2001/02	Electricity Commission 2001/02

Appendix 4

Utility	Govt ownership	Provides non-electric services? y or n?	If yes, type	Non-grid or rural supply	Govt / Cabinet appoints board?	Electricity legislation?	External regulation? Technical?	Commercial?
UNELCO (Vanuatu)	No; 100% private	No	N/A	Rural connections within concession area; no stand-alone	No but one representative from Energy Minister	No national legislation	Yes	Yes, external monitor & control
YSPC (Yap, FSM)	100%	Yes	Water; waste management	All of Yap is essentially rural	Yes, represented by state agencies	Yes, Yap State Law 4-4	No, self-regulating	Yes; state energy policy

Notes: 1. * SHS = Solar Home Systems (low voltage DC photovoltaic systems). 2. N/A = Not Applicable. 3. Blank = no data provided.

Table A4.6b: Utility Structures, Ownership, Policies, Regulation and Coverage

Utility	Power quality law /regulation	Service obligation	Regulation or requirement for:			National RE goal (electricity)	Tariff		Tax on electricity inputs or supply?			National utility or specified service areas?
			IPPs / PPAs *	FIT** or net metering	DSM ***		Determined by	Fuel surcharge	On electricity sold?	On utility equipment?	On fuel for power?	
ASPA (American Samoa)												
CPUC (Chuuk, FSM)	No- patterned on US regulations	No	No	No	Being considered for future	30% RE by 2020	Board	No	US$ 0.128/gal	4% tax on all imported goods	US$ 0.128/gal	Weno and 4 outer islands
CUC (Saipan)	US standard	No	Yes -Public Law 16-17 (Privatisation Law	Net Energy Metering Policy (PL 15-87)	No	40% RE by 2012	Utility Board	Yes	No	Yes	Yes	Saipan, Tinian and Rota
EDT (Tahiti)	LV 10% HV 7-10% freq. 5%	Every paid extension must be connected	French standards	Yes clear policy & tariffs for PV & wind	No DSM services are provided	50% RE by 2020	Concession agreement	No	Territorial & city taxes + 5% VAT		Taxed but varying subsidies to stabilise cost	20 islands; 90% of population of French Polynesia
EPC (Samoa)	No	Yes	No	No	No	20% RE by 2030	Government	Yes	No	No(?)	S$0.4/l of IDO + 15% VAT	National; 97% coverage
FEA (Fiji)	distribution voltage 6%; freq. 2%	No	FEA grid code for IPPs	yes; currently F$0.23 / kWh	commercial audits at FEA cost	90% RE by 2015	Commerce Commission	Not currently	12.5% VAT added to bill	No duty for RE equipment	F$0.18/litre for IDO; F$0.10/l HFO	Main island of Viti Levu + Vanua Levu & Ovalau
GPA (Guam)	US standard	Yes - On Utility approval	No	Net metering	Yes	5% net sales from RE by 2015	Guam Public Utilities Commission	Yes	No	No	No	Throughout Guam
KUA (Kosrae, FSM)	voltage ±5%; 7.5% for industry	No	Under consideration	No	No	No; state energy plan being developed	Board of Directors	Yes	No	4%	No	State of Kosrae, FSM
KAJUR (Kwajalein)												
MEC (Majuro, RMI)	No	planning only	No	No	No	20% RE by 2020	Cabinet	No	No	8%	No	Majuro, Jaluit and Wotje
NPC (Niue)	NZ but no compliance	Safety only	No	No	Only with donor $	100% carbon neutral 2013	Government	No	Yes; 12.5% paid by utility	No	No	National, single island
NUC (Nauru)	Being considered	No	Being prepared	No	No	50% RE by 2015	Government	No	No	No	No	National, single island
PNGP (PNG)	AS/NZS 3000:2007	No	Electricity Industry Policy of Dec 2011 yet to be implemented	Encourage but not formal	No	Government	No	10% GST added to bill	No	Local fuel attracts 10% GST	National	

Appendix 4

Utility	Power quality law /regulation	Service obligation	Regulation or requirement for:			National RE goal (electricity)	Tariff		Tax on electricity inputs or supply?			National utility or specified service areas?
			IPPs / PPAs *	FIT** or net metering	DSM ***		Determined by	Fuel surcharge	On electricity sold?	On utility equipment?	On fuel for power?	
PPUC (Palau)	Yes	No but PUC task is to electrify all of Palau	Yes, within the confines of the law which created the utility. Net metering expected to be approved during 2011	20% RE by 2020	Utility Board	Yes		No	US$ 0.05/gal	Main Island & three other outlying states		
PUB (Kiribati)	AS/NZS 3000:2007					7 – 10% by unspecified date ?	Government. Price Ord. Act 1976, rev 1981	No		No	No. Free of import duty	South Tarawa
PUC (Pohnpei)	No- patterned on US regulations	No	Yes. Regulations under development.	Yes – mandated to accept <50kW	No	State Energy Plan 4MW	Consultation with Energy Commission	Yes				Pohnpei
SIEA (Solomon Isl.)	AS/NZS 3000:2007	Community Service Obligation Regulation	Yes - technical standard requirements	No	No	20% RE by 2018	Govt under Electricity Tariff Regulation 2005	Yes		Yes	SBD$0.22/litre plus 10% GST	Auki, Malu'u, Gizo, Noro, Munda, Kirakira, Lata, Buala, Tulagi and Honiara
TAU (Cook Isl.)	AS/NZS 3000:2007	Yes - on Government approval	Yes	Net metering	No	50% RE by 2015; 100% by 2020	Board	No		100% levy exemptions	Port charges and VAT	Rarotonga
TEC (Tuvalu)	AS/NZS 3000:2007	No	No	No	Being consider-ed	100% RE by 2020	Board	Yes	3% for > 50kWh /my consumption	No	0.05 cent rebate per litre of fuel purchase	Funafuti & all outer islands except Niulakita
TPL (Tonga)	AS/NZS 3000:2007	No	Yes – IPP for private PV systems	Yes	No	50% RE for main grid by 2012	Electricity Commission and TPL	Yes	No	Some exemptions	Taxed but refunded	Tongatapu, Vavau, Haapai and Eua
UNELCO (Vanuatu)	Yes under concession agreement	Yes, any customer request within concession	No	No	No	No RE goal	Regulated under concession agreement	No	12.5% value added tax	No concessions on import duty	15 vatu/litre	Islands of Efate, Tanna & Malekula
YSPSC (Yap, FSM)	No but quality is good	Legally no; 100% electrification goal; so yes in practice.	No	Soon net metering to be introduced	No but comm.& house-holds	State goal of 28% with ADB support	Board	No, built into tariff	No	4% national import duty; exempt from Yap state tax	0.05 US$ per US gallon duty; 0.05 US$/USG Yap excise tax	75% of state: Yap Proper, Ulithi Atoll, Falalop, Woleai

Notes: 1. * IPP = Independent Power Producer; PPA = Power Purchase agreement. 2. ** FIT = Feed-in tariff. 3. *** DSM = demand side management (for customer energy efficiency services). 4. + RE = Renewable Energy. 5. GST = Goods & Services Tax. 6. VAT = Value Added Tax. 7. Blank – no data provided. 8. (?) Questionable result

Appendix 5

Summary of Information and Data Used in 2012 Benchmarking Report

The information used in Appendix 4 and Section 1.8 of the report was taken from the responses from utilities as provided in Section 1 of the questionnaire, supplemented where noted in the report. The data used for calculating indices and preparing the charts of Section 4 (Results) is from the following source, which is stored on the PPA server. This consolidates all data sources used in the 2011 report.

Spreadsheet	Contents
Consolidated data benchmarking 2012 final.xlsx. **Revised: 30/04/2012** **(with a few subsequent amendments)**	This consolidates into a single spreadsheet all data used in reporting for both 2011 and 2012. This includes data provided by utilities in Section 2 of the questionnaire, and consolidates supplementary data on losses, tariffs, and RE percentages. In some cases, data which were clearly wrong (e.g. wrongly entered) were adjusted by the consultants from other data in the submissions. In some cases, as noted in the 'results' section of the report, outlying data were ignored.

Appendix 6

Summary of Data Gaps in Utility Submissions

The tables in this Appendix have been updated from the 2011 Benchmarking Report.

Table A6.1: Summary of Data Gaps in Submissions

Utility		ASPA	CPUC	CUC	EDT	EPC	FEA	GPA	KAJUR	KUA	MEC	NUC	PNGP	PPUC	PUB	PUC	SIEA	TAU	TEC	TPL	UNELCO	YSPSC
Location		Am Samoa	Chuuk FSM	Saipan CNMI	Tahiti	Samoa	Fiji	Guam	Ebeye RMI	Kosrae FSM	Majuro RMI	Nauru	PNG	Palau	Kiribati	Pohnpei FSM	Sol. Islands	Cook Islands	Tuvalu	Tonga	Vanuatu	Yap FSM
Background Questionnaire Section 1		x							x													
Generation	1 – 6																					
	7																					
	8																					
	9 - 10																					
	11 – 16																					
	17 – 18											x					x					
Transmission	19	NA	NA	NA		NA			NA	NA	NA	NA		NA	NA	NA	NA	NA	NA	NA	NA	NA
	20 – 21	NA	NA	NA		NA			NA	NA	NA	NA		NA	NA	NA	NA	NA	NA	NA	NA	NA
	22	NA	NA	NA		NA			NA	NA	NA	NA		NA	NA	NA	NA	NA	NA	NA	NA	NA
	23	NA	NA	NA		NA			NA	NA	NA	NA		NA	NA	NA	NA	NA	NA	NA	NA	NA
Distribut-ion	24										x			x		x						
	25 – 26												x									
	27 – 28										x		x	x	x	x	x					
DSM	29																					
	30 - 31	x		x	x	x			x	x		x	x	x								
	32 - 33	x		x	x	x			x	x		x	x	x								

Utility		ASPA	CPUC	CUC	EDT	EPC	FEA	GPA	KAJUR	KUA	MEC	NUC	PNGP	PPUC	PUB	PUC	SIEA	TAU	TEC	TPL	UNELCO	YSPSC
Location		Am Samoa	Chuuk FSM	Saipan CNMI	Tahiti	Samoa	Fiji	Guam	Ebeye RMI	Kosrae FSM	Majuro RMI	Nauru	PNG	Palau	Kiribati	Pohnpei FSM	Sol. Islands	Cook Islands	Tuvalu	Tonga	Vanuatu	Yap FSM
HR/ Safety	34 – 35	x							x	x		x					x		x			
	36 – 39	x							x	x		x					x		x			
	40 - 42			x					x		x											
Customers	43																					
	44 - 47																					
	48 – 50																					
	51 - 56																					
	57																					
	58																					
Finance	59 - 72			x																		
	73 - 74																					
	75 – 83			x								x						x				
DRA	-																	x				

Notes: 1. **x** = No (or limited) data provided. (NPC not shown). 2. DR = Data Reliability Assessment. 3. DSM = Demand Side Management. 4. 1 – 86 refers to corresponding questions in the Questionnaire, Section 2: detailed data as released with the Benchmarking Manual (September 2012). Question numbers varied slightly in subsequent issues. 5. **NA** = Not Applicable; only FEA, GPA, PNGP and EDT have high voltage transmission grids. 6. Q58 – All respondents confirmed the existence of maintenance plans covering generation, transmission and distribution assets, although few comprehensive plans were provided or sighted.

Appendix 7
Key Reports and Documentation Reviewed

American Public Power Association (APPA). *APPA Selected Financial and Operating Ratios of Public Power Systems, 2010 Data* (November 2011).

Asian Development Bank (ADB). *Regulatory Reforms for Improving the Business Environment in Selected Asian Economies — How Monitoring and Comparative Benchmarking Can Provide Incentive for Reform.* ADB Working Paper Series on Regional Economic Integration No. 40 (2010).

Caribbean Electric Utility Services Corporation (CARILEC) and KEMA. *Benchmark Study of Caribbean Utilities (Fifth Update – Year 2008) Final Report* (Anonymous Version, April 2010).

Council of European Energy Regulators (CEER). *4th Benchmarking Report on Quality of Electricity Supply 2008* (December 2009).

Network of Experts of Small Island System Managers (NESIS). *Small Island Systems Second Benchmarking Report of the Network of Experts of Small Island System Managers – 2004, 2005, 2006 Data* (14 April 2009).

Omara-Ogwang, James Moses. *Establishing a Benchmarking System: Achievements and Lessons Learned from the Uganda Electricity Sector* (Institute for Public-Private Partnerships: 2006).

Pacific Infrastructure Advisory Center (PIAC). *Benchmarking in the Pacific: A Stocktake*. PIAC Infrastructure Sector Resource Document. Working draft prepared by Maria Corazon Alejandrino-Yap (March 2010).

Pacific Power Association (PPA). *Benchmarking Questionnaire*. Excel spreadsheet used for 2001 benchmarking survey as revised 11 July 2003 (2003).

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Pacific Power Association (PPA) and Asian Development Bank (ADB). *Manual of Performance Benchmarking For Pacific Power Utilities* (July 2002).

Pacific Power Association and KEMA. *Quantification of the Power System Energy Losses in South Pacific Utilities* (2012).

(1) Final Data Handbook and (2) Final Report for the following nine utilities:
Nauru Utilities Corporation (NUC);
Electric Power Corporation, Samoa (EPC)
Fiji Electricity Authority (FEA)
Nuie Power Corporation (NPC)
PNG Power Limited (PPL)
Public Utilities Board, Kiribati (PUB)
Solomon Islands Electricity Authority (SIEA)
Te Apongo Uira O Tumu-Te-Varovaro (TAU)
Tuvalu Electricity Corporation (TEC)

Pacific Power Association and KEMA. *Quantification of Energy Efficiency in the Utilities of the U.S. Affiliate States Excluding US Virgin Islands* (2010).

(1) Final Data Handbook and (2) Final Report for the following nine utilities:
Chuuk Public Utility Corporation (CPUC);
Commonwealth Utilities Corporation of Saipan (CUC);
Guam Power Authority (GPA);
Kosrae Utilities Authority (KUA);
Kwajalein Joint Utility Corporation (KAJUR);
Marshall Energy Company (MEC);
Palau Public Utilities Corporation (PPUC);
Pohnpei Utilities Corporation (PUC); and
Yap State Public Service Corporation (YSPSC)

Pacific Power Association (PPA) and Pacific Region Infrastructure Facility (PRIF). *Power Benchmarking Manual. Performance Benchmarking For Pacific Power Utilities* (2012).

Pacific Power Association (PPA) and Pacific Region Infrastructure Facility (PRIF). *Performance Benchmarking for Pacific Power Utilities* (2011).

Pacific Power Association (PPA). Secretariat of the Pacific Community (SPC) and Pacific Infrastructure Advisory Center (PIAC). *Memorandum of Understanding Between PPA and SPC and PIAC (on Behalf of PRIF) on Benchmarking Performance of Power Utilities* (August 2010).

Pacific Region Infrastructure Facility (PRIF). *Pacific Infrastructure Performance Indicators (PIPIs) Working Document* (September 2011).

Pacific Water and Wastes Association (PWWA), *Pacific Water and Wastewater Utilities Benchmarking Report* (2012).

Secretariat of the Pacific Community (SPC). *Country Energy Sector Profile 2009.* Kiribati, Cook Islands, Fiji, Nauru, Niue, Palau, Samoa, Vanuatu, Federated States iof Micronesia, Papua New Guinea, Solomon Islands, Republic of Marshall Islands (2012).

Secretariat of the Pacific Community (SPC). *Indicators for the Framework for Action on Energy Security in the Pacific*. Draft National Energy Data Framework for the SPC Energy Sector Database. Prepared by Gerhard Zieroth (February 2011).

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World Bank. *Understanding Sector Performance: The Case of Utilities in Latin America and the Caribbean.* Sustainable Development Department, Economics Unit, Latin America and the Caribbean Region, Report 53380 (29 June 2009).

World Bank. *Core Indicators for Determinants and Performance of the Electricity Sector in Developing Countries*. Policy Research Working Paper 3599 (May 2005).

Appendix 8

Key Persons Consulted

This list indicates key people contacted during the benchmarking assignment, excluding PIAC staff.

Pacific Power Association:	
Mr Andrew Daka, Executive Director Email: andrewd@ppa.org.fj	Mr Gordon Chang, Deputy Executive Director Email: gordonc@ppa.org.fj
Secretariat of the Pacific Community:	
Mr Solomone Fifita, Deputy Director for Energy Economic Development Division, Suva Email: SolomoneF@spc.int	Mr Frank Vukikomoala, Project Officer Economic Development Division, Suva Email: FrankV@spc.int
Others:	
Mr Paul Zummo, Benchmarking specialist/research analyst American Public Power Association Washington, DC, USA Email: PZummo@publicpower.org	Mr David Padfield Chair, Eurelectric Network of Experts of Small Island System Managers (NESIS), Jersey Electricity PLC Email: dpadfield@jec.co.uk
Mr Andrew Thorington, Acting Executive Director Caribbean Electric Utility Services Corporation (CARILEC) Email: athorington@carilec.org	Mr Tendai Gregan, Power Sector Specialist World Bank, Sydney, Australia Email: tgregan@worldbank.org
Mr Gary Jackson, Executive Director Caribbean Electric Utility Services Corporation (CARILEC) Email: gjackson@carilec.org	Mr Anthony Maxwell, Energy Specialist, Pacific Department, Asian Development Bank, Manila Email: amaxwell@adb.org
Mr Peter Johnston, Director Environmental & Energy Consultants Email: Johnston@connect.com.fj	Mr Conrad Holland, Chief Technical Officer Power & Energy SMEC New Zealand Email: Conrad.holland@smec.com
CEOs and staff of PPA member utilities:	
In addition to the above, PPA and/or the consultants had numerous discussions and/or email contact with over 50 staff (CEOs and others) of the 21 utilities which participated in the exercise.	

Appendix 9

Benchmarking Workshop Summary, July 2012

Photo courtesy of Cori Alejandrino-Yap (PIAC)

The Pacific Power Association (PPA) 21st Annual Conference and Trade Exhibition and the 6th PPA Engineers' Workshop was held in Port Vila, Vanuatu on Monday 16th – Friday 20th July. CEO's Conference Theme was "Mining Energy Efficiencies and Diversifying Energy Portfolio of Island Utilities". The theme of the Engineers Workshop was "Strengthening Energy Security for the Pacific Region". As a part of the Engineer's conference, PIAC hosted a 1 day benchmarking workshop on Thursday 19th July.

The Workshop was prepared and led by Mr. Abraham (Abe) Simpson, PIAC's Regional Benchmarking Specialist, and Ms. Pauline Muscat, PIAC's Energy Specialist. The objectives of the workshop were to:

- Present 2011 benchmarking results
- Understand challenges utilities have in data capture and data integrity.
- Increase understanding and appreciation of benchmarking as a tool for improving the performance of Pacific Island utilities.
- Review questionnaire with delegates and introduce updated Benchmarking Manual.
- Introduce the Balanced Score Card as a framework for executing business strategy and monitoring and improving business performance.
- Provide practical session on how to use benchmarking results to develop a Performance Improvement Plan (PIP).

The workshop was attended by approximately 30 delegates; 14 of them the 2012 benchmarking exercise Liaison Officers for their respective utilities, responsible for collecting the benchmarking data for their utilities, approximately 12 other technical and managerial utility staff and several observers.

Delegates received a Workshop Workbook, a folder that contained the key benchmarking documents and exercises that were to be completed in the course of the workshop. The folder components aligned with the Benchmarking Manual content, and will serve as a useful resource for future use.

The Workshop was opened by Mr. Andrew Daka, Executive Director of the PPA, who has led the benchmarking initiative and encouraged the utilities in their participation as they move towards sustainability of the exercise.

This was followed by an address from Mr. John Austin, Manager of the Pacific Infrastructure Advisory Centre, who welcomed participants on behalf of the PRIF and the development partners. Mr. Austin provided further context to the workshop by recapping some of the lessons learned from the 2010/2011 benchmarking round which had included a request for upfront training for engineers participating in the benchmarking data collection. Mr. Austin covered some of the improvements that have been made in response to the feedback from the previous round, including the allocation of a full day of the Engineer's Workshop devoted to a practical benchmarking workshop, re-design and simplification of the benchmarking questionnaire, the development of the benchmarking manual, and the allocation of resources for supporting the benchmarking initiative.

Ms. Cori Alejandrino-Yap, project officer responsible for the benchmarking exercise on behalf of PIAC, made the final opening statements, thanking the PPA and the development partners and acknowledging the role of the Secretariat of the Pacific Community in the benchmarking exercise. Ms. Yap encouraged participants to take full advantage of the resources available, engage and roll up their sleeves as they prepare to commence the very practical benchmarking workshop.

The workshop was kicked off with a presentation from Mr. Hashmukh Patel, CEO of the Fiji Electricity Authority (FEA), who shared from his practical experience of the crisis that led FEA to transformational reform over 10 years ago. He shared how the benchmarking round of 2002 revealed poor performance of the utility, and how this spurred a performance improvement plan that has now seen the organisation become a standout leader in the Pacific region for utility performance. Mr. Patel shared how key catalysts for the change included updates to the reporting systems, from the use of manual power station logs in 2001 to the current SCADA system where all logs are available for trending. The data trending acts as a clear view window into the performance of the system allowing moment by moment updates that acts as a catalyst to operational improvement.

Photo courtesy of Pauline Muscat (PIAC)

FEA selected four Key Performance Indicators (KPIs) to focus on in order to lead, track and evaluate performance. They were SAIDI (System Average Interruption Duration Indicator), SAIFI (System Average Interruption Frequency Indicator), Lost Time Injury Frequency Duration (LTID) and Lost Time Injury Frequency Rate (LTIFR). Systems were set up to record key data required to calculate the indicators, and these were reported monthly. Mr. Patel encouraged the delegates to start with what they have, and improve information systems and data collection GIS, SCADA, Finance, Customer Management & Billing systems. Mr. Patel promoted the use of the Balanced Scorecard as a framework for executing strategy and the careful analysis of KPIs to help identify problem areas and issues that need to be addressed, and promoted the effectiveness of linking staff remuneration to performance to drive improvement.

Next, Mr. Abe Simpson presented an overview of the results from the 2011 round, including the key learnings from the previous round and how improvements have been made to address those areas in the 2012 round. The presentation included some of the issues had with data collection, measurement of calculation of KPIs, gaps in the data, as well as the configuration of the composite factor that was used to give an overall rating to the utilities.

Ms. Muscat presented the revised *Benchmarking Manual*, an update of the 2002 version. Feedback from the workshop reinforced the usefulness of the *Benchmarking Manual* as a resource for future benchmarking activities. The delegates requested the worked solutions to the KPI workbook found in the Workshop folder, be added to the *Manual*. Additionally feedback was received through the clarification questions that were asked regarding the data inputs, and some CEOs requested further data be collected to enable more KPIs regarding cost of generation. The feedback will be reflected in the revised manual which will be finalised and printed once the benchmarking Questionnaire, data inputs and KPIs have been finalised.

The updated manual will include the following sections:

Section 1 – The Benchmarking Process

Section 2 – 2012 Questionnaire and Data Inputs Explanations with worked examples

Section 3 – Explanation of KPIs

Section 4 – KPI calculations - worked examples

Section 5 - Introduction to Performance Improvement Plans

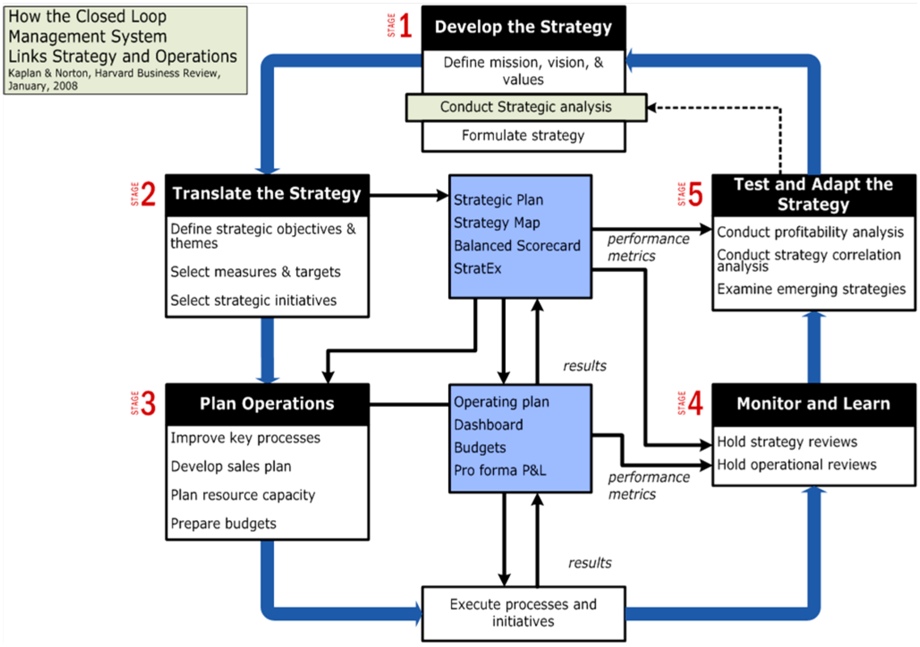
Photo courtesy of Cori Alejandrino-Yap (PIAC)

A step by step walk through the 2012 Benchmarking Questionnaire (Section 2) proved helpful and allowed utilities to seek clarifications and flag any issues. Feedback was compiled for consideration and will drive improvement on the questionnaire.

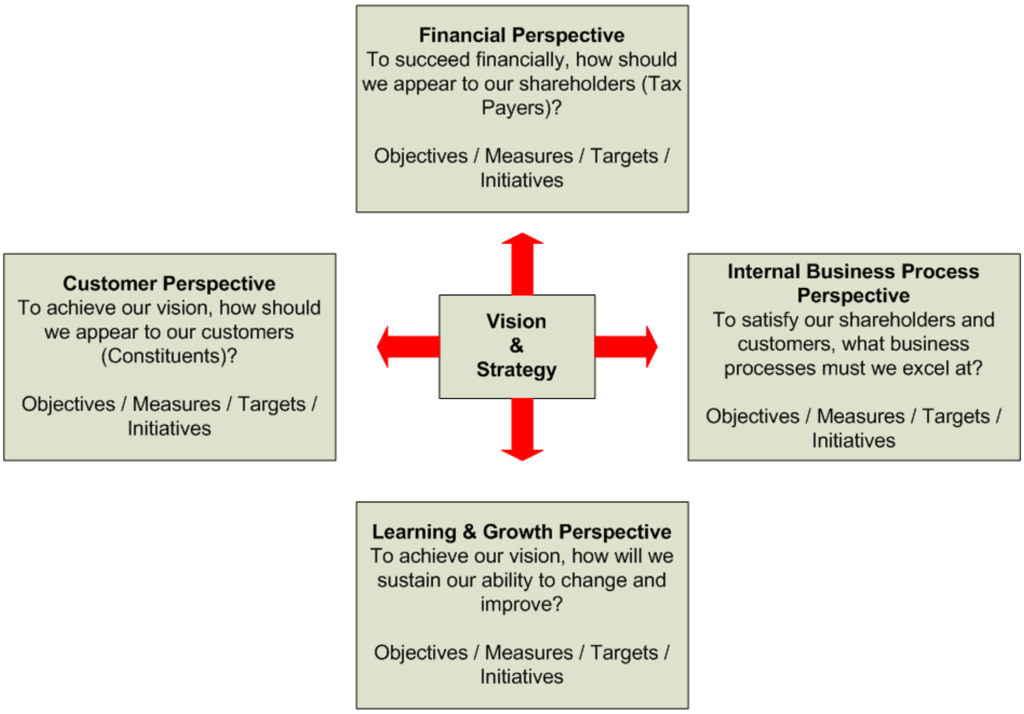
The next segment of the Workshop focused on application of benchmarking through the calculation of key performance indicators. Mr. Simpson led the delegates through the workbook of KPI exercises, found in their folders to calculate the indicators using their own utility's data or the sample data provided. The KPIs covered Generation, Transmission/Distribution, HR, Safety, Financial and general indicators.

The participants found the exercise extremely helpful in developing their understanding of the application of the benchmarking data. The observation was made that it was clear that there was a group of engineers in the room by the way they embraced the opportunity to get their calculators out and apply what they had learned. The success of the session was highlighted by the fact that no one looked up and noticed it was lunch time, and even after lunch was announced, many delegates decided to stay and continue with the exercise.

After lunch was the real test of the workshop's stimulation and the delegate's interest. Wrapping up on the KPI calculation exercise, Mr. Simpson presented on how the Balanced Scorecard can be used for strategy execution and KPI prioritisation. A chart of the process is provided below.



The use of the Balanced Scorecard as a strategic measurement framework was explored. The delegates were afterward led through a process of considering their operations in terms of various perspectives such as Customer, Financial, Internal Business Process, Learning and Growth Perspectives. This was followed by an exercise whereby the delegates developed objectives for each perspective area, and thereby rated the relevance of KPIs for their operations.



Having been through the questionnaire and data inputs, having been through calculation of the KPIs using those inputs, having been through a process of prioritizing KPIs according to a strategy, the next session was on the development of Performance Improvement Plans. Ms. Muscat presented how to move from KPI prioritisation to improvement initiative implementation.

The session encouraged participants in the activities they can undertake immediately, by focusing on the low hanging fruit, that is, the easily achievable improvements that will bring immediate benefits. The initiatives needed demand capital, and may focus on improving reporting systems or better management of human resources.

The participants were led in a group exercise where they used the perspectives analysis they had completed in the previous exercise to identify key KPIs that represent those objectives, and then set targets for those indicators and came up with improvement initiatives to be implemented to address that performance area in the form of a Priority Improvement Plan focusing on three KPIs. An example of improvement initiatives for HR/Safety KPIs is provided below.

KPI #	Indicator Name	Value	Unit	Improvement Initiative
	Human Resources / Safety			
31	Lost Time Injury Duration		days	Human Resources Management Plan
				Safety Initiatives, Use of Safety Standards, PPE,
32	Lost Time Injury Frequency Rate			Training
33	Labour Productivity		%	Performance Based Remuneration

Groups reported back on their Priority Improvement Plans, an exercise that the participants reported was highly beneficial in their feedback.

A final presentation was made by one of the delegates, Mr. Joachim Fong of American Samoa's ASPA, on the installation of a grid connected solar farm.

The workshop was closed with some concluded remarks by Mr. Austin.

Mr. Simpson had participants to fill out a feedback forms where they had an opportunity to rate the workshop in a range of areas including presentation, group interaction, program materials, structure, pitch, pace and content on a scale of 1 to 7, where 7 = Excellent. The feedback form also provided opportunity for participants to share which topics they found most beneficial, suggestions for improvement and provide overall comments. The workshop concluded with a group photo outside the venue.

Review of the feedback forms shows that the feedback received was overwhelmingly positive, with the vast majority of ratings being ‘7’ and positive comments from all participants about the effectiveness of the training workshop. Many participants commented on the benefit of doing the KPI calculations in developing their understanding of benchmarking and its application. Others highlighted the benefit of developing strategy and using KPIs to develop performance improvement initiatives. Many participants rated all topics as being the most beneficial.

Suggestions for improvement included (in order of number of request):

- Provide a two to three day workshop. Give more time to work through exercises.
- Run the workshop annually
- Ensure utilities have the data before the workshop
- Provide more free interactive time with participants and facilitators
- Mandatory follow up every 6 months
- More coverage of benchmarks
- Have each utility bring their data for calculation so they can compare
- At least 2 participants per utility

Positive reports were also received in person after the conference, praising the usefulness and practicality of the workshop and the success in engaging the participants. One CEO who delegated the participation to one of their staff reported that he had never seen his staff member as fired up about benchmarking and implementing improvement initiatives in their utility. Since returning to their home, another participant reported that they will be preparing a report for their management on how they can lift their utility’s performance.

Moving forward, some key points are:

- Utilities have received the questionnaire and data inputs document and are required to submit their data. Data will be collected, analysed and reported back to the utilities.
- The feedback received on the questionnaire, including the need to further clarify some of the data inputs, will be considered, and the data inputs document will be revised for future exercises.
- Several CEOs requested additional KPIs/data inputs in order to track costs more specifically. This request will be considered and if required the questionnaire will be revised for future rounds.
- The Benchmarking Manual will be updated once the questionnaire, data inputs and KPIs are finalised. In the meantime, the workbook folder documents and the workshop presentations have been sent to the participants for reference documentation.
- CEOs of each utility need to lead benchmarking and translate benchmarking results into strategy for improvement including the development of Performance Improvement Plans at their site.
- PIAC are available to provide assistance to utilities of partner countries in:
    - Collection and validation of the benchmarking data
    - Development of Performance Improvement Plans.

Appendix 10

Benchmarking Questionnaire Section One (General Information)

The questionnaire was distributed to utilities is in two parts:

Section 1: Introduction, Instructions and General Utility Information.
This appendix excludes the introductory material and instructions. It includes only the actual questions asked. It has been reproduced in a smaller font than the original to save printing space.

Section 2: Data Spreadsheet.
This is the key data requested from utilities for calculating indicators.

1.0: General Utility Information

Information on the person providing the information

Lead utility coordinator: (who completes the form)	
Approved by utility CEO:	
Position:	
Reporting period:	
Country or territory:	
Name of utility	
Postal address of utility	
E-mail address:	
Back up e-mail address:	
Telephone number:	
Skype address (if any):	

1.1: Electricity services through the grid

Does utility supply the entire country (or state or locality where relevant)?	
If the reply is no, what are the main islands or island groups served by the utility?	
Rural electrification through the grid. Is the utility responsible for supply to rural consumers? If so, how is 'rural' defined? *	
Rural electrification: stand-alone or not grid-connected Is the utility responsible for small mini-grid supply (e.g. village supply, stand-alone solar PV, etc.) If so, explain briefly	

* Connections per km^2 (or per square mile) or other criteria

1.2: Utility ownership, services provided and institutional arrangements

Government ownership (%)	
Private ownership (%)	
Other (%)	

Service other than electricity	Yes/No	Year's turnover as % of total*
Water supply		
Waste management		
Telecommunications		
Petroleum or LPG supply		
Other (indicate service)		

Utility operates under:	Yes/No	Date in effect; date of expiry or comments
An Act of legislature (or equiv.)?		
A concession agreement or license (or concessions/licenses)?		
Other legal framework (for example, part of Public Works?		
Is Government represented on board? (If so indicate if through Finance Ministry., Public Works, Energy Dept., etc.?)		
Does the Government decide tariff levels?		

Regulatory & service framework	Yes/No and Comment
Is utility self-regulating? (If yes, for technical standards or policies on IPPs, PPAs, FITs, etc.? *	

* IPP = Independent power producer; PPA = Power purchase agreement; FIT = Feed-in tariff

Is there an external or independent utility regulator?	
If yes, name & year established and make-up of regulatory members	
If yes, legal responsibilities (e.g. tariffs, tech standards, etc.)	
If yes, regulator's relationship with the Government (govt department, independent govt agency, etc.)	
If no, is an independent regulator being considered by the Government or is it under development?	
Is there a legal requirement, regulation, decree etc. on power quality (e.g. voltage or frequency tolerance)? If yes, briefly describe	
Is there a service obligation (e.g. mandatory supply to rural areas near grid)? If so explain briefly	
Are clear regulations in place to allow independent power supply to the grid by Independent Power Producers (IPPs)? If so, when did this enter into force & is there any formal regulation?	
Is there a feed-in tariff policy (e.g. for private solar PV systems to feed to the grid)? If so, describe briefly	
Is there a requirement to provide demand side management (DSM) energy efficiency services to commercial &/or household consumers? If so, describe briefly.	

Is there a formal national goal for generation from renewable energy? (If so, is this government or utility goal? Briefly describe (e.g. 10% of generation by 2020)	

1.3: Tariff schedule and taxes

Tariff schedule	Other information
The final tariff change introduced in 2010 *	Date change came into effect
All tariff changes in 2011 *	Date change came into effect
Fuel surcharge and dates of any change	Fuel surcharge, if not included in tariff schedule
Tax on consumers	Indicate if the published tariff includes Value added tax (VAT) or other taxes

Fuel import duty & taxes	Other information
Import duty on fuel use	Provide % of CIF value, cents/litre, cents/gallon, etc. as appropriate. Note if utility fuel use is free of import duty
Other tax on fuel use for generation	Provide any additional tax, if any on fuel used for electricity generation. Note if utility fuel use is free of any normal fuel tax
Tax concessions for utility equipment	Provide information on any reduced tax or other concessions for equipment imported by the utility

Appendix 11

Benchmarking Questionnaire Section Two (Data Spreadsheet, Data Reliability)

This appendix has been copied from an Excel spreadsheet and reduced in size to reduce the number of printed pages.
The spreadsheet is available from the PPA.

PACIFIC POWER ASSOCIATION
Pacific Power Utility Benchmarking Study
Questionnaire Section 2: Benchmarking Information

Instructions:

1. Please see the attached Word document file "PPA Benchmarking 2012 - Intro and Section 1" for the Background, Introduction and Section 1 of the Questionnaire.
2. The attached word document "Explanations of Input Data 1" provides explanation of each input, with practical examples and sample calculations.
3. Both Section 1 (Word document) and Section 2 (Excel spreadsheet) will need to be completed for the 2012 Benchmarking Exercise.
4. Please enter the data or information requested in the yellow boxes indicated.
5. Reference unit conversion charts are provided on the Sheet "Reference Unit Conversion"
6. Where appropriate, please mark as follows: n.av. = not available; N/Ap = not applicable
7. All information requested (employment, costs, revenue, etc.) ***refers only to electricity operations***. Do not include information for other services the utility may provide such as water, waste management, telecommunications, fuel supply etc.
8. Before returning the completed questionnaire, **please change the filename to indicate the utility, e.g. TAU, FEA, PNG Power, etc.**

SECTION 2: Introductory Questions

Information on person providing the information:
If the same person has completed both Section 1 and Section 2, indicate the name and then 'same as Section 1' below:

Completed by Benchmarking Liaison Officer (name):		
Position / Title:		
Endorsed by CEO (name):		
Country or territory:		
Name of utility:		
Postal address:		
E-mail address:		
Back up e-mail address:		
Telephone number:		
Skype address (if any):		
Benchmarking Period:		
Start Date for Benchmarking Data Collection Period (Benchmarking Period)		Calendar year is preferred, otherwise use relevant financial/reporting year
End Date for Benchmarking Data Collection Period (Benchmarking Period)		
Date questionnaire completed		
Currency Used by Utility to Report Costs:		All costs are to be provided in this currency

Appendix 11

Ref	Input Name	Units	Explanation	Main Grid 1	Grid 2	Grid 3	Others	
Generation				Generation information is to be provided for the ENTIRE UTILITY SYSTEM				
1	Name of the Grid		Brief name or description of each grid					
2	Total Utility Generation	MWh	Total utility generation for each grid	91,980				MWh
3	Total IPP Generation Purchased	MWh	Purchases from IPPs for each grid	39,240				MWh
4	Maximum Demand / Peak Generation	MW	Maximum demand for each grid	30				MW
5	Minimum Demand Generation	MW	Minimum demand for the each grid	15				MW
6	Guaranteed/Contracted IPP Generation Capacity	MW	The capacity guaranteed by an IPP under contract	5				MW
7	Generator 1 Nameplate Capacity Rating	MW	The capacity for the generator as stated by the nameplate	5				MW
7	Generator 2 Nameplate Capacity Rating	MW	The capacity for the generator as stated by the nameplate	10				MW
7	Generator 3 Nameplate Capacity Rating	MW	The capacity for the generator as stated by the nameplate	10				MW
7	Generator 4 Nameplate Capacity Rating	MW	The capacity for the generator as stated by the nameplate	7				MW
7	Generator 5 Nameplate Capacity Rating	MW	The capacity for the generator as stated by the nameplate	7				MW
7	Generator 6 Nameplate Capacity Rating	MW	The capacity for the generator as stated by the nameplate	10				MW
7	Generator 7 Nameplate Capacity Rating	MW	The capacity for the generator as stated by the nameplate					MW
7	Generator 8 Nameplate Capacity Rating	MW	The capacity for the generator as stated by the nameplate					MW
7	Generator 9 Nameplate Capacity Rating	MW	The capacity for the generator as stated by the nameplate					MW
7	Generator 10 Nameplate Capacity Rating	MW	The capacity for the generator as stated by the nameplate					MW
7	Generator 11 Nameplate Capacity Rating	MW	The capacity for the generator as stated by the nameplate					MW
7	Generator 12 Nameplate Capacity Rating	MW	The capacity for the generator as stated by the nameplate					MW
7	Generator 13 Nameplate Capacity Rating	MW	The capacity for the generator as stated by the nameplate					MW
7	Generator 14 Nameplate Capacity Rating	MW	The capacity for the generator as stated by the nameplate					MW
7	Generator 15 Nameplate Capacity Rating	MW	The capacity for the generator as stated by the nameplate					MW
7	Generator 16 Nameplate Capacity Rating	MW	The capacity for the generator as stated by the nameplate					MW
7	Generator 17 Nameplate Capacity Rating	MW	The capacity for the generator as stated by the nameplate					MW
	(add more as required)							MW
8	Generation by Source (MWh)	MWh	Use the total for Utility for each grid					
8a	Distillate (ADO or IDO)	MWh	Total Utility generation from distillate per grid	45,990				MWh
8b	Heavy fuel oil (HFO or IFO)	MWh	Total Utility generation from heavy fuel oil per grid	13,797				MWh
8c	Biofuels	MWh	Total Utility generation from biofuel per grid	940				MWh
8d	Mixed Fuel	MWh	Total Utility generation from mixed fuel (eg coconut oil and diesel) for each grid. Provide details of mixture, fuels used and % of each in Comments column.	920				MWh
8e	LNG	MWh	Total Utility generation from liquid natural gas for each grid	1,820				MWh
8f	Hydropower	MWh	Total Utility generation from hydro resources for each grid	13,797				MWh
8g	Wind energy	MWh	Total Utility generation from wind energy for each grid	4,599				MWh
8h	Solar Photovoltaics	MWh	Total Utility generation from solar PV for each grid	920				MWh
8i	Biomass	MWh	Total Utility generation from wood or other biomass for each grid	2,759				MWh
8j	Geothermal	MWh	Total Utility generation from geothermal for each grid	5,518				MWh
8k	Other	MWh	Any other sources of generation on each grid. Please specify in Comments column.	920				MWh

Ref	Input Name	Units	Explanation	System Data				
9	Fuel Usage	L / kL / ML						
9a	Distillate (ADO or IDO)	L / kL / ML	Total Distillate usage per year per grid. Select the units used (L/kL/ML)	13,500,000				L or kL or ML?
9b	Heavy fuel oil (HFO or IFO)	L / kL / ML	Total HFO/IDO usage per year per grid. Select the units used (L/kL/ML)	4,100,000				L or kL or ML?
9c	Biofuels	L / kL / ML	Total Biofuel usage per year per grid. Select the units used (L/kL/ML)	230,000				L or kL or ML?
9d	Mixed fuel	L / kL / ML	Total Mixed Fuel usage per year per grid. Select the units used (L/kL/ML). Indicate details of mixture in Comments column	220,000				L or kL or ML?
9e	LNG	L / kL / ML	Total LNG Usage per year per grid. Select the units used (L/kL/ML)					L or kL or ML?
10	Total Lubricants Used in Generation	L / kL / ML	Total lubricants used in generation from ADO/IDO, HFO/IFO, Biofuels, Fuel Mixtures, LNG. Select the units used (L/kL/ML)	70,000				L or kL or ML?
11	Utility Capacity Hours Out of Service Due to Generation Forced Outage Events	MWh	Sum of (Utility Generation Forced Outage Duration multiplied by Capacity Rating)	31,332.5				MWh
12	Utility Capacity Hours Out of Service Due to Generation Planned Outage Events	MWh	Sum of (Utility Generation Planned Outage Duration multiplied by Capacity Rating)	56,600				MWh
13	Utility Capacity Hours Out of Service Due to Generation De-rated Events	MWh	Sum of (Utility Generation De-rated Outage Duration multiplied by Capacity Rating)	2,060.5				MWh
14	IPP Capacity Hours Out of Service Due to Generation Forced Outage Events	MWh	Sum of (IPP Generation Forced Outage Duration multiplied by Capacity Rating)	100				MWh
15	IPP Capacity Hours Out of Service Due to Generation Planned Outage Events	MWh	Sum of (IPP Generation Planned Outage Duration multiplied by Capacity Rating)	2,000				MWh
16	IPP Capacity Hours Out of Service Due to Generation De-rated Events	MWh	Sum of (IPP Generation De-rated Outage Duration multiplied by Capacity Rating)	50				MWh
17	Power Station Usage / Station Auxiliaries	MWh	Total energy used in the power stations operated by the utility	4,600				MWh
18	Enabling Framework for Private Sector Participation IPP/ PPA Arrangement?	Y/N	Enabling framework includes procedures, processes etc. Provide details in Comments column.	Y/N				
Transmission				**Transmission information is to be provided for the MAIN GRID ONLY**				
	Transmission refers only to network of **above 34.5kV**							
19	Does your system have a transmission network?	Y/N	Applies only to Fiji, Guam, PNG and Saipan. Other utilities answer "No" and proceed to 'Distribution'.	Y/N				
20	Number of Unplanned Transmission Outage Events	Events	Number of times in the period when a transmission system fault resulted in an unplanned outage	10				
21	Total duration of Unplanned Transmission Outage Events	hrs	The total sum of the duration of all unplanned transmission system outages in the period	168				
22	Length of Transmission Line	km/miles	Total length of all transmission lines and cables in each network	300	km			
23	Electricity delivered to distribution system	MWH	Total electricity delivered to the distribution system in MWh	124,620				
Distribution				**Distribution information is to be provided for the MAIN GRID ONLY**				
	Distribution refers only to power sent through the grid **at or below 34.5kV**							
24	Number of Distribution Forced Outage Events	Events	The total number of outages due to faults in the distribution network.	1.000				

Appendix 11

Ref	Input Name	Units	Explanation	System Data		
25	Length of Distribution Line	km/miles	The total length of all distribution lines and cables in the distribution network	100,000	km	
26	Total Distribution Transformer Capacity	MVA	The sum of all distribution transformer capacity on the network	60	MVA	
27	Total Customer Interruptions	interruptions	Total number of customer connections affected by distribution outages (both planned and unplanned) in the period	3,227,150	Interruptions	
28	Total Customer Duration Interrupted	customer hrs	Sum of (Custom Interruption x Duration of Interruption)	1,415,400		
Demand Side Management (DSM)				**DSM information is to be provided for the ENTIRE UTILITY SYSTEM**		
29	Does the utility actively engaged in any demand side management initiatives?	Y/N	This includes initiatives across all grid. Select Yes/No for this question and for the following activities. If other activities that are not specified, please specify below in 'Others'.	Y/N		
29a	Replacing incandescent lighting with compact fluorescent lighting	Y/N		Y/N		
29b	Installing sensors on lighting or other	Y/N		Y/N		
29c	Replacing old inefficient air conditioners with high-efficiency units	Y/N		Y/N		
29d	Performance testing of appliances and equipment	Y/N		Y/N		
29e	Replacing old refrigerators and freezers with new, high-efficiency units	Y/N		Y/N		
29f	Have varying rates for peak and off peak electricity usage	Y/N		Y/N		
29g	Educational program to consumers	Y/N		Y/N		
29h	Other 1 (please specify)	Y/N	Any other DSM initiatives. Please specify.	Y/N	Other 1 - Specify here:	
29i	Other 2 (please specify)	Y/N	Any other DSM initiatives. Please specify.	Y/N	Other 2- Specify here:	
29j	Other 3 (please specify)	Y/N	Any other DSM initiatives. Please specify.	Y/N	Other 3 - Specify here:	
29k	Other 4 (please specify)	Y/N	Any other DSM initiatives. Please specify.	Y/N	Other 4 - Specify here:	
29l	Other 5 (please specify)	Y/N	Any other DSM initiatives. Please specify.	Y/N	Other 5 - Specify here:	
30	What is the budget for DSM?	0	Specify DSM budget for reporting period. If no DSM budget, type "0"			
31	How many employees are engaged in DSM?	employees	Provide total number of employees. Provide details in the comments column		Employees	
32	Has there been recorded savings by consumers? How much?	MWh (total)	Select "Yes" or "No". If "Yes", indicate how much in the local currency		MWh(total)	
33	What power Quality Standard applies, if any?		Provide name of the standard. If none applies, type "None".			
Human Resources / Safety				**Human Resource / Safety information is to be combined for the ENTIRE UTILITY SYSTEM**		
34	Total Days Lost Due to Work Injury During Period (excludes contractors)	days	The sum of work days/shifts an employee is unable to report to work due to injury sustained at work. Excludes contractors.	80.00	days	
35	Number of Lost Time Injuries During Period (excludes contractors)	LTIs	Total employee LTIs. Contractor injuries are not counted towards LTIs.	15	LTIs	
36	Total Number of Employees (excludes contractors)	employees	The total number of employees. This factor excludes contractors	800	employees	
37	Total number of employees in Distribution & Customer Service at Start of Period	employees	Total number of employees in Distribution & Customer Service at Start of Period	0	480	employees

Ref	Input Name	Units	Explanation	System Data				
38	Total number of employees in Distribution & Customer Service at End of Period	employees	Total number of employees in Distribution & Customer Service at End of Period	0	530	employees		
39	Total Hours Worked (excludes contractors)	hrs	The total hours worked by employees	1,600,000	hrs			
40	Paid Hours Utility Generation Labour	hrs	Total paid hours for generation labour, taking into account overtime rates	100,000			hrs	
41	Paid Hours Utility Distribution Labour	hrs	Total paid hours labour to maintain and operate the utility's distribution network.	1,166,000	hrs			
42	Total Paid Hours Employees Including Contractors	hrs	The total paid hours for employee labour. This takes overtime (double time etc) into account	1,800,000	hrs			
	Customers / General			**Customer information is to be combined for the ENTIRE UTILITY SYSTEM, except for Electricity Sold which is per grid**				
				Main Grid 1	Grid 2	Grid 3	Others	
43	Electricity Sold	MWh	Total electricity billed to customers in MWh for each grid	100,000				MWh
44	Total Number of Customers at Start of Benchmarking Period	connections	Number of customers at the start of the benchmarking period. Include total of all customer classes for all the networks.	0	165,400	connections		
45	Total Number of Customers at End of Benchmarking Period	connections	Number of customers at the end of the benchmarking period. Include total of all customer classes for all the networks.	0	174,300	connections		
46	Number of Households Supplied (Domestic Connections)	connections	Combined number of domestic connections across all grids, taken at end of benchmarking period	151,300	connections			
47	Total Number of Households in the Country	households	The total number of households in the country.	300,000	households			
48	Lifeline Tariff Available?	Y/N	Indicate Yes or No	Y/N				
49	Maximum Threshold for Monthly Consumption Under Tariff	kWh/mth	Provide the tariff threshold in kWh/month		kWh/mth			
50	Tariff Schedule / Tariff Table Attached?	Y/N	Please attach tariff schedule/table and indicate Yes when this is done.	Y/N				
51	Total Electricity Billed under Lifeline Tariff	MWh	The total electricity billed to customers under Lifeline Tariff in MWh.	2,000	MWh			
52	Total Domestic Electricity Billed	MWh	The total electricity billed to customers under domestic tariff in MWh.	50,000	MWh			
53	Total Commercial Electricity Billed	MWh	The total electricity billed to customers under the commercial tariff in MWh.	10,000	MWh			
54	Total Industrial Electricity Billed	MWh	The total electricity billed to customers under the industrial or maximum demand tariff in MWh.	23,000	MWh			
55	Total Other Electricity Billed	MWh	The total electricity billed to customers under the industrial or maximum demand tariff in MWh. Please specify	15,000	MWh			

Ref	Input Name	Units	Explanation	System Data	
56	Total Unbilled Electricity Usage	MWh	e.g Head Office, Water Services, Street Lighting etc. (This does not include power station usage/station auxiliaries)	5,000	MWh
57	Is the utility self regulated or externally regulated?	self / external	Select self regulated or externally regulated. Provide any details	self / external ?	
58	Do you have a maintenance plan for your utility?	Y/N	This may cover generation, transmission, distribution. Please attach plan.	Y/N	
	Finance			**Finance information is to be combined for the ENTIRE UTILITY SYSTEM**	
59	Depreciation Generation Assets	$	Total depreciation of generation assets over the benchmark period	3,500,000	$
60	Depreciation Transmission & Distribution Assets	$	Total depreciation of transmission & distribution assets over the benchmark period	1,000,000	$
61	Other Depreciation	$	Total depreciation on other electricity assets excluding generation, transmission & distribution assets for benchmarking period.	500,000	$
62	Total Operating Revenue	$	Total Operating Revenue earned from electricity sales.	70,000,000	$
63	Total Operating Expenses	$	Total Operating Expenses excluding depreciation, interest and tax.	46,600,000	$
64	Earnings Before Interest and Tax (EBIT) / Operating Profit	$	Sales revenue minus the cost of goods sold and all expenses except for interest and taxes	18,400,000	$
65	Profit After Tax (PAT) / Earnings After Tax (EAT)	$	Sales revenue after deducting all expenses, including taxes	5,000,000	$
66	Long Term Debt / Non Current Liability	$	Funds obtained from loans, mortgages, bonds, etc. that have repayment terms longer than one year	100,000,000	$
67	Equity / Net Assets / Capital and Reserves	$	Equity / Net Assets / Capital & Reserves represents the owner's funds or claims the owners have on the business.	50,000,000	$
68	Non Current Asset at End of Previous Period	$	The assets that are consumed over a period of more Than a year taken from end of prev period	120,000,000	$
69	Non Current Asset at End of Benchmarking Period	$	The assets that are consumed over a period of more Than a year taken from end of benchmarking period	140,000,000	$
70	Current Assets	$	Value of all assets that are reasonably expected to be converted into cash within one year	50,000,000	$

Ref	Input Name	Units	Explanation	System Data	
71	Current Liabilities	$	Company's debts or obligations that are due within One year	40,000,000	$
72	Debtors/Receivables at Period End	$	Money owed to a business by its clients (customers) and shown on its Balance Sheet as an asset	25,000,000	$
73	Are utility finances independently audited?	Y/N	If Yes, indicate who the auditor was in Comments column	Y/N	
74	What is the accounting standard used by the utility?		eg US GAP, IAS, IPSA, None etc		
Generation Expenditure					
75	Hydrocarbon Based Fuel & Lubrication Oil Expenditure	$	Total expenditure on distillate fuel oil, heavy fuel oil, coconut oil, other hydro carbon based fuels, and lubricating oil	17,000,000	$
76	Duty and Taxes on Hydrocarbon Based Fuel & Lubricating Oil	$	Total duty and taxes paid hydrocarbon based fuel & lubricating oil	1,760,000	
77	Generation O&M Costs (utility)	$	Total cost for operations and maintenance of the Utility. This excludes all IPP generation costs, labour costs and fuel and oil costs.	3,000,000	
78	Generation Labour	$	Total expenditure on labour associated with the generation of electricity	2,000,000	
Transmission/ Distribution Expenditure					
79	Transmission/ Distribution O&M Cost	$	Total expenses incurred in the operations and maintenance of the distribution network		$
80	Transmission/ Distribution Labour	$	Total expenditure on labour for transmission & distribution operations		$
Overheads/ Other Expenditure					
81	Other Labour Expenditure (Customer Service, Head Office, Finance, HR, others)	$	Total labour expenditure for head office and other labourfor electricity operations		$
82	Other Duty/ Taxes	$	All duty and taxes paid to government for equipment and supplies. Do not include personal income tax and other taxes applicable to workers remuneration. GST, VAT or other forms of sales tax is also excluded		$
83	Other Expenditure	$	Total expenditure on items not included in any of the above.		$

Please go to 'Data Reliability Sheet' and Complete

A11.1 Data Reliability Sheets

The quality of the benchmarking data is critical to the validity of the benchmarking results. In the 2012 round of benchmarking, and for future rounds, a separate sheet within the questionnaire requires utilities to provide a self-assessed reliability grade for six key components of the primary data (**Error! Reference source not found.**) in order to better understand data quality issues and encourage improvements in data reliability.

Table A11.1: Key Data Component Reliability Assessment Questions

Question	Description	Reliability Grade (A, B, C or D)
i.	How is fuel consumption calculated or derived?	
ii.	How are generation quantities calculated or derived?	
iii.	How are customer outage impacts calculated or derived?	
iv.	How are network demands and capacity utilisation calculated or derived?	
v.	How are the number of connections or customers calculated?	
vi.	Where is financial information sourced from?	

The general reliability expectations of each grade are described below in Table A11.2, where A represents the most reliable data and D the least reliable data.

Table A11.2 : General Reliability Evaluation

Reliability Grade	Reliability	Description
A	Highly Reliable	Data is based on sound records, procedures, investigations or analyses that are properly documented and recognised as the best available assessment methods. Effective metering or measurement systems exist.
B	Reliable	Generally as in Category A, but with minor shortcomings, e.g. some of the documentation is missing, the assessment is old or some reliance on unconfirmed reports; or there is some extrapolation made (e.g. extrapolations from records that cover more than 50 percent of the utility system).
C	Unreliable	Generally as in Category B, but data is based on extrapolations from records that cover more than 30 per cent (but less than 50 per cent) of the utility system.
D	Highly Unreliable	Data is based on unconfirmed verbal reports and/or cursory inspections or analysis, including extrapolations from such reports/inspections/analysis. There are no reliable metering or measurement systems.

Further guidance for each component is given in Table A11.3, although this is not intended to be a detailed specification. Self-assessments will remain at least partially subjective as a result of variations in circumstances and scale. Please select the Reliability Grade that best represents the reliability for each component in **Error! Reference source not found.** and provide any additional comments on that selection.

Table A11.3: Reliability Grading Guidance

Reliability Grade	Description	
i.	How is fuel consumption calculated or derived?	**Related Questionnaire Data Inputs**
A	Accurate records are kept of deliveries, inventory and consumption of oil and fuel type by location, station and unit. Fuel consumption measurement equipment is temperature compensated. Monthly fuel consumption measurement is taken for each unit and fuel consumption audits are regularly undertaken and reconciled by unit. Audits are carried out by both internal and external parties.	9, 10
B	Records are kept of deliveries, inventory and consumption of oil and fuel type by location and station. Fuel consumption measurement equipment is not temperature compensated. Fuel consumption measurement is taken for power stations and fuel consumption audits are undertaken and reconciled by power stations. Audits are carried out by internal and external parties.	

C	Some records are kept of deliveries, inventory and consumption of oil and fuel type by location and station. Fuel consumption measurement are done by dip stick. Fuel consumption audits are only undertaken by an external party annually and reconciled by power stations.	
D	Some records are kept of deliveries, inventory and consumption of oil and fuel type by location and station. Fuel consumption measurement are done by dip stick. Fuel consumption audits are rarely undertaken or irregular. Heavy reliance on fuel supplier information.	

i.	How are generation quantities calculated or derived?	Related Questionnaire Data Inputs
A	Generation quantities are computed on the basis of measurement by station, unit and auxiliary metering at all grid connected generation points, which are calibrated / verified for accuracy regularly. Generation profiles are monitored continuously and there is an established process for reporting capacity factors. There is an established process for derating of generators and reporting of all related volumes.	2 to 8 inclusive 11 to 17 inclusive
B	Generation quantities are computed on the basis of measurement by unit and station metering at all grid connected generation points. Meters may not be calibrated or verified for accuracy. Reliable generation profiles are available. More manual processing and interpretation of records may be required than A.	
C	Reliable and calibrated metering is not available at all grid connected generation points. Generation profiles are estimated or extrapolated. Derating information is not routinely recorded.	
D	Aggregated generation information is available, with limited information available on unit and station profiles and capacity factors. No reliable calibrated metering systems exist.	

iii.	How are customer outage impacts calculated or derived?	Related Questionnaire Data Inputs
A	Details of individual HV network or generation outages are available and used to calculate customer impact measures and reliability statistics. Records of trip times, restoration sequences, and affected customer numbers are available from SCADA, generator, substation, operating or other records. Outage records are suitable for causal analysis and performance improvement. An established and auditable process is used for evaluation of outage impacts.	11 to 16 inclusive 20,21 24, 27, 28
B	Reliable assessment of HV network and generation outages are available, but may require more manual processing of information from source records than in A. Customer numbers for network segments and affected areas are used to derive reliability statistics but may not be up to date at all times.	
C	Where outage impacts are assessed, they use estimates of outage durations and affected customer numbers. It is likely that not all outages are captured in reporting statistics. Limited processes exist for fault causal analysis and reporting.	
D	Outage analysis may only be performed for large outages, if at all. Outage details are not recorded consistently or for reporting purposes. It may be difficult to extract information from generator, substation and operating records. There are no established processes related to customer outage analysis.	

iv.	How are network demands and capacity utilisation calculated or derived?	Related Questionnaire Data Inputs
A	Calibrated metering equipment is installed at all zone and distribution substations and at consumer's premises for all categories of consumers. Demand information is captured throughout the network. Records are up to date and identify installed capacity of lines and transformers. Billing records and databases reveal regular reading of meters. Established processes exist and are used for reporting of capacity utilisation, losses and network demand profiles. Power system analysis software may be in use and routinely undertaken. Detailed loss breakdowns are regularly updated and available.	4, 5, 23, 26, 32

B	Generally as per A, although processes and systems are not as developed. Limitations of installed metering and substation equipment will require more manual processing of information. Asset records are missing information requiring some extrapolation for assessment purposes. Power system analysis software or studies may be undertaken from time to time.	
C	Metering is not comprehensive enough to allow evaluation of demand and losses easily throughout the network. There may be significant limitations in the records of installed assets. Billing records and aggregate consumption information is incomplete.	
D	Asset records may be well out of date and metering coverage of the network poor. Major assumptions required for evaluation of utilisation at an aggregate level. No meaningful loss breakdown possible. No recent power system analysis completed.	

v.	How are the number of connections or customers calculated?	Related Questionnaire Data Inputs
A	Billing records and databases clearly identify customer specific meters. Billing processes reveal regular reading of meters and meter readings are the basis for charging consumers. Databases of electricity connections and meters are complete. There is a mechanism to identify faulty meters and repair meters. Processes for installation of new connections, installation of meters and generation of bills based on this are interlinked with a robust process.	43 to 56 inclusive
B	Database/ records reveal the list of customers that have meters installed in their electricity connections. Meter data and associated customer databases may be limited and the linkage with the billing system harder to demonstrate.	
C	Records do not reveal the exact number of connections which are metered . Not all billing is based on metered quantities. Processes associated with new connections and metering management may not be robust.	
D	No formalised processes for metering and connection management. Number of current connections estimated with poor linkages to billing system and database coverage.	

vi.	Where is financial information sourced from?	Related Questionnaire Data Inputs
A	Major budget and functional reporting categories identified and separated. Cost allocation standards for common costs are in place. An accrual based double entry accounting system is practiced. Accounting standards are comparable to commercial accounting standards with clear guidelines for recognition of income and expenditure. Accounting and budgeting manuals are in place and are adhered to. Financial statements have full disclosure and are audited regularly and on time.	59 to 83 inclusive
B	Key costs related to generation and distribution are identifiable, although complete segregation is not practiced. Key income and expenditure is recognised based on accrual principles, but accounting standards may not be comparable to commercial accounting standards. Disclosures are complete and are timely and audits undertaken.	
C	Major budget and functional reporting categories are not clearly separated, e.g., between electricity power supply costs and costs for other utility functions such as water, sewerage, etc. Limited useful functional reporting and cost allocation principles in place. Audits may have a significant time lag or may be irregular.	
D	There is no segregation of major budget and functional categories, eg, no clear distinction between electricity power supply costs and costs for other utility functions such as water, sewerage, etc. A cash-based accounting system may be practiced. There are no clear systems for reporting unpaid expenditure or revenues that are due. Disclosures and reporting may not be timely.	

This will be followed up by data reliability audits conducted by the Benchmarking Team when given opportunity through site visits.

Appendix 12

Benchmarking Questionnaire Section Two (Data Spreadsheet, Data Reliability)

Table A12.1: Data from Questionnaire Section 2, Data Reliability Self-Assessment

Utility	ASPA	CPUC	CUC	EDT	EPC	FEA	GPA	KAJUR	KUA	MEC	NUC	PNGP	PPUC	PUB	PUC	SIEA	TAU	TEC	TPL	UNELCO	YSPSC
Key Data Component	American Samoa	Chuuk FSM	Saipan CNMI	Tahiti	Samoa	Fiji	Guam	Ebeye RMI	Kosrae FSM	Majuro RMI	Nauru	PNG	Palau	Kiribati	Pohnpei FSM	Sol. Islands	Cook Islands	Tuvalu	Tonga	Vanuatu	Yap FSM
Fuel Consumption	A	B	B	B	B	A	A	B	B	C	C	AB	B	B	B	B	-	B	B	A	B
Generation Quantities	A	B	A	B	B	A	A	B	B	B	C	A	A	B	C	C	-	B	A	A	BC
Customer Outage Impacts	B	D	B	B	B	A	B	C	B	D	D	B	D	C	D	B	-	C	B	A	C
Network Demand & Capacity	A	BC	A	B	B	A	B	B	B	B	C	A	A	B	C	B	-	B	B	B	B
No of customers & Connections	A	AB	A	A	B	AB	A	A	A	B	B	A	A	C	B	C	-	B	A	A	A
Financial Information Soruces	A	A	A	A	A	A	A	A	A	A	C	A	A	B	A	B	-	B	A	A	B
OVERALL	A+	B	A	A-	B+	A+	A	B+	A-	B-	C	A+	A-	B-	B-	B	na	B	A	A+	B

Notes: 1. **AB, BC** = respondents chose to classify as intermediate performance. 2. Blank = no response (NPC not included)

Table A12.2: Data from Questionnaire Section 2 (Additional Financial Data)

	Costs in local currency				Costs in US$ (calculated from local costs)			
Utility	Generation:	Transmission & Distribution	Other / misc	Total	Generation	Transmission & Distribution	Other / misc	Total
A	38,731,440	3,444,041	5,068,592	47,244,073	38,731,440	3,444,041	5,068,592	47,244,073
B	2961079	188,506	596,980	3,746,565	2,961,079	188,506	596,980	3,746,565
D	12,918,164	1,098,551	1,035,091	15,051,806	12,918,164	1,098,551	1,035,091	15,051,806
E	67,242,768	13412142	26,304,673	106,959,583	28,914,390	5,767,221	11,311,009	45,992,621
G	162,891,767	27,680,769	51,502,464	242,075,000	91,219,390	15,501,231	28,841,380	135,562,000
H	2,243,932	325,288	356,350	2,925,570	2,243,932	325,288	356,350	2,925,570
I	4,460,868	190,865	855,422	5,507,155	4,460,868	190,865	855,422	5,507,155
J	23,699,099	1,408,797	2,008,415	27,116,311	23,699,099	1,408,797	2,008,415	27,116,311
L	296,992,990	5,883,295	74,816,325	377,692,610	41,579,019	823,661	10,474,286	52,876,965
N	27,085,363	4,600,000	9,291,937	40,977,300	15,709,511	2,668,000	5,389,323	23,766,834
O	8,960,169	455,297	712,119	10,127,585	9,497,779	482,615	754,846	10,735,240
P	262,514,000	78,056,000	133,717,000	474,287,000	123,119,066	36,608,264	62,713,273	222,440,603
Q	1,837,676	117,036,167	712,335,045	831,208,888	19,976	1,272,183	7,743,082	9,035,241
R	4,901,185	309,603	659,329	5,870,117	4,901,185	309,603	659,329	5,870,117
S	20,277,000,000	4,033,000,000	3,501,000,000	27,811,000,000	202,770,000	40,330,000	35,010,000	278,110,000
T	300,182,347	21,297,825	35,080,774	356,560,946	300,182,347	21,297,825	35,080,774	356,560,946
V	5,423,403	2,632,993	3,178,056	11,234,452	5,748,807	2,790,973	3,368,739	11,908,519
W	74,139,020	3,037,359	14,012,373	91,188,752	74,139,020	3,037,359	14,012,373	91,188,752
X	17,452,104	1,501,343	1,661,682	20,615,129	17,452,104	1,501,343	1,661,682	20,615,129
Ave					52,645,641	7,318,228	11,944,260	71,908,129
Median					17,452,104	1,501,343	5,068,592	23,766,834
No	19	19	19	19	19	19	19	19

General notes regarding quantitative data in Appendix 12:

1. Some average and median values in this Appendix may differ from some of those in the text of the report because some outlying values were ignored in calculating indicators. The text accompanying Figures in the report identifies any data not used
2. Data used to compare 2010 and 2011 utility operations is not included in this Appendix but is available electronically from the PPA

Appendix 12

Table A12.3: Data from Questionnaire Section 2 (Generation)

Utility	1	2	3	4	5	6	7	8	10	11	12	13
	Load factor (overall) %	Capacity factor %	Availability Factor (overall) %	Labour prod GWh/gen employee	SFC kWh/litre	Lube Oil kWh/litre	Forced outage %	Planned Outage %	Power Station Usage %	Renewable Energy %	IPP Energy Generation %	Petroleum Fuel %
ASPA	79.19	43.51		1.52	3.76	910	0.01	0.05	3.61	0.7	0	99.3
CPUC	39.96	36.63	74.16	0.40	3.35	791.29	5.68	20.16	1.50	0	0	100.0
CUC	75.28	26.13	76	2.56	3.66	435	17.45	5.88	7.45	0	28.47	100.0
EDT	67.52	29.51	86.8	8.81	4.68	1,132	6.26	6.91	0.58	27.2	0.81	72.7
EPC	64.76	36.53			3.81	752	0.01		1.80	32	0	67.7
FEA	64.99	40.02		11.14	4.15	1,057	0.00	0.62	1.04	59.4	3.96	40.6
GPA	79.47	37.81	87	8.86	4.15	2,341	9.860	3.460	5.29	0	42.16	100.0
KAJUR	80.03	44.46		0.75	4.11	1,135	0.41	0.59	4.86	0	0	100.0
KUA	67.50	13.82		0.85	3.93	999	0.03	0.02	0.98	0	0	100.0
MEC	80.53	34.54			4.05	2,692			4.05	0.3	0	100.0
NUC	72.01	56.63	78	1.16	3.54	782	21.87	0.51	1.78	0.2	0	99.8
PNGP	56.70	37.10								58	16.06	42.1
PPUC	70.50	30.70	87	1.19	3.70	870	11.50	1.40	4.80	0.4	0	99.6
PUB	52.23	45.72		0.48	3.77	2,183			4.56	0	0	100.0
PUC	57.49	38.84		1.21	2.96	263			6.10	0	0	100.0
SIEA	61.45	45.83	78	0.85	3.90	1,037	18.73	3.32		0.2	0	100.0
TAU	68.23	32.63	75	1.52	3.79	510	15.43	9.20	1.96	0	0	100.0
TEC	72.63	24.06	83	0.14	3.63	1,387	17.22	0.26	8.63	0.6	0	99.4
TPL	67.34	45.89		1.71	4.08	963			2.68	0	0	100.0
UNELCO	61.23	29.43	97.16	2.29	3.98	827	0.67	2.17	3.12	8.5	0	91.5
YSPSC	65.00	19.00		0.92	3.18	619			8.36	0.1	0	99.9
Average	66.86	35.66	82.14	2.58	3.81	1,084.15	8.34	3.90	3.85	8.93		
Median	67.50	36.63	80.24	1.20	3.80	936.46	6.26	1.78	3.61	0.20		
Number	21	21	10	18	20	20	15	14	19	21	7	21

Table A12.4: Data from Questionnaire Section 2 (Transmission)

Utility	15 Transmission Losses %	16 Reliability Outages/100km	17 Average Transmission Outage Duration (hrs)
FEA	?	4.29	1.39
GPA	?	126.6	57.5
PNGP	?	23.32	2.69
EDT	4.96	13.0	
Average		41.8	20.5
Median			
Number	1	4	4

Table A12.5: Data from Questionnaire Section 2 (Distribution, DSM, HR and Safety)

Utility	19	20	21	22	24	25	26	27	28	29	31	32	33
	Dist. losses %	Customers per Dist Employee	Reliability Outages/ 100km	Transformer Utilisation %	SAIDI minutes / customer / yr	SAIFI interruptions / customer / yr	DSM Initiatives? Y/N	DSM Budget (US$)	DSM FTE Employees	DSM Savings MWh	Lost Time Injury Duration (days)	Lost Time Injury Rate (per mill hours)	Labour Productivity Cust per Employee
ASPA	8.15	307	16	22	183	6							25.62
CPUC	30.02	100	1069	7			N				0.10	8.30	24.90
CUC	7.00	229	24	22	1,148	14.94	Y				0.04		
EDT		566	4	20	90	1					0.10	19.07	80.26
EPC	6.71	154	19	10	1,732	13	Y						55.37
FEA		397	34	7	1,518	22	Y	61,600	1		0.09	4.48	231.48
GPA		298	181	21	1,206	34	Y	82,000	1	4,988	0.00	3.12	85.23
KAJUR	2.05	279	400	24.78	127	5.54	Y						17.91
KUA	18.51	169	17	14									
MEC	26.00	17					N						
NUC	28.58	155	267	10									49.80
PNGP		181					Y		3		0.04	175.09	59.76
PPUC	9.75										0.02	14.73	94.46
PUB	7.63	312	3	18			N				0.02	4.69	44.12
PUC	5.83	262		39			N				0.33	8.19	56.64
SIEA	20.04	325		21	1,075	9							75.59
TAU	10.73	83	5	18	155.00	2.33	Y	32,500		600	0.04	9.31	81.89
TEC	17.45	610	7	17	5.45	0.09							43.89
TPL	12.24	236	87	18.72	1,704	15.60					0.14	5.45	101.48
UNELCO	4.61	403	5	20	583	3.54	Y	54,350	2		0.16	6.01	132.51
YSPSC	26.20	90	19	8		3.30	N				0.02	14.06	26.56
Average	14.21	258.59	134.72	17.61	794	10.0	148,095				0.08	22.71	71.5
Median	10.73	248.82	19.13	18.61	829	6.3	15,605				0.04	8.25	59.8
No	17	20	16	18	12	13	14	4	4	2	13	12	18

Table A12.6: Data from Questionnaire Section 2 (Financial Information)

Utility Code	39	40	41	42	43	44	45	-	-	23	9
	Operating Ratio %	Return on op assets %	Debt Equity Ratio %	Return on Equity %	Current Ratio Assets / liabilities	Debtor Days	Ave price of electricity sold US$ / MWh	Ave cost of electricity sold US$ / MWh	Profit per MWH sold or delivered US$ / MWh	Distrib. O&M cost US $/km	Gen O&M US$/MWh
A	89.78	11.36	1.02	2.58	235.49	18.79	404	373	31	6325	9
B	148.05	(26.83)	121.33		22.57	37.29	533	734	(201)		522
D	118.00	(326.00)	7.49	(14.40)	140.00	39.40	442	523	(81)		366
E	113.61		68.91	1.47	114.32	41.85	399	513	(113)	19737	63
G	89.02	6.11	47.07	11.00	96.51	40.46	228	181	47	1279	120
H	124.21	(14.08)	1.24	(0.07)	193.04	113.75	449	557	(109)	1766	312
I	101.93	(33.00)	55.00	(38.00)	152.51		353	421	(68)	999	12
J	99.02	1.00	23.29	(0.24)	204.00	107.14	410	406	4		351
L	86.40	21.64	7.71	13.84	915.69	64.77	793	789	4	4315	479
M	93.34	12.49	2.69	6.95	9.48	41.41	590			4982	25
N	81.62	5.17	12.32	7.98	102.00	8.85	571	531	40	11008	25
O	109.27	0.52	29.66	0.72	102.92	156.35	579	642	(62)	3066	385
P	92.80	3.95	30.25	2.03	33.30	62.18	378	286	93		
Q	88.94	14.22	23.98	3.53	170.11	60.59	586	163	424 ?	1395	30
R	112.80	(8.70)	12.40	(6.30)	395.48	70.64	608	646	(37)	1637	363
S	63.00	1.67	24.25	4.04	50.95	78.85	377	460	(83)	11149	133
T	90.99	8.19	82.20	(0.74)	1.42	16.22	237	216	21	5519	23
U		7.17	7.57	11.27	12.82		181			6045	
V		2.74	126.58	(10.69)	52.38	107.03	527	?		3786	508
W	104.86						390	403	(13)	10523	
X	98.80	2.45		0.22	84.74		602	596	6		267
Average	100.3	(16.31)	36.05	(0.25)	154.49	62.68	320*	294*	(5)	5846	222
Median	98.8	2.74	23.98	1.47	102.46	60.59	442	513	0.0	4648	200
No	19	19	19	19	20	17	21	18	18	16	18

Notes: 1. * 'Geometric mean for utilities with valid financial data available. **2.** ? – indicates questionable result **3.** Blank = no data available.

Table A12.7: KEMA System Loss Data

Utility	Station losses	Un-metered	Tech	Non-Tech	Tech + Non-Tech	Total	Own use if metered	Other*	
CPUC	3.8%		7.7%	16.1%	23.8%	27.6%		5.72%	lights, water & sewerage
CUC	4.7%		4.4%	10.7%	15.1%	19.8%		0.98%	lights, water & sewerage
EPC	1.3%		6.7%	7.6%	14.3%	15.5%		0.90%	lights, water & sewerage
FEA	1.1%	0.01%	7.5%	0.8%	8.3%	9.4%	0.02%		
GPA	5.4%		6.4%	0.5%	6.9%	12.2%		0.17%	own building use
KAJUR	4.2%		2.8%	12.6%	15.4%	19.5%		3.00%	lights, water & sewerage
KUA	5.0%		5.9%	3.3%	9.2%	14.2%		2.58%	street lights
MEC	8.5%		6.4%	11.4%	17.8%	26.2%		0.67%	street lighting
NPC	5.2%		4.7%	0.03%	4.73%	9.92%		1.94%	lights, water & sewerage
NUC	2.3%		4.4%	15.8%	20.1%	22.4%	n/a		
PNGP			2.1%						
PPUC	6.5%		7.6%	4.3%	11.8%	18.4%		0.76%	street lighting
PUB	4.8%	2.76%	5.9%	5.2%	11.1%	18.7%	1.93%		
PUC	5.1%		5.9%	5.7%	11.6%	16.7%		1.94%	lights, water & sewerage
SIEA	2.9%		7.3%	15.6%	22.9%	25.8%	n/a		
TAU	2.0%	1.00%	4.4%	3.0%	7.4%	10.3%	n/a	1.0%	street lights
TEC	8.6%	1.00%	3.6%	3.5%	7.2%	16.8%	2.51%	3.51%	street lights
TPL	3.0%	1.00%	3.8%	9.7%	13.5%	17.5%	n/a	1.0%	street lights
YSPSC	7.4%		6.4%	4.0%	10.4%	17.9%		7.59%	lights, water & sewerage
Count	19		19	19	19	19		16	
Average	4.5%		5.4%	7.3%	12.8%	18.0%		2.3%	
Median	4.8%		5.9%	5.4%	11.7%	16.7%		1.5%	

Notes: 1. * 'Other' Includes unmetered deliveries for street lights, water, sewerage facilities, etc. except for Fiji, which is metered. 2. Data for north Pacific (US standards) are from KEMA studies on *Quantification of Energy Efficiency in the Utilities of the U.S. Affiliate States (excluding US Virgin Islands*. 2010. 3. Data for South Pacific is from KEMA studies on *Quantification of Energy Efficiency in the Utilities of the South Pacific*, 2011.
4. Scope of studies excluded ASPA, EDT and UNELCO.

Appendix 12

Table A12.8: Calculation of Indicative Composite Technical Indicator

Utility	Specific Fuel Consumption			Capacity Factor			System Losses				Labour Productivity			Composite of four indicators	Composite Indicator sorted from lowest to highest value	
	kWh/ litre	Adjust	Source	Equip use	Adjust	Source	Losses (%)	1.0 minus losses	Adjust	Source	Customers/ Employee	Adjust	Source			
ASPA	3.76	0.80	Q2	43.51	0.77	Q2	0.082	0.919	0.94	Q2	25.61996	0.11	Q2	2.65		Utility
CPUC	3.35	0.72	Q2	39.96	0.71	Q2	0.300	0.700	0.71	Q2	24.90	0.11	Q2	2.26	1.90	YSPSC
CUC	3.66	0.78	Q2	26.13	0.46	Q2	0.070	0.930	0.95	Q2					2.26	TEC
EDT	4.68	1.00	Q2	29.51	0.52	Q2	0.070	0.930	0.95	Q2	80.26	0.35	Q2	2.84	2.26	CPUC
EPC	3.81	0.81	Q2	36.53	0.65	Q2	0.067	0.933	0.95	Q2	55.37	0.24	Q2	2.68	2.55	PUC
FEA	4.15	0.89	Q2	40.02	0.71	Q2	0.081	0.919	0.94	Q2	231.48	1.00	Q2	3.56	2.65	ASPA
GPA	4.15	0.89	Q2	37.81	0.67	Q2	0.070	0.930	0.95	Q2	85.23	0.37	Q2	2.90	2.68	TAU
KAJUR	4.11	0.88	Q2	44.46	0.79	Q2	0.021	0.980	1.00	Q2	17.91	0.08	Q2	2.77	2.68	EPC
KUA	3.93	0.84	Q2	13.82	0.24	Q2	0.185	0.815	0.83	Q2					2.69	PPUC
MEC	4.05	0.87	Q2	34.54	0.61	Q2	0.260	0.740	0.76	Q2					2.72	NUC
NPC															2.77	KAJUR
NUC	3.54	0.76	Q2	56.63	1.00	Q2	0.286	0.714	0.73	Q2	49.80	0.22	Q2	2.72	2.77	PUB
PNGP				37.10	0.66	Q2					59.76	0.26	Q2		2.81	SIEA
PPUC	3.70	0.79	Q2	30.70	0.54	Q2	0.098	0.903	0.92	Q2	94.46	0.41	Q2	2.69	2.84	EDT
PUB	3.77	0.81	Q2	45.72	0.81	Q2	0.076	0.924	0.94	Q2	44.12	0.19	Q2	2.77	2.90	GPA
PUC	2.96	0.63	Q2	38.84	0.69	Q2	0.058	0.942	0.96	Q2	56.64	0.24	Q2	2.55	2.94	UNELCO
SIEA	3.90	0.83	Q2	45.83	0.81	Q2	0.200	0.800	0.82	Q2	75.59	0.33	Q2	2.81	3.04	TPL
TAU	3.79	0.81	Q2	32.63	0.58	Q2	0.107	0.893	0.91	Q2	81.89	0.35	Q2	2.68	3.56	FEA
TEC	3.63	0.78	Q2	24.06	0.42	Q2	0.175	0.826	0.84	Q2	43.89	0.19	Q2	2.26		
TPL	4.08	0.87	Q2	45.89	0.81	Q2	0.122	0.878	0.90	Q2	101.48	0.44	Q2	3.04		
UNELCO	3.98	0.85	Q2	29.43	0.52	Q2	0.046	0.954	0.97	Q2	132.51	0.57	Q2	2.94	2.71	Ave
YSPSC	3.18	0.68	Q2	19.00	0.34	Q2	0.262	0.738	0.75	Q2	26.56	0.11	Q2	1.90	2.74	Median

Sources: 1. Q2 = questionnaire section 2. 2. 'Adjusted' sets best value at 1.0. 3. Composite uses equal weighting for each of the three measures. 4. Insufficient info for PNGP, CUC, MEC, and KUA

= best value for the indicator