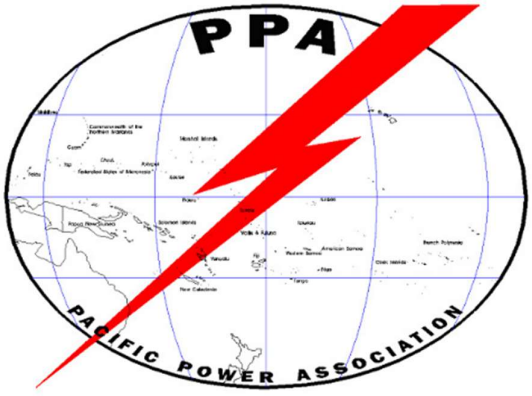


Pacific Power Utilities

Benchmarking Report

2025 Fiscal Year

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

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Pacific Power

Benchmarking

Summary Report

Fiscal Year 2025

Prepared by Pacific Power Association

November 2026

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1. Introduction

This report summarizes the key performance indicators (KPIs) reported by Pacific Power Association (PPA) member utilities for the Fiscal Year 2025, utilizing data collected and analyzed through PPA's Benchmarking Application, PRISM (Pacific Regional Infrastructure & System Metrics). This initiative aims to strengthen governance and institutional capacity within Pacific power utilities and foster data-driven decision-making through peer collaboration. This report supports PPA's objective of improving the region's power quality by providing comprehensive and comparable performance data.

PPA has a long history of facilitating benchmarking studies for its member electricity utilities, with efforts commencing in 2001 and recommencing in 2010 after a nine-year lapse. These exercises have traditionally involved collecting annual data covering various aspects of utility management, culminating in the publication of benchmarking reports. This Fiscal Year 2025 Benchmarking Report includes analyses of utility governance, gender diversity in the energy workforce, data reliability, and performance across 46 KPIs. These reports serve as a crucial tool for PPA members to understand their performance relative to their peers and identify areas for potential improvement.

The development and deployment of PRISM represent a significant evolution in PPA's benchmarking efforts. Unlike previous methodologies that relied on manual data submission and analysis via Microsoft Excel spreadsheets, PRISM provides a regional information sharing network with a dedicated KPI database and dashboard system. This new approach introduces several key differences:

- **Centralized KPI Database:** PRISM utilizes an AI-enabled database (PostgreSQL) to store raw data inputs and automatically calculate KPIs, ensuring consistency and reducing potential interpretation errors. This approach contrasts with past methods, where utilities sometimes provided pre-calculated indicators.
- **Streamlined Data Entry:** Data is primarily intended to be entered into PRISM through a WebApp interface, offering a more structured and potentially automated data submission process.
- **Enhanced Data Validation:** PRISM incorporates data validation tools within the WebApp to improve data quality during entry. The system also features workflows for review and endorsement by BLOs, CEOs, and PPA's BMO, enhancing data checking and accuracy.
- **Dynamic Benchmarking Dashboard:** PRISM features an interactive Benchmarking Dashboard (accessed via https://prismdashboard.org) that allows users to visualize and compare KPIs across utilities, offering a more dynamic and user-friendly experience than static reports.
- **Monthly Performance Tracking:** PRISM can also collect monthly performance data, enabling utilities to integrate benchmarking into their regular management practices, a capability less emphasized in prior annual reports.
- **Contextual Information:** PRISM aims to incorporate utility-specific and country-level descriptive information to contextualize KPI results better and facilitate more meaningful comparisons.

Therefore, this FY25 Benchmarking Report leverages PRISM's capabilities to provide an insightful overview of the performance of participating PPA member utilities, reflecting an advanced and more dynamic approach to data collection, analysis, and reporting compared to the processes followed before FY22. The data and insights presented herein are intended to

support continuous improvement and advancing a sustainable and resilient power sector in the Pacific. The transition to PRISM marks a significant step towards strengthening PPA's utility benchmarking activities and empowering its members with more robust and actionable performance insights.

1.1 Benchmarking Overview

Nineteen out of the twenty-six utility members have provided data for the FY25 report, the same number of utilities that participated in FY24. This exercise began in 2001 and restarted in 2010 after a lapse of 9 years. The list of participating utilities during this period is shown in Table 1.1.

Table 1.1: Utility Participation in FY01 and from FY10 to FY25

Utility			Data Period																
			2001	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Acronym	Name	Country/ Territory	Year Data Collected																
			2002	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2024	2024	2026	2026
ASPA	American Samoa Power Authority	American Samoa	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	×	✓	✓	✓	✓
CPUC	Chuuk Public Utility Corporation	Fed. States of Micronesia (FSM)	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓
CUC	Commonwealth Utilities Corporation	Commonwealth of Northern Marianas	×	✓	✓	✓	✓	×	✓	×	✓	✓	✓	×	×	✓	✓	✓	✓
EDT	Electricite de Tahiti	French Polynesia	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	×	×	×	×	×	×	×
EEC	Electricite et Eau de Caledonia	New Caladonia	✓	×	×	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓
EEWF	Electricite et Eau de Wallis et Futuna	Wallis & Futuna	✓	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×
EFL	Energy Fiji Limited	Fiji	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	×	×	✓	✓	✓	✓	✓
ENERCAL	Societe Neo-Caledonnenne D'Energie	New Caladonia	✓	×	×	×	×	×	×	×	×	×	×	✓	✓	×	×	×	×
EPC	Electric Power Corporation	Samoa	✓	✓	✓	✓	✓	✓	✓	✓	×	✓	×	✓	✓	✓	✓	✓	✓
GPA	Guam Power Authority	Guam	✓	✓	✓	✓	✓	✓	✓	✓	×	✓	×	✓	✓	×	×	×	×
KAJUR	Kwajalein Atoll Joint Utility Resources	Marshall Islands (RMI)	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	×	×	×	×	×	×	×
KUA	Kosrae Utilities Authority	Fed. States of Micronesia (FSM)	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓
MEC	Marshall Energy Company	Marshall Islands (RMI)	×	✓	✓	✓	✓	✓	✓	✓	✓	✓	×	✓	✓	✓	✓	✓	✓
NPC	Niue Power Corporation	Niue	✓	✓	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×
NUC	Nauru Utilities Corporation	Nauru	×	✓	✓	✓	×	×	✓	✓	✓	✓	×	✓	✓	✓	✓	✓	✓
PPL	PNG Power ltd.	Papua New Guinea (PNG)	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓
PPUC	Palau Public Utilities Corporation	Palau	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓
PUB	Public Utilities Board	Kiribati	✓	✓	✓	✓	✓	✓	✓	×	✓	✓	✓	✓	✓	✓	✓	✓	✓
PUC	Pohnpei Utilities Corporation	Fed. States of Micronesia (FSM)	✓	×	✓	✓	✓	×	✓	✓	✓	✓	✓	✓	✓	✓	×	✓	✓
SCE	Southern California Edison	Santa Catalina Island												✓	✓	×	×	×	×
SP	Solomon Power	Solomon Islands	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓
TAU	Te Aponga Uira O Tunu-Te-Varovaro	Cook Islands	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓
TEC	Tuvalu Electricity Corporation	Tuvalu	×	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓
TPL	Tonga Power Limited	Tonga	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓
UNELCO	UNELCO Vanuatu Ltd.	Vanuatu	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓
YSPSC	Yap State Public Service Corporation	Fed. States of Micronesia (FSM)	×	✓	✓	✓	✓	✓	✓	×	✓	✓	✓	✓	✓	✓	✓	✓	✓
		Total	20	21	21	21	21	19	22	18	21	22	15	20	20	19	18	19	19

Table 1.2 shows the percentage of data submitted by each participating utility. This percentage is calculated as the number of data points approved by the CEO—the final step in the data submission process—divided by the total number of data points requested.

Table 1.2: Percentage of Data Submitted FY25

Utility	Percentage of Data Submitted
PUB	100%

TPL	100%
UNELCO	100%
TAU	99%
ASPA	98%
EEC	97%
EPC	96%
TEC	93%
SP	92%
NUC	67%
MEC	61%
PUC	58%
PPUC	24%
CPUC	22%
YSPSC	17%
CUC	12%
KUA	10%
PPL	6%
EFL	5%

2. Governance

2.1 Quality Standards and Regulatory Structure

The quality standard and regulatory structure data provided by utilities are shown in Table 2.1.

Table 2.1: Quality Standard and Regulatory Structures of Utilities

Utility	Power Quality Standards	Self Regulated or Externally Regulated	Public/Private Ownership	Accounting Standards
ASPA	US	Self-Regulated	Public	US GAAP
CPUC	NEC	Self-Regulated	Public	IAS & IFRS
CUC	US	Externally Regulated	Public	IAS
EEC	EN50160	Externally Regulated	Private	French GAAP & IFRS
EFL	AUS/NZ	Externally Regulated	Public-Private	IFRS
EPC	AUS/NZ	Self-Regulated	Public	IAS
KUA	KUA	Externally Regulated	Public-Private	US GAAP
MEC	US	Externally Regulated	Public-Private	US GAAP
NUC	AUS/NZ	Externally Regulated	Public-Private	NZ IFRS
PPL	AUS/NZ	Externally Regulated	Public-Private	IFRS
PPUC	AUS/NZ	Externally Regulated	Public	US GAAP
PUB	AUS/NZ	Externally Regulated	Public-Private	US GAAP
PUC	US	Self-Regulated	Public-Private	US GAAP
SP	AUS/NZ	Self-Regulated	Public	IFRS
TAU	AUS/NZ	Externally Regulated	Public	NZ IFRS
TEC	AUS/NZ	Self-Regulated	Public	IAS
TPL	AUS/NZ	Externally Regulated	Public	IFRS
UNELCO	Self	Externally Regulated	Private	French GAAP & IFRS
YSPSC	US	Self-Regulated	Public-Private	US GAAP

2.2 Governance Assessment

The governance of participating Pacific power utilities shows varying implementation of practices. Table 2.2: presents a detailed tabulation of governance indicators across multiple utilities. The responses highlighted in green indicate best practices for governance.

The data indicate that most utilities have established codes of conduct, with nearly all reporting that these codes are both in place and implemented. Similarly, commercial mandates are widely established, though their implementation varies slightly among utilities.

Performance contracts for CEOs appear to be standard practice across most reporting utilities, with only a few exceptions. Annual reviews of these performance contracts are also commonly implemented.

The presence of ministers or public servants representing line/sector ministries on utility boards varies substantially. Some utilities report no ministerial appointments to their boards, while others indicate that ministers or public servants from relevant ministries are appointed to their boards.

Strategic planning practices appear relatively strong across the sector, with most utilities reporting that they have adopted and implemented strategic plans that include forecasts for three or more years. However, two utilities have not adopted such plans.

Most utilities complete their annual reports within four months of the end of the reporting year, though there are some exceptions. The disclosure of performance against strategic plans in these annual reports varies, with some utilities not including this information.

Some utilities demonstrate strong governance frameworks, including CPUC, EEC EFL, EPC, PPL, PPUC, PUB, SP, TAU, and UNELCO, which report positive responses across most or all governance indicators.

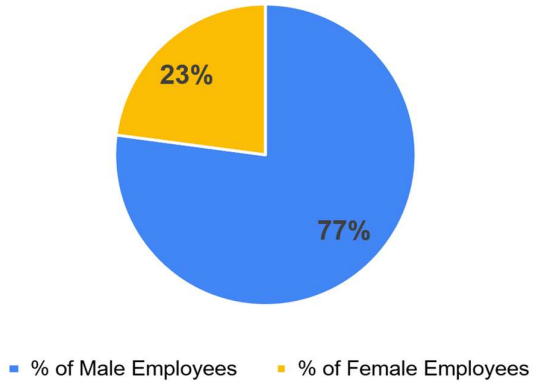
Table 2.2: Governance Practices at PPA Utilities

	ASPA	CPUC	CUC	EEC	EFL	EPC	KUA	MEC	NUC	PUB	PUC	PPL	PPUC	SP	TAU	TEC	TPL	UNELCO	YSPSC
Ensuring the basis for an effective corporate governance framework																			
Is a Code of Conduct in place?	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	No	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes
Is a Code of Conduct implemented?	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	No	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes
Is a commercial mandate in place?	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	No	Yes	Yes	No
Is a commercial mandate implemented?	Yes	Yes	Yes	Yes	Yes	Yes	No	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	No	Yes	Yes	No
Is the CEO on a performance contract?	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	No	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	No
Does the CEO's performance contract include annual reviews?	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	No	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	No
Board composition																			
Are Ministers appointed to the Board?	Yes	No	Yes	No	No	No	No	Yes	No	No	No	No	No	No	No	No	No	No	No
Are Ministers or public servants representing the line/sector Ministry appointed to the Board?	Yes	No	Yes	No	Yes	No	Yes	Yes	Yes	No	No	No	No	No	No	Yes	No	No	Yes
Strategic planning																			
Has a Strategic Plan been adopted?	Yes	Yes	No	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	No
Does the Strategic Plan include three or more years of forecasts?	Yes	Yes	No	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	No
Is the Strategic Plan implemented?	Yes	Yes	No	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	No
Disclosure and transparency																			
Is the Annual Report completed within four months of the end of the reporting year?	Yes	Yes	Yes	Yes	Yes	Yes	Yes	No	Yes	Yes	No	Yes	No	Yes	Yes	Yes	No	Yes	Yes
Is the Annual Report audited?	Yes	No	No	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	No	Yes	Yes	Yes	Yes	No
Does the Annual Report disclose performance relative to the Strategic Plan?	No	Yes	No	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	No	Yes	No	Yes	No

3. Gender

The total workforce of Pacific power utilities is predominantly male, with female employees representing a much smaller portion of the utilities' workforce. Figure 3.1 shows the breakdown.

Figure 3.1: Overall Gender Representation in PPA Utilities

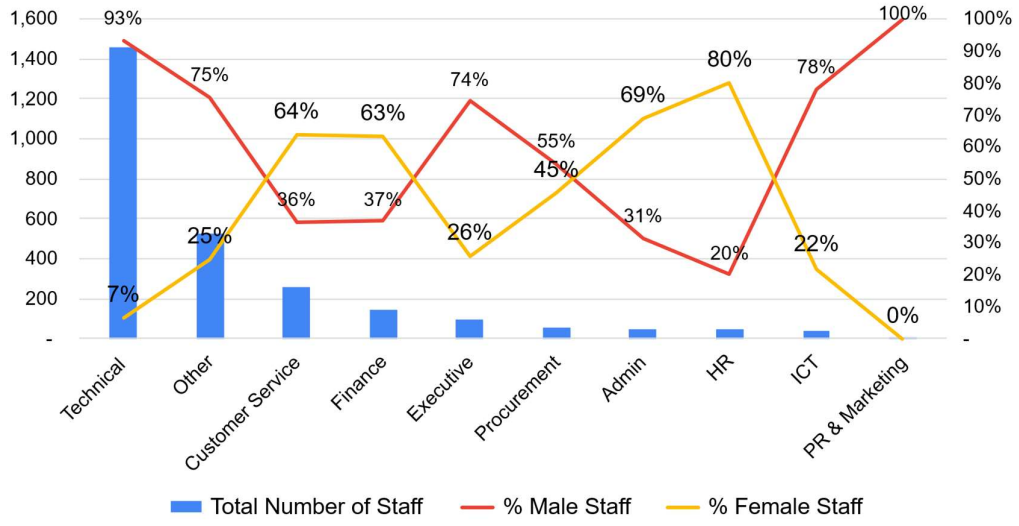


Out of 19 participating utilities, only two have a female CEO. The ratio of second in command is 5:2 (male to female). Gender representation varies substantially across different divisions, as shown below:

- Technical: 1,359 male and 97 female employees
- Finance: 54 male and 93 female employees
- Administrative: 15 male and 33 female employees
- Procurement: 30 male and 25 female employees
- ICT: 32 male and 9 female employees
- Human Resource: 9 male and 36 female employees
- Customer Service: 94 male and 165 female
- PR & Marketing: 5 male and 0 female employees
- Other: 399 male and 130 female employees

The data shows 72 male executives compared to 25 female executives. This representation at leadership levels provides insight into the gender balance in decision-making roles within Pacific power utilities. Figure 3.2 shows the workforce gender breakdown by functional division.

Figure 3.2: Workforce by Division and Gender



4. KPI Results

4.1 Introduction

This section provides performance results for the 19 utilities that submitted data in the FY25 reporting year. The results are comprised of KPI results and the region's maximum, minimum, and median (middle) values.

An indication of utility size is provided via a color-coding system determined by utility peak load following the PPA's membership level categorizations:

- Green indicates an annual peak load of less than 5MW (small)
- Orange indicates an annual peak load between 5MW and 30MW (medium)
- Red indicates an annual peak load of 30MW or greater (large)

Table 4.1 provides an overview of some key characteristics of the participating utilities, including the applicable color coding.

Table 4.1: Utility Key Characteristics

Utilities	Peak Demand (for Largest Grid)	Size Category	Smaller Grids Serviced	Total Annual Energy (MWH)	Renewable Energy Contribution
ASPA		Medium	Yes	207,525.41	3.8%
CPUC		Small	Yes	19,180.58	3.8%
CUC		Large	Yes		
EFL		Large	Yes		
EPC		Medium	Yes	218,997.73	30.1%
KUA		Small	No		
MEC	10.20	Medium	Yes	69,328.04	0.1%
NUC		Medium	No	193,974.29	0.8%
PPL		Large	Yes		
PPUC		Medium	Yes	77,806.86	
PUB	7.47	Medium	No	38,975.65	0.5%
PUC		Medium	Yes	44,781.53	3.8%
SP		Medium	Yes	85,289.19	3.2%
TAU	6.03	Medium	No	3,904.32	99.7%
TEC		Small	Yes	2,641.23	32.4%
TPL	12.45	Medium	Yes	90,748.73	19.8%
UNELCO	12.73	Medium	No	55,822.07	8.4%
YSPSC	1.90	Small	Yes	11,153.56	7.6%

Note:

1. The peak demand is for the largest grid operated by the utility, while the energy demand is aggregated for all the grids operated by the utility.

2. Only utilities that reported data are included in the table.

4.2 Generation

This section presents the generation KPIs included in PRISM. For power utilities in the Pacific, benchmarking generation indicators is critical because generation costs and reliability largely determine the affordability and stability of electricity supply in small, isolated island systems. Many Pacific utilities depend on imported diesel or other expensive fuels and operate a mix of aging thermal units and new renewable plants, so inefficiencies or unplanned outages quickly translate into higher tariffs, supply disruptions, or increased subsidies.

By systematically tracking and comparing KPIs such as fuel efficiency, load factor, capacity factor, forced outage rates, and renewable energy penetration against regional or international benchmarks, utilities can identify underperforming units, optimize maintenance schedules, improve dispatch decisions, and plan investments in more efficient or resilient technologies. This evidence-based approach can help PPA members control costs, reduce exposure to fuel price shocks, improve reliability, and make a stronger case to regulators, governments, and donors for financing cleaner and more efficient generation assets.

4.2.1 Load Factor

The load factor (LF) is a key performance metric that measures power system capacity utilization. It is calculated by dividing the average load demand by the peak demand over a specified period. This report presents LF for each electricity grid service area operated by the utility for the fiscal year.

Understanding load factor provides crucial insights into system efficiency:

- A low LF indicates peak demand significantly exceeds average demand, resulting in underutilized production capacity. This suggests inefficient resource use, as infrastructure must be maintained to meet occasional high peaks rather than consistent usage.

- A high LF typically signals efficient capacity utilization, characterized by a relatively steady demand profile. However, it's important to note that a high LF can be misleading when it results from forced load shedding due to insufficient production capacity. In such cases, the elevated load factor reflects system constraints rather than operational efficiency.

Industry standards establish that the minimum acceptable LF is 50%. Pacific Island utilities target a benchmark of 80%. Utilities can implement various strategies to improve load factor performance:

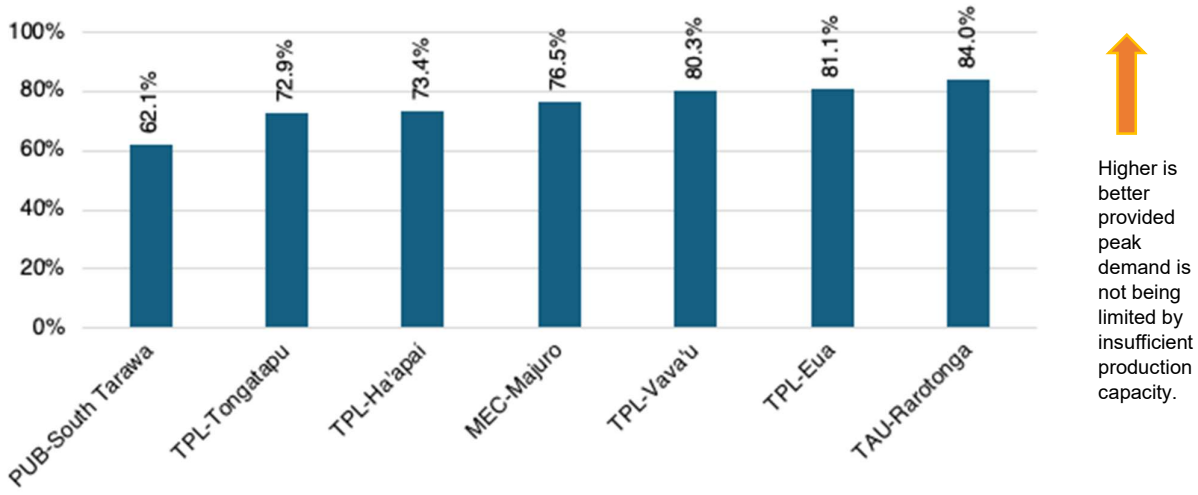
- Demand-side management
- Time-of-use tariffs
- Peak lopping
- Demand shifting strategies

These optimization strategies are expected to play an increasingly significant role in Pacific power sector policies, as they help manage peak demand while improving overall system efficiency.[1]

[1] PPA ADB, Pacific Power Utilities, pp. 5-1.

For the 2025 fiscal year, eight service areas reported their load factor data (Figure 4.1).[2] The values range from 62.1% to 84.0%, with a median of 76.5%.

Figure 4.1: Load Factor



4.2.2 Capacity Factor

The capacity factor (CF) is also an indicator of the effectiveness of using 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 firm capacity. The lower the CF, the greater the production reserve capacity available for demand when production units are taken out of service for maintenance or repairs due to faults. It also may suggest overinvestment in production capacity, which is best avoided.

A higher CF indicates a peak demand that approaches available production capacity. This may make scheduling maintenance for the generating plants difficult and result in load shedding during peak load periods when generators are taken out of service due to faults.

The investment in production capacity is determined by the power security policy adopted by the utility. Utilities may adopt a security policy of N-1 or N-2. N-1 production capacity is the maintenance of sufficient production capacity to cater for the loss of the generating unit with the largest capacity in the fleet. Likewise, N-2 caters to the loss of the two largest units in the fleet.

The minimum production capacity is determined by the power security policy adopted based on experience regarding reliability, the cost of investment, and expectations regarding the lifespan of the firm's production equipment. Installing more capacity than required would be an inefficient way of utilizing a utility's financial resources, while underinvesting may compromise the reliability of the power supply.

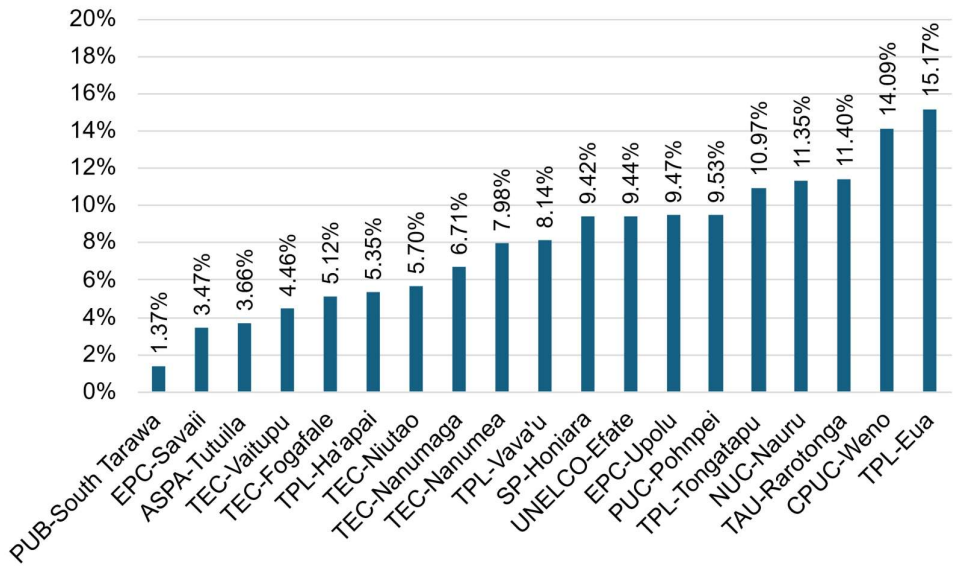
The data from 2025 allows examination of capacity factors across different generation types. Note that the following charts include data aggregated for generation capacity owned by the utilities, excluding generation capacity owned by IPPs in the service areas.

[2] A bug in the WebApp prevented the platform from displaying the data inputs required to calculate the Load Factor KPI. As a result, utilities have not had sufficient time to report the required data. The issue has now been resolved, and utilities have been asked to enter the data as soon as possible.

Solar Capacity Factor

In 2025, utilities reported solar capacity factors for 19 service areas as shown in Figure 4.2. The median solar capacity factor was 5.70%, with values ranging from 1.37% to 15.17%.

Figure 4.2: Solar Capacity Factor



Too high a CF, risk having insufficient capacity to meet demand at all times

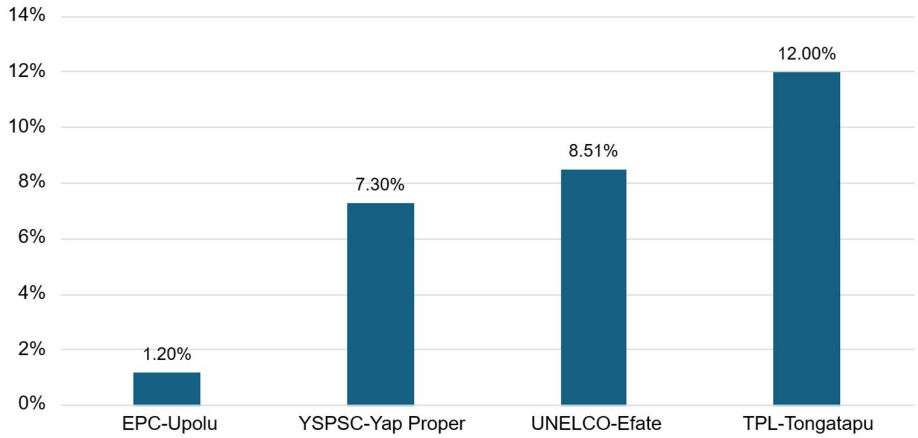
A low CF indicates over investment in capacity.

Pacific Benchmark >40%

Wind Capacity Factor

In 2025, three service areas reported wind capacity factors, as shown in Figure 4.3. The median wind capacity factor was 7.91%, with values ranging from 1.20% to 12.00%.

Figure 4.3: Wind Capacity Factor

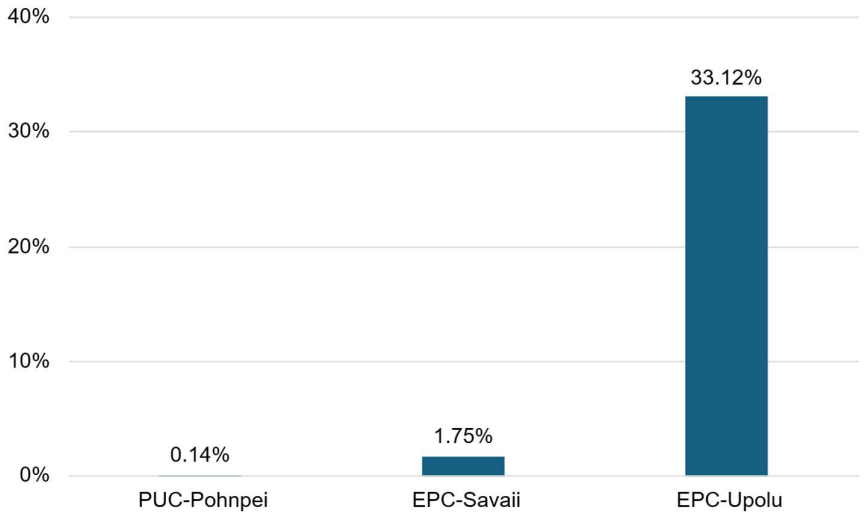


For the Pacific Islands a wind turbine capacity factors is expected to exceed 20%.

Hydropower Capacity Factor – Dams

In 2025, three service areas reported dam hydropower capacity factor, as shown in Figure 4.4. The median hydropower capacity factor was 1.75%, with values ranging from 0.14% to 33.12%.

Figure 4.4: Hydropower Capacity Factor (Dams)



The higher the capacity factor, the better the performance. The larger the storage the larger the capacity factor.

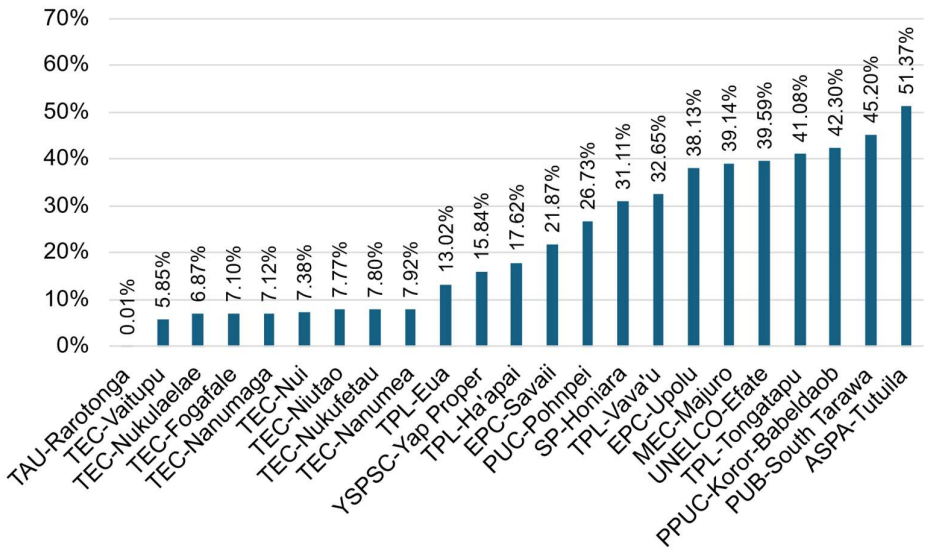
Hydropower Capacity Factor – Run of Rivers

In 2025, no service areas reported run-of-rivers hydropower capacity factor.

Diesel Capacity Factor

Diesel generation capacity factors vary substantially across the Pacific utilities. A total of 23 service areas reported their diesel capacity factors in 2025, as shown in Figure 4.5. The median diesel capacity factor was 17.62%, with values ranging from a minimum of 0.01% to a maximum of 51.37%.

Figure 4.5: Diesel Capacity Factor



Too high a CF, risk having insufficient capacity to meet demand at all times

A low CF indicates over investment in capacity.

Pacific Benchmark >40%

4.2.3 Availability Factor

The availability factor (AF) indicates how well a power plant is operated and maintained. It is determined by the actual hours the unit is available for production divided by the maximum available hours for the period. Because power plants need to be taken out of service for routine maintenance, an AF of 100% is not achievable. The type of power plant and its mode of operation may affect the AF. For a base load diesel power plant, with higher running hours, more routine maintenance would be

required, resulting in a lower AF. An AF between 90% and 95% is expected for such a power plant. The AF should be a little higher for a plant that is operated less frequently.

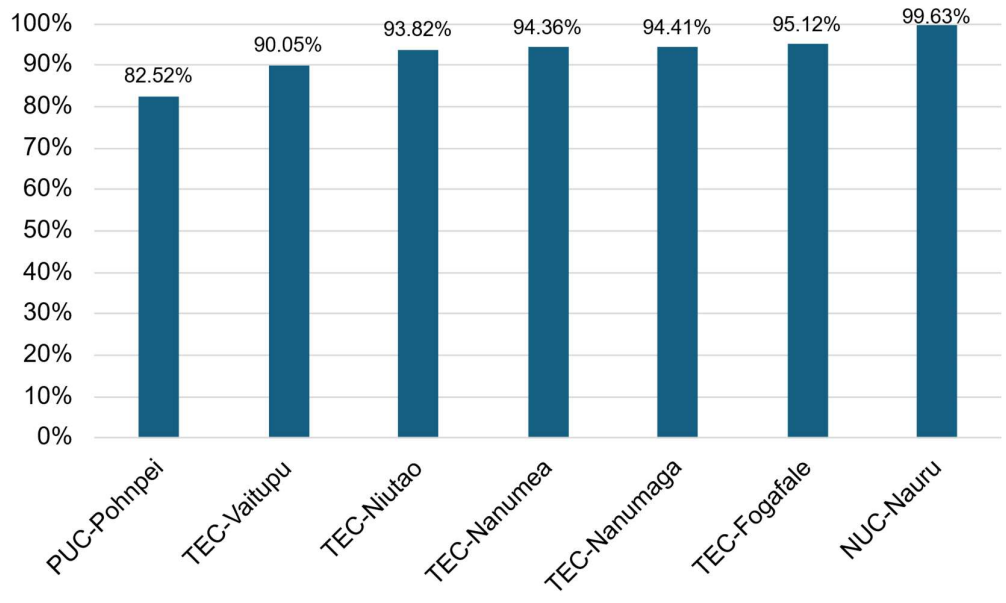
A higher-than-expected AF may mean the plant is being insufficiently maintained, which could soon lead to more frequent breakdowns. A lower AF indicates more frequent breakdowns and outages for repairs due to poor maintenance and operation protocols.

This section presents the availability factors for different generation technologies based on the 2025 data.

Solar Availability Factor

In 2025, seven service areas reported data for solar availability factors shown in Figure 4.6. The median reported value was 94.36%, with values ranging from 82.52% to 99.63%.

Figure 4.6: Solar Availability Factor



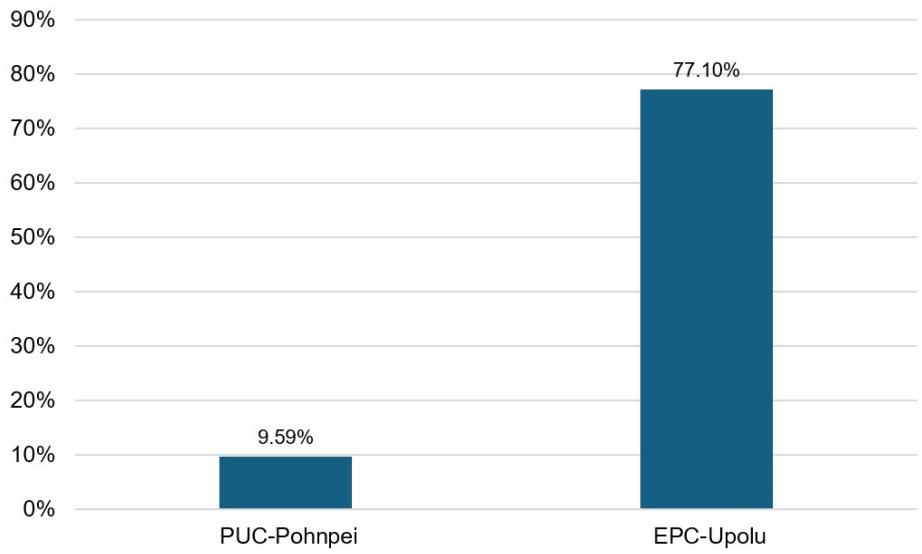
Wind Availability Factor

In 2025, no service areas reported on wind availability factor.

Hydropower Availability Factor - Dams

In 2025, two service areas reported an availability factor for hydropower dams, as shown in Figure 4.7. The median was 43.35%, with values ranging from 9.59% to 77.10%.

Figure 4.7: Hydropower – Dams Availability Factor



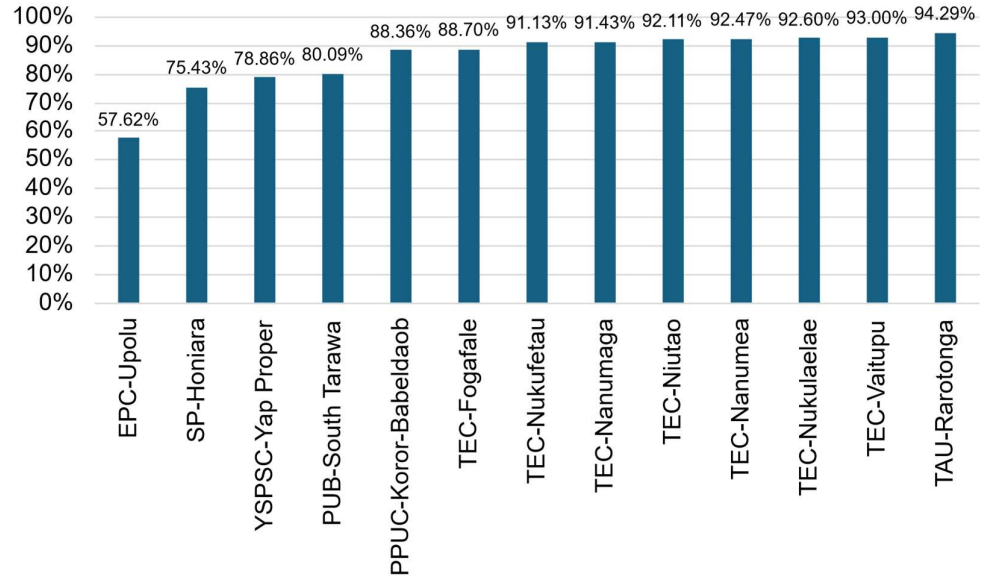
Hydropower Availability Factor - Rivers

In 2025, no service areas reported on availability factor for hydropower – rivers.

Diesel Availability Factor

Diesel generation, the most common form of power generation in the Pacific region, had 21 service areas reporting on availability factor in 2025. The data shows considerable variation, but the median value across all diesel generation service areas is 91.13%. Eight service areas reported very high results (more than 95%), which were excluded from Figure 4.8.

Figure 4.8: Diesel Availability Factor

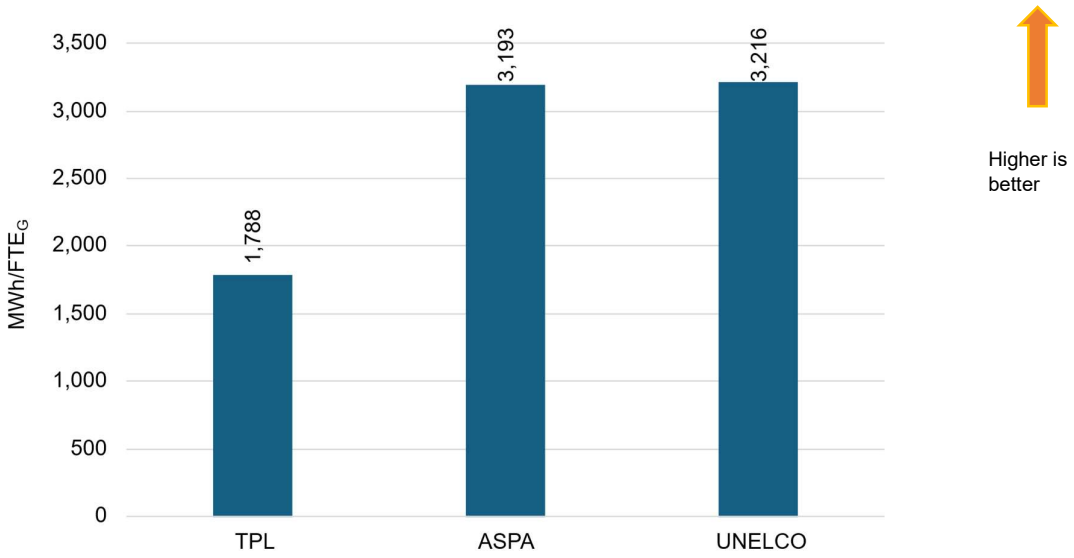


4.2.4 Generation Labor Productivity

Generation Labor Productivity (GLP) is a measure of the total energy produced per full-time employee equivalent (FTE_G). Benchmarking of GLP for comparable utilities in size, demand, and generation asset types would indicate whether the utility production team is right-sized.

In 2025, three utilities reported Generation Labor Productivity, which shows substantial variation across utilities (seeFigure 4.9). The maximum reported GLP was 3,216 MWh/FTE_G, while the minimum was 1,788 MWh/FTE_G. The median value across the reporting utilities was 3,193 MWh/FTE_G.

Figure 4.9: Generation Labor Productivity



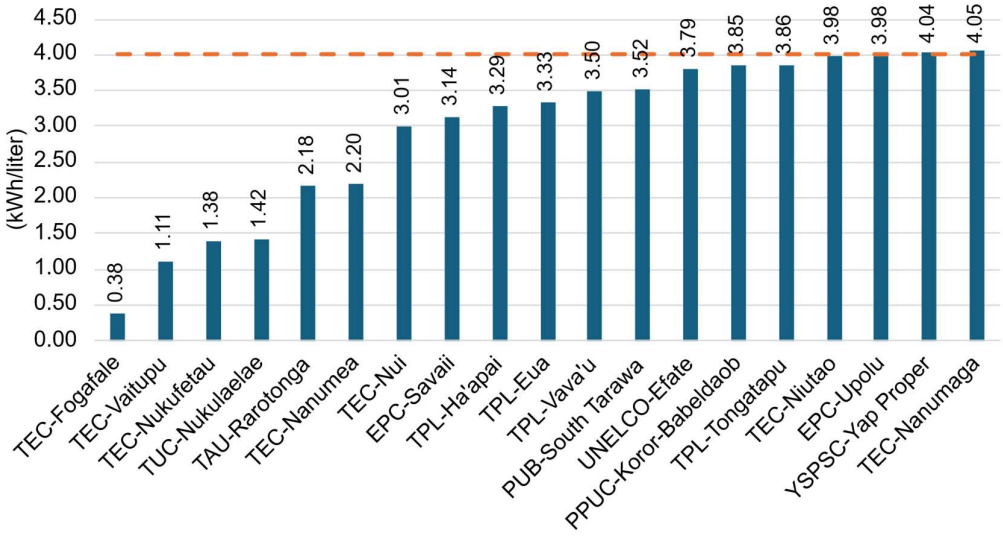
4.2.5 Specific Fuel Consumption DFO (kWh/Liter)

Specific fuel consumption (SFC) for diesel fuel oil (DFO) is a measure of the efficiency of fuel used for power generation utilizing diesel-fired power generators, and is often reported in kWh/liter, kg/kWh, or kWh/gallon. It is a critical performance indicator because fuel costs account for the bulk of generation expenses in a typical diesel-based power utility. Importantly, SFC refers to the efficiency of utility fossil fuel generation only – it does not include purchased energy from Independent Power Producers (IPPs). Furthermore, non-diesel generation is not factored into this indicator.

As power utilities transition away from fossil fuel-based production of power to renewable resources, and more IPPs are engaged in the production of energy, the impact of fossil fuel will factor less in the overall efficiency and costs of energy production.

There were 24 service areas reporting this metric in 2025. The values ranged from a minimum of 0.38 kWh/liter to a maximum of 4.05 kWh/liter, with a median value of 3.50 kWh/liter. Three reported values were identified as outliers and excluded from Figure 4.10.

Figure 4.10: Specific Fuel Consumption



The benchmark for SFC in the Pacific is 4 kWh/liter (dotted line in Figure 4.10). A lower indicator value reflects a less efficient operation of the diesel generator.

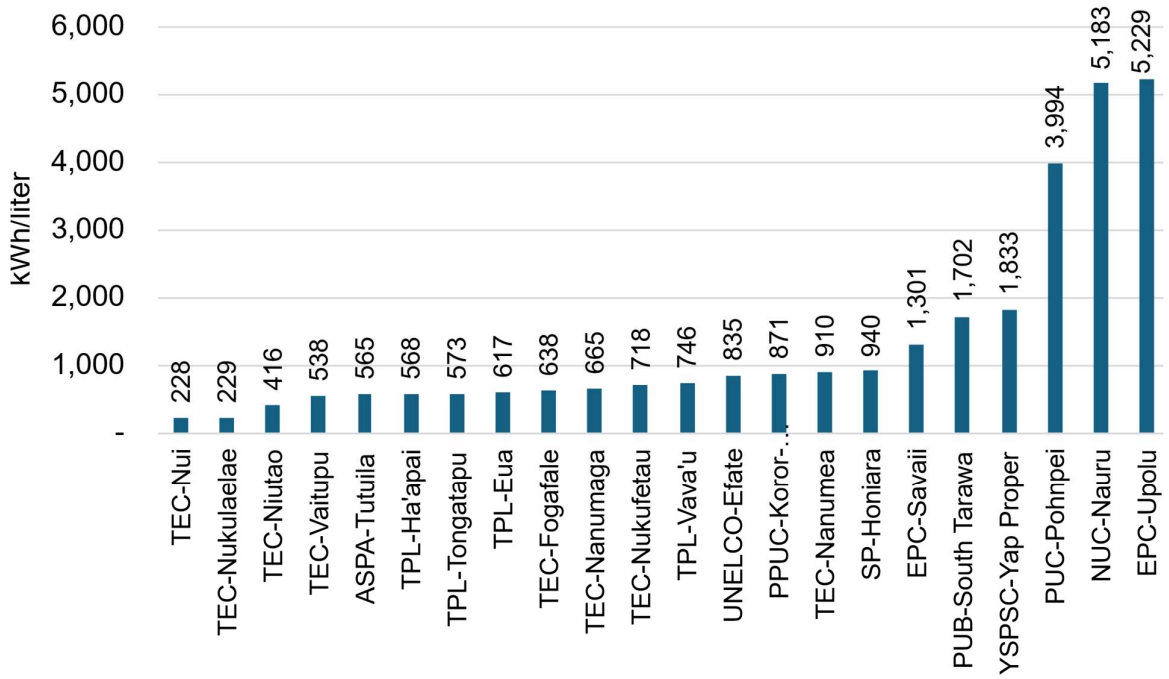
4.2.6 Specific Lubricating Oil Consumption

Specific Lubricating Oil Consumption (SLOC) is a measure of the lubricating oil efficiency of usage by the diesel and HFO generating units and is determined by the number of kWh generated per liter of lubricating oil consumed. The benchmark varies according to the size and condition of the diesel engine. Lower lubricating oil efficiency can be attributed to poor maintenance, e.g., due to worn piston rings or leaks in the system. Reasonable values are about 500–700 kWh per liter for a 1 MW engine and 1,000–1,300 kWh per liter for a 4–5 MW engine.

For the 2025 fiscal year, 24 service areas reported SLOC data. The values ranged from a minimum of 228 kWh/liter to a maximum of 5,229 kWh/liter. The median value across all reporting service areas was 732 kWh/liter. Two of the reported service area values were identified as outliers and excluded from Figure 4.11.

SLOC, much like the SFC, will become less important as an indicator as the contribution to the energy produced is increased from renewable sources, especially from solar PV power plants.

Figure 4.11: Specific Lubrication Oil Consumption



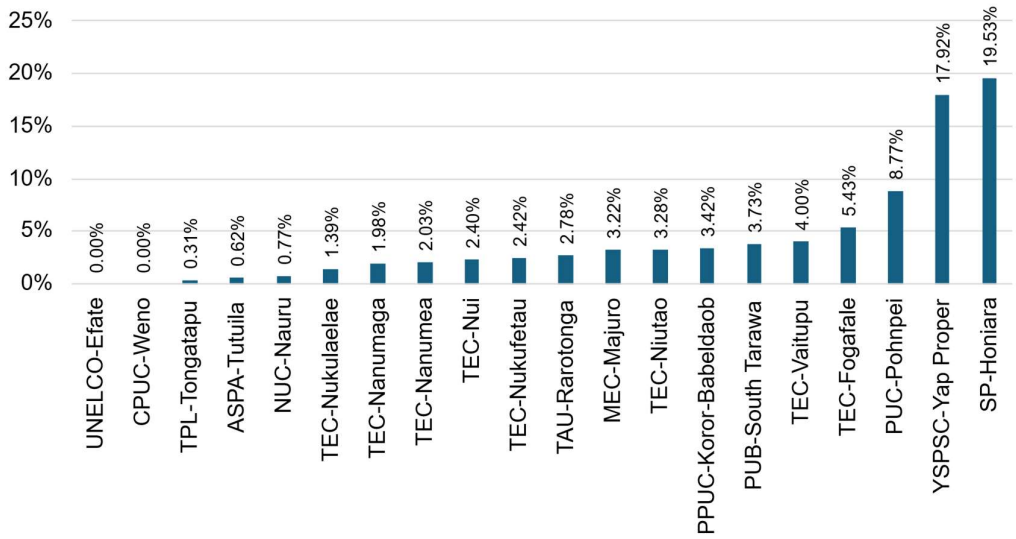
4.2.7 Forced Outage

A forced outage is an unplanned outage (or generator downtime) that has been forced on the utility. Unplanned outages are attributable to issues with generators that compelled the utility to take them out of service.

This indicator serves as a measure of generation system reliability and maintenance effectiveness. The KPI enables utility managers to evaluate the health of their generation fleet and the effectiveness of their maintenance programs. System planners use this information to assess reserve margin requirements and capacity planning needs. The indicator also helps identify potential systemic issues that may require attention through maintenance program modifications or capital investments.

In 2025, 20 service areas reported on forced outages. However, five service area results were excluded from Figure 4.12 because they were identified as outliers. The median forced outage indicator was 2.03%, while the Pacific benchmark is less than 3%. Results ranged from a minimum of 0% to 19.53%.

Figure 4.12: Forced Outage

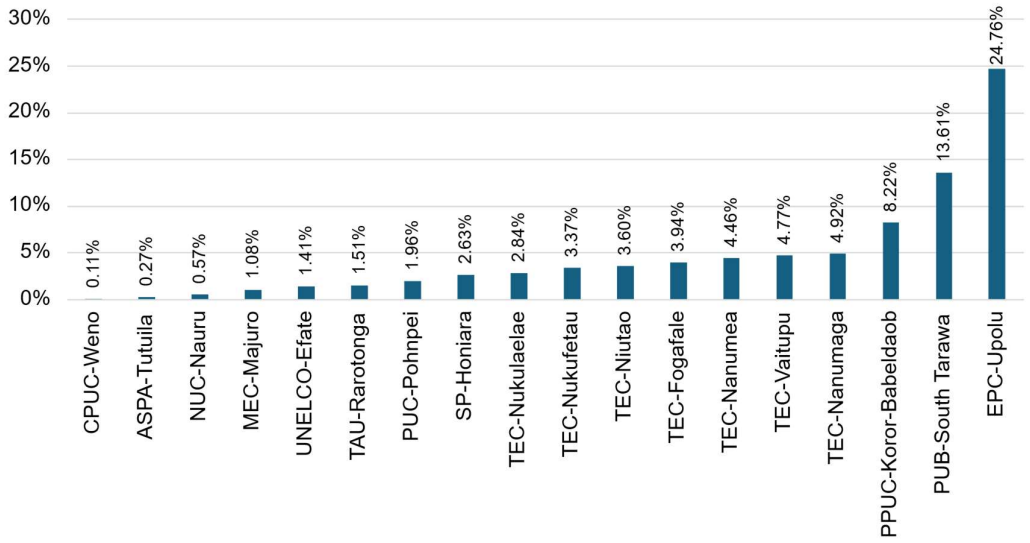


4.2.8 Planned Outage

Planned or scheduled outages measure the proportion of downtime for planned maintenance activities that require the plant to be shut down. It is a scheduled loss of generating capacity as a percentage of installed capacity to generate energy. Planned maintenance of generating equipment is often compromised in Pacific Island utilities. Some reasons for this are (1) insufficient firm reserve capacity to allow the extended shutdown of generators due for scheduled maintenance, (2) a lack of spare parts in store, leading to long downtimes awaiting delivery of spares, and (3) a lack of funds for major contracted service work. When the intervals between maintenance are extended, the probability that generators will break down increases.

Figure 4.13 shows the planned outage indicator for 21 power grids for the fiscal year 2025, with three outliers excluded. The median planned outage indicator was 3.11%, with values ranging from a minimum of 0.11% to a maximum of 24.76%. The Pacific benchmark is below 3%. A planned outage indicator that is too low may indicate the lack of scheduled maintenance, which would eventually result in a higher-than-expected result for the forced outage indicator.

Figure 4.13: Planned Outages



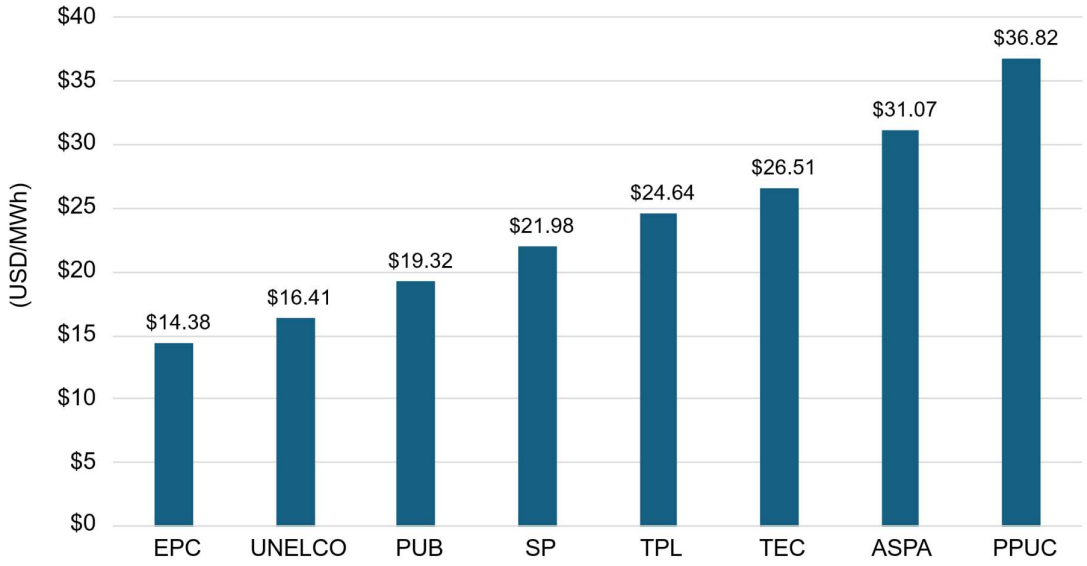
4.2.9 Generation Operations and Maintenance (O&M) Costs

Generation Operations and Maintenance (O&M) Costs per MWh measures the operational and maintenance expenditure required to produce each megawatt-hour of electricity. This metric indicates the cost efficiency of generation operations by normalizing O&M expenses against power production.

This indicator serves as a primary measure of generation cost efficiency and helps utilities optimize their operational expenses. Technical managers use it to evaluate cost control effectiveness and budget performance. Operations managers usually rely on this KPI to assess maintenance program value and identify opportunities for efficiency improvements. The metric supports both short-term operational decisions and long-term planning for generation asset management.

In 2025, 10 utilities reported their Generation O&M costs, with two outliers removed. The values ranged from a minimum of $14.38 per MWh to a maximum of $36.82 per MWh, with a median value of $23.31 per MWh.

Figure 4.14: Generation O&M Costs (USD/MWh)



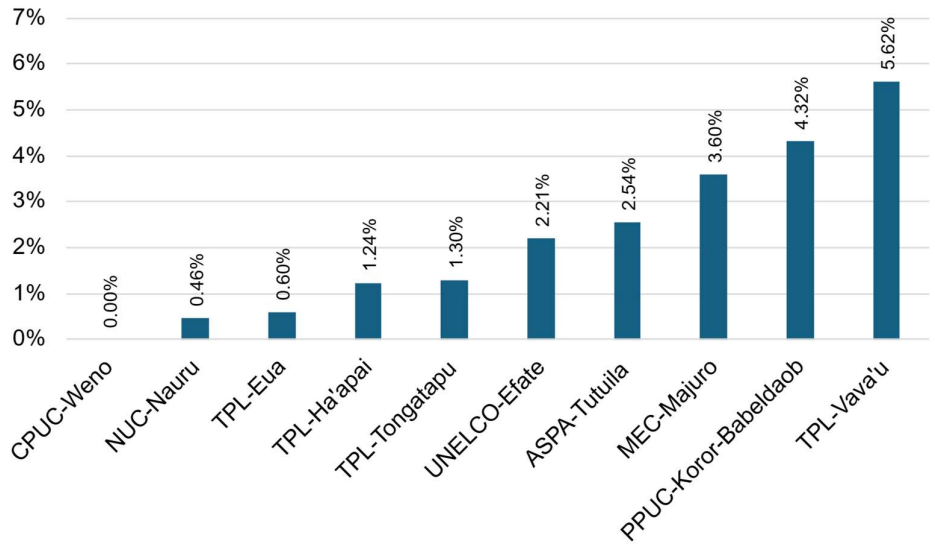
4.2.10 Power Station Usage / Station Auxiliaries

Power Station Usage (also known as Station Auxiliaries) measures the percentage of generated electricity consumed internally by the power station for its own operations. This metric indicates the energy efficiency of plant auxiliary systems such as cooling systems, lighting, control systems, fuel handling equipment, and other support infrastructure.

This indicator serves as a key measure of generation plant efficiency, helping utilities evaluate the energy consumed by essential support systems. Plant managers usually use this KPI to optimize auxiliary system operations and identify potential efficiency improvements. The indicator enables utilities to assess the net power available for distribution to customers and evaluate the effectiveness of energy conservation measures within their generation facilities. Understanding station auxiliary consumption patterns supports both operational optimization and long-term planning for plant upgrades.

A value below 5% is considered acceptable, with lower values being preferable. In 2025, power station usage across the 10 reporting service areas ranged from a minimum of 0% to a maximum of 5.62%, with a median value of 1.76%.

Figure 4.15: Power Station Usage

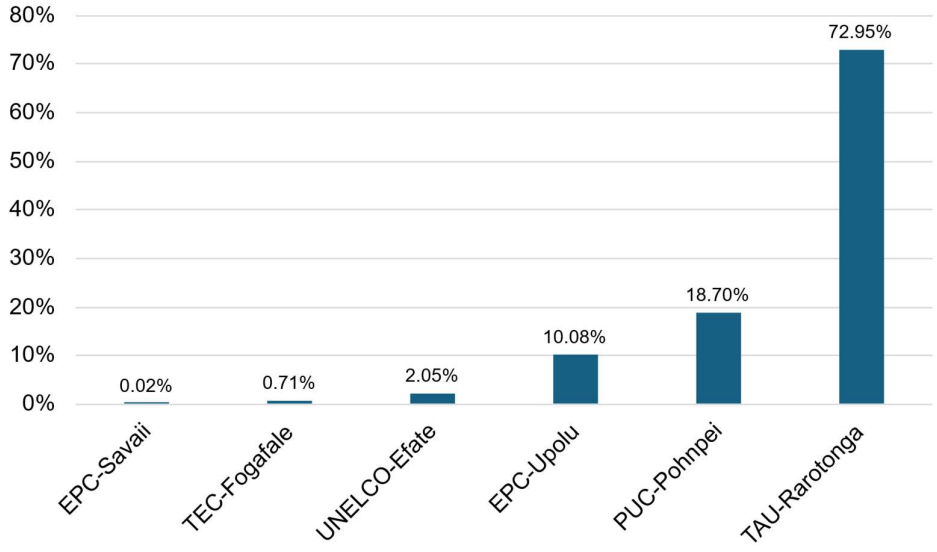


4.2.11 IPP Generation

Pacific Island utilities increasingly adopt Independent Power Producer arrangements to involve the private sector in meeting the challenges of capacity investment to satisfy the power demand. Figure 4.16 illustrates the percentage of energy demand met by IPPs for utilities that have adopted this strategy in their production mix.

In 2025, six service areas reported IPP generation data. The percentage of energy demand met by IPPs ranged from a minimum of 0.02% to a maximum of 72.95%. The median value across reporting service areas was 6.07%.

Figure 4.16: IPP Production of Energy

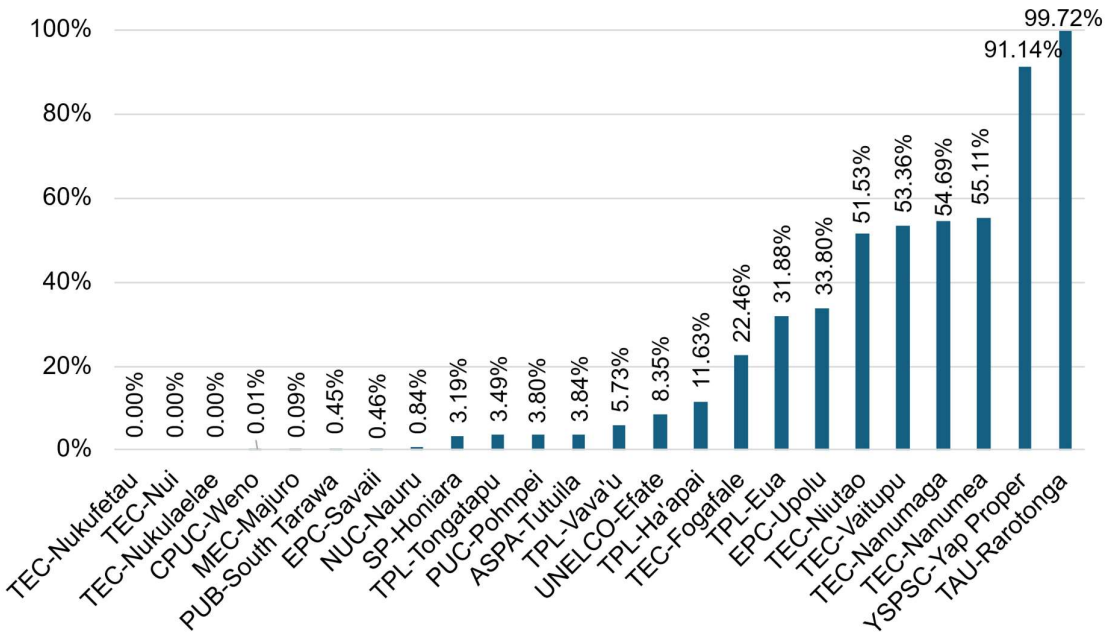


4.2.12 Renewable Energy to Grid

The Pacific Island states have adopted aggressive aspirational targets for transitioning to renewable energy to mitigate the impact of climate change. The power sector is a major sector involved in implementing this policy. In 2025, 24 service areas reported on the

contribution of renewable energy to their grids. The renewable energy contributions ranged from a minimum of 0% to a maximum of 99.72%, with a median value of 4.79%.

Figure 4.17: Renewable Energy Contribution



4.3 Transmission Indicators

This section presents the results for transmission KPIs. For PPA members with transmission networks, benchmarking is important because it provides a clear, objective measure of how efficiently and reliably the high-voltage backbone of the power system is operating. By tracking and comparing KPIs such as network losses and transmission reliability against regional or international benchmarks, utilities can identify weaknesses in their networks, prioritize maintenance or upgrades, and allocate scarce resources where they will deliver the most improvement.

4.3.1 Transmission (General)

For the benchmarking exercise, the transmission network is defined as equipment operating at a voltage greater than 33kV. For utilities with a transmission network, the benchmarking questionnaire requested data to determine transmission losses and outage statistics to measure transmission system reliability. System reliability has been tracked based on transmission reliability (outage events per 100 kilometers) and average transmission outage duration (in minutes).

Transmission Losses represents the percentage of electrical energy lost during the transmission of electricity from generation sources to distribution substations. This KPI quantifies the efficiency of the high-voltage transmission system in delivering power across the network.

Transmission Reliability measures the frequency of power outages or disruptions in the transmission network, expressed as the number of outages per 100 kilometers of transmission lines. This KPI provides insight into the robustness and dependability of the high-voltage transmission infrastructure.

This component of the benchmarking also tracks transmission SAIDI (average duration of scheduled transmission system interruptions experienced by customers during the reporting period), as well as transmission SAIFI (average number of scheduled transmission interruptions experienced by customers during the reporting period).

No utility reported transmission data for 2025; therefore, transmission KPIs have been excluded from this report.

4.4 Distribution Indicators

This section presents PRISM's KPI results for distribution. For power utilities in the Pacific, benchmarking distribution KPIs is important because the distribution network is the part of the system that directly delivers electricity to customers, so its efficiency and reliability have the greatest immediate impact on service quality and revenue. In small, isolated island systems with aging infrastructure, limited technical staff, and high exposure to storms and other natural hazards, problems such as high technical and commercial losses, frequent outages, and delayed repairs are common.

By tracking and comparing KPIs—such as distribution network losses, distribution reliability, and distribution O&M expenses—against regional or international benchmarks, utilities can identify weaknesses, prioritize maintenance and investment, and allocate scarce resources more effectively. This approach can help utilities improve operational efficiency, reduce losses, and enhance customer satisfaction.

4.4.13 Network Delivery Losses

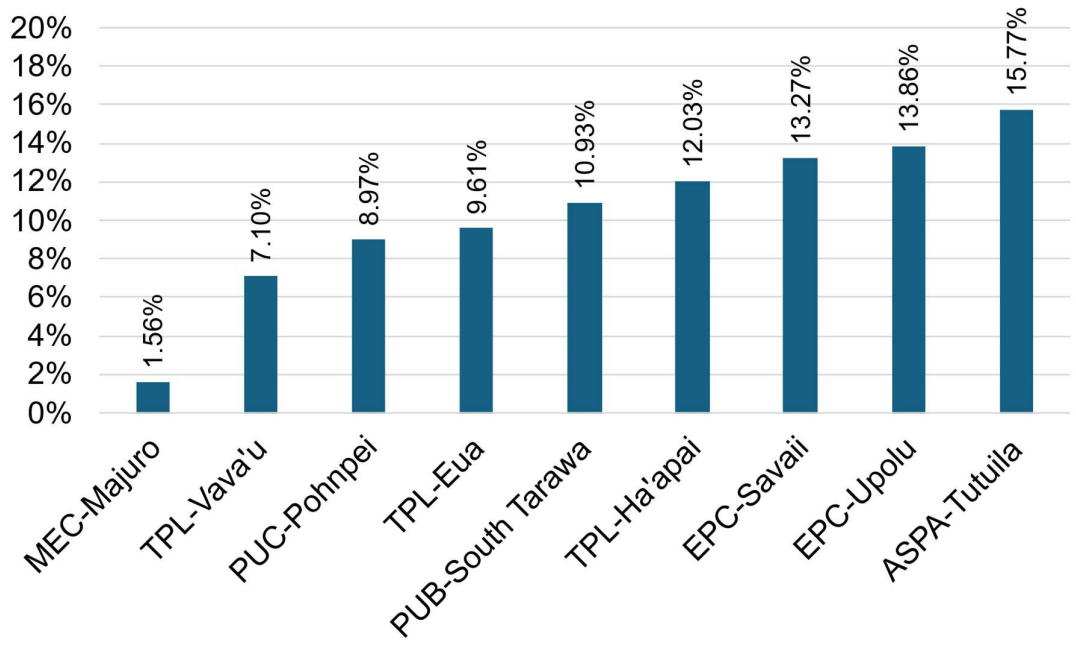
Network delivery losses are defined as the net generation minus electricity sold, divided by net generation, and expressed as a percentage. Net Generation is energy generated less the power station auxiliary usage. For utilities that have a transmission network, this loss includes the transmission and distribution network losses. This is only true for utility members of the PPA who have a transmission network. For the other utility members who do not have a transmission network, the Network Delivery Losses are equal to the Distribution Losses. Therefore, in this report, the Distribution loss is not presented separately as in previous reports.

The losses comprise technical and non-technical losses. Technical losses are mainly caused by resistance in the network lines and cables, which may be exacerbated by imbalances in the currents for each phase and high resistance joints in the distribution system. These depend on distribution voltages, loading, conductor material, physical dimensions, and state of conductors. Non-technical losses are those attributable to electricity used by a consumer but not paid for, including electricity theft, meter reading and accounting errors, unmetered connections, metering errors, etc.

This category should not include the use of electricity within the utility itself (other facility use), free provision for street lighting, or electricity provided to the water and sewerage waste management for utilities responsible for electricity, water, and sewerage services.

In 2025, there were 15 service areas reporting their network delivery losses. However, six outliers were excluded from Figure 4.18. The results show considerable variation across the Pacific region. The minimum reported value was 1.56%, while the maximum was 15.77%. The median value was 10.93%.

Figure 4.18: Network (Distribution) Delivery Losses

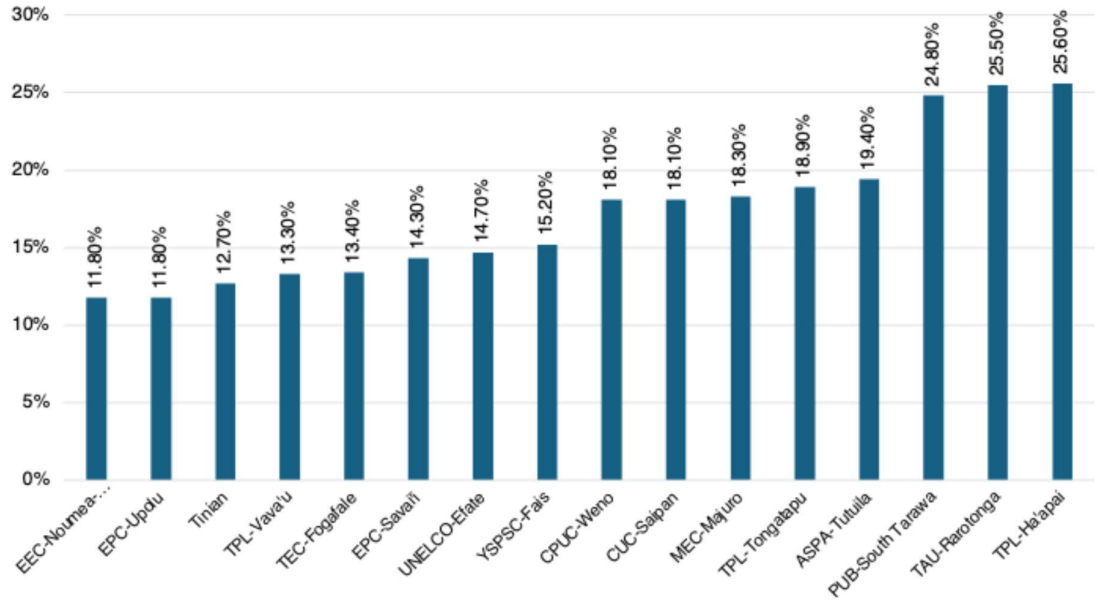


4.4.14 Distribution Transformer Utilization

This indicator measures the transformer's average load against the transformer capacity in megavolt amperes (MVA). It is calculated by dividing the total electricity sold by the total capacity of distribution transformers. High utilization implies an efficient capital expenditure process for investing in distribution transformer capacity to meet the demands of customers. This process takes into consideration non-coincident demand characteristics, demand growth, and contingency requirements to maintain supply security and reliability.

As seen in Figure 4.19, data for transformer utilization in Pacific utilities was not reliable. Out of 24 reporting service areas, eight outliers were removed because results were either below 10% or above 40%. In 2002, a regional goal of 30% was set. 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." The range for transformer utilization factor in 2025 was from 11.80% to 25.60%. The median transformer utilization factor across the nine reporting service areas included in Figure 4.19 was 16.65%.

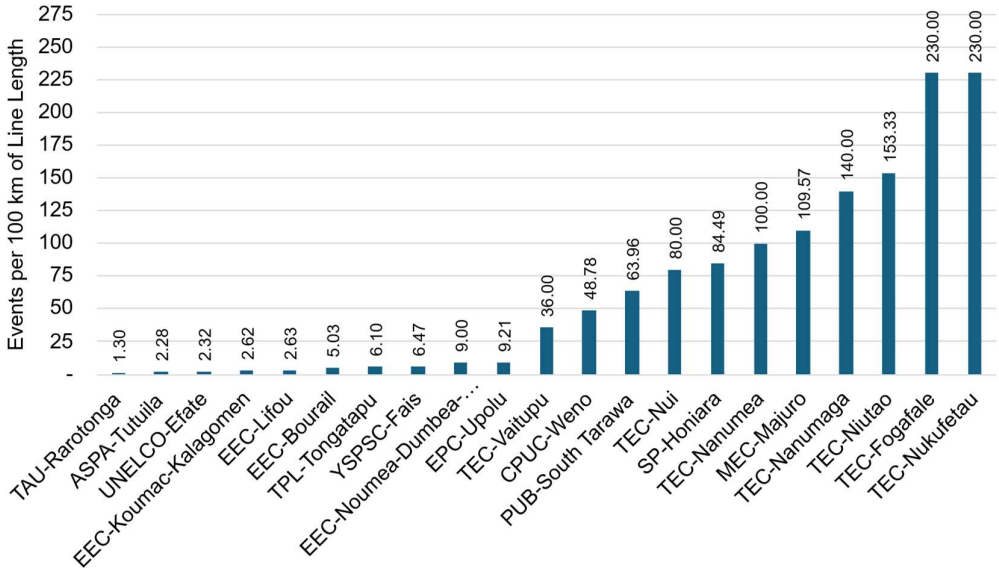
Figure 4.19: Distribution Transformer Utilization



4.4.15 Distribution Reliability

This indicator measures the number of forced outage events per 100km of distribution line as a way of assessing the reliability of the distribution network. In 2025, data were collected from 23 service areas, with two outliers removed from the sample. The distribution reliability values ranged from a minimum of 1.3 to a maximum of 230.0 forced outage events per 100 km of distribution line. The median value across all reporting service areas, excluding outliers, was 36.0 events per 100 km.

Figure 4.20: Distribution Reliability (Forced Outage Events)



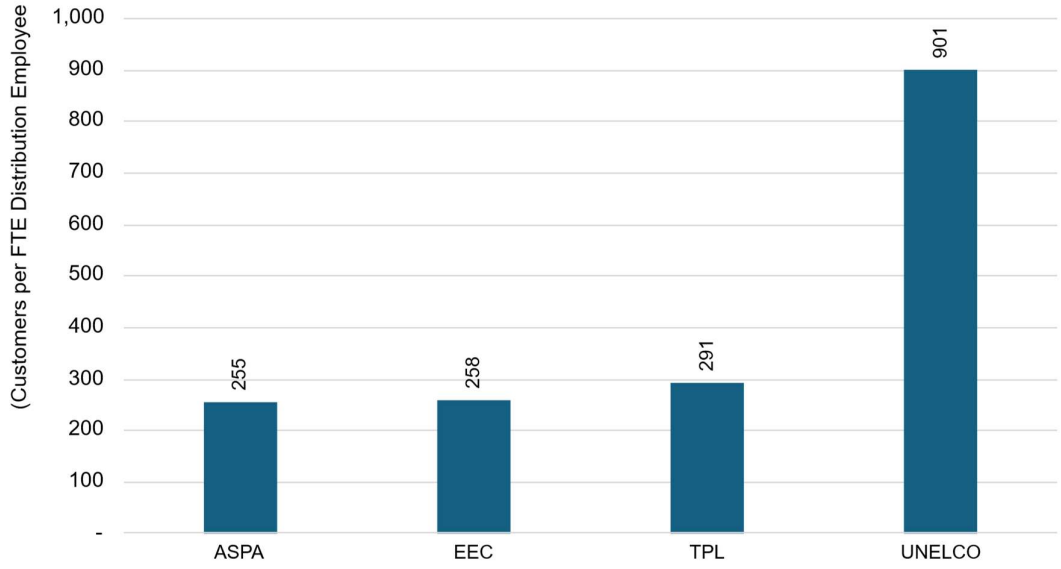
4.4.16 Customers per Distribution Employee

Customers per Distribution Employee measures the number of customers served by each full-time-equivalent distribution employee. This metric indicates workforce efficiency in the distribution segment and helps evaluate staffing levels relative to the customer base being served.

This indicator serves as a measure of distribution workforce productivity and staffing efficiency. The metric enables utility managers to evaluate their staffing levels and assess workforce deployment effectiveness. HR managers can also use this information to guide recruitment strategies and workforce development programs.

In 2025, four utilities reported this metric. The values range from 255 to 901, with a median value of 275 customers per distribution employee. The data shows substantial variation across different utilities. Most utilities reported between 250 and 300 customers per distribution employee.

Figure 4.21: Customers per Distribution Employee

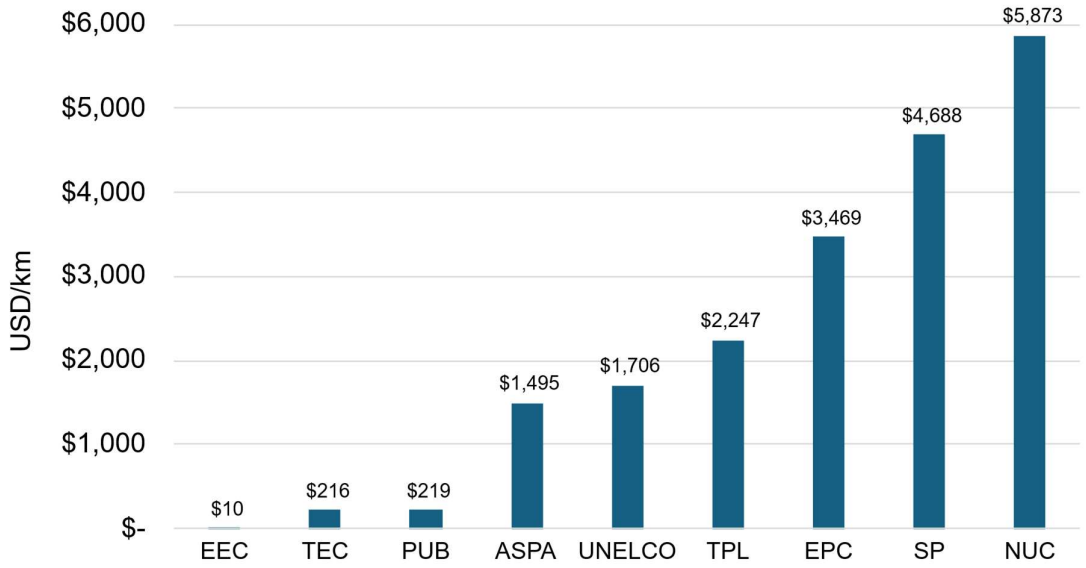


4.4.17 Distribution O&M Expenses

The Distribution Operations and Maintenance O&M costs are the total expenses incurred in the operations and maintenance of the distribution network. This includes all vehicle operating costs and all other costs related to distribution operations. This total O&M cost is divided by the distribution line length.

In 2025, 10 utilities reported their Distribution O&M expenses, with one outlier removed from the sample. The data shows a wide range of values, from a minimum of $9.86 per km to a maximum of $5,873.20 per km. The median value across reporting utilities was $1,705.70 per km.

Figure 4.22: Distribution Operations and Maintenance Expenses



4.5 SAIDI and SAIFI

This section presents the results for SAIDI (System Average Interruption Duration Index) and SAIFI (System Average Interruption Frequency Index). For power utilities in the Pacific, benchmarking SAIDI and SAIFI is crucial because these KPIs provide an objective picture of how often and how long customers experience outages. In small, geographically dispersed island systems that rely on aging infrastructure and are highly exposed to storms, fuel shortages, and natural disasters, service reliability can fluctuate widely.

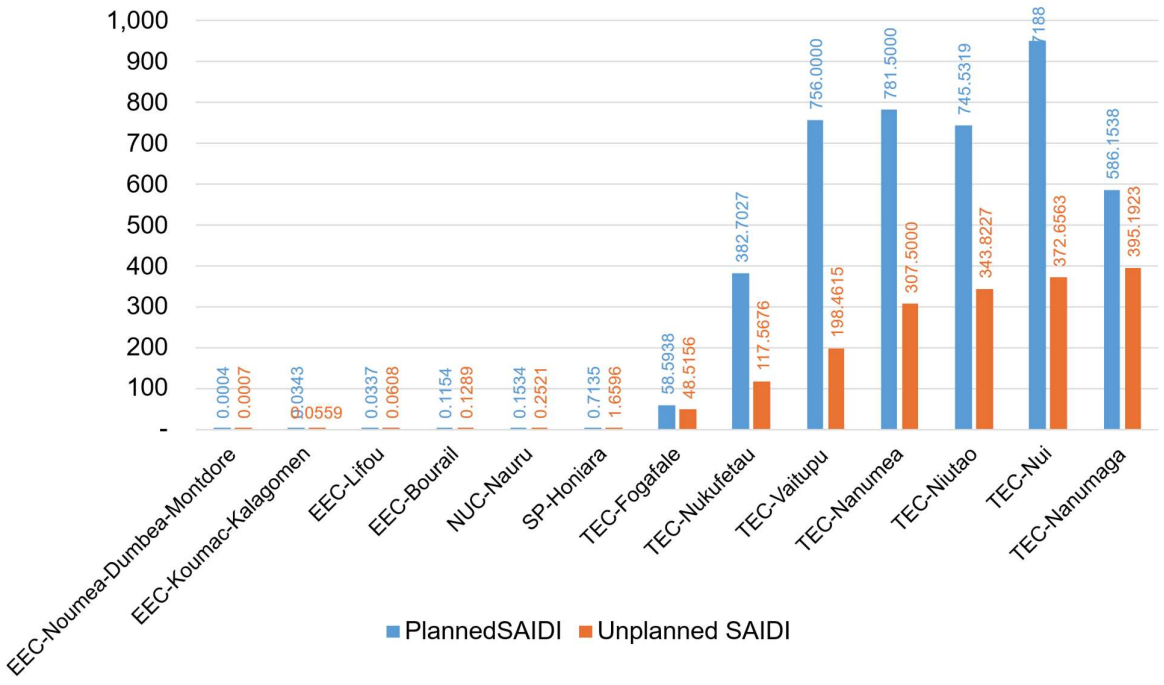
Tracking SAIDI and SAIFI over time and comparing them with regional or international benchmarks helps utilities pinpoint weak points in their networks, plan maintenance and investments more effectively, and demonstrate to regulators and donors that they are improving service quality. Reliable benchmarking also helps balance limited financial resources with reliability targets, ensuring that scarce funds are directed to the interventions that will have the greatest impact on reducing outage frequency and duration. By communicating these results transparently, utilities strengthen customer trust and accountability while building the case for further investment in resilience and modernization.

4.5.1 System Average Interruption Duration Index (SAIDI)

SAIDI indicates the average duration of power outages experienced by customers and is measured in customer minutes. The results are shown in Figure 4.23 as Planned and Unplanned outages that have resulted in power interruptions to customers. Only utilities that reported both planned and unplanned SAIDI in 2025 are included. The benchmark for Pacific Island utilities is for the total Planned and Unplanned SAIDI to be below 200 customer minutes.

A total of 19 service areas reported SAIDI values for 2025. However, six outlier values were removed from the sample. The maximum Planned SAIDI value was 949.7 minutes, while the maximum Unplanned SAIDI value was 395.2 minutes. The median Planned SAIDI was 58.6 minutes, and the median Unplanned SAIDI was 48.5 minutes.

Figure 4.23: SAIDI (Minutes per Customer)

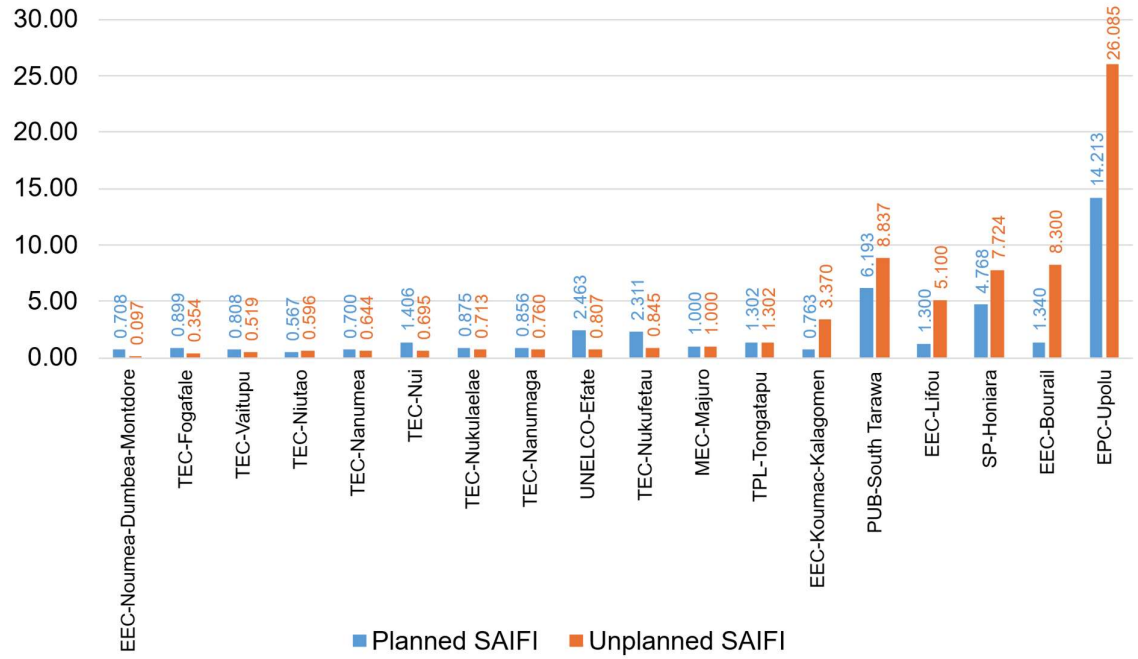


4.5.2 System Average Interruption Frequency Index (SAIFI)

SAIFI indicates the average frequency of power interruptions experienced by customers over the fiscal year. For small island utilities, the power interruptions to customers caused by generation events can be significant compared to distribution network events. Only utilities that reported both planned and unplanned SAIFI in 2025 are included.

A total of 18 service areas reported SAIFI values for 2025, as shown in Figure 4.24. The maximum Planned SAIFI value was 14.21 interruptions annually per customer, while the maximum Unplanned SAIFI value was 26.08. The median Planned SAIFI was 1.15 interruptions per customer, and the median Unplanned SAIFI was 0.826.

Figure 4.24: SAIFI (Events per Customer)



4.6 Financial Indicators

This section presents the financial KPIs included in PRISM. Benchmarking financial indicators is especially important for power utilities in the Pacific because these utilities operate in small, isolated markets with high operating costs from imported fuel, shipping, and spare parts. Regularly tracking and comparing financial performance against peers helps them ensure cost recovery, liquidity, and prudent debt management so they remain financially viable and able to provide reliable service. Benchmarking also reveals inefficiencies in revenue collection, tariff structures, or cost control, allowing utilities to identify best practices and adopt reforms such as reducing technical and commercial losses.

Benchmarking financial KPIs also allow PPA members to improve transparency and accountability to stakeholders by showing how the utility performs relative to peers and accepted standards, which in turn builds trust and supports good governance. Transparent benchmarking can also strengthen the credibility of utilities with development banks, donors, and investors, which increasingly require evidence of sound financial management to extend concessional financing or favorable lending terms.

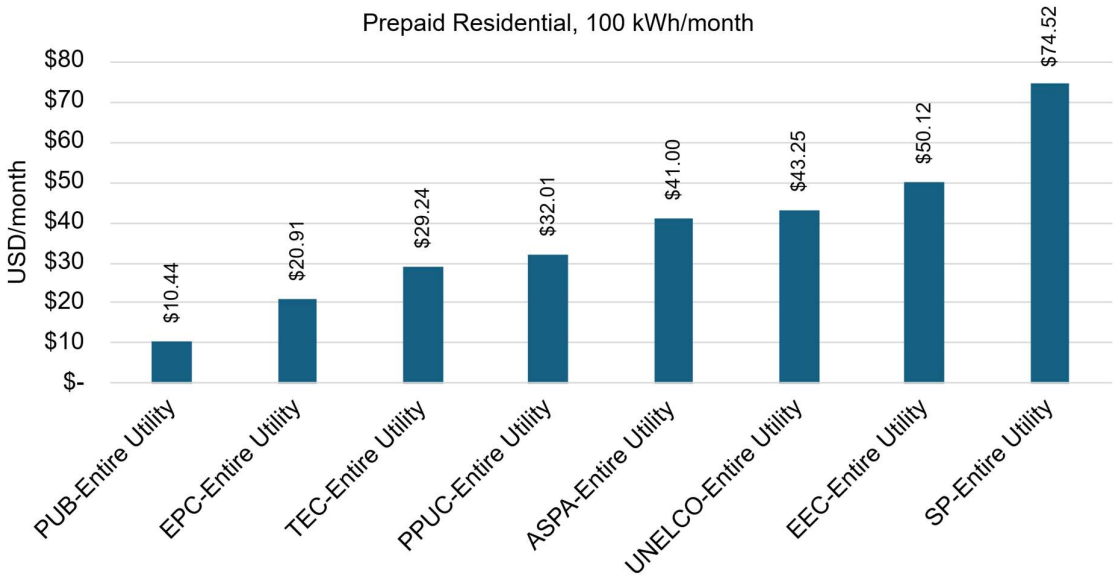
Finally, because utilities in the Pacific are highly vulnerable to climate change, natural disasters, and global fuel price shocks, financial benchmarking helps them build reserves, manage debt prudently, and plan capital investments in renewable energy and resilience projects.

4.6.1 Tariff Impact

Conducting tariff analysis of Pacific utilities is highly complex due to the different tariff schedules and structures. This section, therefore, compares the impact of the tariff schedule applied to customers of various categories. The monthly bills for domestic or residential customers (both prepaid and postpaid) with a usage of 100 kWh, 200 kWh, and 500 kWh are compared, ranked, and graphed in ascending order. The same is done for commercial customers with usages of 1,000 and 5,000 kWh per month. For industrial customers, the monthly electricity bill for a usage of 10,000 kWh per month is compared.

(i) Prepaid Residential Customer (100 kWh per month)

Figure 4.25: Prepaid Residential Customer with Usage of 100 kWh per month



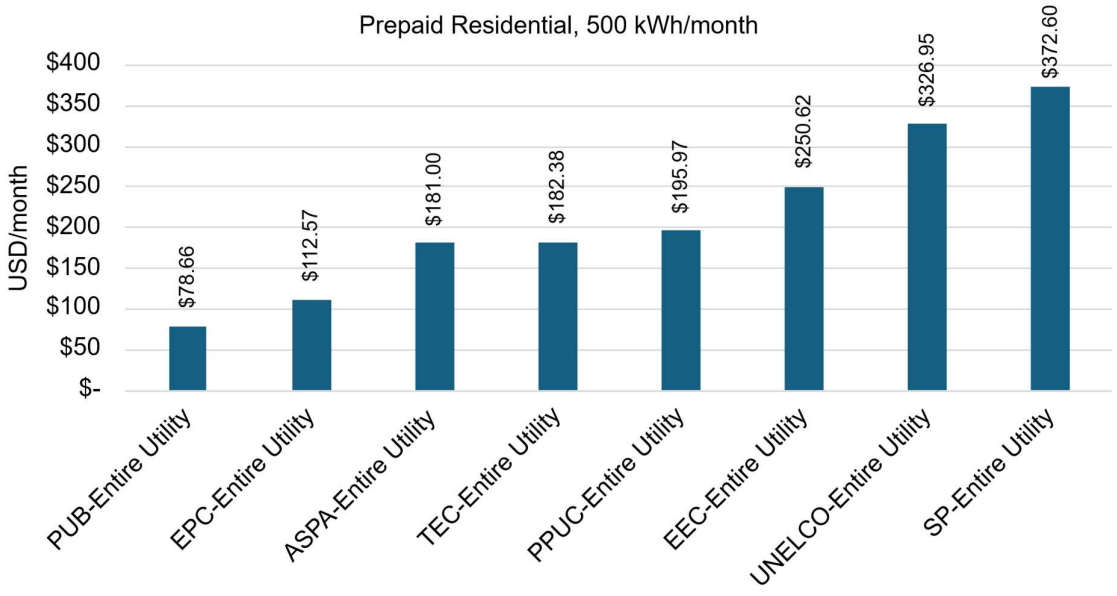
(ii) Prepaid Residential Customer (200 kWh per month)

Figure 4.26: Prepaid Residential Customer with Usage of 200 kWh per month



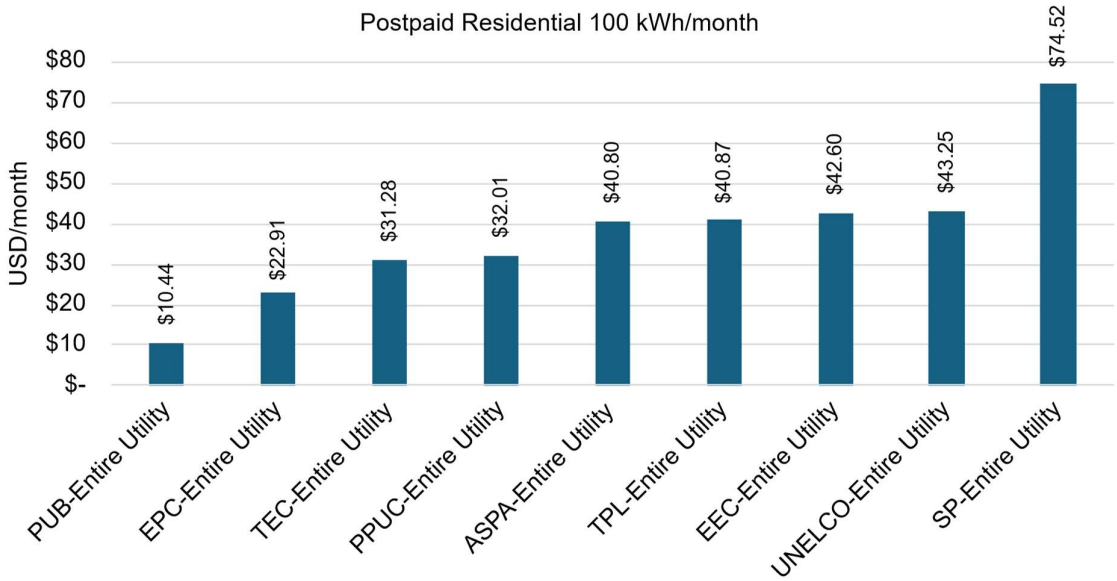
(iii) Prepaid Residential Customer (500 kWh per month)

Figure 4.27: Prepaid Residential Customer with Usage of 500 kWh per month



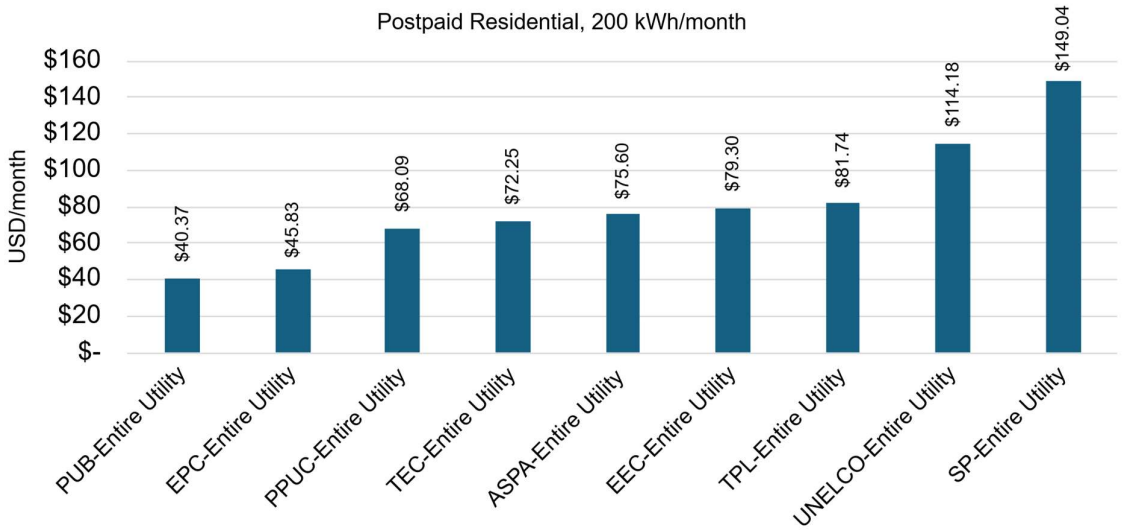
(iv) Postpaid Residential Customer (100 kWh per month)

Figure 4.28: Postpaid Residential Customer with Usage of 100 kWh per month



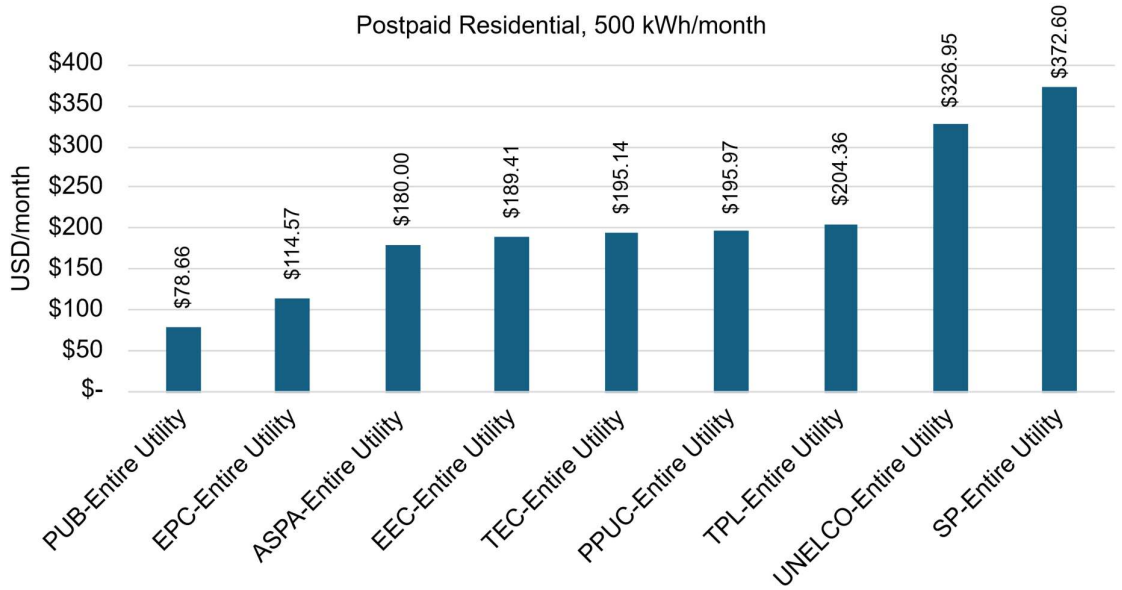
(v) Postpaid Residential Customer (200 kWh per month)

Figure 4.29: Postpaid Residential Customer with Usage of 200 kWh per month



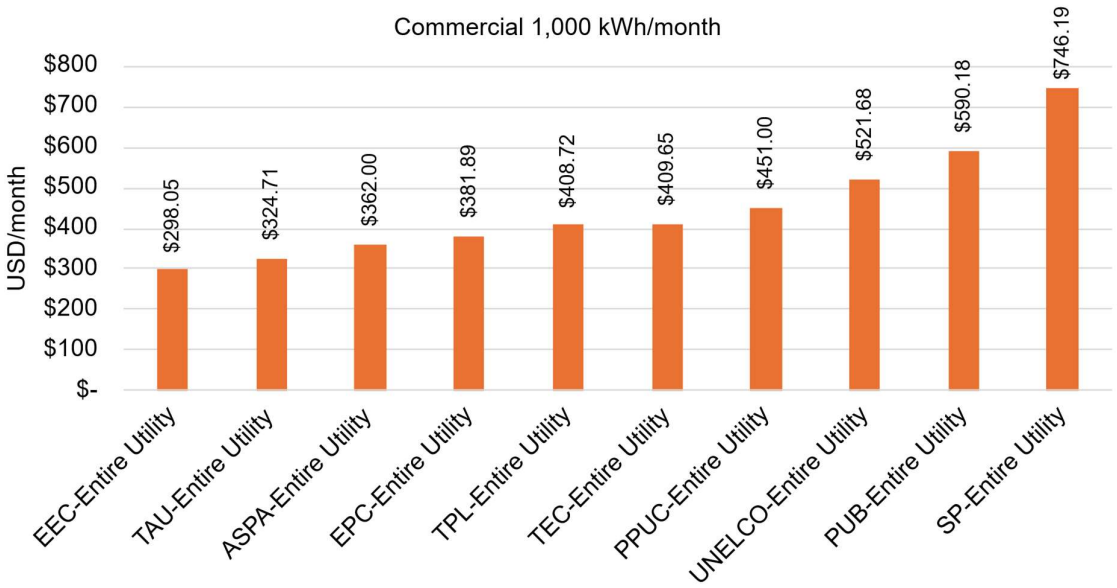
(vi) Postpaid Residential Customer (500 kWh per month)

Figure 4.30: Postpaid Residential Customer with Usage of 500 kWh per month



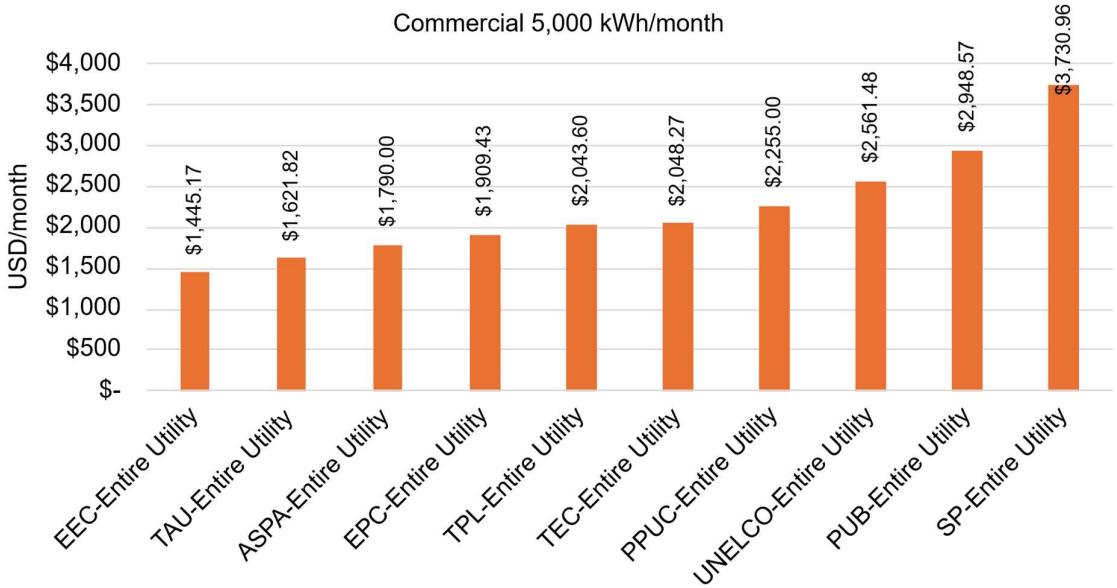
(vii) Commercial Customer (1,000 kWh per month)

Figure 4.31: Commercial Customer with Usage of 1,000 kWh per month



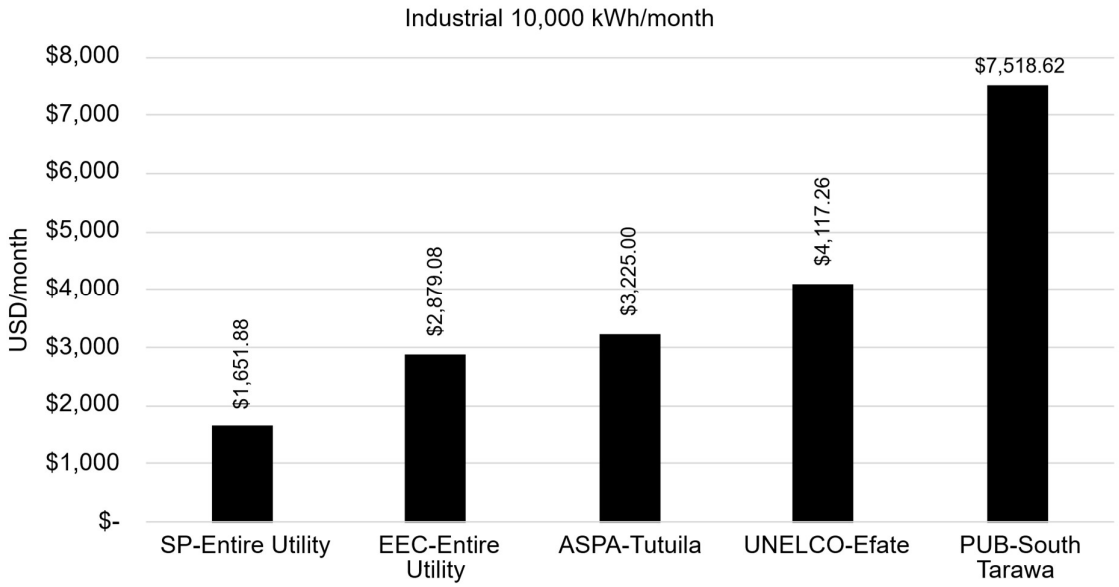
(viii) Commercial Customer (5,000 kWh per month)

Figure 4.32: Commercial Customer with Usage of 5,000 kWh per month



(ix) Industrial Customer (10,000kWh per month)

Figure 4.33: Industrial Customer with Usage of 10,000 kWh per month



4.6.2 Utility Cost Breakdown

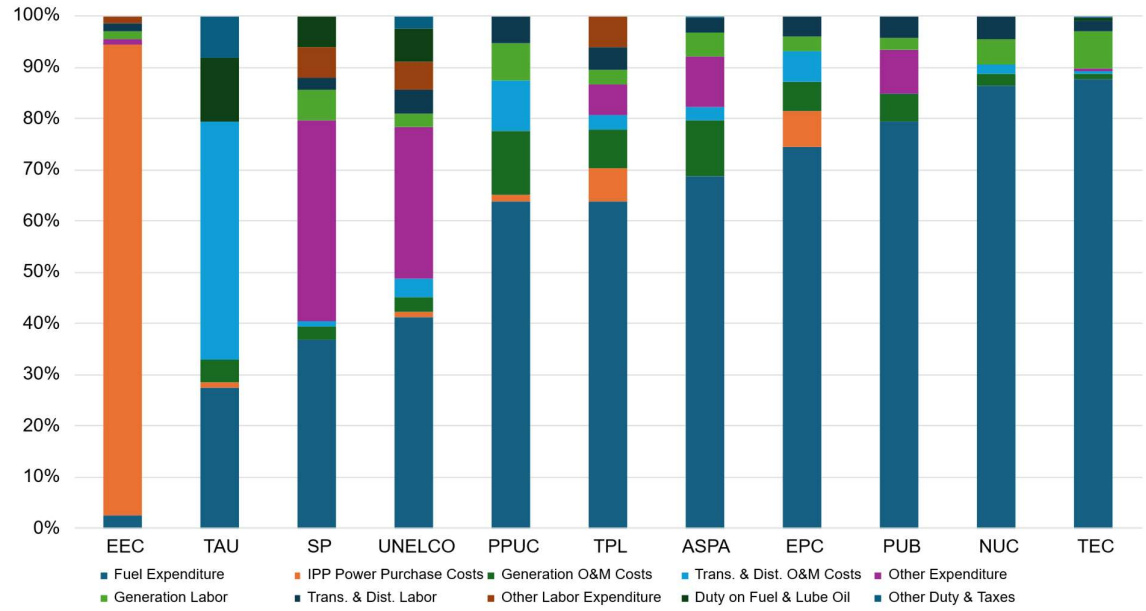
The Utility Cost Breakdown analyzes the composition of a utility's total operating costs by categorizing expenses into their major components. This metric provides visibility into the relative significance of different cost elements and helps identify the main drivers of operational expenses.

Cost structure management in Pacific Island utilities requires consideration of their unique operating environment. Factors such as fuel import dependency, geographical isolation, and limited economies of scale can significantly impact cost patterns. Understanding these influences helps establish appropriate cost management strategies and improvement targets.

The cost categories for which information was collected in 2025 included hydrocarbon-based fuel expenditure, power purchase costs, generation O&M costs, transmission and distribution O&M costs, other expenditure, generation labor costs, transmission and distribution labor costs, other labor expenditure, duty on fuel and lubricating oil, and other duty and taxes. The contributions of each component are presented for the 11 utilities that reported sufficient data in Figure 4.34 below.

Fuel expenditure remains the largest component in the utilities' cost structure, ranging from 2.6% to 87.6%, with a median value of 63.9%. Power purchase costs represented a significant cost component for some utilities, with EEC reporting the highest share at 91.8%. Generation O&M costs ranged from 0.1% to 12.4% across reporting utilities, while transmission and distribution O&M costs showed substantial variation, ranging from 0.0% to 46.4%. Labor costs were divided into three categories: generation labor, transmission and distribution labor, and other labor expenditure. Generation labor ranged from 0.0% to 7.4%, transmission and distribution labor from 0.9% to 13.5%, and other labor expenditure from 0.0% to 5.2%. Some utilities also reported significant percentages for "other expenditure," with SP reporting the highest at 39.2% followed by UNELCO at 29.6%. Only a few utilities reported duty on fuel and lubricating oil, with TAU reporting 12.4% and UNELCO reporting 6.5%. Similarly, for other duties and taxes, TAU reported the highest at 8.1%.

Figure 4.34: Utility Cost Breakdown



4.6.3 Debt-to-Equity Ratio

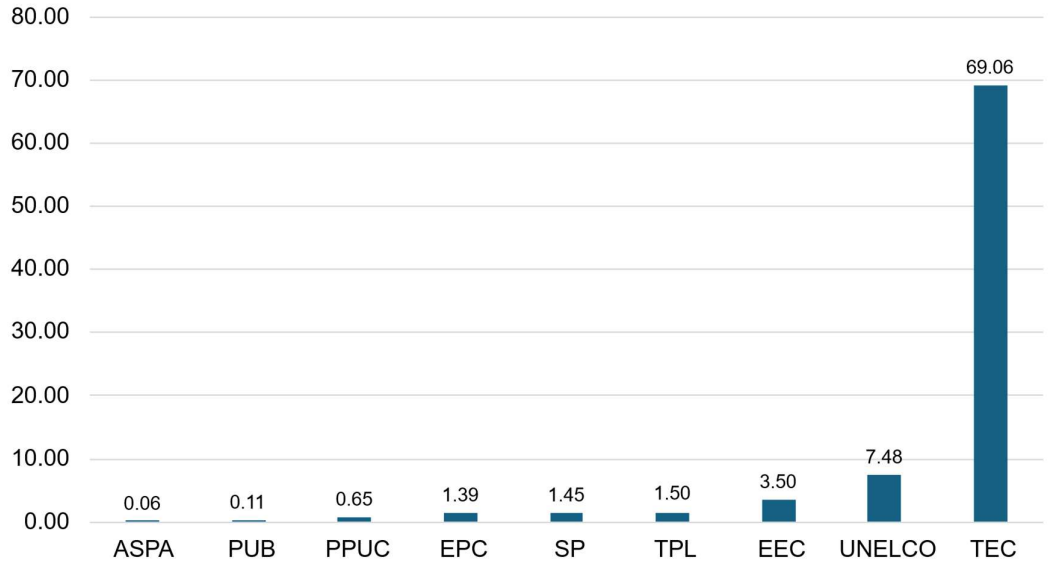
The Debt-to-Equity Ratio measures a utility's financial leverage by comparing total liabilities to total equity. This metric indicates how much of the utility's capital structure is financed through debt versus shareholder equity, providing insight into financial risk and long-term solvency.

The relationship between debt financing and operational sustainability requires careful consideration in the Pacific utility context. While debt financing can support necessary infrastructure investments, the associated fixed obligations must align with the utility's revenue generation capacity and operational stability. Regular analysis of leverage patterns helps ensure the sustainability of financing arrangements.

Infrastructure development needs often create pressure for increased leverage in Pacific utilities. The requirement to maintain and expand power systems must be balanced against debt service capabilities and financial risk tolerance. Clear documentation of capital structure decisions helps demonstrate prudent financial management while supporting necessary infrastructure investments. Moreover, some smaller utilities do not have access to debt funding and rely on their government or grants from donors for large projects, so they have no long-term debt obligations.

In 2025, nine utilities reported their Debt-to-Equity Ratio. The values ranged from a minimum of 0.06 to a maximum of 69.06, with a median value of 1.45.

Figure 4.35: Debt-to-Equity Ratio



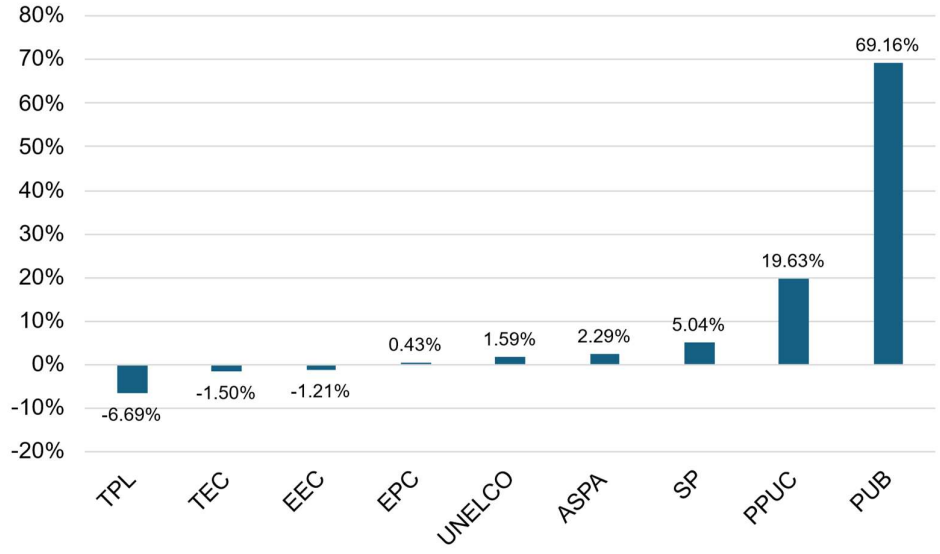
4.6.4 Return on Assets

The rate of return on assets (ROA) is the return generated from the investment in the business's assets. ROA indicates how efficient management is at using its assets to generate earnings.

Asset performance management in Pacific Island utilities requires consideration of factors such as infrastructure age, environmental conditions, and replacement costs. The relatively high fixed asset investment typical of island utilities makes ROA performance particularly significant for overall financial sustainability.

Pacific power utilities generally do not earn commercial rates of return, and this is reflected in Figure 4.36. In 2025, nine utilities reported their ROA. The values ranged from a minimum of -6.69% to a maximum of 69.16%, with a median value of 1.59%.

Figure 4.36: Return on Assets



4.6.5 Return on Equity

Return on Equity (ROE) measures the financial return generated relative to shareholder investment, expressed

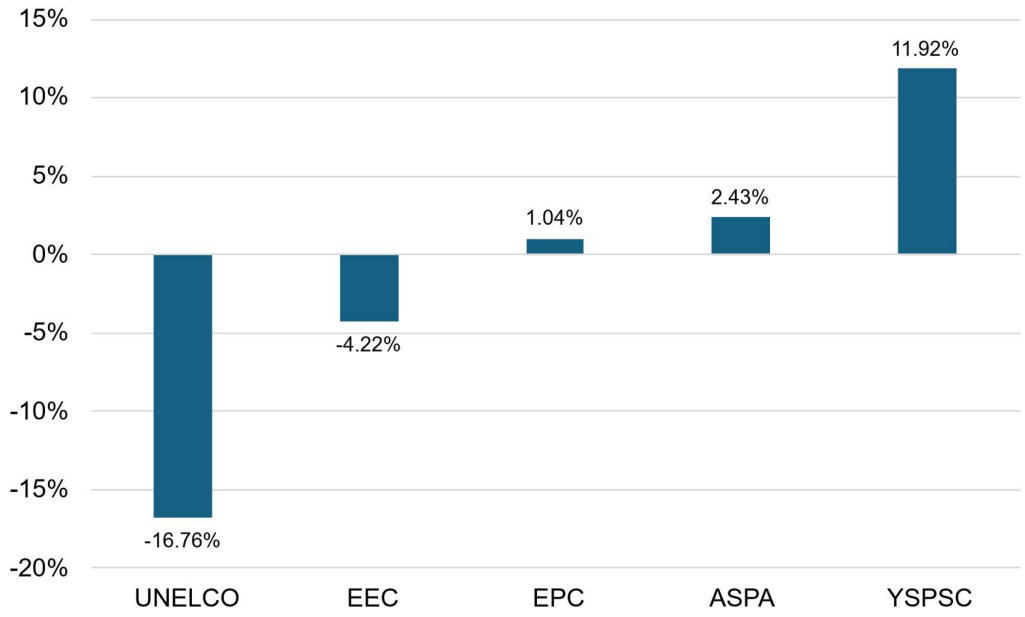
as a percentage. This metric indicates how efficiently a utility generates profits from shareholder capital, providing insight into financial performance from an ownership perspective.

ROE management in Pacific Island utilities requires consideration of their unique ownership structures and public service obligations. Many utilities operate as state-owned enterprises with mandates that balance financial returns against social objectives. Understanding this context helps in establishing appropriate return expectations and performance targets.

The interpretation of ROE must account for the specific operating environment of Pacific utilities. Factors such as scale constraints, infrastructure requirements, and service obligations can affect achievable returns. Regular analysis of return patterns helps ensure financial sustainability while meeting public service responsibilities.

Results for ROE are shown in Figure 4.37. In 2025, nine utilities reported their ROE, with four outliers excluded. The values ranged from a minimum of -16.76% to a maximum of 11.92%, with a median value of 1.04%.

Figure 4.37: Return on Equity



4.6.6 Current Ratio

The current ratio measures the ability of a 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. A current ratio above 1 is desirable. A ratio below 1 implies that the utility is not able to cover its current liabilities.

This indicator serves as a fundamental measure of financial liquidity and short-term solvency. The metric enables utility managers to evaluate their organization's ability to meet short-term financial commitments while maintaining normal operations. Financial planners use this information to assess working capital adequacy and guide treasury management decisions. Understanding liquidity patterns helps utilities optimize their working capital structure while ensuring operational stability.

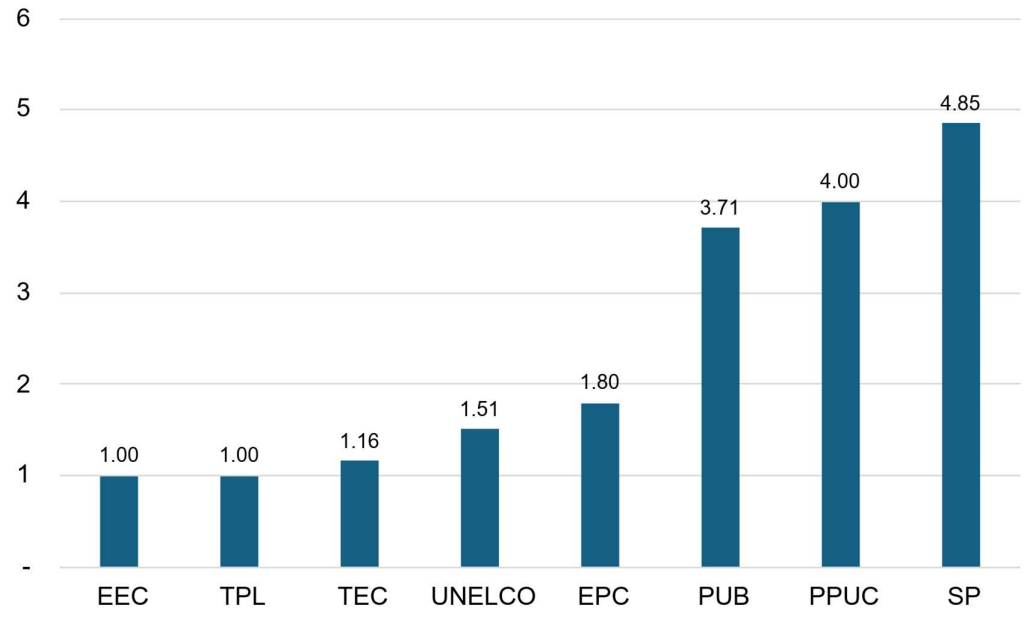
Liquidity management in Pacific Island utilities requires careful attention to factors such as revenue collection patterns, supply chain requirements, and seasonal variations in cash flow.

The relatively isolated nature of many island utilities makes maintaining adequate liquidity particularly important for ensuring operational continuity.

Working capital requirements often reflect the unique operating environment of Pacific utilities. Extended supply chains for critical materials and equipment may necessitate higher inventory levels, while weather-related risks might require larger cash reserves. Understanding these factors helps utilities establish appropriate liquidity targets and management strategies.

In 2025, eight utilities reported their current ratio values, as shown in Figure 4.38. The median current ratio was 1.66, with a maximum of 4.85 and a minimum of 1.00. All reporting utilities had current ratios above or equal to 1, indicating they can meet their current liabilities.

Figure 4.38: Current Ratio



4.6.7 Operating Ratio

The operating ratio is a measure of how efficiently a business operates, in this case, by providing electricity service. It is determined by dividing the sum of the cost of sales and other operating expenses by the revenue earned; it therefore expresses the business's operating expenses as a percentage of its revenue. An operating ratio below 100% indicates a profitable operation. An operating ratio above 100% indicates that it is costing an organization more to provide the service than the revenue derived from the service.

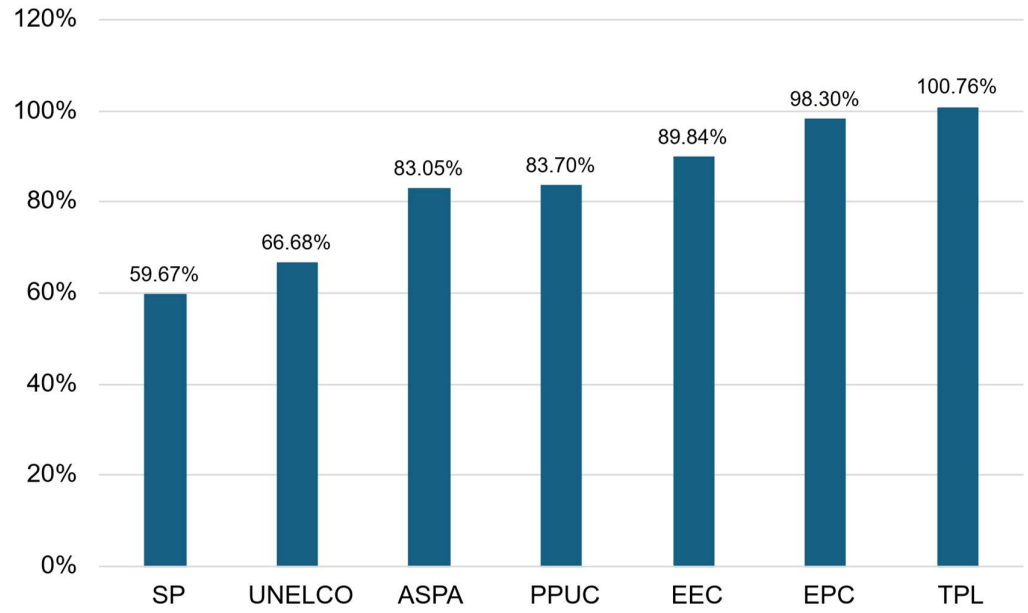
This indicator serves as a fundamental measure of operational efficiency and cost control effectiveness. The metric enables utility managers to evaluate their success in managing operating costs relative to revenue generation. Financial planners use this information to assess operational sustainability and identify areas requiring cost control or revenue enhancement. Understanding operating ratio trends helps utilities optimize their operational efficiency while maintaining service quality standards.

Operating ratio management in Pacific Island utilities presents unique challenges related to scale economies, resource availability, and operating environment. The relatively small customer base and high fixed costs typical of island utilities can make it challenging to achieve operating ratios comparable to larger mainland utilities. Understanding these constraints helps in setting appropriate performance targets and identifying improvement opportunities.

Cost management requires particular attention in Pacific Island contexts due to factors such as fuel import dependency, specialized maintenance requirements, and limited competition for services. Regular analysis of operating ratio components helps identify areas where cost control efforts or efficiency improvements might be most effective. The relationship between operating costs and service quality must be carefully considered to ensure cost control efforts don't compromise reliability.

In 2025, nine utilities reported their operating ratio, with two outliers excluded from the sample. The median operating ratio was 83.70%, with a maximum of 100.76% and a minimum of 59.67%. Six utilities reported operating ratios below 100%, indicating profitable operations, while one utility reported operating ratios at or above 100%.

Figure 4.39: Operating Ratio

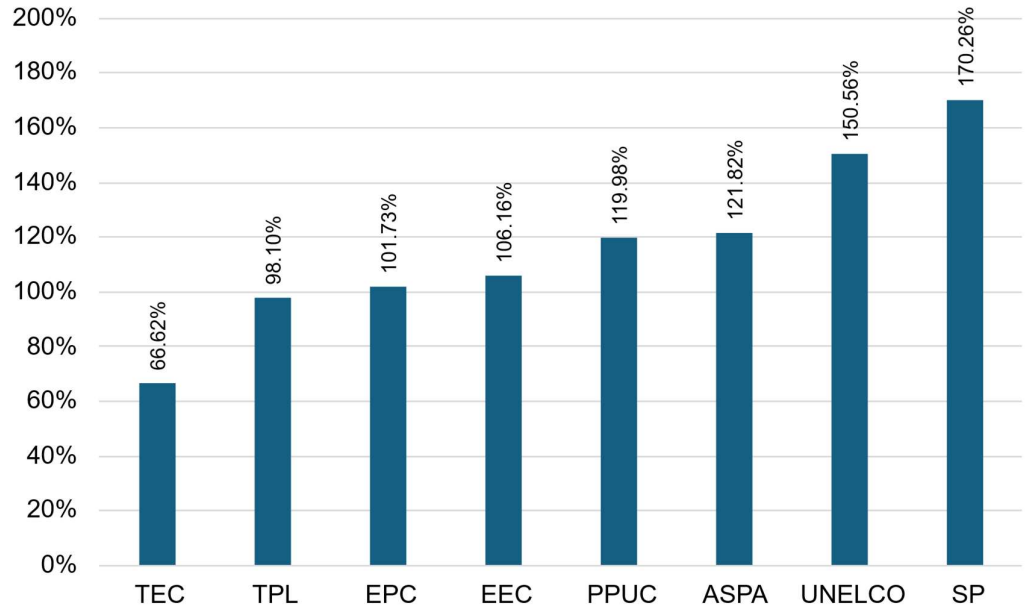


4.6.8 Operating Cost Recovery

Operating cost recovery measures how much of a utility's operating costs are covered by its revenues; revenue is divided by the sum of the cost of sales, other operating expenses (less bad debt), and taxes. A percentage above 100% indicates that revenues exceed operating costs, while a percentage below 100% indicates that operating costs exceed revenues.

In 2025, nine utilities reported their operating cost recovery, with one outlier excluded from the sample. The median operating cost recovery was 113.07%, with a maximum of 170.26% and a minimum of 66.62%. Six utilities reported operating cost recovery above 100%, indicating revenues exceeding operating costs, while two utilities reported operating cost recovery below 100%.

Figure 4.40: Operating Cost Recovery



4.6.9 Debtor Days

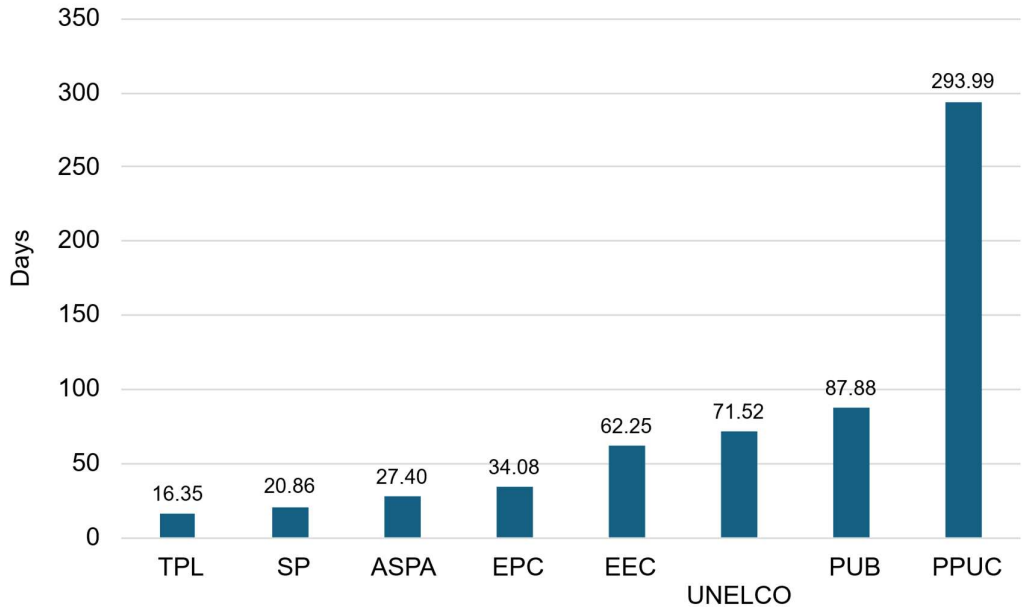
Debtor Days measures the average number of days it takes a utility to collect payment after billing customers. This metric indicates the effectiveness of the utility's revenue collection practices and provides insight into working capital management.

This indicator serves as an important measure of revenue collection efficiency and cash flow management. The metric enables utility managers to evaluate the effectiveness of their billing and collection practices while monitoring the financial health of their receivables portfolio. Financial managers use this information to forecast cash flows and manage working capital requirements. Understanding collection patterns helps utilities optimize their revenue management practices while maintaining positive customer relationships.

The effective management of receivables requires balancing collection efficiency with customer service considerations. While prompt payment collection is important for financial sustainability, collection practices must remain sensitive to community circumstances and payment capabilities. Clear documentation of collection policies and performance helps demonstrate fair treatment while supporting necessary collection actions.

In 2025, eight utilities reported their debtor days. The median was 48.2 days, with a maximum of 293.9 days, and a minimum of 16.4 days, and an average of 76.8 days. For comparison, the Pacific median was 30.9 days in 2024, 48.4 days in 2023, and 56.5 days in 2022.

Figure 4.41: Debtor Days



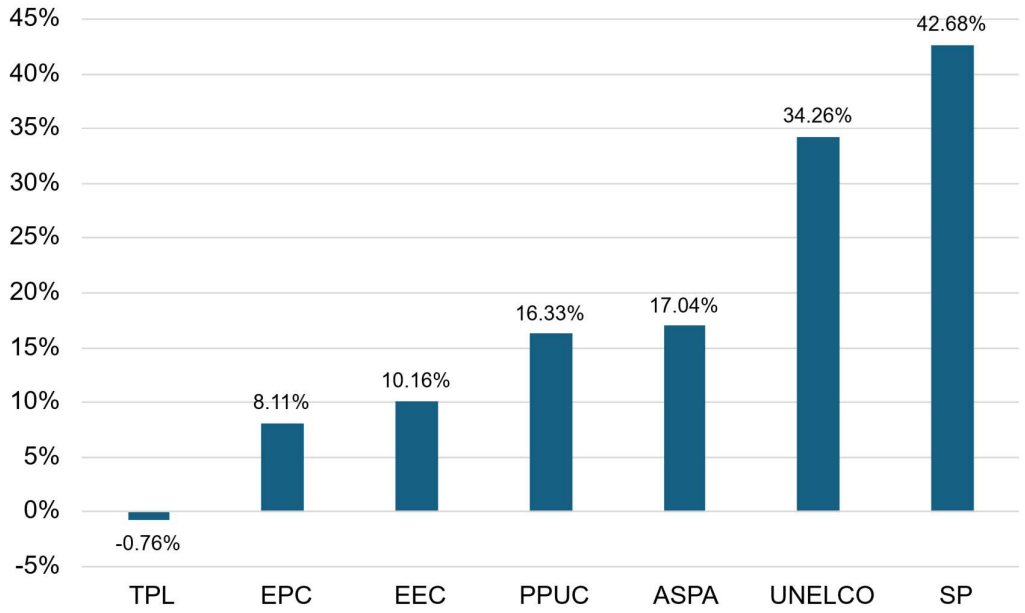
4.6.10 EBITDA Margin

EBITDA (Earnings Before Interest, Taxes, Depreciation and Amortization) Margin measures a utility's operating profitability before accounting for capital costs, financing expenses, and tax obligations, expressed as a percentage of revenue. This metric provides insight into core operational performance by focusing on earnings from regular business activities.

This indicator serves as a crucial measure of operational profitability and business performance. The metric enables utility managers to evaluate their core operations' effectiveness in generating earnings, independent of capital structure and tax considerations. Financial analysts use this information to assess operational efficiency and compare performance across utilities with different capital structures. Understanding EBITDA patterns helps utilities optimize their operational strategies while maintaining financial sustainability.

Figure 4.42 shows the EBITDA margin for the nine utilities that provided sufficient data for the 2025 fiscal year. Two outliers were excluded from the figure. The EBITDA margins ranged from -0.76% to 42.68%, with a median value of 16.33%. The utility performance varies significantly across the region, with six utilities reporting positive EBITDA margins and one utility reporting a negative EBITDA margin.

Figure 4.42: EBITDA Margin



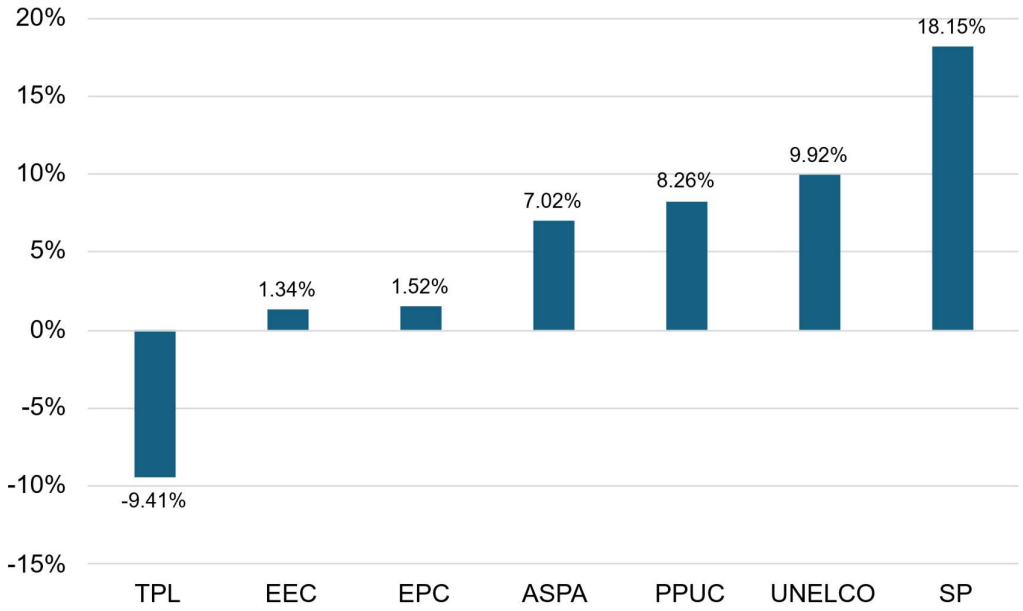
4.6.11 EBIT Margin

EBIT (Earnings Before Interest and Taxes) Margin measures a utility's operating profitability after accounting for capital costs but before financing expenses and tax obligations, expressed as a percentage of revenue. This metric provides insight into operational performance while considering the impact of infrastructure investments through depreciation and amortization.

This indicator serves as an essential measure of operational performance that includes the impact of capital investment decisions. The metric enables utility managers to evaluate their operations' effectiveness while considering the cost of maintaining and replacing infrastructure assets. Financial analysts use this information to assess operational sustainability and compare utilities with different asset profiles. Understanding EBIT patterns helps utilities optimize their operational and investment strategies while maintaining financial viability.

Figure 4.43 presents the EBIT margin for the 9 utilities that provided data for the 2025 fiscal year, with two outliers excluded from the figure. The EBIT margins range from -9.41% to 18.15%, with a median value of 7.02%. Six utilities reported positive EBIT margins, while one utility reported a negative EBIT margin.

Figure 4.43: EBIT Margin



4.6.12 Profit Margin

Profit Margin measures a utility's overall profitability by expressing profit as a percentage of revenue. This comprehensive metric reflects the final financial performance after accounting for all operating costs, capital charges, financing expenses, and tax obligations.

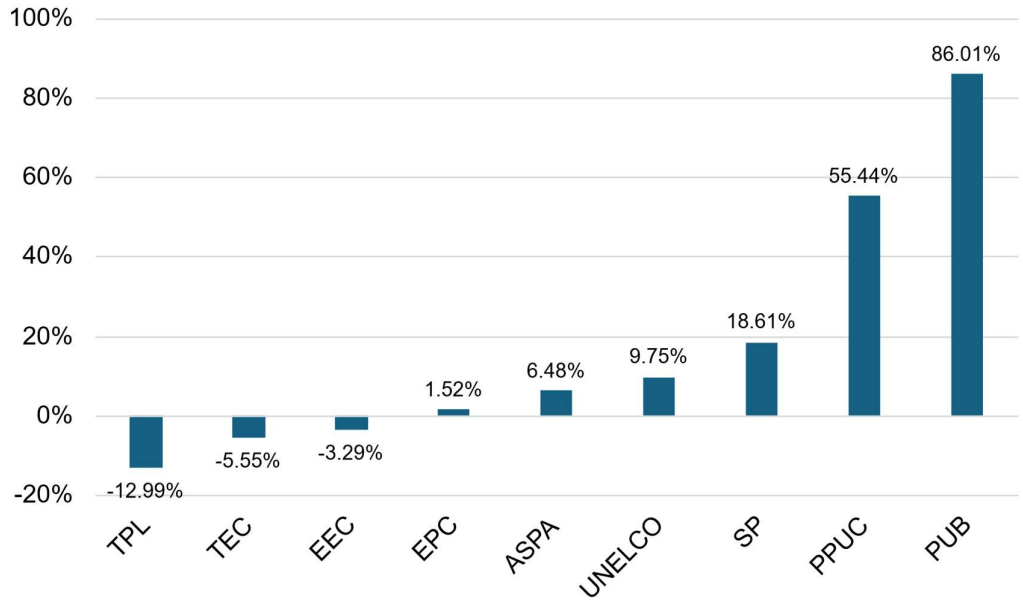
This indicator serves as an important measure of financial performance and value creation. This KPI enables utility managers to evaluate their success in generating returns while fulfilling their service obligations. Senior leadership and stakeholders use this information to assess overall business sustainability and strategic effectiveness. Understanding profit margin patterns helps utilities optimize their comprehensive business strategies while maintaining appropriate returns.

Profit margin management in Pacific Island utilities requires balancing financial sustainability with public service obligations. As often state-owned enterprises, these utilities must maintain adequate profitability while ensuring affordable and reliable power supply. Understanding this dual mandate helps establish appropriate performance targets and strategic priorities.

The interpretation of profit margins must consider the specific operating environment of Pacific utilities. Factors such as geographical isolation, weather exposure, and limited economies of scale can affect achievable returns. Regular analysis of profitability patterns helps ensure long-term sustainability while meeting community service requirements.

Figure 4.44 shows the profit margin for the nine utilities that provided data for the 2025 fiscal year. The profit margins range from -12.99% to 86.01%, with a median value of 6.48%. Six utilities reported positive profit margins, while three utilities reported negative profit margins.

Figure 4.44: Profit Margin



4.7 Human Resources & Safety Indicators

This section presents the HR and Safety KPIs included in PRISM. Safety performance management in Pacific Island utilities requires attention to specific regional challenges including remote operations, extreme weather conditions, and limited access to specialized medical facilities. These factors can influence both injury prevention strategies and recovery durations. Understanding these constraints helps develop appropriate safety programs and response protocols.

The interpretation of injury duration and frequency patterns must consider both direct and indirect impacts on utility operations. Beyond the immediate effect on workforce availability, extended injury durations or frequent accidents can affect team morale, productivity, and operational continuity. Regular analysis of duration and frequency trends helps identify opportunities for both prevention and response improvement.

The relationship between safety investment and injury outcomes requires careful attention. While preventive measures may require significant resources, they often prove more cost effective than managing extended absences and replacement staffing. Clear documentation of injury impacts helps justify necessary investments in safety programs and equipment.

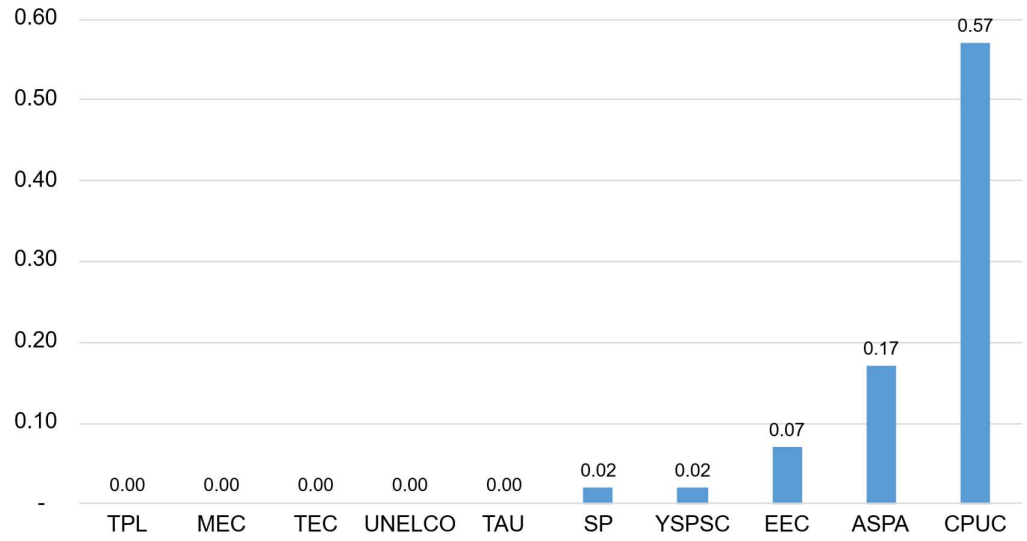
The implications of safety performance extend beyond immediate operational impacts to affect long-term workforce sustainability and organizational culture. Understanding these relationships helps utilities optimize their safety strategies and demonstrate their commitment to employee wellbeing. Regular review of injury metrics supports both program improvement and stakeholder communication about safety performance

4.7.1 Lost Time Injury Duration Rate

Lost Time Injury Duration Rate (LTIDR) measures the average number of days lost per employee due to work-related injuries. This KPI quantifies the severity of workplace injuries by calculating the duration of time employees are unable to work due to occupational incidents. This KPI serves as a critical measure of workplace safety performance and injury severity. The metric enables utility managers to evaluate the effectiveness of their safety programs and assess the impact of workplace injuries on workforce availability. Safety managers use this information to identify high-risk areas and guide prevention strategies. Understanding injury patterns helps utilities enhance their safety protocols while protecting employee wellbeing.

LTIDR for the 2025 fiscal year shows substantial variance across reporting utilities. Nine utilities reported LTIDR data, with values ranging from a minimum of zero days per employee to a maximum of 0.57 days per employee. The median LTIDR value across reporting utilities was 0.01 days.

Figure 4.45: Lost Time Injury Duration Rate (Days/employee)

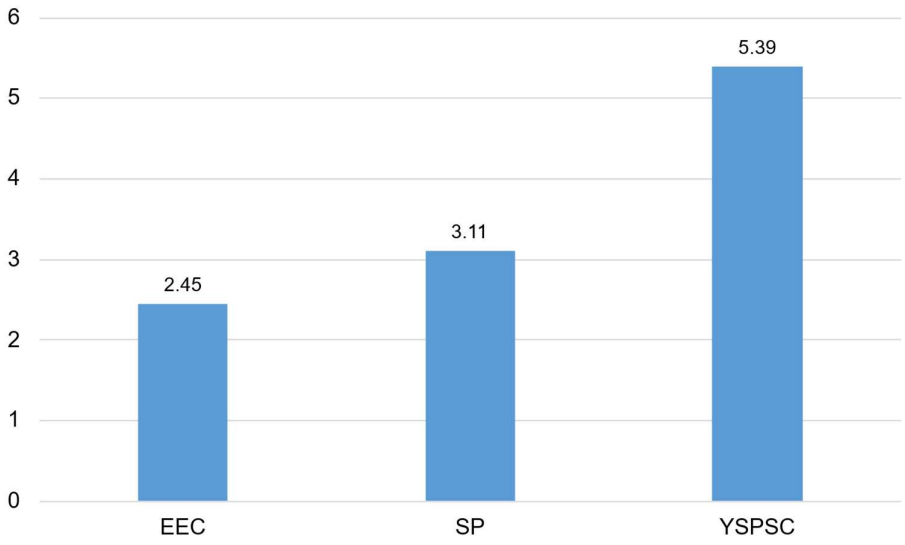


4.7.2 Lost Time Injury Frequency Rate

Lost Time Injury Frequency Rate measures the number of lost-time injuries per million hours worked. This metric standardizes the frequency of workplace incidents resulting in lost time, enabling comparison across utilities of different sizes and operational scales. This indicator also serves as a fundamental measure of workplace safety effectiveness and incident prevention. The metric enables utility managers to evaluate their safety program performance against industry standards and organizational targets. Safety professionals can also use this information to assess risk management effectiveness and guide prevention strategies.

Five utilities reported LTIFR values for the 2025 fiscal year, with two outliers removed from this sample. The LTIFR values show significant variation, ranging from a minimum of 2.45 incidents per million hours worked to a maximum of 5.39. The median value across reporting utilities was 3.11.

Figure 4.46: Lost Time Injury Frequency (Number of incidents per million hours)



4.7.3 Overall Labor Productivity

Overall Labor Productivity measures the number of customers per employee. This indicator serves as a fundamental measure of workforce efficiency and organizational productivity. The metric enables utility managers to evaluate staffing effectiveness and assess resource allocation across operations. HR planners use this information to guide workforce planning and development strategies. Understanding productivity patterns helps utilities optimize their staffing models while maintaining service quality.

Labor productivity management in Pacific Island utilities requires consideration of their unique operating environment. Factors such as geographical dispersion, service territory characteristics, and limited automation opportunities can influence productivity levels. Understanding these constraints helps establish appropriate performance targets and improvement strategies.

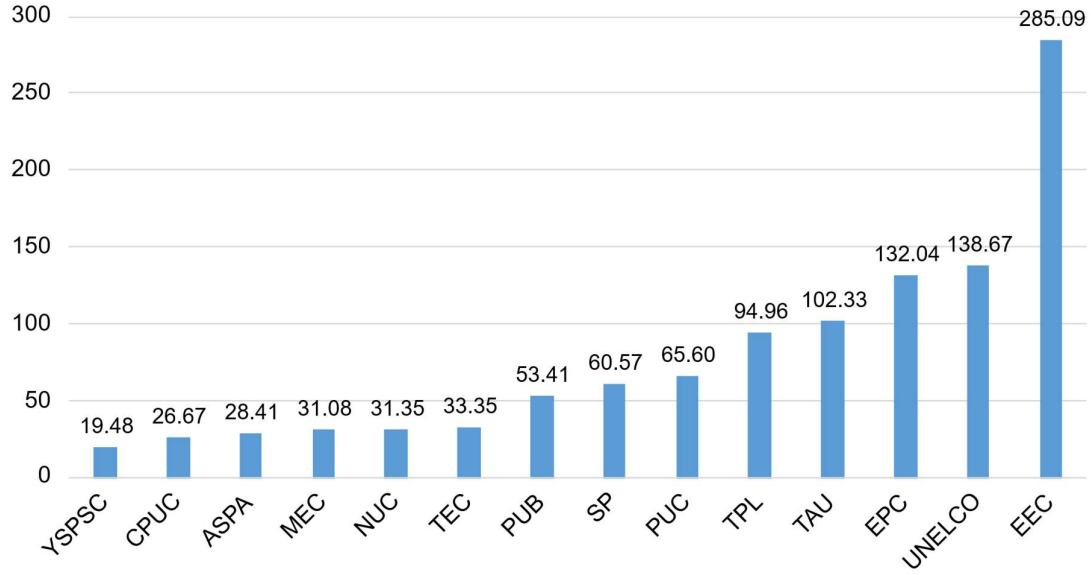
The interpretation of productivity metrics must consider both efficiency and service quality objectives. While high customer-to-employee ratios may indicate efficient resource utilization, staffing levels must remain sufficient to maintain reliable service and respond to system needs. Regular analysis of productivity trends helps ensure appropriate balance between efficiency and operational effectiveness.

The relationship between workforce productivity and service delivery requires careful attention. Training investments, technology adoption, and process improvements can enhance productivity while supporting service quality. Clear documentation of productivity patterns helps demonstrate effective resource management while supporting necessary workforce investments.

Moreover, the economic implications of labor productivity extend throughout utility operations and affect both financial sustainability and service affordability. Understanding these relationships helps utilities optimize their workforce strategies and justify their staffing decisions. Regular review of productivity metrics supports both operational improvement and stakeholder communication about workforce effectiveness.

In 2025, 14 utilities provided information on their labor productivity. The labor productivity values show significant variation across utilities, ranging from a minimum of 19.48 to a maximum of 285.09. The median productivity was 53.41 customers per employee.

Figure 4.47: Overall Labor Productivity (Customers/employee)



5. Findings and Recommended Priorities

The 2025 benchmarking data reveal several important trends and patterns across Pacific power utilities that merit attention. Because participation and data completeness vary considerably by indicator, and the utilities reporting each KPI differ from year to year, these findings should be read alongside the number of utilities reporting each KPI in Section 4, and year-on-year comparisons should be treated with caution.

5.1.1 Findings

- **Generation Mix and Renewable Energy Transition.** Progress in the region's transition to renewable energy remains uneven. Across the 24 service areas reporting, the median renewable energy share was below 5%, and eight service areas reported less than 1%. The highest shares were reported by smaller grids with solar-hybrid systems, including several of Tuvalu's outer-island grids (51% to 55%), while larger grids such as TPL-Tongatapu (3.5%) and SP-Honiara (3.2%) reported low shares. PPL's hydropower-based grids did not report renewable energy data this year, which largely explains the lower regional median compared with 2024. Overall, the data suggest that the rate of new renewable energy deployment has been slower than anticipated despite ambitious targets set by many countries.

- **Performance of Existing Renewable Assets.** Reported capacity factors for utility-owned renewable plants remain low: the median was 5.7% for solar, 4.3% for wind and 1.8% for dam-based hydropower, while the median solar availability factor was 94.4%. These results point to some combination of underperforming or out-of-service plant, curtailment, and inconsistent reporting of installed capacity. Ensuring that existing renewable assets deliver their expected output is as important as adding new capacity.

- **Diesel Generation Performance.** Diesel remains the backbone of most Pacific systems, and fuel is the largest single cost component (median 63.9% of utility costs). The median specific fuel consumption was 3.50 kWh/liter, below the Pacific benchmark of 4 kWh/liter, and only four of the service areas shown in Figure 4.10 met the benchmark. The median forced outage indicator rose to 2.03% (from 1.14% in 2024), with a maximum of 19.5%, and diesel availability was particularly low at EPC-Upolu (57.6%) and SP-Honiara (75.4%). Power station usage, by contrast, was within the 5% benchmark at almost all reporting service areas. Improving diesel efficiency and maintenance would yield significant fuel savings and reliability gains.

- **Operational Performance.** Network losses remain a critical area requiring improvement. Excluding six of the 15 submissions identified as outliers, network delivery losses ranged from 1.6% to 15.8%, with a median of 10.9%. Because so many values had to be excluded, the true range of losses in the region is likely to be wider. Reducing technical and non-technical losses represents a significant opportunity to improve financial performance, often through targeted metering and network investments with short payback periods.

- **Service Reliability.** SAIDI and SAIFI reporting improved compared with 2024, although six of the 19 SAIDI submissions were still excluded as outliers. The median planned and unplanned SAIDI (58.6 and 48.5 minutes) together fall within the Pacific benchmark of 200 customer minutes, but several of Tuvalu's outer-island grids reported planned SAIDI above

700 minutes, and the values close to zero reported by some utilities warrant verification. The median distribution reliability was 36 forced outage events per 100 km of distribution line, and no utility reported transmission data for 2025.

- **Financial Sustainability.** Financial results for 2025 are generally positive among the utilities that reported, although only eight or nine utilities provided data for most indicators. The median operating cost recovery was 113.1%, with TEC (66.6%) and TPL (98.1%) below 100%; the median EBITDA margin was 16.3% and the median EBIT margin 7.0%; and all eight utilities reporting a current ratio had a ratio of at least 1. However, three utilities reported negative profit margins, the median return on assets was only 1.6%, and median debtor days rose to 48.2 (from 30.9 in 2024), close to the Pacific benchmark of 50 days, with one utility at 294 days. Leverage also varies widely, with debt-to-equity ratios ranging from 0.06 to 69. Low returns continue to challenge utilities' ability to invest in maintenance, system improvements, and renewable energy technologies. The utilities facing the largest gaps may require targeted interventions in tariff structures, operational efficiency, and governance.
- **Governance and Management.** Most utilities have codes of conduct, CEO performance contracts and strategic plans in place, and disclosure practices improved compared with 2024. Nevertheless, four of the 19 participating utilities do not have their annual reports audited, four do not complete them within four months of the end of the reporting year, and five do not disclose performance against their strategic plans. Two utilities (CUC and YSPSC) have not adopted a strategic plan, and ministers are appointed to the boards of three utilities. The relationship between governance practices and financial performance could not be tested robustly with this year's sample and should be examined as the PRISM time series grows.
- **Gender Representation.** Women represent 23% of the total utility workforce in 2025, and representation remains highly uneven across different functional areas. Women account for less than 7% of technical employees (97 of 1,456), while they make up the majority of finance, administrative, and human resources staff. At the leadership level, women hold 25 of 97 executive positions (26%), and two of the 19 participating utilities have a female CEO, up from one in 2024.
- **Health and Safety.** Nine utilities reported lost time injury duration data and seven reported lost time injury frequency data. The median lost time injury frequency rate was 3.1 per million hours worked (3.9 in 2024), with a maximum of 5.4 after two outliers were excluded. The limited number of utilities reporting makes it difficult to assess safety performance across the region.

5.1.2 Priority Areas for Utilities

Based on the 2025 benchmarking results, we identify the following priority areas for Pacific power utilities:

1. Strategic Renewable Energy Integration

Pacific utilities should prioritize developing realistic, comprehensive energy transition roadmaps that:

- Match technology choices to each utility's specific circumstances and resources
- Plan systematically for battery storage requirements as renewable penetration increases
- Focus initial investments on opportunities with the highest fuel cost savings relative to capital expenditure

- Establish practical implementation timelines while maintaining progress toward renewable targets
- Ensure that existing solar, wind, and hydropower assets achieve their expected output through effective operations and maintenance, timely repair of inverters and batteries, and monitoring of curtailment

2. Diesel Generation Efficiency and Maintenance

To reduce fuel costs, which remain the largest component of utility expenditure, and improve supply reliability, utilities should focus on:

- Monitoring specific fuel consumption by generating unit and power station, and targeting improvement to at least the 4 kWh/liter benchmark
- Investigating the causes of low availability and rising forced outage rates in diesel fleets
- Protecting planned maintenance schedules by maintaining adequate reserve capacity and spare parts inventories
- Optimizing generator dispatch and unit commitment, particularly as renewable energy penetration increases

3. System Loss Reduction

Utilities should make loss reduction a central focus by:

- Identifying and targeting the highest sources of both technical and non-technical losses
- Upgrading distribution infrastructure in high-loss areas
- Implementing modern metering systems to better track and reduce losses
- Improving the measurement of losses, including metering at generation and feeder level, so that reported figures are reliable
- Establishing clear loss reduction targets with regular performance monitoring

4. Reliability Measurement and Management

To improve service reliability and how it is measured, utilities should focus on:

- Adopting standard outage recording definitions (e.g., IEEE 1366) for SAIDI and SAIFI, distinguishing planned and unplanned interruptions and their generation, transmission, or distribution causes
- Implementing outage management records or systems that capture the number of customers affected and the duration of each interruption
- Scheduling and coordinating planned maintenance to minimize customer interruption time, particularly where planned SAIDI exceeds the benchmark
- Using reliability data to target maintenance, vegetation management, and network investment on the worst-performing grids and feeders

5. Financial Performance Enhancement

To strengthen financial sustainability, utilities should focus on:

- Setting tariffs that recover the full cost of service, including depreciation, so that assets can be maintained and replaced, while maintaining affordability
- Clarifying and formalizing any subsidy arrangements with government stakeholders
- Strengthening revenue collection where debtor days exceed the Pacific benchmark of 50 days
- Reviewing capital structures where leverage is high to ensure that debt service remains sustainable
- Promoting customer energy efficiency to manage demand and costs
- Using competitive procurement to secure the most cost-effective power generation options

6. Governance Strengthening

To address the governance gaps identified in this report, utilities should:

- Enhance board independence and relevant expertise
- Implement performance-based management frameworks
- Develop robust strategic planning processes with measurable targets
- Improve transparency by having annual reports audited, published within four months of the end of the reporting year, and disclosing performance against the strategic plan

7. Technical Capacity Development

To address operational challenges, utilities should prioritize:

- Training staff on renewable technology integration and advanced grid management
- Participating in regional technical knowledge-sharing initiatives
- Implementing standardized maintenance protocols to improve reliability
- Collaborating across utilities to leverage specialized expertise

8. Data Quality Improvement

To enhance decision-making and future benchmarking, utilities should focus on:

- Standardizing data collection methodologies
- Implementing digital systems for performance tracking
- Conducting regular internal performance reviews against benchmarks
- Increasing the detail and accuracy of operational metrics

9. Gender Balance Advancement

To improve workforce diversity across all utility functions:

- Creating targeted pathways for women to enter technical roles
- Establishing professional development and mentoring programs
- Ensuring workplace policies promote inclusion and equity

- Setting specific goals for female representation at all organizational levels, including technical roles and executive positions

10. Workplace Health and Safety

To improve workforce safety, utilities should focus on:

- Recording lost time injuries and hours worked consistently so that injury frequency and duration rates can be benchmarked
- Implementing safety management systems, with particular attention to network field work
- Sharing incident lessons and safety practices through PPA networks

5.1.3 Conclusion

The 2025 benchmarking results highlight both progress and persistent challenges across Pacific power utilities. Reporting utilities generally recover their operating costs and maintain adequate liquidity, and governance disclosure has improved, but diesel efficiency remains below benchmark at most power stations, debtor days have risen, and the transition to renewable energy is proceeding unevenly. Accelerated action is needed in the priority areas identified above, and improving the completeness and reliability of the data reported through PRISM, including broader participation and full reporting of financial and transmission data, is a precondition for tracking this progress. By focusing attention and resources on these key priorities, utilities can build on their existing strengths and address critical gaps, ultimately delivering more reliable, affordable, and sustainable electricity services throughout the Pacific region.

6. Glossary of KPIs

Availability Factor (AF):

Definition: The ratio of the actual time (after accounting for planned and unplanned outages) a power plant is available and generating electricity to the total time in a specific period. It is typically expressed as a percentage.

Importance: Measures the reliability and availability of the power plant. A high AF indicates the plant is consistently available to generate power, while a lower AF may suggest maintenance issues or frequent breakdowns. Tracking AF helps assess how well a power plant is operated and maintained.

Capacity Factor (CF):

Definition: The ratio of the actual electricity generation of a power plant to its maximum potential generation capacity over a specific period.

Importance: Shows how consistently a power plant produces electricity at its full capacity. A higher CF generally indicates better utilization of installed capacity. However, an extremely high CF might also suggest insufficient reserve capacity for maintenance or unexpected outages. The indicator is calculated separately by generation source (solar, wind, diesel, etc.) and by utility vs. Independent Power Producers (IPPs) to provide more specific insights.

Customers per Full-Time Equivalent (FTE) Distribution Employee:

Definition: Measures the number of customers or connections served by each FTE distribution employee.

Importance: Evaluates labor productivity in the distribution segment of the energy utility. A higher number generally suggests greater efficiency of the distribution workforce.

Current Ratio:

Definition: A financial ratio that measures the utility's ability to pay its short-term obligations (current liabilities) using its current assets.

Importance: Indicates the utility's short-term financial health and liquidity. A ratio above 1 is generally desirable, suggesting the utility has enough liquid assets to cover its immediate liabilities.

Debtor Days:

Definition: Measures the average number of days it takes for the utility to collect debts (receivables) owed to it.

Importance: Assesses the efficiency of debt collection and cash flow management. A lower number of debtor days indicates more efficient collection processes and better cash flow.

Debt to Equity Ratio:

Definition: A financial metric that represents the ratio of total liabilities to equity.

Importance: Assesses the capital structure of the utility and its level of financial leverage. A high ratio suggests the utility relies more on debt financing, which can increase financial risk.

Distribution O&M Expenses per km Line Length:

Definition: Represents the total Operations and Maintenance (O&M) expenses incurred in the operation and maintenance of the distribution network, divided by the length of distribution lines in kilometers. Typically expressed in currency units per kilometer.

Importance: Assesses the cost efficiency of maintaining the distribution infrastructure. Tracking this helps understand the cost of maintaining the distribution network relative to its size.

Distribution Reliability (Events/100 km):

Definition: Measures the frequency of power outages or disruptions in the distribution network per 100 kilometers of distribution lines.

Importance: Quantifies the reliability of the distribution infrastructure and its impact on customers. A lower number of outage events indicates a more reliable distribution network.

Distribution Transformer Utilization Factor (TUF):

Definition: Measures the average load on distribution transformers in relation to their capacity, typically expressed as a percentage.

Importance: Assesses how efficiently distribution transformers are utilized to meet customer demands. Higher utilization generally implies more efficient capital expenditure in transformer capacity.

Earnings Before Interest and Taxes (EBIT) Margin (%):

Definition: A measure of the profitability of a utility's operations after accounting for costs to maintain the utility's asset base, but before accounting for debt and taxes.

Importance: Indicates the profitability of core operations before financing and taxation effects.

Earnings Before Interest, Taxes, Depreciation, and Amortization (EBITDA) Margin (%):

Definition: A measure of the profitability of a utility's operations before accounting for debt, taxes, depreciation, and amortization.

Importance: Provides a view of operational profitability and cash flow generation.

Forced Outage Indicator (%):

Definition: Represents the percentage of unplanned or forced generator outages compared to the total available time.

Importance: Measures the reliability of power plant equipment by quantifying the frequency of unexpected shutdowns. A lower percentage indicates better equipment reliability.

Generation Labor Productivity (GLP):

Definition: Measures the efficiency of labor in the power generation process, often expressed as MWh per employee.

Importance: Helps evaluate workforce efficiency in power generation and assess whether the production team is appropriately sized.

Generation O&M Costs per MWh:

Definition: Represents the total O&M expenses incurred in generating electricity, divided by the total electricity generated, typically expressed in currency units per MWh

Importance: Provides insights into the cost efficiency of power generation. Lower costs per MWh generally indicate better efficiency in managing generation expenses.

Generation Planned Outage Indicator (%):

Definition: Represents the percentage of planned outages for maintenance or upgrades of generators compared to the total available time.

Importance: Assesses the proactive maintenance and downtime scheduling of power plants. A balanced indicator suggests appropriate maintenance scheduling to prevent unexpected breakdowns.

Independent Power Producer (IPP) Generation (%):

Definition: Represents the percentage of electricity generation contributed by IPPs compared to the total generation.

Importance: Measures the share of power generated by third-party entities in the utility's supply mix. This can be relevant for understanding the utility's reliance on external power sources.

Load Factor (LF):

Definition: The ratio of the average load demand to the peak demand over a specific period, often a year.

Importance: Measures the usage of production capacity and indicates the balance between average and peak loads. A higher load factor generally indicates more efficient use of generation capacity.

Lost Time Injury Duration Rate (Days):

Definition: Measures the average duration of time lost per employee due to work-related injuries that result in lost working hours.

Importance: Quantifies the amount of time employees are unable to work due to injuries and provides insights into workplace safety and health. Lower duration rates indicate better safety performance.

Lost Time Injury Frequency Rate (LTIFR) (Number of Incidents per Million Hours):

Definition: Measures the frequency of work-related injuries that result in lost working hours per million hours worked by employees.

Importance: Assesses the rate of injury incidents in the workplace, helping evaluate safety performance. Lower frequency rates indicate a safer work environment.

Network Delivery Losses (%):

Definition: Represent the percentage of electricity lost during the delivery of electricity from distribution substations to end-users, including technical and non-technical losses.

Importance: Reflects the efficiency of the distribution network in delivering electricity to customers and highlights areas where losses can be reduced.

Operating Cost Recovery (%):

Definition: Measures the percentage of a utility's operating costs recovered through the revenue the utility earns.

Importance: Assesses the financial sustainability of a utility's operations. A recovery rate of 100% or higher indicates that the utility is covering its operating expenses.

Operating Ratio (%):

Definition: A financial metric that assesses the efficiency of the utility's operations by comparing the costs of goods and services (excluding depreciation) to the revenue earned.

Importance: Indicates how efficiently a business is operating in providing electricity service. An operating ratio below 100 indicates a profitable operation.

Overall Labor Productivity:

Definition: Measures the efficiency of the workforce by evaluating the number of customers served per employee.

Importance: Assesses the productivity of the entire workforce in providing services to customers.

Planned System Average Interruption Duration Index (SAIDI) (Minutes/Customer):

Definition: Measures the average duration of planned power interruptions per customer in minutes, calculated separately for transmission and distribution networks.

Importance: Quantifies the planned downtime experienced by customers on average due to scheduled outages for maintenance or upgrades.

Planned System Average Interruption Frequency Index (SAIFI) (Events/Customer):

Definition: Measures the average number of planned power interruptions per customer, calculated separately for transmission and distribution networks.

Importance: Quantifies the number of planned outages experienced by customers on average.

Profit Margin (%):

Definition: Measures the profitability of a utility's operations, inclusive of all costs.

Importance: Represents the overall profitability of the utility after all expenses.

Power Station Usage or Station Auxiliaries (%):

Definition: Represents the percentage of power generated that is used for station auxiliary systems.

Importance: Quantifies the proportion of electricity consumed for internal plant operations. Lower usage indicates greater efficiency in internal consumption.

Renewable Energy to Grid (%):

Definition: Represents the percentage of electricity generated from renewable energy sources compared to the total electricity supplied to the grid.

Importance: Assesses the contribution of renewable energy to the overall energy mix, reflecting the utility's progress towards sustainability goals.

Return on Assets (ROA) (%):

Definition: A financial indicator that measures the return generated from the utility's investment in its assets.

Importance: Indicates how efficiently management uses its assets to generate earnings. Higher ROA suggests better asset utilization.

Return on Equity (ROE) (%):

Definition: A financial metric that measures the financial returns on the owners' funds invested in the utility.

Importance: Assesses the profitability and performance of the utility in generating returns for its shareholders.

Specific Fuel Consumption for Diesel Fuel Oil (DFO) (kWh/liter):

Definition: Measures the amount of DFO required to generate a unit of electricity.

Importance: Assesses the fuel efficiency of diesel power generation. Higher kWh per liter values indicate better fuel efficiency.

Specific Fuel Consumption for Heavy Fuel Oil (HFO) (kWh/liter):

Definition: Measures the amount of HFO required to generate a unit of electricity.

Importance: Evaluates the fuel efficiency of power generation using HFO. Higher kWh per liter values indicate better fuel efficiency.

Specific Lubricating Oil Consumption (kWh/liter):

Definition: Measures the amount of lubricating oil consumed per unit of power generated.

Importance: Assesses the **efficiency of lubrication systems** in power generation equipment. Higher kWh per liter values indicate better efficiency.

Tariff Impact (USD):

Definition: Refers to the effect of the utility's tariff structure on different customer categories by calculating monthly bills for varying consumption levels.

Importance: Assesses how the utility's pricing policies impact the size of monthly bills for residential, commercial, and industrial customers. This helps understand affordability and tariff competitiveness.

Transmission Losses (%):

Definition: The percentage of electrical energy lost during the transmission of electricity.

Importance: Measures the efficiency of the transmission system in delivering power from generation sources to distribution substations. Lower losses indicate a more efficient transmission network.

Transmission Reliability (Outages per 100 km):

Definition: Measures the frequency of power outages or disruptions in the transmission network per 100 km of transmission lines.

Importance: Assesses the reliability and resilience of the transmission infrastructure. A lower number of outages per 100 km indicates a more reliable transmission system.

Unplanned SAIDI (Minutes/Customer):

Definition: Measures the average duration of unplanned power interruptions experienced by customers in minutes, calculated separately for transmission and distribution networks.

Importance: Quantifies the average amount of time customers are without electricity. Lower SAIDI values indicate better service reliability.

Unplanned SAIFI (Events/Customer):

Definition: Measures the average number of unplanned power interruptions experienced by customers, calculated separately for transmission and distribution networks.

Importance: Quantifies the average number of power outage events per customer. Lower SAIFI values indicate fewer service interruptions.

Utility Cost Breakdown (%):

Definition: Provides a detailed breakdown of the various cost categories incurred by the utility in its operations.

Importance: Helps analyze and understand the composition of the utility's expenses, such as fuel, O&M, labor, and other costs. This allows for identifying areas where cost management efforts can be focused.

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