EAS

ENERGY AUTHORITY SURINAME

ELECTRICITY SECTOR PLAN

Volume III – Regulatory Plan

May 2025

CASTALIA

GRID ADVISORS

Electricity Sector Plan

Volume III – Regulatory Plan

May 2025

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Abbreviations and acronyms

AHFP	Afobaka Hydro Power Facility
ANGLEC	Anguilla Electricity Company Limited
APUA	Antigua Public Utilities Authority
BEL	Belize Electricity Limited
BELCO	Bermuda Electric Light Company Limited
BLPC	Barbados Light & Power Company
BPL	Bahamas Power & Light Company
Btu	British thermal units
BVIEC	British Virgin Islands Electricity Corp.
CAIDI	Customer Average Interruption Duration Index
CAPEX	Capital Expenditure
CARILEC	The Caribbean Electric Utility Services Corporation
CC	Connection Code
CRM	Customer Relationship Management
CUC	Caribbean Utilities Company Ltd.
DOMLEC	Dominica Electricity Services Limited
EAS	Energy Authority of Suriname
EBITDA	Earnings before Interest, Taxes, Depreciation, and Amortization
EBS	Energie Bedrijven Suriname
EIMS	Energy Information Management System
ELMAR	N.V. Electriciteit-Maatschappij Aruba
ENIC	Energie Voorziening Nickerie
EoI	Expression of Interest
EPAR	Energie Voorziening Paramaribo
EPP	Environmentally preferable purchasing
ESP	Electricity Sector Plan
ETL	Extract, Transform, and Load
FIT	Feed-In Tariff
GBPC	Grand Bahama Power Company
GDP	Gross Domestic Product

GDPR	General Data Protection Regulation
GHG	Greenhouse gases
GPL	Guyana Power & Light Inc.
GRENLEC	Grenada Electricity Services Limited
GWh	Gigawatt-hour
HFO	Heavy Fuel Oil
Hm3	Cubic hectometers
HR	Human resources
HSEQ	Health, safety, environment, and quality
HV	High Voltage
IDB	Interamerican Development Bank
IEA	International Energy Agency
IPP	Independent Power Producer
JPS	Jamaica Public Service
km	Kilometer
KPI	Key Performance Indicators
kVArh	kilovolt-ampere reactive hour
kW	Kilovolt
kWh	kilowatt-hour
LUCELEC	St. Lucia Electricity Services Ltd.
LV	Low Voltage
MNH	Ministry of Natural Resources
MST	Magnetic secure transmission
MUL	Montserrat Utilities Limited
MV	Megavolt
MVA	Megavolt-ampere
MW	Megawatt
MWh	Megawatt-hour
NEVLEC	Nevis Electricity Company Ltd.
NFC	Near-field communication
NGO	Non-governmental organization
O&M	Operations and Maintenance

OPEX	Operating Expenditures
PPA	Power Purchase Agreement
PV	Photovoltaic
QR reader	Quick response reader
RAB	Regulated Asset Base
RE	Renewable Energy
RFP	Request for Proposal
RGM	Rosebel Gold Mine
RICE	Reciprocating Internal Combustion Engines
SAIDI	System Average Interruption Duration Index
SAIFI	System Average Interruption Frequency Index
SCADA	Supervisory Control and Data Acquisition
SDGs	Sustainable Development Goals
SKELEC	St. Kitts Electricity Company Ltd.
SLA	Service level agreement
SPCS	Staatsolie Power Company Suriname
SRD	Surinamese dollar
SRMC	Short-Run Marginal Cost
T&D	Transmission and Distribution
T&TEC	Trinidad & Tobago Electricity Commission
UK	United Kingdom
US$	United States dollars
VINLEC	St. Vincent Electricity Services Ltd.
WACC	Weighted Average Cost of Capital
WEB	Water En Energiebedrijf Bonaire N.V.
YPP	Youth Professional Program

1 Introduction

As a statutory requirement,[1] the Electricity Sector Plan (ESP) is a critical element of the reform of Suriname's electricity sector's governance framework, complementing the establishment of the Energy Authority of Suriname (EAS), the implementation of cost-reflective yet affordable tariffs, and the strategic reorganization of the sector. The ESP covers a 20-year long-term strategic view with a 5-year action plan.

The ESP includes:

- **Volume I – Strategic Plan**, which includes a national and international energy sector, and an assessment of the national targets regarding renewable energies, energy efficiency, and energy access.
- **Volume II – Technical Plan**, which provides the electricity demand forecast and expansion plan for Suriname, including an energy efficiency plan, an investment plan for rural electrification, and a tariff/subsidy path.
- **Volume III – Regulatory Plan**, which includes tariff and feed-in tariff methodologies, single-buyer procedures, regulatory accounting rules, performance standards, interconnection rules, subsidy policies, energy efficiency measures, and rural electrification initiatives.

This document is Volume III of the ESP, outlining the Regulatory Plan. The Electricity Act defines the regulatory methodologies that govern the electricity sector. Through the Electricity Act, the Government of Suriname mandates the development of:

- **Single buyer procedures**—The Electricity Act grants single buyer and retailer responsibilities to the Electricity Company, an entity that will be unbundled from what is currently N.V. Energie Bedrijven Suriname (EBS).[2,3] The Act mandates the creation of single buyer procedures to incorporate new generation capacity into the National Grid. The Electricity Sector Plan (ESP) will provide guidance on procedures for selecting, tendering, and procuring utility-scale renewable energy.[4] Section 2 describes the single buyer procedures to guide EBS through each step of the procurement process.
- **Electricity tariff methodology**—the ESP must define the methodology for allocating costs and structuring and setting tariffs[5] to help the EAS in the transition towards cost-reflective tariffs. Cost-reflective tariffs ensure that the rates customers pay reflect the cost for the

1 Electricity Act, 2016. Articles 8 to 9.

2 Electricity Act 2016. "Article 10.2-3."

3 EBS will be unbundled into several units, including the Electricity Company (which will oversee transmission and distribution, and the single buyer and retailer functions). Other subsidiary companies will include N.V. EBS Power Company (EPC), N.V. EBS Shared Services, and N.V. Ogane. In addition, C-Level N.V. EBS will oversee management functions.

4 EBS has hired a separate consultant to design renewable energy tenders for solar PV, wind, and biomass projects. The consultant is responsible for establishing the renewable energy tender design elements and drafting the tender documents and draft Power Purchase Agreement (PPA).

5 Electricity Act 2016. "Article 17.5"

utility to supply electricity. This includes the cost of purchasing electricity from Independent Power Producers (IPPs) and investing in, operating, and maintaining generation, transmission, and distribution assets ("cost of service").[6] Section 3 describes the electricity tariff methodology.

- **Regulatory accounting rules** – [To be inserted]
- **Performance standards**— Key performance indicators (KPIs) play a fundamental role in the ESP. They help set the ESP's overarching objective to improve performance in the electricity sector and support the EAS in overseeing its ESP. KPIs allow the EAS to set targets and monitor performance to hold stakeholders accountable. To measure performance against these KPIs, the EAS will collect, track, and analyze data from key actors in the electricity sector. The data will be stored in the Energy Information Management System (EIMS)—an information platform that will collect and process sector data to monitor performance. Section 5 describes the performance standards for the sector.
- **Interconnection rules**—The Electricity Act states that private producers[7] must follow rules and conditions to connect to the National Grid.[8] The Act mandates that a Certification Institution verify the electrical installations to ensure compliance with the interconnection rules and conditions.[9] These interconnection rules include general procedures for the interconnection process, as well as the technical requirements for interconnection to the National Grid (Section 6).
- **Feed-in tariff methodology[10]**—The Electricity Act allows households and businesses to install small-scale renewable energy systems for their own consumption.[11] The Act states that these distributed generation customers will be able to receive compensation for electricity they feed into the National Grid and mandates that the commercial terms for compensation be established in the ESP.[12] These commercial terms must be based on the provisions in the Electricity Act, the tariff structure in the new tariff methodology, and the flows of electricity to and from the distributed generation system. Section 7 describes the

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6 Council of European Energy Regulators. 2017. "Electricity Distribution Network Tariffs CEER Guidelines of Good Practice." https://www.ceer.eu/wp-content/uploads/2024/04/CEER-DS-WG-Best-Practice-Tariffs-GGP-external-publication_final.pdf

7 The Electricity Act defines private producers as "a natural person or legal entity, that generates sustainable electricity for his own consumption and offsets the electricity supplied to the National Grid with his own consumption as Consumer, on conditions and for rates as recorded in the ESP."

Electricity Act 2016. "Article 1(f)."

8 Electricity Act 2016. "Article 20."

9 The Electricity Act mandates that a Certification Institution must be established by Government regulation by 2018. EBS may be appointed as the Certification Institution, but is required to transfer its activities as Certification Institution to a separate business unit.

Electricity Act 2016. "Article 23.1." and Notes to the Act, pg. xvii.

10 Distributed generation customers are also known as *prosumers*.

11 Electricity Act 2016. "Article 20."

12 Electricity Act 2016, Notes to the Act, pg. xvii.

commercial terms (feed-in tariff) for selling electricity from distributed generation customers.

- **Energy efficiency policy**: Section 8 provides a policy and regulatory overview of energy efficiency and distributed generation. It also evaluates the status of the implementation of energy-efficient equipment/appliances and distributed generation.

2 Single buyer procedures

The Electricity Act grants single buyer responsibilities to the Electricity Company (EBS) and mandates the creation of single buyer procedures to incorporate new generation capacity onto the National Grid.[13] The single buyer procedures described below provide guidance on how a single buyer can procure and manage contracts to purchase electricity from independent power producers (IPPs).

There are three types of producers that are eligible to generate electricity: [14]

- **Licensed producer**—A legal entity (or business unit within a legal entity) that generates electricity to supply the National Grid.[15] A licensed producer does not consume electricity beyond what is used in the generation process. Licensed producers generate electricity from renewable sources. Only licensed producers that are state-owned companies may produce electricity from fossil fuels.[16] Staatsolie Power Company Suriname (SPCS) and EBS are the only licensed producers in Suriname.
- **Private producer**:[17] A natural person or legal entity that generates electricity from renewable sources for their consumption (distributed generation customer) and to feed into the National Grid.[18] The Electricity Act does not limit the amount of electricity that private producers can feed into the National Grid but limits the amount of electricity that is eligible for payment from EBS (see Section 7).[19]
- **Producer with a contract with the State**—State-owned companies that generate electricity for the National Grid using hydropower or other generation sources with potentially major social consequences and environmental effects.[20]

As the single buyer, the Electricity Company is responsible for organizing the public tender and providing relevant documentation. The Electricity Company must use efficient and transparent

13 Electricity Act 2016. "Article 10."

14 Electricity Act 2016. "Article 20.1."

15 Electricity Act 2016. "Article 1(d)."

16 Electricity Act 2016. Notes to the Act, pg. xvii.

17 Electricity Act 2016. "Article 20.1(b)."

18 Electricity Act 2016. "Article 1(f)."

19 Electricity Act 2016. "Article 20.4."

20 Article 21 states only state-owned companies can develop hydro power or other renewable generation projects with potentially major social consequences and environmental effects.

Electricity Act 2016. "Article 20.1(c)-21.2."

procedures to select, tender, and procure new generation.[21] The Energy Authority of Suriname (EAS) is responsible for supervising the process.[22]

EBS has hired a separate consultant to design renewable energy tenders for solar PV, wind, and biomass projects. The consultant is responsible for establishing the renewable energy tender design elements and drafting the tender documents and Power Purchase Agreements (PPAs), which will be critical to the single buyer procedures described below.[23]

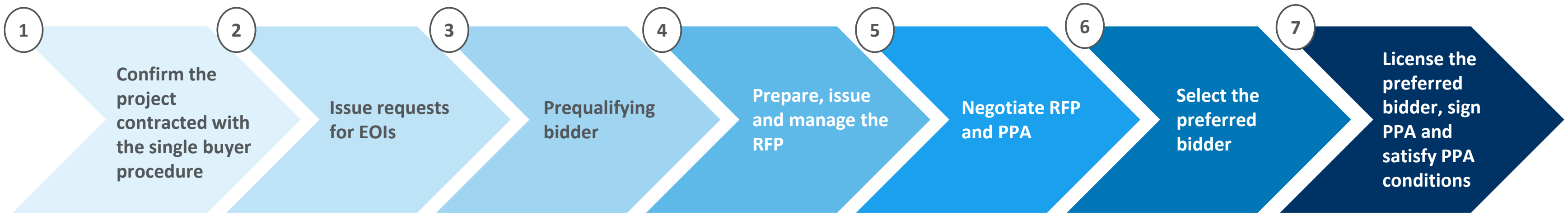
Figure 2.1 below summarizes single buyer procedures for tendering, selecting, and awarding IPPs contracts. Each step is described in the respective subsections below.

[21] Electricity Act 2016. Notes to the Act, pg. xvii.

[22] Electricity Act 2016. "Article 21.1, Article 24, Article 25."
Electricity Act 2016. Notes to the Act, pg. xxi.

[23] EBS. 2023. "Consultancy services to support renewable energy tenders in Suriname."

Figure 2.1: Single buyer procedures



1. Confirm the project contracted with the single buyer procedure

- Review ESP to identify projects that need to be contracted with single buyer procedures (EBS)
- Request "no objection" from EAS for using single buyer procedures (EBS)
- Provide "no objection" to using single buyer procedures (EAS)

2. Issue requests for EOIs

- Prepare request for EOI (EBS)
- Publish request for EOI (EBS)

3. Prequalifying bidder

- Submit EOIs (Bidders)
- Evaluate EOIs and develop a shortlist of prequalified bidders (EBS)
- Notify prequalified bidders they have been shortlisted (EBS)

4. Prepare, issue and manage the RFP

- Prepare draft RFP and request "no objection" from EAS (EBS)
- Provide "no objection" to draft RFP (EAS)
- Prepare draft PPA and request "no objection" from EAS (EBS)
- Provide "no objection" to draft PPA (EAS)
- Send RFP to prequalified bidders (EBS)

5. Negotiate RFP and PPA

- Respond to queries from bidders (EBS)
- Hold bidders' conference (EBS)
- Adjust and negotiate RFP and PPA and request "no objection" from EAS (EBS)
- Provide "no objection" to final version of RFP and PPA (EAS)
- Prepare and submit proposals (Bidders)

6. Select the preferred bidder

- Evaluate proposals submitted by the bidders, select preferred bidder, and request "no objection" from EAS (EBS)
- Provide "no objection" to preferred bidder (EAS)
- Inform bidders of result of proposal evaluation (EBS)

7. License the preferred bidder, sign PPA and satisfy PPA conditions

- License the preferred bidder (Minister responsible for energy)
- Sign the PPA (EBS and the preferred bidder)
- Satisfy all conditions to the PPA becoming effective (EBS, preferred bidder, and others)

2.1 Confirm project to be contracted with single buyer procedures

The ESP will include a 5-year expansion plan outlining the sector's projected generation capacity needs. The expansion plan will specify:

- The approximate capacity and type of generation technology;
- The approximate timing of when the capacity should come online; and
- The approximate location and/or system where the capacity should be added (for example, in EPAR, ENIC, or one of the rural districts).

Additionally, the Electricity Act mandates that EBS prepare a 5-year Quality and Capacity Plan and provide evidence to the EAS at least every two years that this plan is adequate.[24]

The expansion of generation capacity using sustainable electricity for the National Grid must be procured by public tender.[25] This means that renewable sources such as solar and wind projects, for instance, should be awarded to bidders who will become licensed producers through public procurement. Public procurement is meant to encourage competition in utility-scale renewable generation and improve the sector's economic efficiency.[26]

There are exceptions, however. EBS can directly contract state-owned companies that are licensed producers of thermal generation, hydropower, or any other project with potentially major social and environmental consequences.[27] This means that state-owned companies can be exempt from the public procurement process.

EBS should submit a request for 'no objection' to the EAS regarding the method it proposes to use for contracting new generation capacity. In the request for 'no objection,' EBS should specify the capacity (in megawatts), generation type, grid (EPAR, ENIC, or one of the Rural Districts), approximate location, the method of procurement (single buyer procedures or direct contracting), and the approximate date to begin procurement (this will depend on when the capacity is expected to come online and the approximate time required to procure it).

After EBS receives the EAS's 'no objection,' it can proceed to use the single buyer procedures to contract the new generation capacity.

2.2 Issue Requests for Expressions of Interest

Requesting EOIs from potential bidders allows EBS to prequalify bidders based on the technical and financial capability to develop the project.

24 Electricity Act 2016. "Article 15."

25 Electricity Act 2016. "Article 21.1."

26 Electricity Act 2016, Notes to the Act, pg. xvi.

27 The State has the right to procure or generate electricity itself. It also has the right to supply this electricity to the Electricity Company or energy-intensive businesses via the National Grid or other networks, on special conditions and at special rates. Electricity Act 2016. "Article 10.3."

Issuing Requests for EOIs also allows EBS to provide sufficient information to attract interest from credible potential bidders. The information to be provided includes information regarding:

- The size (in MW), technology (for example, solar PV or wind), and location of the project to be contracted;
- The amount of energy (in kWh) and firm capacity (in MW), if any, to be contracted from the project;
- Summary of any preparatory work already undertaken, including any findings related to the project's potential viability;
- The duration, pricing mechanism, and other key aspects of the PPA that will be used to purchase the electricity from the project;
- General information regarding EBS's financial standing; and
- Some basic information regarding the grid to which the project will be connected. This includes peak demand, annual consumption, and composition of the existing generation matrix.

Prequalifying bidders will allow EBS to:

- Receive more comparable proposals—All concerns about capability are resolved before requesting full proposals;
- Reduce costs in reviewing proposals—EBS will only review full proposals from bidders that it already knows have the necessary technical and financial capability; and
- Incentivize bidders to invest more effort into their proposals and focus on price competitiveness—Bidders will put more time into their proposals if they already know they have the capabilities that EBS is looking for. Additionally, when bidders know that all their competitors have also been prequalified, it shifts the focus of their proposals towards price competitiveness. This is because the opportunity to leverage a bidder's extensive experience as a justification for a higher price is significantly reduced.

For the first project to be contracted using single buyer procedures, EBS should develop a template for the Request for EOIs in accordance with the Renewable Energy Tender Framework. Once EBS has developed the template and has a clear understanding of the project to be contracted, it should take approximately 2 weeks for EBS to develop a Request for EOIs for the project.

2.3 Pre-qualify bidders

Once bidders submit EOIs, EBS should prequalify them by evaluating the EOIs it has received. The evaluation will ensure that the prequalified bidders have the technical and financial capability to complete the project. EBS should establish a technical committee to evaluate the EOIs.

In the evaluation of the EOIs, the technical committee should seek to strike the right balance between ensuring only serious bidders move to the next phase and not wanting to restrict competition for the project.

This means that the shortlist of prequalified bidders should include no less than three and no more than six companies. Shortlisting less than three firms could result in only one bidder. In contrast, shortlisting more than six firms could provide less incentive for the firms to bid since the probabilities of winning are lower.

For most projects, EBS should be able to evaluate the EOIs and develop a shortlist of prequalified bidders within 15 working days. EBS should then notify all prequalified bidders that they have been prequalified.

2.4 Prepare, issue, and manage the RFP

The next step in the single buyer procedures is for EBS to send the RFP to the prequalified bidders. The RFP should provide the following:

- Output specifications;
- Instructions to bidders;
- Evaluation criteria for assessing proposals;
- The draft PPA; and
- Proposal templates.[28]

These elements are described in more detail below.

Output specifications

The output specifications should be detailed enough so that any proposal that satisfies these requirements meets the identified generation and/or capacity need. These specifications must include:

- The power requirement of the proposed generator plant (that is, the required capacity in MW). This would also include the expected MWh of electricity that the proposed plant would generate annually;
- The expected capacity factor of the proposed plant;
- The feed-in location of the National Grid;
- The minimum energy efficiency values required;
- The nature of the primary energy sources to be used for the project; and
- The expected lifetime of the project.[29]

[28] EBS has hired a separate consultant to design renewable energy tenders for solar PV, wind, and biomass projects. The ongoing consultancy related to designing the RE tendering framework is expected to cover and draft each of these elements. These elements are expected to be complete by March 2025

[29] Electricity Act 2016. "Article 21.3."

Instructions to bidders

The instructions to bidders set out the legal rules that operationalize the procurement process—that is, how bidders can expect the procurement process to be run. The instructions also set out what the bidders' proposals are expected to include, which often include the bidder's technical proposal, the proposed cost, and a markup of the draft PPA.

Evaluation criteria for assessing proposals

EBS must clearly communicate the criteria it will use to assess proposals to maximize the quality of the submitted proposals and minimize the risk of legal disputes. According to Article 21 of the Electricity Act, these criteria should include the applicant's technical, economic, and financial capability and experience, the capacity factor of the proposed plant, the environmental and social impacts and proposed mitigation measures, and minimum energy efficiency standards.[30]

EBS should aim to select the bidder that is most competent and offers the lowest price. The proposed approach for selecting the preferred bidder is the "technical threshold, best financial score" approach. Under this approach, bidders' proposals are first assessed on whether their technical proposal meets the output specifications. For bidders that pass the technical threshold, their financial bids are then opened, and the bid with the best financial score (typically the lowest cost or the most favorable financial terms) is selected as the winning bid. This approach maximizes competition on price, is the most objective and transparent to apply, and is the least open to legal challenge.

The draft PPA

EBS shall include a draft PPA as part of the tendering documents, using the template PPA of the Renewable Energy Tender Framework.[31] At a minimum, the draft PPA should include the following terms:

- Output specifications—The project's capacity and the expected annual generation in MWh;
- Monitoring and enforcement arrangements—EBS's way of checking that the developer is doing as it promised, and the tools for making sure that it does;
- Payment mechanisms—How and when EBS will pay for the generation services;
- Mechanism to respond to changing external circumstances—How the two parties allocate the risk of events occurring that will affect the commercial viability of the project in ways the parties did not contemplate;
- Dispute resolution mechanisms—How to resolve problems if they arise;
- Termination provisions—The circumstances in which the contract ends naturally, how either party can bring the agreement to an end early, and what the parties agree to do if early termination occurs (for example, compensate the other); and

[30] Ibid.

[31] Electricity Act 2016, Notes to the Act, pg. xx.

- Other obligations—EBS may also have other responsibilities as part of the project, such as ensuring the relevant assets are in place to deliver electricity to the grid.

EBS should request 'no objection' from the EAS for the draft PPA. The EAS should review the draft PPA against the Renewable Energy Tender Framework and provide its opinion within 15 working days of receiving the request from EBS.

Proposal templates

The proposal templates are the forms that the prequalified bidders will use to prepare their proposals. For example, there will be standard forms the bidders use to present their financial information, information regarding similar projects they have completed, and information detailing the capabilities of their management team.

EBS should request 'no objection' from the EAS for the final version of the RFP it will send to the prequalified bidders. The EAS should review the RFP against the Renewable Energy Tender Framework and provide its opinion within 15 working days of receiving the request from EBS.

After the EAS has provided its 'no objection,' EBS should send the RFP to the prequalified bidders.

2.5 Negotiate final version of the RFP and PPA

During the tendering process, EBS can make changes to the draft PPA and other components of the RFP if all bidders are informed about them.[32] Whenever a bidder has questions or requests clarification of the RFP, EBS must send its response to *all* bidders to ensure they all have access to the same information.

To maximize the benefits of its engagement with the bidders, EBS should consider:

- Holding scheduled meetings soon after releasing the RFP to discuss the documents with bidders and answer their queries with all bidders in attendance;
- Permitting bidders to conduct due diligence on the project; and
- Answering bidders' questions and requests for clarification as they arise.

After EBS has negotiated the final version of the RFP and the PPA with the prequalified bidders, it should request a 'no objection' from the EAS. The EAS should review the RFP and PPA against the Renewable Energy Tender Framework and provide its opinion within 30 working days. After receiving the 'no objection' from the EAS, EBS should then send the final versions of the RFP and the PPA to the prequalified bidders.

2.6 Select the preferred bidder

EBS should evaluate proposals and identify the preferred bidder by strictly following the evaluation process set out in the RFP. To evaluate proposals, EBS must:

[32] Electricity Act 2016, Notes to the Act, pg. xx.

- Check whether proposals are valid, including all necessary documents and content required by the RFP;
- Confirm bidders' qualifications to check that pre-qualified bidders still meet the technical and financial pre-qualification criteria;
- Evaluate bidders' technical proposals to determine whether they meet the output specifications and give them a technical score based on the evaluation criteria in the RFP;
- Evaluate bidders' financial proposals to determine bidders' financial scores based on the evaluation criteria in the RFP; and
- Rank conforming proposals and identify the preferred bidder, based on the selection process set out in the RFP.

While EBS will ideally negotiate and sign the PPA with the preferred bidder, there is always the risk that this does not happen. EBS should ensure that other bidders are available should negotiations fail with the preferred bidder. This is usually done through an express requirement in the RFP that proposals should be valid for a period of, for example, 180 days.

EBS should document the evaluation process thoroughly and prepare an evaluation report showing how the selection criteria were applied and the basis on which the preferred bidder was selected. The evaluation report is to ensure transparency in the evaluation. EBS should submit the evaluation report upon the request of EAS and bidders. This will help EBS ensure it complies with Article 21 of the Electricity Act and the tender process defined. It also provides evidence of the robustness of the process in case EBS needs to respond to any legal challenges by aggrieved bidders who were not ranked as the preferred bidder.

After selecting the preferred bidder, EBS should request the 'no objection' from the EAS for awarding the project to that bidder. Within 15 working days of receiving the request, the EAS should provide its 'no objection,' notify EBS of any reasons for which it cannot provide its 'no objection,' or request any additional information it may need. If the EAS does not provide its 'no objection,' EBS will have 30 days to respond to the EAS's notification by providing any additional information or justification as required. The EAS will then have 15 days to issue its 'no objection' or to notify EBS that it must select another bidder. The EAS's decision must be based strictly on any provisions in the Electricity Act and on the Renewable Energy Tender Framework. This same process will apply until the EAS provides its 'no objection' to awarding the project to one of the bidders.

After it has received the 'no objection' from the EAS, EBS should notify all bidders of the outcome of the tender process.

2.7 License the preferred bidder, sign the PPA, and satisfy PPA conditions

Once EBS has selected the preferred bidder, there are three steps before the developer starts work:

- **Step 1: License the preferred bidder**: The Minister[33] must grant the license to the preferred bidder.[34]
- **Step 2: Sign the PPA**: Sign the PPA within the timeframe established therein.
- **Step 3: Satisfy all conditions for the PPA to become effective:** The preferred bidder and EBS must complete other arrangements they need to make before work can commence on the project. For example, these arrangements can include:
  - Finalizing and executing all related contracts, including obtaining committed financing;
  - Securing final approval from relevant government entities;
  - Securing permits and planning approvals; and
  - Commencing or completing the process of acquiring the project land.

The EAS should closely monitor the process and ensure that EBS (and the public sector more broadly) fulfills its obligations promptly. EBS should also monitor the risk that the conditions are not satisfied and consider whether negotiations with the second-ranked bidder must commence. EBS should ensure that it obtains legal advice on satisfying the conditions and the circumstances in which it begins negotiations with the preferred bidder.

3 Electricity tariff methodology

3.1 Best practice principles for tariff-setting and regulation

The Electricity Act defines guiding principles for setting cost-reflective tariffs. The tariffs should:

- Allow EBS to recover the efficient costs for the procurement, transmission, distribution, and retail of electricity,[35] as well as a permitted margin on capital invested in assets;[36]
- Reflect the difference in costs incurred per customer type;[37] and
- Include a connection fee based on the efficient cost of establishing the physical connection of the installation.[38]

In addition to the principles set in the Electricity Act, the following principles should guide a cost-reflective tariff-setting methodology. Tariffs should:

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[33] Article 1(a) of the Electricity Act 2016 defines Minister as “the Minister responsible for the energy sector.”

[34] Electricity Act 2016. “Article 21.4.”

[35] Electricity Act 2016. “Article 17.1”

[36] Electricity Act 2016. “Article 17.2”

[37] Electricity Act 2016. “Article 17.3”

[38] Electricity Act 2016. “Article 18”

- **Reflect the short-run marginal cost (SRMC) by the time of day[39] to incentivize efficient generation and consumption of electricity**. The SRMC represents the cost of supplying an additional unit of electricity. In a conventional power system, the SRMC is usually the cost of the marginal generator, that is, the generator that supplies the last kWh needed to meet demand. The charge would be higher at peak times to reflect the investment cost in generation capacity to meet peak demand. If tariffs reflect the SRMC, consumers are likely to shift consumption to when the SRMC is lower and reduce consumption when the SRMC is higher (for example, during peak time), resulting in an efficient allocation of resources. Table 3.1 describes the advantages and disadvantages of cost-based tariffs and those of revenue-based tariffs.
- **Include a mechanism to recover the cost of renewable energy (RE) generation**. Tariffs should allow the utility to recover the upfront capital cost in generation assets. The upfront capital cost is the majority of the cost associated with RE generation, while operating costs are close to zero.[40] The SMRC of RE generation is close to zero because the resources needed to run the plants (such as solar and wind) are free when available, so it does not cost more to generate an additional unit of electricity. Likewise, hydro generation has near-zero SRMC when water is available, or when the reservoir of a storage hydro plant is full.[41] If the SRMC is near zero when there is RE generation, tariffs reflecting the SRMC will also be near zero. Without a mechanism to recover the cost of RE generation, tariffs will not allow the utility to recover the upfront capital cost of investing in RE generation or the cost of purchasing generation from RE IPPs. Mechanisms to recover the cost of RE generation include, for example, a pass-through reflecting the cost of generation purchased from RE IPPs or distributed energy customers or a tariff reset wherever significant RE generation is commissioned.[42]
- **Incentivize efficient investment in distributed generation**. Regulation of distributed generation should:
  - Discourage investment when its installation and operating costs across its life exceed its lifecycle benefits;
  - Ensure profits of utilities do not fall as customers switch to distributed generation, compared to profits without it; and
  - Ensure the safety of the power system is maintained as a growing number of distributed generation systems connect to the grid.

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[39] Caribbean Development Bank. 2023. "The Minimum Regulatory Function for the Electricity Sector in Caribbean Countries."

[40] The upfront capital cost of thermal generation is relatively low compared to renewables, but operation and maintenance (O&M) costs are relatively higher because of fuel costs.

[41] The SRMC of storage hydro can, however, increase in a wholesale market when water levels are low due to the opportunity cost of generating now or generating and selling later when market prices are higher. See: Huisman et al. 2014. "Hydro reservoir levels and power price dynamics. Empirical insight on the nonlinear influence of fuel and emission cost of Nord Pool day-ahead electricity prices." In Journal of Energy and Development 40(1-2). https://nmbu.brage.unit.no/nmbu-xmlui/bitstream/handle/11250/2577473/JOEED%2B2015%2B%2528003%2529.pdf?sequence=1&isAllowed=y

[42] Caribbean Development Bank. 2023. "The Minimum Regulatory Function for the Electricity Sector in Caribbean Countries."

For this, the tariff structure should contain:

- One or several fixed charges, to ensure EBS's customers who own an interconnected distributed generation system ("distributed generation customers") pay their share of fixed costs (as they still use EBS's transmission and distribution system when their system is not generating); and
- A feed-in tariff (FIT) set at the avoided cost of generation at the time of sale, to ensure that total system costs do not increase as EBS's customers switch to distributed generation.

Additionally, the framework for distributed generation should define capacity limits, such as a cap on the size of the distributed system or a cap on the total capacity of distributed generation that can connect to the grid. The framework should also include contracts with minimum FIT duration to provide revenue predictability to distributed generation customers.[43] Section 7 explains the recommended regulation and tariff mechanisms for distributed generation and Appendix A explains the business models that utilities can adopt to adapt to increasing distributed generation.

- **Be established for a multi-year regulatory period**, in line with the Electricity Act's requirement to update the ESP every 5 years.[44]

Table 3.1: Cost-based tariffs and revenue-based tariffs: Advantages and disadvantages

	Description	Advantages	Disadvantages
Cost-based tariffs	Tariffs are set to recover the efficient cost of service	▪ Helps ensure that utility recovers its costs and has financial stability ▪ Incentivizes utility to invest in infrastructure needed for delivering service at required standards	▪ Does not incentivize utility to minimize costs ▪ Risks overinvestment in unnecessary infrastructure as the utility is guaranteed to recover its costs
Revenue-based tariffs	Tariffs are set so that the utility achieves a revenue target (typically defined by the regulator)	▪ Incentivizes utility to minimize costs ▪ Can be easier to set than cost-based tariffs	▪ Risk that utility underinvests in infrastructure

Beyond principles for cost-reflectiveness, a tariff-setting methodology should also be guided by the following principles:

[43] Caribbean Development Bank. 2023. "The Minimum Regulatory Function for the Electricity Sector in Caribbean Countries."

[44] Electricity Act. 2016. "Article 8"

- Fairness: Tariffs should not burden low-income households disproportionately compared to higher-income households;[45]
- Simplicity: Tariffs should be easy to understand and implement, as far as practicable, for both the regulator and customers;[46]
- Stability: The tariff-setting methodology should not be subject to frequent changes to maintain regulatory certainty and predictability for the sector stakeholders;[47] and
- Transparency: The tariff-setting methodology should be open, clear, and accessible to stakeholders.[48]

Regulators must prioritize certain principles as there are inherent trade-offs. For example, locational marginal tariffs improve cost-reflectiveness as they reflect the cost of supplying electricity in a specific location. However, this can reduce simplicity and fairness, as customers in rural regions—where supply costs are higher and incomes are often lower—may end up paying significantly more for electricity than those in urban areas.

3.2 Steps of EAS's tariff methodology

The Tariff Methodology used by the EAS should reflect the guiding principles defined in Section 3.1. A cost-reflective tariff-setting methodology typically consists of five steps explained in **Error! Reference source not found.**.

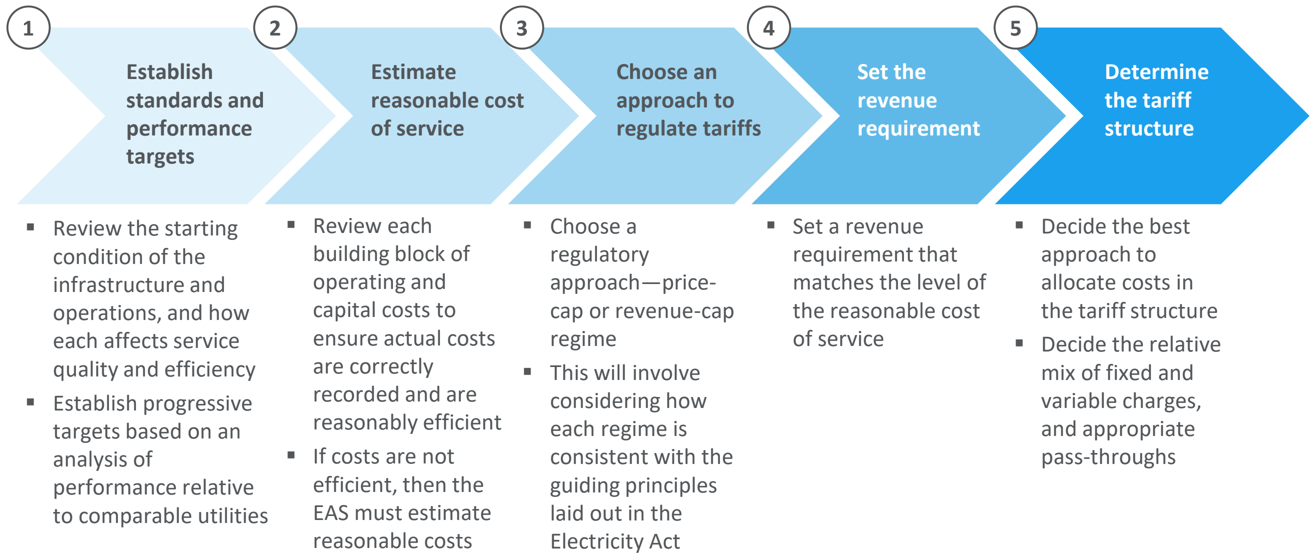
[45] Covington et al. 2024. "Method for evaluating fairness of electricity tariffs with regard to income level of residential buildings," in Applied Energy Volume 353, Part B. https://www.sciencedirect.com/science/article/abs/pii/S0306261923014940

[46] Council of European Energy Regulators. 2017. "Electricity Distribution Network Tariffs CEER Guidelines of Good Practice." https://www.ceer.eu/wp-content/uploads/2024/04/CEER-DS-WG-Best-Practice-Tariffs-GGP-external-publication_final.pdf

[47] Reneses et al. 2014. "Distribution pricing: theoretical principles and practical approaches" https://ietresearch.onlinelibrary.wiley.com/doi/10.1049/iet-gtd.2013.0817

[48] Council of European Energy Regulators. 2017. "Electricity Distribution Network Tariffs CEER Guidelines of Good Practice."

Figure 3.1: Steps of cost-reflective tariff-setting methodology



This Tariff Manual covers steps 2 to 5. Step 1 is covered in Section 5, which assesses the baseline performance of Suriname's electricity sector, defines key performance indicators (KPIs), and sets minimum supply standards and KPI targets against which the EAS will assess the sector's performance. Setting standards and targets is key to tariff-setting as it provides the basis for EBS to plan and make the investments necessary to meet these requirements, which is then recovered through tariffs.

This section explains how the EAS implements each step based on the review of the EAS's Excel-based tariff tool:[49]

- The EAS estimates the reasonable cost of service, comprising operating expenditures (OPEX), depreciation, and return on investment. This indicates that the EAS uses the building blocks approach (Section 3.2.1);
- The EAS follows a cost-of-service regulation approach to setting tariffs. Section 3.2.2 explains why another approach might be more suitable for Suriname;
- The EAS determines the revenue requirement by deducting revenue from electricity sales to Rosebel Gold Mines (RGM) and connection fees paid by customers from the revenue requirement (Section 3.2.3);
- The EAS allocates fixed and variable costs across customer categories (Section 3.2.4); and

[49] EAS. 2024. "Tarievenmodel - FINAL aangepast met branstofprijzen forecast 2024 jan 18 EAS.xlsx" Shared by the EAS with the Castalia-Grid Advisors Team in August 2024.

- The EAS determines the tariff structure, including fixed and variable charges (Section 3.2.5).

3.2.1 Estimate the reasonable cost of service

The reasonable cost of service reflects the expenses (or building blocks) that EBS incurs to provide electricity services efficiently to customers. EBS's cost of service is made of the following building blocks:[50,51]

- **Operating expenditures**, which cover all costs associated with EBS's core operations: the cost of generation from EBS-owned assets, electricity purchases from IPPs, and other costs of operating and maintaining generation, transmission, and distribution assets;
- **Depreciation**,[52] which refers to the cost incurred by using up the value of EBS' assets for supplying electricity. The depreciation expense for an asset is determined by allocating the original investment cost to accounting periods over the asset's operational lifetime. The depreciation expense is added to the cost of service once the corresponding asset is operational. Adding the depreciation expense to the cost of service allows the utility to earn the funds required for the repayment of capital borrowed to invest in the assets. The depreciation expense allocated in each accounting period is logged on the utility's income statement, while the remaining unallocated amount, the "net asset value," is logged as an asset in the utility's balance sheet;[53] and
- **A return on investment**,[54] which is an allowance for the recovery of capital invested by EBS, typically calculated by multiplying the regulatory asset base by the allowed rate of return.[55]

The estimated reasonable cost of service represents EBS's revenue requirement. As illustrated in Figure 3.2, the revenue requirement should enable EBS to expand access and increase the quality of service to meet its minimum supply standards and KPI targets (see Section 5).

The building block approach that the EAS uses is consistent with best practice for forecasting the cost of service and calculating the revenue requirement for regulatory purposes. Regulators in

50 Taxes are typically a building block, but are not discussed in this Volume as EBS is exempt from paying corporate taxes.

51 USAID. 2021. "Depreciation expense: A primer for regulators." https://pubs.naruc.org/pub.cfm?id=6ADEB9EF-1866-DAAC-99FB-DBB28B7DF4FB

52 Depreciation is also referred to as "return of investment."

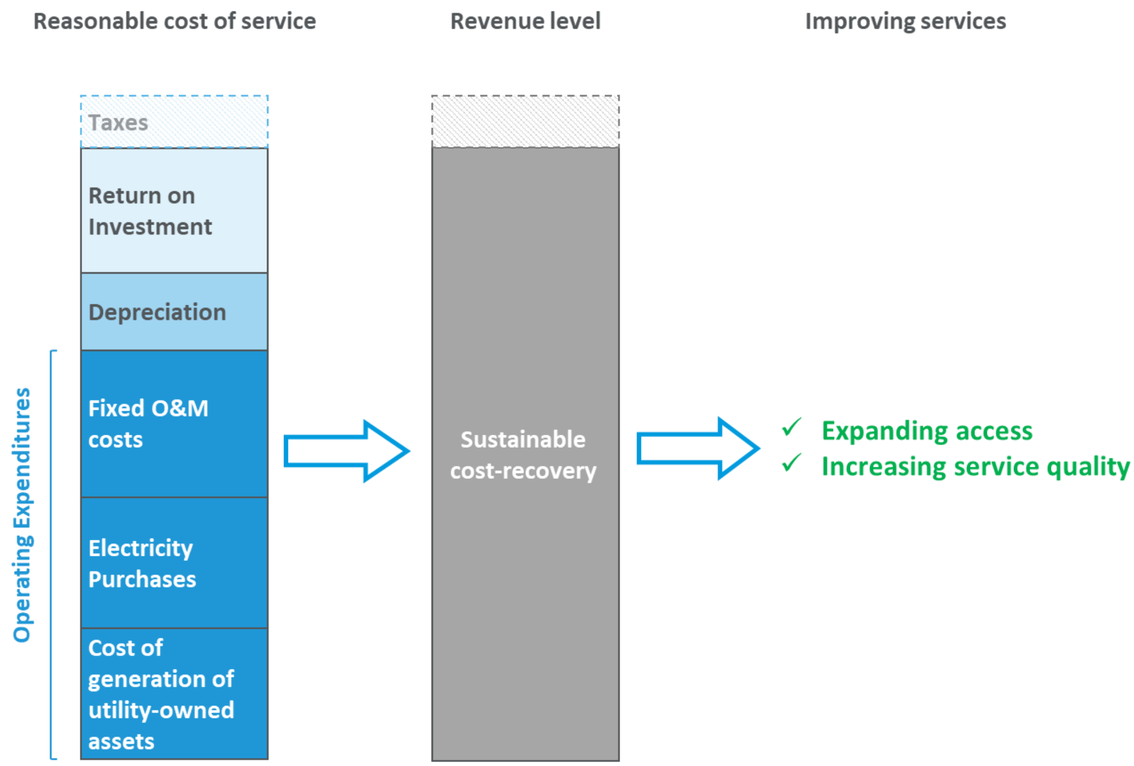
53 USAID. 2021. "Depreciation expense: A primer for regulators." https://pubs.naruc.org/pub.cfm?id=6ADEB9EF-1866-DAAC-99FB-DBB28B7DF4FB

54 Electricity Act 2016. "Article 17"

55 Australian Energy Regulator. 2017. "Consumer information session: Building Block Model." https://www.aer.gov.au/system/files/AER%20information%20session%20one%20-%20Overview%20of%20building%20block%20framework%20-%2030%20November%202017.pdf

Jamaica,[56] Australia,[57] the United Kingdom (UK),[58] as well as a majority of regulators in the European Union,[59] for example, use this approach.

Figure 3.2: Relationship between the reasonable cost of service, revenue levels, and improving service



Note: In principle, taxes are included in the calculation of the cost of service but do not apply in Suriname as EBS is not subject to corporate taxation.

In the tool, the EAS uses the IMF exchange rate to convert USD to SRD. To be consistent with S.B. 2024 No. 41, the EAS should use the Suriname Central Bank's USD/SRD exchange rate and update the exchange rate in the model quarterly, using the average exchange rate of the previous quarter.

56 OUR. 2023. "JPS' 2023 Annual Tariff Review Determination Notice." https://our.org.jm/document/jps-2023-annual-tariff-review-determination-notice/

57 Parliament of Australia. "Overview of the regulatory framework and revenue determination process." https://www.aph.gov.au/Parliamentary_Business/Committees/Senate/Environment_and_Communications/Electricity_and_AER/~/media/Committees/ec_ctte/Electricity_and_AER/Interim_Report/c03.pdf

58 Ofgem. 2020. "Consultation. RIIO-2 Draft Determinations – Core Document." https://www.ofgem.gov.uk/sites/default/files/docs/2020/07/draft_determinations_-_core_document_redacted.pdf

59 ACER. 2018. "Methodologies and parameters used to determine the allowed or target revenue of gas transmission system operators (TSOs)." https://www.acer.europa.eu/sites/default/files/documents/Publications/Consultant%20Report.pdf

Operating expenditures

OPEX comprise of:

- The cost of electricity generated by EBS-owned assets;
- The cost of electricity purchased under the take-or-pay Power Purchase Agreements (PPAs) between the Government and Staatsolie Power Company Suriname N.V. (SPCS) for heavy fuel oil (HFO) and hydro generation; and
- Fixed operations and maintenance (O&M) costs.

These are explained in more detail below.

Cost of generation of EBS-owned assets

The EAS calculates the total generation cost of EBS-owned plants (DPP1 and DPP2) for each system (EPAR, ENIC, and the rural districts) based on:

- A base price, indexed on the price of fuel for thermal generation (DPP1, DPP2, ENIC, and the rural districts) by multiplying the base price with the ratio of the average Staatsolie oil price over three months and a reference oil price. It is unclear what source the EAS uses for the reference oil price;
- The O&M cost; and
- Total energy generated, including losses.

Electricity purchases

For SPCS HFO purchases, the PPA stipulates a minimum energy output of 443,700MWh per year[60] and a monthly per MWh price set based on:[61]

- A fixed cost of US$40 per MWh, which covers non-fuel operations and maintenance costs (US$10 per MWh) and capital costs and margin (US$30 per MWh); and
- The variable cost of fuel and lubricants. The fuel cost is determined in the fuel supply contract between the Government and Staatsolie. The quantity of fuel assumed to be used for thermal generation is determined based on a fuel efficiency factor rather than the actual amount of fuel used. However, the PPA is currently under review, and one of the proposed modifications is to amend the PPA so that the actual amount of fuel used is paid for.

The EAS calculates the total annual cost of SPCS HFO purchases by first multiplying the fixed cost per MWh by the minimum energy output. It then multiplies the fuel cost per MWh by the actual generation output. The fuel cost per MWh is determined using a fuel efficiency factor of 1.38 barrels per MWh and the average Staatsolie oil price over a 3-month period. Finally, the EAS adds the total fixed costs and total fuel costs to arrive at the total annual cost of SPCS HFO purchases.

60 IMF-Fiscal Affairs Department, 2023. "Suriname: Reforming Electricity Subsidies."

61 Government of Suriname. 2013. "Power Purchase Agreement between Government of Republic of Suriname and Staatsolie Power Company Suriname N.V."

For SPCS hydro purchases, the PPA stipulates a minimum energy output of 919,800MWh (based on an average available capacity of 105MW) and a fixed price of US$19.67 per MWh.[62] To calculate the total cost of SPCS hydro purchases, the EAS multiplies the minimum energy output with the fixed price and adds the cost of an additional energy output of 173,134MWh, assuming an additional available capacity of 20MW and the same fixed price.

The methodology used to calculate generation costs has the following gaps:

- It does not reflect the SRMC;
- It does not reflect the variations in generation costs by the time of day;
- It does not include a mechanism to recover the cost of purchases from RE IPPs; and
- It does not include a mechanism reflecting the variations in fuel costs. The State Decree S.B. 2024 no.41 defines a formula to ensure that variations in fuel costs are transparently passed through to customers:

$$Fuel\ clause\ =\ (((TG - H)\ *\ avg\ FUEL\ /\ avg\ TE)\ /\ TG)\ /\ (1 - VE)$$

  Where "TG" is the total quantity of electricity generated, "H" is the total quantity of purchases from SPCS hydro, "avg FUEL" is the weighted average price of fuels (such as HFO and diesel), "avg TE" is the weighted average thermal efficiency, and "VE" is total energy losses and own consumption.

  S.B. 2024 no.41 plans for quarterly adjustments of the fuel charge. The EAS's tool does not integrate the formula.

The EAS may consider adding two separate pass-through charges to the tariff structure:

- **A fuel adjustment charge to the tariff structure**: As noted above, the EAS's tool does not integrate the fuel adjustment charge formula defined in S.B. 2024 no.41. The EAS should integrate this formula and adjust the charge quarterly, as prescribed in the Decree, to allow EBS to pass through the fuel cost to customers, reflecting variations in fuel costs, including savings. For example, the Jamaica Public Service (JPS) has a separate pass-through fuel charge to its tariff structure:[63] JPS may pass the full fuel cost to customers, subject to system losses and heat rate efficiency targets.[64] JPS may adjust the fuel charge monthly;[65] and
- **A RE charge to recover the cost of power purchased from IPPs and distributed energy customers**. This charge would allow EBS to recover the cost of power purchases from IPPs

62 IMF-Fiscal Affairs Department. 2023. "Suriname: Reforming Electricity Subsidies."

63 Caribbean Development Bank. 2023. "The Minimum Regulatory Function for the Electricity Sector in Caribbean Countries." https://www.caribank.org/publications-and-resources/resource-library/technical-notes/minimum-regulatory-function-electricity-sector-caribbean-countries

64 OUR. 2022. "Jamaica Public Service Company Limited Annual Review and Extraordinary Rate Review 2022 Determination Notice." https://our.org.jm/wp-content/uploads/2022/08/2022-JPS-Annual-Tariff-and-Extraordinary-Determination-Notice-2.pdf

65 The Jamaica Gazette. 2016. "Jamaica Public Service Company Limited Electricity Licence 2016." https://our.org.jm/wp-content/uploads/2021/04/jps_electricity_licence_2016_-_ja_gazette_wed_2016_jan_27_0.pdf

and self-generators. When a large-scale renewable energy project is commissioned, the EAS should add it to the calculations of the cost of electricity purchases in the same way as other PPAs, and reflect the cost in the pass-through. To reflect the cost of self-generators, the EAS should calculate the total cost of paying the FIT to self-generators monthly based on the FIT for each customer category and total amount of electricity that EBS buys from self-generators in each customer category. The EAS can adjust this charge quarterly like the fuel charge. For example, JPS's tariffs also include an IPP charge. For some customer categories, the IPP charge is a variable charge representing the non-fuel costs allocated to each customer category that JPS pays to IPPs for generation supply. For other customer categories, JPS charges a variable and a fixed charge (per kVA).[66]

These charges should appear separately on the bill, giving customers transparency on the share that the cost of fuel and electricity purchases represents in their bills.

Fixed O&M costs

Fixed O&M costs cover transmission and distribution (T&D) costs, staff costs, and other O&M costs. The EAS may consider disaggregating these costs into the value chain components (generation, transmission, and distribution) to have a more granular view of each component's costs. Table 3.2 provides international examples of the allowed O&M costs that may be included in the revenue requirement calculations. As the table shows, these regulators use a more detailed breakdown of O&M costs compared to the EAS's current methodology.

[66] Caribbean Development Bank. 2023. "The Minimum Regulatory Function for the Electricity Sector in Caribbean Countries." https://www.caribank.org/publications-and-resources/resource-library/technical-notes/minimum-regulatory-function-electricity-sector-caribbean-countries

Table 3.2: International review of allowed O&M costs

Country	Allowed O&M costs
Jamaica	All prudently incurred costs that are not directly associated with investments in capital plant and other operating costs, including but not limited to: ▪ Salaries and other costs related to employees ▪ Operating costs of generation, transmission, distribution, and supply facilities ▪ PPA costs and other related costs, such as working capital and credit support charges incurred under approved PPAs, fuel supply agreements, and other related infrastructure arrangements ▪ Interest and other financial costs on other borrowings and working capital requirements not associated with capital investment ▪ Rents and leases on property associated with JPS ▪ Taxes other than income taxes
Australia	Non-capital costs incurred, such as vegetation management, maintenance, emergency response, network support, and corporate overheads
UK	▪ Direct O&M costs: fault repairs, planned inspections and maintenance, operational property, operational delivery, commercial and incentives, system capability and risk, national control, markets ▪ Closely associated indirect costs: operational information technology and telecoms, project management, network design and engineering, system mapping, engineering management and clerical support, network policy, health safety and environment, operational training, stores and logistics, vehicles and transport, market facilitation, network planning ▪ Business support costs: Information technology and telecoms, property management, human resources and non-operational training, finance audit and regulation, insurance, procurement, Chief Executive Officer and group management, staff costs

Source: OUR,[67] AER,[68] Ofgem[69]

Depreciation

The EAS calculates net asset value and depreciation. Net asset value comprises the purchase price of tangible fixed assets, including land, buildings, machines, and installations. The EAS uses depreciation as a hardcoded input in its Excel tariff calculation tool, but the source of this input is unclear.

[67] The Jamaica Gazette. 2016. "Jamaica Public Service Company Limited Electricity Licence 2016." https://our.org.jm/wp-content/uploads/2021/04/jps_electricity_licence_2016_-_ja_gazette_wed_2016_jan_27_0.pdf

[68] Australian Energy Regulator. 2021. "Better Resets Handbook Towards Consumer Centric Network Proposal." https://www.aer.gov.au/system/files/Better%20Reset%20Handbook%20-%20December%202021.pdf

[69] Ofgem. 2024. "Guidance RIIO-GT2 Gas Transmission Price Control – Regulatory Instructions and Guidance: version 2.3." https://www.ofgem.gov.uk/sites/default/files/2024-04/RIIO-GT2%20-%20Regulatory%20Instructions%20and%20Guidance%20v2.3%20Clean.pdf

Return on investment

The return on investment refers to the cost incurred to finance asset investments. Financing costs include the cost of debt (typically interest) and the cost of equity. The total return on investment can be estimated using the formula:

$$(WACC * RAB)$$

Which refers to the weighted average cost of capital (WACC) for the value of the regulated asset base (RAB). Table 3.3 shows the three approaches to calculating the WACC and their advantages and disadvantages.

Table 3.3: Three approaches to calculating the WACC

WACC	Formula	Advantages	Disadvantages
Pre-tax WACC	WACC (pre-tax) = g × Rd + (1 / (1 – t)) × Re × (1 – g) where g is gearing; Rd is the cost of debt; Re the pre-tax cost of equity; and t is the corporation tax rate. The (1 / (1-t)) term is called the "tax wedge" and is used to adjust the observed cost of equity, which is post-tax, to its *pre*-tax level	▪ Focuses on the utility's core operations and the cost of capital required to finance them	▪ Might overestimate the utility's cost of capital ▪ Limits comparisons with utilities that have tax obligations
Post-tax WACC	WACC (post-tax) = g × Rd × (1 – t) + Re (1 – g) where g is gearing; Rd is the cost of debt; Re the cost of equity; and t is the corporation tax rate. The (1 – t) term is known as the "tax shield".	▪ Captures the tax benefit associated with gearing (as interest is deducted before tax is calculated) ▪ Provides a more accurate estimate of the cost of capital	▪ More complex calculations (interest costs should be excluded from the calculations of the tax building block of the formula, as the tax deductibility of interest costs is already captured in the formula)
Vanilla WACC	The vanilla WACC abstracts from all considerations of tax: WACC (vanilla) = g × Rd + Re x (1 – g) where g is gearing; Rd is the cost of debt; and Re the cost of equity.	▪ Simplifies calculations ▪ Focuses on the utility's core operations and the cost of capital required to finance them	▪ Requires managing corporate tax liabilities as a cash-flow item and adding it to the utility's operating costs

Source: Oxera,[70] ACER[71]

Table 3.4 provides a review of the approaches used in Jamaica, the UK, and Australia, where the regulators use either the pre-tax or vanilla WACC. None of these regulators use the post-tax WACC. Most regulators in the European Union use the pre-tax WACC as well.[72] Given that EBS is

[70] Oxera. "Which WACC When?" https://www.oxera.com/agenda/which-wacc-when-a-cost-of-capital-puzzle-revisited/

[71] ACER. 2018. "Methodologies and parameters used to determine the allowed or target revenue of gas transmission system operators (TSOs)." https://www.acer.europa.eu/sites/default/files/documents/Publications/Consultant%20Report.pdf

[72] ACER. 2018. "Methodologies and parameters used to determine the allowed or target revenue of gas transmission system operators (TSOs)." https://www.acer.europa.eu/sites/default/files/documents/Publications/Consultant%20Report.pdf

not subject to corporate tax, the pre-tax WACC or vanilla WACC approaches appear to be more suitable for Suriname.

Table 3.4: International review of approaches to calculate the WACC

Country	Approach used to calculate the WACC
Jamaica	Nominal pre-tax WACC
Australia	Nominal vanilla WACC
UK	Real vanilla WACC

Sources: OUR,[73] AER,[74] Ofgem[75]

The State Decree S.B. 2021 no.88 defines an allowed rate of return on investment of 8 percent of the book value as of December 31 of the previous year.[76] The allowed rate of return is likely nominal, although the State Decree does not clearly state whether it is nominal or real. It is unclear whether the EAS uses this rate of return in its tariff model. It cannot be assessed whether this rate of return is appropriate to determine EBS's tariffs, as the State Decree does not specify how this rate of return was calculated.

3.2.2 Choose an approach to regulating tariffs

Choosing an approach to regulating tariffs is key because it determines how the EAS sets, reviews, and adjusts tariffs. Approaches typically fall under the following categories:

- Cost-of-service regulation: The regulator determines how much revenue the utility requires to recover the efficient costs it has incurred to supply electricity, including a reasonable rate of return, and sets tariffs to match this revenue requirement;[77]
- Control and command regulation: The regulator sets performance targets and instructs the utility how to achieve them;[78]
- Incentive regulation: The regulator incentivizes the utility to increase efficiency by enticing it with the opportunity to increase its profits; and

73 JPS. 2023. "2023 Submission Annual Tariff Adjustment." https://our.org.jm/wp-content/uploads/2023/05/JPS-2023-Annual-Filing_May-5-2023.pdf

74 Australian Energy Regulator. 2023. "Rate of Return Instrument Explanatory Statement." https://www.aer.gov.au/system/files/AER%20-%20Rate%20of%20Return%20Instrument%20-%20Explanatory%20Statement%20-%2024%20February%202023_1.pdf

75 Ofgem. 2023. "ED2 Price Control Financial Handbook." https://www.ofgem.gov.uk/sites/default/files/2023-02/ED2%20PCFH%20V1.pdf

76 State Decree S.B. 2021 no. 88. "Article 3"

77 Pato et al. 2019. "Performance-based regulation: Aligning incentives with clean energy outcomes." https://www.raponline.org/wp-content/uploads/2023/09/rap-zp-pb-jr-performance-based-regulation-2019-june2.pdf

78 Berg, Sanford. "Introduction to the fundamentals of incentive regulation." https://regulationbodyofknowledge.org/wp-content/uploads/2013/03/Berg_Introduction_to_the.pdf

- Performance-based regulation: The regulator sets performance targets and rewards and penalties for overachievement or underachievement and lets the utility decide how to achieve these targets best. Performance-based regulation is often used synonymously with incentive regulation,[79] but performance-based regulation shifts the utility's focus from inputs (such as capital expenditure, CAPEX) to outputs (achieving the standards and KPI targets).[80]

The EAS currently uses cost-of-service regulation. While this approach helps ensure the utility's financial sustainability, it does not incentivize the utility to improve efficiency. Cost-of-service regulation may even incentivize the utility to overinvest in assets and inflate costs without additional measures such as regulatory lags and efficiency audits.[81]

To address this issue, the EAS may consider using incentive regulation. Incentive regulation includes two approaches:[82]

- Price-cap regulation: The regulator sets a cap on the tariffs that the utility may charge; and
- Revenue-cap regulation: The regulator sets a cap on the revenue that the utility may earn. The utility may decide how to set tariffs as long as its revenue does not exceed the cap. Regulators in Australia,[83] Jamaica,[84] and most European countries use this approach. In the UK, the regulator uses performance-based regulation.[85]

Both approaches incentivize the utility to decrease costs and increase efficiency, which benefits both the utility and society. The utility has incentives to do so to maximize its profits. Increasing efficiency benefits society as the resulting cost savings are passed to customers in the next regulatory tariff period.[86]

Both approaches still require the regulator to estimate the utility's cost of service and revenue requirement. The regulator needs to know these to adjust the price cap or revenue cap.

Table 3.5 summarizes the price-cap and revenue-cap approaches, including their pros and cons.

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[79] Zarakas et al. 2017. « Performance Based Regulations Plans. Goals, Incentives and Alignment. » https://www.brattle.com/wp-content/uploads/2021/05/14487_2017_12_06_-_brown_et_al_-_pbr_plans_goals_incentives_and_alignment_-_for_dte.pdf

[80] Pato et al. 2019. "Performance-based regulation: Aligning incentives with clean energy outcomes."

[81] Berg, Sanford. "Introduction to the fundamentals of incentive regulation."

[82] Ofgem. 2009. "Characteristics of alternative price control frameworks: An overview." https://www.ofgem.gov.uk/sites/default/files/docs/2009/02/rpi_characteristics-of-alternative-price-control-frameworks_270209_0.pdf

[83] Australian Energy Regulator. 2022. "Annual Pricing Process Review." https://www.aer.gov.au/system/files/Annual%20pricing%20process%20review%20-%20Final%20position%20paper%20-%20Side%20constraint%20mechanism.pdf

[84] Office of Utilities Regulation. 2020. "Jamaica Public Service Company Limited Rate Review 2019-2024. Determination Notice." https://our.org.jm/wp-content/uploads/2021/04/jps_2019-2024_tariff_review_determination_notice_-_final_-20201224.pdf

[85] Pato et al. 2019. "Performance-based regulation: Aligning incentives with clean energy outcomes."

[86] Pato et al. 2019. "Performance-based regulation: Aligning incentives with clean energy outcomes."

Table 3.5: Performance-based regulation: Price-cap and Revenue-cap

Approach	Description	Pros	Cons
Price-cap	▪ The regulator sets a cap on the average tariff that the utility may charge ▪ The regulator indexes the cap to increases in input prices and increases in EBS's operational efficiency ▪ The regulator adjusts the cap at the end of the regulatory period	▪ Incentivizes the utility to reduce its costs ▪ Incentivizes the utility to expand access to earn more revenue ▪ Provides some flexibility to the utility in structuring and setting tariffs as long as its average tariff does not exceed the cap	▪ Disincentivizes energy-efficient consumption ▪ The utility bears the demand risk: If demand is below the forecasted level, the utility may not meet its revenue requirement ▪ The utility bears the risk of force majeure events that would result in unexpected cost increases ▪ If the utility decreases its costs, customers will not benefit from reduced tariffs until the next tariff review
Revenue-cap	▪ The regulator sets the maximum revenue the utility may earn during the regulatory period ▪ The regulator indexes the cap to increases in input prices and increases in the utility's operational efficiency ▪ The regulator adjusts the cap at the end of the regulatory period	▪ Incentivizes the utility to reduce its costs ▪ Provides full flexibility to the utility in structuring and setting tariffs as long as total revenue does not exceed the cap ▪ Allows the utility to compensate for a decrease in demand (for example, due to an increase in distributed generation and energy efficiency) by raising tariffs in the next regulatory period up to the revenue cap	▪ Disincentivize the utility to expand access as its revenue remains the same irrespective of demand ▪ Risk of cost-shifting between customers if the utility raises tariffs to compensate for decreased demand due to customers switching to distributed generation and energy-efficient appliances

Sources: Campbell, Alrick;[87] Commerce Commission of New Zealand;[88] The Word Bank[89]

3.2.3 Determine the revenue requirement

The revenue requirement represents the amount of revenue that EBS must earn from energy sales to recover its reasonable cost of service. The EAS calculates the revenue requirement by:

[87] Campbell. 2018. "Cap prices or cap revenues? The dilemma of electric utility networks." In Energy Economics vol 74. https://www.sciencedirect.com/science/article/abs/pii/S0140988318302792

[88] Commerce Commission New Zealand. 2020. "Revenue cap for electricity distribution businesses and Covid-19 related impacts." https://comcom.govt.nz/__data/assets/pdf_file/0022/223753/Revenue-cap-guidance-for-electricity-lines-businesses-August-2020.PDF

[89] Harris et al. 2005. "The Regulation of Investment in Utilities Concepts and Applications." https://documents1.worldbank.org/curated/zh/652031468140974650/pdf/343650PAPER0Re101OFFICIAL0USE0ONLY1.pdf

- Calculating the revenue from RGM and the revenue from connection fees paid by customers; then
- Deducting the revenue from RGM and connection fees from total costs, which the EAS calculates by summing:
  - Fixed costs, which comprise fixed O&M costs, depreciation, and return on investment; and
  - Variable costs, which comprise the generation costs of EBS-owned assets electricity purchases, the regulatory fee (a fixed fee of SRD0.01 per kWh meant to cover the cost of managing and regulating the sector), and the portion of connection costs that EBS does not recover through the connection fee.[90]

The current tariff methodology does not assess the effect of the FIT for distributed generation on EBS's revenue. The EAS should consider integrating such assessment into its tariff methodology because it would allow the EAS to monitor the effect of the FIT on EBS's revenue and take appropriate measures in case the FIT threatens EBS's financial sustainability. To do so, the EAS should calculate the decrease in sales in each customer category due to self-generation and how much of its total revenue this decrease represents.

3.2.4 Allocate costs

The EAS uses the accounting approach to allocate EBS's fixed and variable costs between customer categories. Best practices when using this approach are to:

- Identify and classify the fixed and variable costs;
- Link fixed and variable costs to cost drivers that represent how EBS incurs these costs, such as peak demand, reflecting the cost of investing in peak capacity to meet the demand of each customer category; and energy consumption, reflecting variable costs; and
- Allocate the costs across customer classes using either direct allocation (allocating costs directly to the customer category that incurs them) or proportional allocation (allocating costs based on the proportion of the cost driver that the customer category represents).

Using proportional allocation, the EAS follows best practices in allocating EBS's fixed and variable costs across customer categories. The EAS allocates costs as follows:

- First, the EAS determines for each customer category the total number of customers and total consumption, based on data from EBS, and the peak load, based on consumption and assumptions on the load factor of each category;
- Then, the EAS determines the allocation of costs between low voltage (LV) and high voltage (HV) customer categories by:

[90] State Decree S.B. 2021 no 88, "Article 7" requires the EAS to recover the portion of connection costs that is not covered by the connection fees through the variable charge.

  - Calculating the amount of energy sold (grossed up for losses) to LV customers and the amount sold to HV customers;
  - Calculating the amount of capacity needed to serve LV customers and the amount required to serve HV customers; and
  - Calculating the share of energy sales and capacity that the LV and HV customers represent. The share of energy costs allocated to LV customers and HV customers is then based on their share of energy sales, and the share of CAPEX and OPEX allocated to LV customers and HV customers is based on their share of capacity
- Finally, the EAS allocates the total cost of service between customer categories by:
  - Calculating the share of peak demand of each customer category and multiplying fixed costs by this share; and
  - Calculating the share of consumption of each customer category and multiplying variable costs by this share.

3.2.5 Determine the tariff structure

The EAS establishes a disaggregated tariff structure, which includes:

- A variable charge per unit consumed: This charge covers the inputs for generating electricity, which for EBS includes electricity purchases and the cost of generation of the plants it owns. The EAS calculates the variable charge by dividing the allocated variable costs for each customer category by the total consumption of each category. S.B. 2024 No.41 introduces a single-tier system for commercial and industrial customers. This is an appropriate system for such customers because the purpose of multi-block tariffs is to cross-subsidize the consumption of low-income customers. Therefore, multi-block tariffs are typically used for residential customers to ensure electricity remains affordable for low-income households, but are not advisable for commercial and industrial customers.
- A fixed charge: This charge covers the costs that EBS incurs regardless of the electricity consumed. The EAS calculates the fixed charge by dividing the allocated fixed costs for each customer category by the number of customers (for LV customers) or the kVA (for HV customers) in each category.

Connections above 2MW

S.B. 2024 No. 41 defines a new customer group comprising connections with capacity above 2MW. This group requires tailored tariff structures due to its unique energy demand. The EAS's tariff structure already includes a fixed charge per kVA for HV customers, which includes connections above 2MW, in addition to the variable charge per kWh. However, S.B. 2024 No.41 also requires recording kVAh consumption for connections above 2MW. The EAS should use the following tariff structure for connections above 2MW: a variable charge per kWh, a variable charge per kVAh, and a fixed charge per kVA.

Distributed generation

The current tariff structure risks incentivizing investment in distributed generation at a sub-optimal level or in other words, at a level where its costs would exceed its benefits (see Section 7).

The structure does not have a fixed charge for distributed generation owners to cover their share of fixed costs. Moreover, the FIT is set at 115 percent of the variable charge, which may be higher than the avoided cost of generation at the time of sale and an increase in total system costs as distributed generation capacity grows.

Prepaid electricity service

The tariff structure for prepaid electricity service should be the same as for post-paid. Customers using prepaid services will pay the fixed charge to EBS monthly and will pay their consumption on a prepaid basis. The EAS should identify any costs related to delivering the prepaid service and factor these costs into the variable charge, meaning that the prepaid variable charge is likely to be higher than the post-paid variable charge.

Tariff adjustments are only applied to prepaid services when customers recharge after the adjustments. This can lead to customers recharging months' worth of consumption to mitigate tariff increases, and the utility under-recovering its costs. It is therefore recommended to impose a maximum limit on the amount of recharge that customers can purchase at once. For example, if the EAS plans to adjust tariffs quarterly, the maximum recharge can be determined based on the average quarterly consumption of each customer category, so that the average customer would have to recharge at least every quarter.

To allow for flexible management of electricity consumption for customers who opt for prepaid services, EBS should partner with vendors that provide customers with various and easy ways to recharge.

4 Regulatory accounting rules

[To be inserted]

5 Performance standards

To achieve the ESP objectives, this document includes key performance indicators (KPIs). The KPIs will be the basis for the Energy Authority of Suriname (EAS) to establish targets, assess performance against those targets, and set minimum standards for the Electricity Company[91] and power producers. As part of its role in overseeing the preparation and implementation of the ESP, the EAS is responsible for:

[91] The Electricity Company is the grid operator, single buyer, and single retailer of electricity for the National Grid (Electricity Act. 2016. "Article 10"). EBS is the Electricity Company as of the date of this Volume. In addition to owning and operating the grid, EBS generates about 25 percent of the total electricity supply for the EPAR, ENIC, and some rural systems.

- Monitoring the performance of the electricity sector against the KPIs by collecting, tracking, and analyzing data from key actors that generate, transmit, and distribute electricity on the National Grid;[92] and
- Managing the Energy Information Management System (EIMS), which is the platform for collecting, storing, tracking, processing, and analyzing data.[93]

This section provides the following:

- A description of the EAS's functions and responsibilities related to data management and performance assessment (Section 5.1);
- An overview of the EIMS (Section 5.2);
- The list of KPIs that make up the EIMS, along with the formulas and data points required to calculate each KPI (Section 5.3). A phased approach is recommended, starting with a small set of KPIs to allow the EAS and sector stakeholders to build capacity in collecting data and to get familiar with the new system. Section 5.5.4 covers the methodology used to select these KPIs, given the sector's objectives, best practices in the region, the local context, and expected development and changes in the energy sector;
- A list of baseline KPIs for Suriname (Section 5.6);
- Minimum supply standards for Suriname (Section 5.7);
- KPI targets (Section 5.8); and
- A strategy to achieve KPI targets and supply standards (5.9).

5.1 EAS's responsibilities related to data management

The EAS is responsible for the data management in the electricity sector, which includes:

- Collecting, processing, and interpreting all relevant data from the electricity sector;
- Publishing reliable and consistent statistics annually in a manner accessible to the Government, the electricity sector stakeholders, and consumers; and
- Maintaining a management information system for the electricity sector stakeholders.[94]

To fulfill its responsibilities, the Electricity Act lists the minimum data that stakeholders must provide to the EAS (Table 5.1)[95] and empowers the EAS to define the period within which

[92] The National Grid refers to all systems operated by the Electricity Company, including the Paramaribo Electricity System (EPAR), the Nickerie Electricity System (ENIC), and the smaller Rural District electricity systems.

[93] Electricity Act. 2016. "Article 4" and "Article 8"

[94] Electricity Act. 2016. "Article 5"

[95] Electricity Act. 2016. "Article 7"

stakeholders should provide the requested data[96] and to request additional data it considers necessary.[97]

The Electricity Act also empowers the EAS to impose administrative penalties of up to SRD10 million on stakeholders who do not comply with reporting requirements. The EAS is to define guidelines for the imposition of such penalties, including the amounts and processes to impose them.[98]

Table 5.1: Minimum data to be provided by electricity sector stakeholders to the EAS

Stakeholder	Data to be provided to the EAS
Electricity Company (Energie Bedrijven Suriname, EBS)	▪ Load curve of each sub-station in the National Grid ▪ Electricity supply curve of power producers in the National Grid ▪ kWh supplied monthly by power producers ▪ Power outage statistics and detailed information on power outages in which the load outage exceeds 1MW ▪ Monthly kWh consumption per consumer group ▪ Monthly kWh charge invoiced per consumer group ▪ Monthly kVA charged invoiced per consumer group ▪ Monthly kVArh invoiced per consumer group ▪ Monthly costs per power producer for supplying electricity ▪ Number of new connections per month ▪ Any relevant data concerning operational and maintenance costs ▪ Quarterly staff turnover
Power producers	▪ MWh supplied monthly to the Electricity Company ▪ Amount of fuel consumed to generate electricity ▪ Availability of capacity in the past month ▪ Availability of capacity in the upcoming quarter

Source: Electricity Act. 2016. "Article 7"

In addition to the above data, the EAS may request and collect additional data from stakeholders. At a minimum, the EAS should collect the data required to calculate the KPIs in the EIMS (see Section 5.5).

5.2 Overview of the EIMS

The EIMS is a platform for collecting, storing, tracking, processing, and analyzing data submitted by electricity sector stakeholders. The purpose of the EIMS is to:

[96] Electricity Act. 2016. "Article 6"

[97] Electricity Act. 2016. "Article 7"

[98] Electricity Act. 2016. "Article 26"

- Streamline and simplify data collection and analysis by processing data from various sources in a single platform;
- Promote transparency and reduce information asymmetry by requiring the open disclosure of sector data;
- Help the EAS monitor the performance of the sector; and
- Help the Government make informed decisions related to the sector.

The EAS approved the technical specifications and implementation plan for the EIMS in August 2023 and expects it to be operational in 2025.[99]

This section describes the design of the EIMS. Section 5.3 covers the structure of the EIMS, as defined in the Technical Specifications.[100] Section 5.4 covers the recommended principles for data collection and auditing.

5.3 Structure of the EIMS

The EIMS is designed to be:

- Expandable and scalable, allowing the EAS to manage an increasing amount of data; and
- Flexible, adapting to future regulatory requirements.

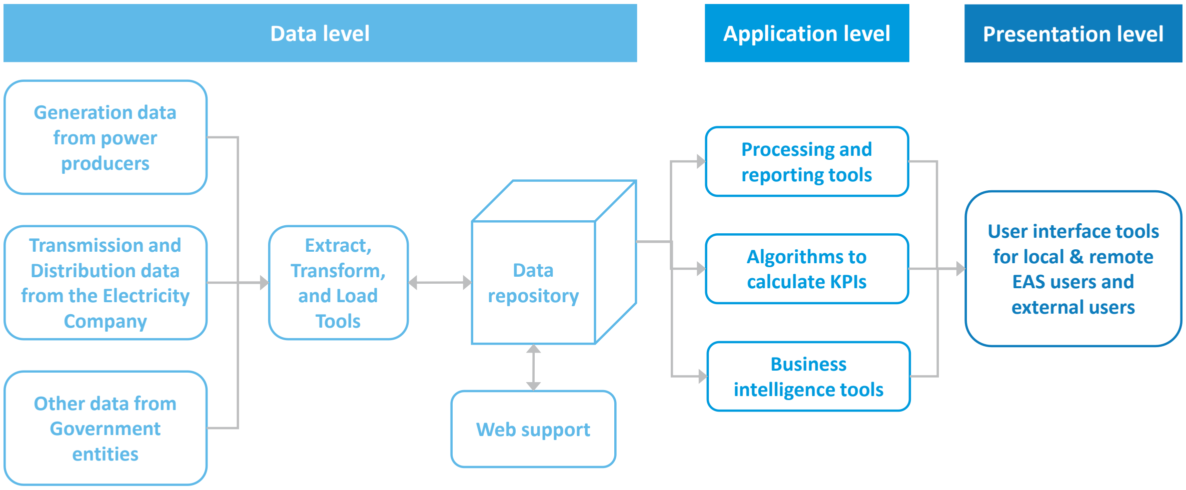
Figure 5.1 explains the structure of the EIMS, which comprises three levels, and Table 5.2 below it explains the purpose of each level and how it works.[101]

[99] Information shared by the EAS, July 2024.

[100] IDB. 2023. “Consultancy to Support the Design and Development of the Energy Information Management System (EIMS) for Energy Authority of Suriname (EAS). Deliverable #2: Technical Specifications of EIMS.”

[101] The source for all information in this section is IDB. 2023. “Consultancy to Support the Design and Development of the Energy Information Management System (EIMS) for Energy Authority of Suriname (EAS). Deliverable #2: Technical Specifications of EIMS.”

Figure 5.1: Structure of the EIMS



Source: Adapted from IDB. 2023. "Consultancy to Support the Design and Development of the Energy Information Management System (EIMS) for the Energy Authority of Suriname (EAS). Deliverable #2: Technical Specifications of EIMS."

Table 5.2 explains in detail the functions of each level.

Table 5.2: Functions of the three levels of the EIMS

Level	Functions
Data level	Interfaces where external users can use Extract, Transform, and Load (ETL) tools to perform the following functions: ▪ Data extraction: collecting data from multiple sources ▪ Data verification: finding and correcting errors in data ▪ Data transformation: converting data from its original format to a specific format useful for the repository ▪ Data loading: sorting, consolidating, summarizing, integrity checking, and generating indexes as required ▪ Data update: updating the data from the sources
Application level	▪ Where users use business intelligence and simulation tools and applications to run KPI calculations, reporting, and simulation ▪ The EIMS allows for calculating a defined set list of KPIs (see Section 5.5) and adding new KPIs or modifying the existing list ▪ The simulation tools assist users to create scenarios where any parameter of the KPI calculations can vary
Presentation level	Interface where users can generate outputs of the data processing, such as dashboards, graphs, and tables. The EIMS also provides the following displays: ▪ A geographical display showing all the generation plants and other relevant facilities ▪ A single-line diagram of the National Grid ▪ A general single-line diagram of the connection of the generation plants to the transmission system ▪ Tables based on data collected and calculated by the EIMS

Level	Functions
	▪ Trending graphs

Source: IDB. 2023. "Consultancy to Support the Design and Development of the Energy Information Management System (EIMS) for the Energy Authority of Suriname (EAS). Deliverable #2: Technical Specifications of EIMS."

5.4 System for data collection and auditing

The accuracy of performance monitoring and analysis depends on the sufficiency and quality of the supporting data. Having a well-defined data collection and auditing system is key to ensuring that the data is of sufficient quality. Section 5.4.1 outlines a system for data collection, and Section 5.4.2 outlines a system for data auditing.

5.4.1 Data collection

To collect data, the EAS should:

- **Determine the data to be collected.** In addition to the set of minimum data required (Table 5.1), the EAS should collect the data necessary to monitor performance through the KPIs described in Section 5.5. In order to accurately calculate the KPIs, data should be complete, consistent, and of sufficient quality to enable granular analysis.
- **Define the source, type, format, collection method, and periodicity of the collection.** Data sources that will feed into the EIMS comprise EBS's Transmission Supervisory Control and Data Acquisition (SCADA) and Distribution SCADA,[102] data from power producers, and data from Government entities. Table 5.3 summarizes the data source, type and format, and periodicity of collection planned for the EIMS.
- **Implement the systems for data collection.** These systems include the Extract, Transform, and Load (ETL) tools (see Section 5.3) and the data repository.[103]
- **Inform data source entities of the data collection process and their requirements.** The EAS should communicate the data needed, its type and format (including sharing templates where required), and timelines for submission. Each entity should define roles and responsibilities to submit the required data per EAS's instructions.

Table 5.3: Data sources, type, and collection periodicity

Data source	Data type and format	Periodicity of collection
EBS Transmission SCADA	SCADA Real-Time Signals and Measurements	Hourly
EBS Distribution SCADA	SCADA Real-Time Signals and Measurements	Hourly

[102] EBS's Transmission SCADA is operational. The Distribution SCADA is expected to be operational by August 2025.

[103] IDB. 2023. "Consultancy to Support the Design and Development of the Energy Information Management System (EIMS) for Energy Authority of Suriname (EAS). Deliverable #2: Technical Specifications of EIMS."

Data source	Data type and format	Periodicity of collection
Staatsolie Power Company Suriname	To be defined	Daily
Afobaka	To be defined	Daily
Rosebel	To be defined	Daily
Government entities	MS-Excel file	Monthly

Note: The EAS and EBS may choose to revise the technical specifications, including the periodicity of collection, once the EIMS is fully implemented.
Source: IDB. 2023. "Consultancy to Support the Design and Development of the Energy Information Management System (EIMS) for the Energy Authority of Suriname (EAS). Deliverable #2: Technical Specifications of EIMS."

5.4.2 Data auditing

Auditing data ensures its accuracy, consistency, and completeness. Data auditing is particularly important when data comes from different sources, as in Suriname. In such cases, there is a risk that data overlap, be represented differently, or contradict each other.[104]

Data auditing involves the following steps:

- **Define the requirements for data quality**—Identify the key attributes, metrics, and standards that will qualify the data quality (for example, the data should be of this type and in this format).[105] This also includes defining the rules and logic to verify and validate the data.
- **Profiling and assessing data**—Profiling consists of analyzing the data sources' structure, content, and metadata using tools and techniques such as frequency analysis, dependency analysis, pattern analysis, and outlier analysis to identify the data's characteristics, relationships, and anomalies. Anomalies can be, for example, duplicate records, missing values, null values, and/or outliers. Assessing involves comparing the data with the data quality requirements to quantify and prioritize the issues that must be addressed.
- **Establish a data cleaning strategy** to resolve quality issues, which can be either:
  - A passive strategy, which flags, reports, or rejects the data that does not meet the quality requirements; or
  - An active strategy, which modifies the original data by correcting, standardizing, enriching, or deduplicating it.
- **Test and monitor the data cleansing** to ensure the results of the data cleaning strategy meet the data quality requirements.

[104] Erhard Rahm, Hong Hai Do. 2000. "Data Cleaning: Problems and Current Approaches." https://www.betterevaluation.org/sites/default/files/data_cleaning.pdf

[105] Dhamotharan Seenivasan. 2023. "ETL (Extract, Transform, Load) Best Practices." https://ijcttjournal.org/2023/Volume-71%20Issue-1/IJCTT-V71I1P106.pdf

- **Automate and standardize the data cleansing process.** This can be done using ETL tools built into the EIMS.[106] The ETL tools should perform data auditing before storing it in the repository to ensure that raw data is entirely compliant and ready for processing and that invalid data is flagged or rejected before it is stored and processed.[107]

5.5 Understanding the KPIs

The Technical Specifications of the EIMS define 41 KPIs, measured across Suriname's different systems—the Paramaribo Electricity System (EPAR), the Nickerie Electricity System (ENIC), and the rural district systems. Three KPIs were removed from the list in the EIMS by combining financial KPIs that were differentiated between "before subsidies" and "after subsidies," as this distinction is irrelevant since the Government plans to phase out subsidies in 2024.

In addition to the KPIs already defined in the EIMS, 12 new KPIs[108] are recommended to reflect recent developments, notably:

- The ability to gather and collect more and better data, allowing for calculating new KPIs;
- The need to assess the performance of new technologies that will play a greater role in Suriname's generation mix, namely solar PV, wind, and battery storage;
- The Government's policy to reduce emissions from the energy sector as stated in the Nationally Determined Contribution;[109] and
- EBS's initiatives to improve its operational and financial performance while working towards becoming a "utility of the future" (see Box 5.1).

These additions bring the total amount of recommended KPIs to 50. These KPIs are broken down by the sector objectives defined in the Electricity Act:

- **Availability**—Ensuring that customers have a reliable supply and that electricity suppliers have sufficient energy sources to meet current and future demand. Section 5.5.1 presents the 14 KPIs that measure availability.
- **Affordability**—Ensuring that supply costs are minimized for customers and electricity suppliers allocate resources efficiently (including exploring other energy sources and using

[106] IBM. 2024. "What is ETL (extract, transform, load)?."https://www.ibm.com/topics/etl

[107] Bilal Khan, Saifullah Jan, Wahab Khan and Muhammad Imran Chughtai. 2023. "An Overview of ETL Techniques, Tools, Processes and Evaluations in Data Warehousing." https://www.techscience.com/jbd/v6n1/55252/html

[108] The following KPIs were added: 1) Availability—percentage of times voltage is outside regulated levels; 2) Affordability—average tariff for residential and non-residential customers, share of electricity expenses in income for residential customers in the bottom quintile, average cost of fuel, customers per employee, share of staff cost from non-fuel OPEX, share of smart meters; and 3) Environmental sustainability—CO_2 emissions from electricity generation, SO_2 emissions from electricity generation, NOx emissions from electricity generation, share of electricity generation from distributed solar PV, share of installed capacity from distributed solar PV.

[109] The Republic of Suriname. 2020. "Nationally Determined Contribution 2020." https://unfccc.int/sites/default/files/NDC/2022-06/Suriname%20Second%20NDC.pdf

the most cost-effective solutions). Section 5.5.2 presents the 26 KPIs that measure affordability.

- **Sustainability**—Ensuring that customers consume electricity efficiently and electricity suppliers generate electricity in an environmentally sustainable manner. Section 5.5.3 presents the ten KPIs that measure sustainability.[110]

As the EIMS will be a new system, it is recommended that the data collection process be implemented in phases. To start, the EAS should monitor a subset of the full list of KPIs (first phase), and gradually increase these in subsequent phase(s) as the EAS and sector stakeholders build capacity to manage and process data using the EIMS. Sections 5.5.1, 5.5.2, and 5.5.3 include the complete list of recommended KPIs categorized by sector objective and recommended phase. The phase in which each KPI is recommended is based on how easy it is to get the data needed to calculate it and how important it is for monitoring the system's performance.

In the first phase of EIMS implementation, it is recommended that the EAS focus on data collection for the EPAR and ENIC systems, using data from EBS and Staatsolie Power Company Suriname (SPCS). In subsequent phases, the EAS can expand the scope to cover the rural districts as well.

Section 5.5.4 explains the methodology used to select the KPIs, including verifying the sector objectives, reviewing international and regional best practices, and reviewing the data collected from EBS.

Box 5.1: Becoming a utility of the future

A utility of the future is a utility that not only provides high-quality services efficiently and sustainably but is also:[111]

- Innovative, introducing novel methods to run operations and provide high-quality service,
- Inclusive: improving the ability, opportunity, and dignity of people disadvantaged based on their identity to take part in society,
- Market- and customer-oriented: operating like a firm in a competitive market, and
- Resilient: having the capacity to prepare for disruptions, to recover from shocks and stresses, and to adapt and grow from a disruptive experience.

The World Bank's Utility of the Future framework defines practices that EBS can implement towards becoming innovative, inclusive, market- and customer-oriented, and resilient. These measures cover the five essential functions of a utility:

- Technical operations,
- Commercial operations,
- Financial management,
- HR management, and
- Organization and Strategy.

[110] Electricity Act. 2016. "Explanatory notes"

[111] World Bank. 2021. "Utility of the Future." https://documents1.worldbank.org/curated/en/796201616482838636/pdf/Utility-of-the-Future-Taking-Water-and-Sanitation-Utilities-Beyond-the-Next-Level.pdf

Appendix B contains the matrices that describe these practices across the five functions, covering a complete set of areas and topics. The practices are described in the columns under “Utility of the Future dimensions.” For example, the practices to become an inclusive utility are described in the column “Inclusion.” A cell containing “Not applicable” means that the dimension is irrelevant to the topic.

Source: World Bank. 2021. “Utility of the Future Program.” https://www.worldbank.org/en/topic/water/publication/utility-of-the-future

5.5.1 KPIs to measure availability

Availability refers to ensuring customers have a reliable electricity supply and that electricity suppliers have sufficient energy sources to meet current and future demand. The KPIs to assess availability can be broken down into four sub-objectives explained in Table 5.4.

Table 5.4: Sub-objectives for availability

Sub-objective	Explanation	Reference
Reliability of service	Consumers should experience minimal service interruptions	Electricity Act: ▪ Article 8 requires the ESP to ensure a reliable electricity supply ▪ Article 15 gives responsibility to the Electricity Company to ensure the safety and reliability of electricity supply
Service coverage	Every resident of Suriname should have access to electricity	Goal 1 of the Draft Energy Policy 2013-2033: “All citizens have access to reliable and affordable energy supplies, and Suriname can meet its energy demands for households and industry, improving the quality of life of all”
Quality of commercial services	Consumers should receive high-quality customer service whenever necessary	Electricity Act, Article 11 requires the Electricity Company to ensure the quality of the electricity supply

Table 5.5 lists the KPIs to monitor in the first phase and Table 5.6 the KPIs to add in subsequent phases.

Table 5.5: KPIs to measure availability—To monitor in Phase 1

Sub-objective and function	KPI	Formula	Scope	Unit	Frequency of reporting
Reliable supply of electricity **Technical performance**	System Average Interruption Duration Index (SAIDI)	$\frac{\sum_{i=1}^{n}(MI * CI)_i}{C}$ MI = Duration of interruption in minutes CI = Number of customers interrupted C = Total number of customers	▪ At EIMS's launch: – EPAR – ENIC ▪ Add rural districts in subsequent phases	Minutes	Quarterly
Reliable supply of electricity **Technical performance**	System Average Interruption Frequency Index (SAIFI)	$\frac{\sum_{i=1}^{n} CI_i}{C}$ CI_i = Total number of customers interrupted C = Total number of customers	▪ At EIMS's launch: – EPAR – ENIC ▪ Add rural districts in subsequent phases	Number	Quarterly
Reliable supply of electricity **Technical performance**	Customer Average Interruption Duration Index (CAIDI)	$\frac{SAIDI}{SAIFI}$	▪ At EIMS's launch: – EPAR – ENIC ▪ Add rural districts in subsequent phases	Minutes	Quarterly
Reliable supply of electricity **Technical performance**	Available capacity	$\frac{AG}{IG} * 100\%$ AG = Available generation capacity (MW) IG = Total installed generation capacity (MW)	▪ At EIMS's launch: – EPAR – ENIC ▪ Add rural districts in subsequent phases	%	Annually
Reliable supply of electricity **Technical performance**	Generation reserve margin	$\frac{AG}{Peak} * 100\%$ AG = Available generation capacity (MW) Peak = Peak demand (MW)	▪ EPAR ▪ ENIC	%	Annually
Service coverage **Technical performance**	Electricity coverage	$\frac{P\ Access}{P} * 100\%$ P Access = People with access to service	▪ At EIMS's launch: – EPAR	%	Annually

Sub-objective and function	KPI	Formula	Scope	Unit	Frequency of reporting
		P = People in the service area[112]	– ENIC ▪ Add rural districts in subsequent phases		
Quality of commercial services **Commercial performance**	Customer complaints per 1,000 customers	$\frac{Complaint}{(\frac{C}{1,000})}$ Complaint = Total number of complaints C = Total number of customers	▪ At EIMS's launch: – EPAR – ENIC ▪ Add rural districts in subsequent phases	Number	Annually

Source: IDB. 2023. "Consultancy to Support the Design and Development of the Energy Information Management System (EIMS) for the Energy Authority of Suriname (EAS). Deliverable #2: Technical Specifications of EIMS."

Table 5.6: KPIs to measure availability—To add in subsequent phases

Sub-objective and function	KPI	Formula	Scope	Unit	Frequency of reporting
Reliable supply of electricity **Technical performance**	Availability factor	$\frac{P\ hours}{Hours} * 100\%$ P hours = Hours plant is available during the year Hours = Total hours in a year	▪ EPAR DPP1 ▪ EPAR DPP2 ▪ EPAR SPCS ▪ EPAR AHPF ▪ ENIC Clara ▪ Rural districts	%	Annually
Reliable supply of electricity **Technical performance**	Transmission outages	$\frac{T\ faults}{(\frac{T}{100})}$	▪ EPAR ▪ ENIC	Faults/ 100km/ year	Annually

lxlsl[112] The number of people in the service area is estimated based on the number of households in each area where the Electricity Company provides service.

Sub-objective and function	KPI	Formula	Scope	Unit	Frequency of reporting
		T faults = Number of transmission outages during the year (T/100) = 100km of transmission system length			
Reliable supply of electricity **Technical performance**	Distribution outages	$\frac{D\ faults}{(\frac{D}{100})}$ D faults = Number of distribution outages during the year (D/100) = 100km of distribution system length	▪ EPAR ▪ ENIC	Faults/ 100km/ year	Annually
Reliable supply of electricity **Technical performance**	Percentage of times voltage is outside regulated levels[113]	$\frac{V\ out\ reg}{Total\ measurement\ time} * 100\%$ V out reg = Total time voltage is outside regulated levels	▪ EPAR ▪ ENIC ▪ Rural districts	%	Annually
Quality of commercial services **Commercial performance**	Average connection period	$\frac{\sum_{i=1}^{n}(FCD - AD)_i}{A}$ FCD = Final connection date AD = Application date A = Number of applications in a year	▪ Electricity Company	Days	Annually
Quality of commercial services **Commercial performance**	Connection period duration	$\frac{ACP}{A} * 100\%$ ACP = Number of applications with a connection period longer than 3 months A = Number of applications in a year	▪ Electricity Company	%	Annually

[113] This is generally measured at specific points on the distribution system.

Sub-objective and function	KPI	Formula	Scope	Unit	Frequency of reporting
Demand management **Technical performance**	Load factor[114]	$\frac{N\ Gen}{(Peak * 8{,}760)} * 100\%$ N Gen= Net generation (MWh) Peak = Peak demand (MW)	▪ EPAR ▪ ENIC	%	Annually

Source: IDB. 2023. "Consultancy to Support the Design and Development of the Energy Information Management System (EIMS) for the Energy Authority of Suriname (EAS). Deliverable #2: Technical Specifications of EIMS."

[114] Load factor is a measure of the efficiency and utilization of electrical energy usage. A higher load factor indicates a relatively flat load profile, which typically allows for more efficient use of generation resources, as there is a lower need for spinning reserves and fast ramp up and down to meet demand during peaks. The load factor is a KPI used to monitor overall sector demand, but should not be used to directly assess EBS's performance.

5.5.2 KPIs to measure affordability

Affordability of supply refers to making sure supply costs are minimized and resources are allocated efficiently. This includes exploring other energy sources and incentivizing other energy producers to supply more cost-effective solutions. The KPIs to assess affordability can be broken down into four sub-objectives explained in Table 5.7.

Table 5.7: Sub-objectives for affordability

Sub-objective	Explanation	Reference
Affordability for customers	Consumers should be able to afford the electricity required to meet their needs	Goals 1 and 2 of the Draft Energy Policy (see Table 5.4)
Operational efficiency	The Electricity Company and IPPs must deliver electricity to customers in a cost-effective manner while ensuring high-quality service	▪ Draft Energy Policy's vision of "a modern, efficient energy sector" ▪ The Electricity Act: – Article 8 requires the ESP to ensure an efficient and sustainable electricity supply – Article 11 requires the Electricity Company to operate economically in the most efficient manner
Financial efficiency	The Electricity Company must use resources effectively by minimizing costs and leveraging assets to generate revenue	Draft Energy Policy's vision and the Electricity Act, Articles 8 and 11 (see above)
Commercial efficiency	The Electricity Company must efficiently collect outstanding bills from customers	Electricity Act, Article 9 requires the ESP to include "the minimum standards for a dependable electricity sector, for the Consumers to rely upon" and "the quality and safety standards that will apply for the electricity supply sector"

Table 5.8 lists the KPIs to monitor in the first phase and Table 5.9 the KPIs to add in subsequent phases.

Table 5.8: KPIs to measure affordability—To monitor in Phase 1

Sub-objective and function	KPI	Formula	Scope	Unit	Frequency of reporting
Affordability for customers **Commercial performance**	Revenue per kWh sold to residential customers	$\frac{Revenue}{Sales}$ Revenue = Revenue from electricity sales to residential customers (SRD) Sales = Electricity sales to residential customers (kWh)	▪ Electricity Company	SRD/kWh	Annually
Affordability for customers **Commercial performance**	Revenue per kWh sold to non-residential customers	$\frac{Revenue}{Sales}$ Revenue = Revenue from electricity sales to non-residential customers (SRD) Sales = Electricity sales to non-residential customers (kWh)	▪ Electricity Company	SRD/kWh	Annually
Operational efficiency **Technical performance**	Heat rate	$\frac{Fuel}{G\ Gen}$ Fuel = Fuel input (Btu) G Gen = Gross generation (kWh)	▪ In the first phase: – EPAR DD1 – EPAR DD2 – EPAR SPCS – ENIC Clara ▪ Add rural districts in subsequent phases	Btu/ kWh	Annually
Operational efficiency **Technical performance**	System losses	$\frac{(G\ Gen - Sales)}{G\ Gen} * 100\%$ G Gen = Gross generation (MWh) Sales = Electricity sales (MWh)	▪ In the first phase: – EPAR – ENIC ▪ Add rural districts in subsequent phases	%	Annually
Financial efficiency **Financial performance**	EBITDA margin	$\frac{EBITDA}{Revenue} * 100\%$ EBITDA = Earnings before interest, taxes, depreciation, and amortization	▪ Electricity Company	%	Annually

Sub-objective and function	KPI	Formula	Scope	Unit	Frequency of reporting
		Revenue = Revenue from electricity sales (SRD)			

Source: IDB. 2023. "Consultancy to Support the Design and Development of the Energy Information Management System (EIMS) for the Energy Authority of Suriname (EAS). Deliverable #2: Technical Specifications of EIMS."

Table 5.9: KPIs to measure affordability—To add in subsequent phases

Sub-objective and function	KPI	Formula	Scope	Unit	Frequency of reporting
Affordability for customers **Commercial performance**	Share of electricity expenses in income for residential customers in the bottom quintile	$\frac{Total\ electricity\ expenses}{Total\ income\ bottom\ quintile} * 100\%$ Total electricity expenses = monthly amount of electricity bills for residential customers in the bottom quintile Total income bottom quintile = monthly income of residential customers in the bottom quintile	▪ Electricity Company	%	Annually
Operational efficiency **Technical performance**	Plant utilization factor	$\frac{G\ Gen}{(AG * 8{,}760)} * 100\%$ G Gen = Gross generation (MWh) AG = Available generation capacity (MW)	▪ EPAR DPP1 ▪ EPAR DPP2 ▪ ENIC Clara ▪ EPAR SPCS ▪ AHPF	%	Annually
Operational efficiency **Technical performance**	Auxiliary consumption	$\frac{(G\ Gen - N\ Gen)}{G\ Gen} * 100\%$ G Gen = Gross generation (MWh) N Gen = Net generation (MWh)	▪ EPAR DPP1 ▪ EPAR DPP2 ▪ ENIC Clara ▪ EPAR SPCS ▪ EPAR AHPF ▪ Rural districts	%	Annually

Sub-objective and function	KPI	Formula	Scope	Unit	Frequency of reporting
Operational efficiency **Technical performance**	Transmission and distribution system losses (loss ratio)	$\frac{T\&D\ Loss}{N\ Gen} * 100\%$ T&D Loss = Total transmission and distribution losses (MWh) N Gen = Net generation (MWh)	▪ EPAR ▪ ENIC	%	Annually
Operational efficiency **Technical performance**	Transmission system losses (loss ratio)	$\frac{T\ Loss}{N\ Gen} * 100\%$ T Loss = Transmission system losses (MWh) N Gen = Net generation (MWh)	▪ EPAR ▪ ENIC	%	Annually
Operational efficiency **Technical performance**	Distribution system losses (loss ratio)	$\frac{D\ Loss}{N\ Gen} * 100\%$ D Loss = Distribution system losses (MWh) N Gen = Net generation (MWh)	▪ EPAR ▪ ENIC	%	Annually
Operational efficiency **Commercial performance**	Average non-fuel OPEX per kWh sold	$\frac{NF\ OPEX}{Sales}$ NF OPEX = Non-fuel OPEX (SRD)[115] Sales = Electricity sales (kWh)	▪ Electricity Company	SRD/kWh	Annually
Operational efficiency **Commercial performance**	Average cost of fuel	$\frac{Fuel\ cost}{Sales}$ Fuel cost = Total cost of fuel (SRD) Sales = Electricity sales (kWh)	▪ Electricity Company	SRD/kWh	Quarterly
Operational efficiency **HR performance**	Customers per employee	$\frac{Total\ number\ of\ customers}{Total\ number\ of\ employees}$	▪ Electricity Company	Customers / employee	Annually

[115] Non-fuel operating expenses include maintenance and equipment costs, employee and contracting costs, operation costs, and administrative costs.

Sub-objective and function	KPI	Formula	Scope	Unit	Frequency of reporting
Operational efficiency **HR performance**	Staff cost as share of non-fuel OPEX	$\frac{Total\ staff\ cost}{Total\ non-fuel\ OPEX}$	▪ Electricity Company	%	Annually
Financial efficiency **Financial performance**	Subsidy dependence	$\frac{Subsidy}{Revenue} * 100\%$ Subsidy = Subsidies from Government (SRD) Revenue = Revenue from electricity sales (SRD)	▪ Electricity Company	%	Annually
Financial efficiency **Financial performance**	Net income/loss over revenue	$\frac{NIA}{Revenue} * 100\%$ NIA = Net income/(loss) (SRD) Revenue = Revenue from electricity sales (SRD)	▪ Electricity Company	%	Annually
Financial efficiency **Financial performance**	Revenue per kWh	$\frac{Revenue}{Sales}$ Revenue = Revenue from electricity sales (SRD) Sales = Electricity sales (kWh)	▪ Electricity Company	SRD/kWh	Annually
Financial efficiency **Financial performance**	Return on assets	$\frac{NIB}{Assets} * 100\%$ NIB = Net income/(losses) (SRD) Assets = Assets in the regulatory asset base (SRD)	▪ Electricity Company	%	Annually
Financial efficiency **Financial performance**	Return on equity	$\frac{NIB}{(E)} * 100\%$ NIB: Net income/(losses) (SRD) E = Equity (SRD)	▪ Electricity Company	%	Annually
Financial efficiency **Financial performance**	Debt service coverage ratio	$\frac{EBITDA}{(I + Principal)}$ EBITDA = Earnings before interest, taxes, depreciation, and amortization (SRD) I = Interest paid (SRD) Principal = Repayment of principal on loans (SRD)	▪ Electricity Company	Ratio	Annually

Sub-objective and function	KPI	Formula	Scope	Unit	Frequency of reporting
Commercial efficiency **Commercial performance**	Collection rate	$\frac{Cash}{Revenue} * 100\%$ Cash = Cash collected from customers (SRD) Revenue = Revenue from electricity sales (SRD)	▪ Electricity Company	%	Annually
Commercial efficiency **Commercial performance**	Accounts receivable days (average collection period)	$\frac{Net\ AR}{\left(\frac{Revenue}{365}\right)}$ Net AR = Net accounts receivable (SRD) Revenue = Revenue from electricity sales (SRD)	▪ Electricity Company	Days	Annually
Commercial efficiency **Commercial performance**	Billing accuracy	$1 - \frac{(P\ Con - B\ Con)}{P\ Con} * 100\%$ P Con = Physical consumption (MW) B Con = Billed consumption (MW)	▪ Electricity Company	%	Annually
Commercial efficiency **Commercial performance**	Share of smart meters	$\frac{S\ Meters}{Meters} * 100\%$ S Meters = Smart meters Meters = Total number of meters	▪ Electricity Company	%	Annually
Commercial efficiency **Commercial performance**	Metering efficiency	$\frac{R\ Meters}{Meters} * 100\%$ R Meters = Meters read at least every trimester Meters = Total number of meters	▪ Electricity Company	%	Annually

Source: IDB. 2023. "Consultancy to Support the Design and Development of the Energy Information Management System (EIMS) for the Energy Authority of Suriname (EAS). Deliverable #2: Technical Specifications of EIMS."

5.5.3 KPIs to measure environmental sustainability

Article 8 of the Electricity Act requires the ESP to ensure an environmentally sound electricity supply. The objective of environmental sustainability refers to ensuring that consumers consume electricity efficiently and that electricity suppliers generate electricity in an environmentally sustainable manner. The KPIs to assess environmental sustainability can be broken down into two sub-objectives explained in Table 5.10.

Table 5.10: Sub-objectives for environmental sustainability

Sub-objective	Explanation	Reference
Energy savings	Consumers must efficiently use electricity. This can include energy efficiency measures or energy conservation	Goal 5 of the Draft National Energy Policy 2013-2033: "Surinamese are well aware of the importance of energy conservation, use energy wisely, and continuously pursue opportunities for improving their use of energy"
Renewable energy production	Electricity suppliers should explore renewable energy generation to increase environmentally sustainable production	Draft National Energy Policy 2013-2033 defines increasing renewable energy generation as one of the seven priority areas

Table 5.11 lists the KPIs to monitor in the first phase and Table 5.12 the KPIs to add in subsequent phases.

Table 5.11: KPIs to measure environmental sustainability—To monitor in Phase 1

Sub-objective and function	KPI	Formula	Scope	Unit	Frequency of reporting
Energy savings **Commercial performance**	Electricity consumption over GDP	$\frac{G\ Grid}{GDP}$ G Grid = Gross generation for the National Grid (MWh) GDP = Gross domestic product (Constant SRD)	▪ Electricity Company	MWh/ SRD	Quarterly
Renewable energy production **Technical performance**	Electricity generated with renewable energy	$\frac{G\ RE}{G\ Grid} * 100\%$ G RE = Gross generation by RE facilities (MWh) G Grid = Gross generation for the National Grid (MWh)	▪ Electricity Company	%	Quarterly

Source: IDB. 2023. "Consultancy to Support the Design and Development of the Energy Information Management System (EIMS) for the Energy Authority of Suriname (EAS). Deliverable #2: Technical Specifications of EIMS."

Table 5.12: KPIs to measure environmental sustainability—To add in subsequent phases

Sub-objective and function	KPI	Formula	Scope	Unit	Frequency of reporting
Energy savings **Commercial performance**	Average monthly consumption by customers in the National Grid	$\frac{AE}{C}$ AE = Average monthly sales of electricity to customers (kWh) C = Number of customers	▪ Electricity Company	kWh/ customer	Quarterly
Energy savings **Commercial performance**	Average monthly consumption by residential customers in the National Grid	$\frac{AER}{CR}$ AER = Average monthly sales of electricity to residential customers (kWh) CR =Number of residential customers	▪ Electricity Company	kWh/ customer	Quarterly

Sub-objective and function	KPI	Formula	Scope	Unit	Frequency of reporting
Energy savings **Commercial performance**	Average monthly consumption by non-residential customers in the National Grid	$\frac{AEN}{CN}$ AEN = Average monthly sales of electricity to non-residential customers (kWh) CN = Number of non-residential customers	▪ Electricity Company	kWh/ customer	Quarterly
Renewable energy production **Technical performance**	CO_2 emissions from electricity generation	$\frac{Baseline\ CO2\ emissions}{Current\ CO2\ emissions}$ Current CO_2 emissions = CO2 emissions recorded in the year for which the KPI is calculated	▪ National grid	tCO_2/kWh	Annually
Renewable energy production **Technical performance**	SO_2 emissions from electricity generation	$\frac{Baseline\ SO2\ emissions}{Current\ SO2\ emissions}$ Current SO_2 emissions = SO2 emissions recorded in the year for which the KPI is calculated	▪ National grid	tSO_2/kWh	Annually
Renewable energy production **Technical performance**	NOx emissions from electricity generation	$\frac{Baseline\ NOx\ emissions}{Current\ NOx\ emissions}$ Current NOx emissions = NOx emissions recorded in the year for which the KPI is calculated	▪ National grid	tNOx/kWh	Annually
Renewable energy production **Commercial performance**	Share of electricity generation from distributed solar PV	$\frac{Total\ Distributed\ Solar\ PV\ generation}{Total\ generation}$	▪ EPAR ▪ ENIC ▪ Rural districts	%	Annually
Renewable energy production **Commercial performance**	Share of installed capacity from distributed solar PV	$\frac{Total\ Distributed\ Solar\ PV\ capacity}{Total\ capacity}$	▪ EPAR ▪ ENIC ▪ Rural districts	%	Annually

Source: IDB. 2023. "Consultancy to Support the Design and Development of the Energy Information Management System (EIMS) for the Energy Authority of Suriname (EAS). Deliverable #2: Technical Specifications of EIMS."

5.5.4 Methodology to select the KPIs

The selected KPIs should reflect the energy sector's and ESP's objectives of availability, affordability, and environmental sustainability. The KPIs should also be consistent with global and regional best practices but be tailored to reflect the local context. To determine the KPIs, this analysis reviewed:

- Databases of KPIs that are commonly used to monitor electricity sectors; and
- Regulatory reporting requirements used in other regional and international benchmarks, to understand which KPIs other regulators request from electricity utilities and at what frequency.

Databases

Several databases were reviewed to cross-reference best practices for KPIs for the energy sector in Latin America and the Caribbean. These databases are:

- The IDB Latin America and Caribbean Sustainable Energy Rating Database;
- The World Bank Latin America and Caribbean Utility Benchmarking Database; and
- The International Energy Agency (IEA) Energy Efficiency Indicators Database.

The analysis of these databases involved identifying the most common indicators for each objective and sub-objective. Subsequently, the formula and data points required to calculate each indicator were determined. The most frequently used and relevant indicators were then selected as KPIs for the EIMS.

After selecting KPIs consistent with best practices in the region, the KPIs were adjusted for Suriname. For example, given the nature of the electricity systems in the National Grid, certain KPIs measure performance per system or generation plant. For instance, the availability factor was broken down to measure plant availability for each generation plant. Financial KPIs monitor the performance of EBS and are calculated using audited financial statements.[116]

Regulatory reporting requirements

Regulatory reporting requirements define the data and information that stakeholders must submit to the EAS.

Reporting requirements are regulatory obligations for electricity utilities to provide regular and transparent information on various aspects of operations. These requirements help to ensure accountability and compliance with regulations and that stakeholders, such as regulators, shareholders, and customers, are provided with necessary information.

Reviewing regulatory reporting requirements in regional and international benchmarks helps to understand which KPIs other regulators use to monitor electricity sectors and assess the appropriate reporting frequency for each KPI.

[116] As of July 2024, all assets, liabilities, and stakeholder equity are held by what is now N.V. Energie Bedrijven Suriname (EBS), the entity which produces audited financial statements. EBS will be unbundled into several units, including the Electricity Company (which oversees transmission and distribution and the single buyer and retailer functions), C-Level N.V. EBS, and three subsidiary companies—EPC, N.V. EBS Shared Services, and N.V. Ogane.

The following markets were reviewed:

- International: The United Kingdom (UK) and Australia,[117] considered best practice markets globally; and
- Regional: Jamaica, where regulation is considered best practice regionally, and The Bahamas, as it has relevant similarities to Suriname. These similarities include that the independent regulator was established the same year as the EAS.[118] Further, the state-owned utility Bahamas Power and Light (BPL) supplies electricity to 24 separate island systems across the Family Islands and New Providence. Standardizing and effectively implementing data management and monitoring processes across multiple isolated systems can be a challenge, which Suriname also faces given its lack of a single centralized grid.

Table 5.13 shows the reporting requirements in these markets and the frequency to which these are reported.

[117] Distribution companies in Australia are regulated at the State-level instead of the federal level. This analysis uses the regulation of Western Australia as a benchmark.

[118] URCA. 2016. "URCA is the new regulator for the Electricity Sector (ES)." https://urcabahamas.bs/wp-content/uploads/2017/01/URCA-is-the-Electricity-Sector-ES-New Regulator.pdf#:~:text=The%20Utilities%20Regulation%20and%20Competition%20Authority%20%28URCA%29%20advises,for%20the%20Electricity%20Sector%20%28ES%29%20in%20The%20Bahamas.

Table 5.13: Reporting requirements in other markets

KPI	United Kingdom	Australia	Jamaica	Bahamas	Notes
Technical					
System Average Interruption Duration Index	√, annually	√, annually	√, quarterly	√, annually	
System Average Interruption Frequency Index	√, annually	√, annually	√, quarterly	√, annually	
Customer Average Interruption Duration Index	√, annually	√, annually	√, quarterly		
Available capacity				√, quarterly	
Generation reserve margin					
Availability factor					
Transmission reliability faults				√, annually	▪ **Bahamas:** BPL (the utility) must report the number of outages and the number of transformer failures
Distribution reliability faults				√, annually	▪ **Bahamas:** BPL must report the number of outages and the number of transformer failures
Service coverage		√, annually			▪ **Western Australia:** Distribution companies must report the number of new connections
Load factor				√, annually	
Plant utilization factor					
Heat rate			√, monthly	√, quarterly	
Auxiliary consumption					
System losses	√, annually		√, monthly	√, annually	
Transmission system losses	√, annually		√, monthly		

KPI	United Kingdom	Australia	Jamaica	Bahamas	Notes
Distribution system losses	√, annually	√, annually	√, monthly		
Electricity generated with renewable energy					
Commercial					
Metering efficiency					
Share of smart meters			√, annually		
Billing accuracy			√, quarterly	√, quarterly	▪ **Jamaica:** Guaranteed Standards require the utility to base estimated bills on the average of the last three meter readings and prohibit JPS (the utility) from issuing more than two consecutive estimated bills. JPS's license requires it to submit quarterly reports on its performance against the Guaranteed Standards. ▪ **Bahamas:** Standards for Power Quality and Reliability require BPL to base estimated bills on the average of the last three meter readings. The Bahamas electricity regulator requires the utility to submit its achievements for each of the Customer Quality of Service standards quarterly.
Collection rate				√, quarterly	
Accounts receivable days				√, annually	
Customer complaints per 1,000 customers	√, annually	√, annually		√, quarterly	▪ **UK and Western Australia**: Distribution companies must report the total number of complaints, as well as the percentage of complaints that are repeat complaints in the UK ▪ **Bahamas**: BPL is required to report the number of complaints received, the nature of each complaint, the status of each complaint, and the number of complaints that have been escalated to the regulator

KPI	United Kingdom	Australia	Jamaica	Bahamas	Notes
Average time to process complaints	✓, annually	✓, annually	✓, quarterly	✓, quarterly	▪ **UK**: Distribution companies must report the percentage of complaints outstanding after 1 day and 31 days and the percentage of decisions from the energy ombudsman that go against the distribution company ▪ **Western Australia**: Distribution companies must report the number of complaints addressed within 15 and 20 business days ▪ **Jamaica**: JPS's Guaranteed Standards require it to complete investigations within 30 business days ▪ **Bahamas**: Standards for Power Quality and Reliability require BPL to acknowledge complaints within 5 business days and advise on resolution or the need to investigate further within 10 business days. The Bahamas electricity regulator requires the utility to submit quarterly its achievements for each of the Customer Quality of Service standards.
Average connection period	✓, annually		✓, quarterly	✓, quarterly	▪ **Jamaica**: JPS's Guaranteed Standards require it to connect new customers within 5 days of establishing a contract ▪ **Bahamas**: BPL's Standards for Power Quality and Reliability require it to connect new customers within 5 business days for simple connections and within up to 120 business for complex connections (e.g., connections in remote parts of the Family Islands)
Connection period duration					
Average monthly consumption					
Electricity consumption over GDP					
Average tariff for residential customers				✓, quarterly	

KPI	United Kingdom	Australia	Jamaica	Bahamas	Notes
Average tariff for non-residential customers				✓, quarterly	▪ **Bahamas**: BPL is required to report on the average price per kWh of electricity sold to industrial consumers
Share of electricity expenses in income for residential customers in the bottom quintile					
Financial					
Audited financial statements			✓, annually	✓, annually	▪ **UK**: Distribution companies must report total capital expenditure (capex), load-related capex, non-load-related capex, network operating costs, operational support cost, business support costs ▪ **Bahamas**: According to its license, BPL is required to maintain separate accounts for generation, T&D, and supply services to assist in setting tariffs
Average non-fuel OPEX per kWh sold					
Average cost of fuel			✓, monthly	✓, quarterly	
EBITDA margin					
Subsidy dependence				✓, annually	▪ **Bahamas**: BPL is required to report on its operating expenses covered by revenues (calculated as (utility operating cost/billed revenue) * 100%)
Net income/(loss) over revenue					
Revenue per kWh					
Return on assets	✓, annually				▪ **UK**: Distribution companies must report return on capital
Return on equity	✓, annually				
Debt service coverage ratio					

KPI	United Kingdom	Australia	Jamaica	Bahamas	Notes
Human resources					
Customers per employee				✓, bi-annually	
Share of staff cost from non-fuel operating expenses				✓, annually	

Sources: Australia: Economic Regulation Authority;[119] Jamaica: OUR;[120] UK: Ofgem;[121] Bahamas: URCA[122]

[119] Economic Regulation Authority. 2023. "Electricity Distribution License Performance Reporting Handbook." https://www.erawa.com.au/cproot/23233/2/Electricity-Distribution-Licence-Performance-Reporting-Handbook-2023-clean-.PDF

Economic Regulation Authority. 2023. "Electricity Retail Licence Performance Reporting Handbook"https://www.erawa.com.au/cproot/23220/2/2023-Electricity-retail-licence-performance-reporting-handbook---clean-version.PDF

Economic Regulation Authority. 2024. "Regulatory Guidelines." https://www.erawa.com.au/electricity/electricity-licensing/document-archive/regulatory-guidelines

[120] Office of Utilities Regulation. 2024. "Jamaica Public Service Company Limited Rate Review 2019-2024." https://our.org.jm/wp-content/uploads/2021/04/jps_2019-2024_tariff_review_determination_notice_-_final_-20201224.pdf

Office of Utilities Regulation. 2022. "Comprehensive Review of Guaranteed Standards Scheme for the Jamaica Public Service Company Limited and the National Water Commission." https://our.org.jm/wp-content/uploads/2022/06/JPS-NWC-Determination-Notice-2024-Feb-28.pdf

Office of Utilities Regulation. 2022. "Jamaica Public Service Company Limited, Annual Review and Extraordinary Rate Review." https://our.org.jm/wp-content/uploads/2022/08/2022-JPS-Annual-Tariff-and-Extraordinary-Determination-Notice-2.pdf

[121] Grant McEachran, Ofgem. 2017. "Guide to the RII0-ED1 electricity distribution price control." https://www.ofgem.gov.uk/sites/default/files/docs/2017/01/guide_to_riioed1.pdf

Ofgem. 2024. "Energy Network Indicators." https://www.ofgem.gov.uk/energy-network-indicators

[122] URCA. 2020. "Public Electricity Supply Licensees Reporting Obligations Procedures and Guidelines." https://urcabahamas.bs/decisions/es-10-2020-public-electricity-supply-licensees-reporting-obligations-procedures-and-guidelines-final-decision-on-reporting-requirements/ and URCA. 2020. "Consumer Protection Regulations for the Electricity Sector in the Bahamas." https://urcabahamas.bs/wp-content/uploads/2020/12/8_12_20-Final-ES-CPR.pdf

5.6 Baseline KPIs

Most baseline KPIs for Suriname will need to be updated once the relevant data is available or confirmed. Table 5.14 below shows the KPIs and the baseline values (as of 2023) that can be calculated for EBS with the available information. Once additional data is provided directly or through the EIMS, all the KPIs defined in should be easily calculated.

Table 5.14: KPI baseline for EBS (2023)

KPI	Baseline value
Available capacity percentage	▪ EPAR: 87% ▪ ENIC: 75% ▪ Albina: 49% ▪ Apoera: 59% ▪ Coronie: 63% ▪ Moengo: 48% ▪ Wageningen: 51% ▪ Pokigron: 40%
Generation reserve margin	▪ EPAR: 169% ▪ ENIC: 129%
Plant availability	▪ SPCS: 87% ▪ AHFP: 95%
Load factor	▪ EPAR: 77% ▪ ENIC: 63%
Plant utilization factor	▪ DPP1: 5% ▪ SPCS: 66% ▪ AHFP: 74% ▪ ENIC: 52%
Heat rate	▪ DPP1: 8,269Btu/kWh ▪ SPCS: 7,494Btu/kWh ▪ ENIC: 8,127Btu/kWh ▪ Rural districts: 9,552Btu/kWh
Auxiliary consumption	▪ DPP1: 14%
Average cost of fuel	▪ SPCS: 4,350 SRD/kWh
EBITDA margin	▪ EBS: -84%
Net income/(loss) over revenue (before subsidies)	▪ EBS: -122%
Return on assets (before subsidies)	▪ EBS: -50%
Return on equity (before subsidies)	▪ EBS: 33%

KPI	Baseline value
Number of customers per employee	▪ EBS: 170 customers per employee

Source: Castalia-Grid Advisors calculations based on EBS data provided.

5.7 Minimum supply standards

Minimum supply standards are baseline requirements that EBS must meet to comply with its regulatory obligations and ensure the quality of electricity supply in terms of:

- Power quality and reliability—The physical quality of the electricity service measured with variables such as voltage level and system frequency; and
- Customer service quality—The aspects related to the interaction between the utility and its customers, such as the time it takes to establish new connections, billing accuracy, and complaint treatment.

Supply standards are particularly important in markets like Suriname, where there is a single buyer and retailer of electricity, as there is no competitive incentive to improve service.

Section 5.7.1 reviews supply standards enforced in international and regional markets. Markets reviewed include:

- International: The United Kingdom (UK) and Australia,[123] considered best practice markets globally; and
- Regional: Jamaica, where regulation is considered best practice regionally, and The Bahamas, which has relevant similarities to Suriname. These similarities include the fact that the independent regulator was established the same year as the EAS.[124] Further, the state-owned utility Bahamas Power and Light (BPL) supplies electricity to 24 separate island systems across the Family Islands and New Providence. Standardizing and effectively implementing data management and monitoring processes across multiple isolated systems can be challenging for Suriname, given its lack of a single centralized grid.

Based on this review and best practices, Section 5.7.2 recommends supply standards for Suriname.

5.7.1 Review of international and regional supply standards

The following sections review the supply standards defined by regulators in the UK, Australia, Jamaica, and The Bahamas to ensure the power quality and reliability of supply and the quality of customer service.

[123] Distribution companies in Australia are regulated at the State-level instead of the federal level. This analysis uses the regulation of Western Australia as a benchmark.

[124] URCA. 2016. "URCA is the new regulator for the Electricity Sector (ES)." https://urcabahamas.bs/wp-content/uploads/2017/01/URCA-is-the-Electricity-Sector-ES-New Regulator.pdf#:~:text=The%20Utilities%20Regulation%20and%20Competition%20Authority%20%28URCA%29%20advises,for%20the%20Electricity%20Sector%20%28ES%29%20in%20The%20Bahamas.

Power quality and reliability

Supply standards to ensure power quality and reliability commonly include voltage and frequency deviation. Voltage and frequency variations outside the ranges can lead to system outages and malfunctions, underperformance, and failure of consumers' equipment and devices because the power system and consumers' electrical equipment and devices are built to operate within specific voltage and frequency ranges. Further, metrics such as SAIFI and SAIDI measure the frequency and duration of power outages.

Table 5.15 shows the standards for voltage and frequency deviation in the reviewed markets. The standards for absolute voltage and frequency levels are not shown because these are specific to each power system.

Table 5.15: International and regional supply standards for power quality and reliability

Standard	UK	Australia	Jamaica	The Bahamas
Voltage deviation	+10%, -6%	+/- 6%	+/- 5%	+/- 5%
Frequency deviation	+/- 1%	+/- 2.5%	+/- 0.4%	+/- 2%

Sources: UK: National Grid;[125]Australia: Western Australia Government;[126]Jamaica: OUR;[127] The Bahamas: URCA[128]

Customer service quality

Customer service quality standards ensure that customers receive reliable, efficient, and fair service. These standards commonly cover the following areas:

- Connection and disconnection services
- Metering and usage information
- Billing and payment services
- Response time to inquiries and complaints
- Customer communication and information, and
- Service quality during outages.

[125] National Grid. 2024. "The guaranteed Standards of Performance Customer Payment Scheme." https://www.nationalgrid.co.uk/downloads-view-reciteme/660296

ESO. 2024."What is frequency?." https://www.nationalgrideso.com/electricity-explained/how-do-we-balance-grid/what-frequency

[126] Western Australia Government. 2004. "Electricity Industry(Network Quality and Reliability of Supply) Code 2005."https://www.legislation.wa.gov.au/legislation/prod/filestore.nsf/FileURL/mrdoc_46909.pdf/$FILE/Electricity%20Industry%20(Network%20Quality%20and%20Reliability%20of%20Supply)%20Code%202005%20-%20%5B01-i0-00%5D.pdf?OpenElement

[127] Office of Utilities Regulation. 2024. "Jamaica Public Service Company Limited Rate Review 2019-2024."https://our.org.jm/wp-content/uploads/2021/04/jps_2019-2024_tariff_review_determination_notice_-_final_-20201224.pdf ; https://our.org.jm/wp-content/uploads/2021/01/electricity_act_-_jamaica_electricity_book_of_codes_-_clean.pdf

[128] URCA. 2023. "Standard for Power Quality and Reliability in Electric Power Systems."https://www.urcabahamas.bs/wp-content/uploads/2023/12/UED_-ES-09-2023-Standard-for-Power-Quality-and-Reliability-in-Electric-Power-Systems-SoR-and-FD-1.pdf

Table 5.16 shows the standards for customer service quality in the reviewed markets. As the table shows, regulators can set different values for the same standard depending on the type of customer or its location.

Table 5.16: International and regional supply standards for commercial quality

Standard	UK	Australia	Jamaica	The Bahamas
Commencement of service				
Service activation and transfer	▪ Within 5 business days	▪ Urban customers: Within 2 business days ▪ Rural customers: Within 6 business days		▪ Within 5 business days
Service connection	▪ Within 40 business days	▪ Within 20 business days	▪ Simple connection: 5 business days ▪ From 30 meters (m) to 250m of distribution line: estimate within 15 business days, connection within 40 business days after payment	▪ Simple connection: within 5 business days ▪ Complex service connection: within 120 business days
Metering				
Meter reading	At least once a year	At least once a year	▪ 99% of meters read within the time specified in JPS's billing cycle ▪ No more than two consecutive estimated bills	▪ Residential customers: every 3 months ▪ Non-residential: every 2 months
Meter replacement			▪ Within 20 business days after detection of fault (not due to tampering by the customer) ▪ For meter change, notification within 1 billing period of the change	
Billing				
Billing period		▪ Bill issued at least once every 100 days		95% of consumers in the billing period (the period between two-meter readings, whether actual or estimated) invoiced for no more than 33 days

Standard	UK	Australia	Jamaica	The Bahamas
Complaints				
Complaints response and resolution	▪ For voltage complaints: send an explanation within 5 business days and visit the customer's premises for investigation within 7 business days ▪ For meter complaints: send assessment and inform of action within 5 business days	▪ Acknowledgment within 10 business days ▪ Resolution within 20 business days	▪ Acknowledgement within 5 business days ▪ Resolution within 30 business days (60 if it involves a third party)	▪ For bill complaints: – Acknowledgement within 5 business days – Resolution within 30 days ▪ For voltage complaints: – Assessment within 5 business days – Resolution within 30 days
Trouble call dispatched to 24-hour service crews within 24 hours			▪ Response within 5 hours for emergency calls (broken wires, broken poles, fires)	▪ Within 24 hours of receipt of verified trouble call unless specific arrangements are made with the consumer to address otherwise
Fault repaired	▪ For distributor's fuse repair: – 3 hours on a working day – 4 hours on a non-working day		▪ Within 48 hours for urban customers ▪ Within 96 hours for rural customers	▪ Within 12 hours on a single consumer service ▪ Within 24 hours for multiple customers
Reconnection				
Reconnection after disconnection for non-payment	▪ Within 24 hours of payment of the overdue amount and reconnection fee	▪ Urban customers: within 2 business days ▪ Rural customers: within 6 business days	▪ Within 24 hours of payment of the overdue amount and reconnection fee	▪ Within 2 business days after payment of the overdue amount and reconnection fee
Reconnection after wrongful disconnection		▪ As soon as possible after receiving the customer's claim	▪ Within 5 business hours	▪ Within 6 business hours
Outages				

Standard	UK	Australia	Jamaica	The Bahamas
Notification of planned outages	▪ At least 48 hours in advance by a letter, a card, a text, or email	▪ At least 72 hours in advance individually (e.g., a notice in the mail) or to local customers generally (e.g., a notice in the local newspaper or radio)	▪ At least 48 hours in advance	At least 24 hours in advance via the local media, social media platforms, emails, and BPL's website
Supply restored after unplanned distribution system fault	▪ Within 12 hours for normal weather (affecting less than 5,000 people) ▪ Within 24 hours for normal weather (over 5,000 people) or medium severe weather events ▪ Within 48 hours for large severe weather events	▪ Within 12 hours	▪ Within 24 hours	▪ Within 24 hours

Sources: UK: National Grid;[129] Australia: Economic Regulation Authority;[130] Jamaica: Office of Utilities Regulation;[131] The Bahamas: URCA[132]

[129] National Grid. 2024. "The guaranteed Standards of Performance Customer Payment Scheme." https://www.nationalgrid.co.uk/downloads-view-reciteme/660296 ; https://www.legislation.gov.uk/uksi/2015/1544/contents/made ; https://www.ofgem.gov.uk/sites/default/files/docs/2019/02/licence_guide_metering_billing_and_payments_1.pdf

[130] Economic Regulation Authority. 2024. "Switched on: Energy Consumers Guide." https://www.erawa.com.au/gas/switched-on-energy-consumers-guide

[131] Office of Utilities Regulation. 2024. "Determination Notice." https://our.org.jm/wp-content/uploads/2022/06/JPS-NWC-Determination-Notice-2024-Feb-28.pdf ; https://www.jpsco.com/wp-content/uploads/2022/03/JPS-2019_24-Rate-Application-Public-Version.pdf

[132] URCA. 2020. "Consumer Protection Regulations for the Electricity Sector in the Bahamas."

5.7.2 Supply standards for Suriname

Table 5.17 recommends the minimum supply standards for Suriname's electricity sector to ensure the quality of commercial service. The standards and their levels are based on those commonly used in international and regional markets reviewed in the previous section. For power quality, the EAS should define standards for voltage and system frequency levels and deviation that are consistent with the Grid Code. Common standards for power quality include metrics for voltage regulation, voltage unbalance, harmonics content, and flicker content.[133]

The recommended supply standard values can be updated in the ESP as more data on EBS's baseline performance becomes available.[134] At that point, it will be possible to confirm that the standards recommended in Table 5.17 are in line with current levels of service in Suriname.

The EAS may choose which standards should be guaranteed. Guaranteed standards are service levels that must be met for individual customers and involve compensatory payment to the affected customer if breached. Guaranteed standards generally relate to quality of commercial service. Standards that are not guaranteed do not involve compensatory payment to affected customers but can involve payment of penalties to the regulator. Non-guaranteed standards generally cover areas of service that affect a large number of customers and where it is not feasible to give individual guarantees, such as reliability and power quality.[135]

Table 5.17: Minimum supply standards for Suriname

Standard name	Unit	Standard level
Power quality		
Nominal voltage	kV	To be consistent with Grid Code
Voltage deviation	%	To be consistent with Grid Code
Nominal system frequency	Hz	To be consistent with Grid Code
System frequency deviation	%	To be consistent with Grid Code
Customer service quality		
Service action and transfer	Days	Within 5 business days
Service connection	Days	Within 5 to 40 business days, depending on the location and complexity of the connection
Meter reading	Frequency	100% of the meters are read at least once a quarter

[133] Ramon Nadira, Nelson Bacalao, and Carlos Dortolina. 2006. "Measuring the Performance of Distribution Utilities A Top-Down/Bottom-Up Approach" IEEE PES Transmission and Distribution Conference and Exposition Latin America, Venezuela.

[134] The Electricity Act empowers the EAS to request the data required to assess EBS's compliance with the supply standards and define the timeline for EBS to submit that data.

[135] OUR, 1999. "Quality of service standards for electric utility service." https://our.org.jm/wp-content/uploads/2021/01/quality_of_service_standards_for_electric_utility_services_-_a_consultative_document_nov_1999.pdf

Standard name	Unit	Standard level
Meter replacement	Days	Within 20 business days after the detection of a fault that is not due to tampering by the customer
Customer calls	%	▪ 70% of calls are answered within 30 seconds ▪ 100% of emergency calls are answered within 30 minutes
Complaint acknowledgement	Days	Within 5 business days
Complaint resolution	Days	▪ Technical issues: Within 7 business days ▪ Non-technical issues: Within 20 business days ▪ If a third party is involved: Within 60 business days
Fault repair	Days	▪ Urban: within 48 hours ▪ Rural: within 96 hours
Reconnection after disconnection for non-payment	Days	Within 2 business days
Reconnection after wrongful disconnection	Days	Within 6 hours
Notification of planned outages	Hours	At least 48 hours in advance
Notification of unplanned outages	Hours	Within 2 hours after the unplanned outage has occurred
Supply restored after unplanned distribution system fault	Hours	Within 24 hours

5.8 KPI targets

KPI targets will help the sector improve its performance to achieve an electricity supply that is available, affordable, and environmentally sustainable, per the sector's goals. KPI targets provide a benchmark against which the EAS can measure and assess EBS's performance, indicating where improvements are needed or where EBS is performing well. The targets should be realistic and achievable (defined based on EBS's baseline performance) but also aspirational (providing a trajectory for EBS to improve performance).

Table 5.18 recommends a minimum set of KPI targets for EBS. These targets have been defined based on sector best practice and the performance of Caribbean utilities that are relatively well-performing. Once data on EBS's baseline performance is provided, all KPI targets will be revisited and updated, if needed.

Table 5.18: KPI targets for Suriname

Objective	KPI	Unit	Baseline performance	Medium-term target	Long-term target
Availability	SAIDI	Minutes/ customer/year	Not available (NA)	▪ Urban: 250 ▪ Rural: 350	▪ Urban: 100 ▪ Rural: 200

Objective	KPI	Unit	Baseline performance	Medium-term target	Long-term target
	SAIFI	Interruptions/ customer/year	NA	▪ Urban: 6 ▪ Rural: 8	▪ Urban: 2 ▪ Rural: 4
	Service coverage	%	NA	▪ Urban: 100% ▪ Rural: TBD	▪ Urban: 100% ▪ Rural: TBD
Affordability	System losses	%	NA	15%	10%
	Heat rate	Btu/kWh	NA	To be defined (TBD)	TBD
Environmental sustainability	Electricity generated with renewable energy	%	NA	35%	TBD
	CO_2 emissions from electricity generation	tCO2/kWh	NA	TBD	TBD
	SO_2 emissions from electricity generation	tSO2/kWh	NA	TBD	TBD
	NOx emissions from electricity generation	tNOx/kWh	NA	TBD	TBD

Note: When baseline data is provided, all targets will be revisited and updated if needed. Medium-term is defined as the first 5 years of implementation of the ESP. Long-term is defined as the end of the 20 years covered by the ESP.

Policy decisions will inform KPI targets related to reducing emissions. Suriname's Nationally Determined Contribution (NDC) defines the energy sector as one of the sectors focused on reducing emissions. The NDC plans to reduce emissions from the energy sector by increasing renewable energy and energy efficiency, although it does not set specific emissions reduction targets.[136] If the Government chooses to define such targets in the future, the KPI targets above should be updated to reflect them.

Likewise, available generation resources and technologies will inform KPI targets. For example, the expansion plan will determine the future generation mix, which will impact the amount of electricity generated with renewable energy. The ESP will include revised KPI targets as more data becomes available and further analysis of the generation mix is completed.

5.9 Strategy to achieve KPI targets and supply standards

This section recommends actions to help EBS achieve KPI targets and meet supply standards and, ultimately, the energy sector's availability, affordability, and environmental sustainability objectives.

[136] The Republic of Suriname. 2020. "Nationally Determined Contribution 2020." https://unfccc.int/sites/default/files/NDC/2022-06/Suriname%20Second%20NDC.pdf

The EAS and EBS face various challenges in improving the sector's performance. These challenges notably relate to establishing an effective institutional and regulatory framework. The MNH needs to build capacity to plan and implement an energy policy.[137] Likewise, the relatively recently established EAS needs to continue building its capacity to regulate the sector, including data collection and management, which are expected to improve with the implementation of the EIMS. The EAS and EBS will also have to adapt their roles as new responsibilities might arise from:

- The implementation of reforms planned in the Electricity Act and the ESP, like the tariff reforms and the Electricity Act's mandate to unbundle EBS into separate units for generation, transmission, distribution, and retail;[138] and
- The development and changes in the energy sector, particularly with new technologies and consumer preferences.

Other notable challenges are:

- The lack of generation and transmission planning, which is expected to be addressed with the development of the expansion plan;
- The financial performance of EBS, which has historically relied on subsidies to operate; and
- The low reliability and high service cost in sparsely populated areas in the hinterland, with most sites receiving only 6 hours of electricity per day and relying on expensive diesel units.[139]

To improve EBS's performance and enable it to achieve the KPI targets and meet its minimum supply standards, the first step is to perform an operational and maturity diagnostic. The diagnostic will:

- Assess EBS's baseline performance, strengths, and weaknesses in detail, including areas of inefficiencies that could be reduced or eliminated to decrease costs. This assessment will be carried out with a quantitative analysis (using KPIs) and a qualitative analysis of the processes and systems in place for EBS to carry out its functions and how clearly defined and implemented they are across EBS. The assessment will cover technical operations, commercial operations, financial performance and management, organization and strategy, human resources; and
- Define improvement strategies that are fit-for-purpose to address EBS's weaknesses and move it towards becoming a utility of the future.

Performing the diagnostic involves the following steps:

- Collecting and reviewing data that is accurate, complete, consistent, and of sufficient quality—this could be done using the EIMS and additional requests to EBS if needed.

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[137] MNH. 2023. "Terms of Reference. Consultancy Services for the Preparation and Development of the ESP."

[138] IDB. 2024. "Suriname: Electricity Sector Regulatory Review & Minimum Regulatory Function Strategy." p 9.

[139] MNH. 2023. "Terms of Reference. Consultancy Services for the Preparation and Development of the ESP."

- Reviewing the legal and regulatory framework for the energy sector to ensure that EBS complies with its legal and regulatory obligations, such as its minimum supply standards.
- Using tools to gather, organize, and assess data, such as:
  - An Excel-based tool that scores EBS's operations and maturity using metrics
  - Consultations with EBS staff to gather information that might not be documented; and
  - Performance trend analysis and benchmarking.
- Recommending actions to be implemented by:
  - EBS, to improve its performance and maturity, and
  - The EAS, to effectively incentivize EBS to improve performance, in a way that supports the sector's objectives without creating an unnecessary regulatory burden.

As the diagnostic is carried out, the EAS should implement a training plan to build its capacity to monitor KPIs and understand and enforce its regulatory powers to be as effective as possible.

6 Interconnection rules

Article 16 of the Electricity Act specifies that "the Electricity Company is required to provide a connection to the National Grid[140] to any (legal) person requesting this connection, in accordance with the conditions set forth in the ESP, including the agreed time period between application and connection and within the authorized charges rate schedule."[141] Therefore, the ESP will establish the conditions that the distributed generation customers must adhere to in order to interconnect to the National Grid.[142] These interconnection rules include general guidelines and procedures that govern the interconnection process and the technical requirements to interconnect the generation facilities to the National Grid. The Electricity Act provides general provisions regarding these rules and describes the role of the Certification Institution in this process (as discussed in Section 6.1). The interconnection rules themselves, including the procedures for the interconnection process and the technical requirements, are in the Surinamese Grid Code – Connection Code ("Connection Code") and are summarized in Section 6.2.

6.1 Provisions for interconnection in the Electricity Act

The Electricity Act defines a private producer—a distributed generation customer—as "a natural person or legal entity that generates sustainable electricity for his own consumption and offsets the electricity supplied to the National Grid with his own consumption as Consumer."[143] In this

[140] Article 1(j) of the Electricity Act defines National Grid as "all the grids operated by the Electricity Company."

[141] Electricity Act 2016. "Article 16.1."

[142] The Electricity Act defines National Grid as "all the grids operated by the Electricity Company."
Electricity Act 2016. "Article 1(j)."

[143] Electricity Act 2016. "Article 1(f), Article 20.4."

regard, distributed generation customers must be connected to the National Grid so that the Electricity Company can dispatch the renewable energy generated.

Article 20 of the Electricity Act states that all producers must follow rules and other conditions to connect to the National Grid. These can include, for example, conditions for maintaining installations and equipment.[144] The ESP will provide other rules for connecting generating units to the National Grid and other technical specifications and procedures.[145]In addition, the Electricity Act states that an independent[146] Certification Institution must verify the electrical installations of distributed generation customers and those of the Electricity Company, other producers, and customers.[147] The Certification Institution thereby ensures that distributed generation customers comply with the interconnection rules by conducting inspections and certifying any new or temporary installations before they are connected to the National Grid and modifications or expansions of existing installations to the National Grid.[148]

Like all other electrical installations of the Electricity Company, Producers, and Consumers, the interconnection of new generation units can only be carried out by certified Electrical Contractors. An Electrical Contractor is defined as an authorized natural person or legal entity responsible for the construction, expansion and maintenance of electrical installations of Consumers and future Consumers.

The EAS is responsible for recognizing an Electrical Contractor and provides the ability for an Electrical Contractor to be certified. Electrical Contractors are tested every three years based on this recognition. The EAS may supplement the existing conditions with which Electrical Contractors must comply to be recognized as such. The conditions are laid down in the ESP.

The Electrical Contractors are required to follow the set guidelines in connection with the performance of their work. The EAS may issue binding instructions in that regard.

By law, both electrical contractors and the Certification Institution are considered to be part of the energy sector and, therefore, must comply with its regulations.

The Certification Institution is responsible for conducting inspections, statutory or otherwise, of electrical installations on the instructions and at the expense of the owner of the installation in question. Inspection and certification of electrical installations by the certification institution is mandatory in the following cases:

- For new installations, before connecting to the National Grid;
- For temporary installations, before connecting to the National Grid; and
- On modification or expansion of installations already connected to the National Grid.

[144] Electricity Act 2016. “Article 20.2.”

[145] Electricity Act 2016. “Article 20.5(b).”

[146] Electricity Act 2016. “Explanatory notes – Certification Institution.”

[147] Electricity Act 2016. “Article 23.”

[148] Electricity Act 2016. “Article 23.4.”

If there is reason to do so, the EAS, as the supervisory authority, may order new inspections of installations that have already been certified. The certification standards are laid down in the ESP.

The Electrical Contractors and the Certification Institution are under the supervision of the EAS and in the event of failure to comply with the regulations and/or guidelines in the ESP, may be issued with binding instructions by the EAS, with the possibility of imposing penalties in the event of non-compliance. The EAS is authorized to request the data or information that it considers necessary for the performance of its tasks from Electrical Contractors and the Certification Institution, as well as the Electricity Company, Producers or subsidized consumers.

In the absence of an independent Certification Institution (as mandated to be established in the Electricity Act), EBS may be appointed as the certification institution but will then be required to transfer its activities as a certification institution to a business unit separated from other activities, with separate accounts.

It is accepted industry practice to apply and enforce international standards relative to the following aspects of electrical transmission infrastructure facilities:

- Technical characteristics;
- Safety;
- Power quality;
- Protection and control;
- Impact on the network; and
- Maintenance and monitoring.

Below are the main international standards that are recommended to be used by the Certification Institution to verify that the connection of transmission infrastructure equipment to the network in Suriname meets industry-accepted norms:

- ANSI/IEEE C2: National Electricity Safety Code;
- International Mechanical Code/2000;
- IEC 60617: Graphical Symbols for Drawings;
- IEC 61082-1: Preparation of Documents used in Electro Technology;
- ISO 128-1: Technical drawings - General principles of presentation;
- ISO 9000: Quality Management: Parts 1 to 4;
- ISO 9001: Quality Systems Model for Quality Assurance in Final Design, Development, Production, Installation and Servicing;
- ISO 10005: Quality Management Systems – Guidelines for Quality Plans;
- ISO 10006: Guidelines for Quality Management in projects;
- IEC 60038: It defines the nominal voltages of electrical systems and the limits that equipment must comply with in terms of operating voltages;

- IEC 60947: Establishes the requirements for electrical protection and control equipment, such as switches, relays and circuit breakers, used to protect electrical systems from overloads and short circuits;
- IEC 60255: Standards for protection relays and their applications in transmission systems;
- IEC 61850: Standard for electrical substation automation and data communication, covering the interconnection of protection, control and monitoring equipment within electrical networks;
- IEC 61672: Establishes the requirements for power quality measurement, such as measurement of harmonics and voltage variations;
- IEEE 1547: It is one of the key standards for the interconnection of distributed energy resources (such as generators and solar panels) to distribution and transmission networks. It defines the technical and performance requirements that equipment must meet to ensure safe and reliable integration;
- IEEE 519: Establishes limits and criteria for power quality, especially in relation to harmonic distortions, which are generated by non-linear electrical equipment, such as inverters in distributed generation systems;
- IEEE 142 (Green Book): It is a reference standard for the protection of electrical systems, providing guidelines on grounding and control of fault currents;
- ANSI C37: Standards for circuit breakers, disconnectors and other protection equipment in transmission and distribution systems;
- ANSI C50: Standards for electric generators and motors, including requirements for their connection to the electrical grid;
- ANSI C84: Establishes standards for service voltages and their tolerances in distribution and transmission networks;
- NERC Reliability Standards: These standards cover a wide range of topics, including the connection of generation equipment to the grid, frequency control, voltage stability, and protection of transmission systems;
- PRC (Protection and Control) Standards: These establish the requirements for protection systems used in the transmission network, such as protection against short-circuit events or for disconnecting equipment in the event of failures;
- ISO 9001: Related to quality management in energy companies, which ensures that equipment and connections are managed according to high-quality procedures;
- ISO 50001: Focused on energy management within industrial facilities, which also applies to the connection of equipment to electrical networks.

6.2 Interconnection rules

The ESP will include the technical requirements and procedures (hereafter referred to as *interconnection rules*) for distributed generation customers to connect to the National Grid. The interconnection rules themselves, including the procedures for the interconnection process and the technical requirements for interconnection to the National Grid, are in the Connection Code.

The Connection Code sets the technical conditions and requirements for regulating the access of generation units, demand facilities, and distribution systems to the National Grid, ensuring the safe and secure functioning of the Surinamese Power System.

6.2.1 Connection process

In general, all distributed generation customers, regardless of their size (in terms of MW capacity) and location on the system, can connect to the National Grid, provided they meet the provisions of the Connection Code. Further, since distributed generation customers may be both generation and demand facilities (or connections), they must meet the provisions applicable to generation units[149] and demand facilities.[150]

The Connection Code prescribes that all new generation units (independent of whether or not they are subject to the tendering process as per the Electricity Act[151]) and demand facilities must complete the six-step process illustrated in Figure 6.1 to apply for a connection request.[152]

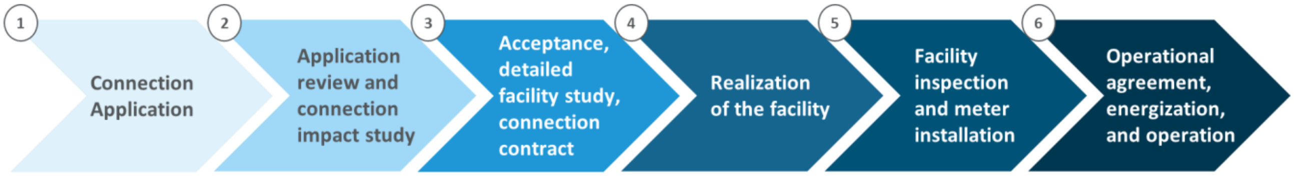
[149] Connection Code. "Section 5, 7."

[150] Connection Code. "Section 6."

[151] Electricity Act 2016. "Article 21."

[152] Connection Code. "Section 3."

Figure 6.1: Steps for interconnecting to the National Grid



1. Connection Application

- **Preliminary studies:** The Applicant conducts cost and revenue assessments for the Facility, with EBS providing support on hosting capacity and connection issues if needed
- **Connection Application**: The Applicant submits a connection application with payment proof and required documents, which EBS reviews for validity

2. Application review and connection impact study

- **impact Study:** EBS assesses grid impact within 120 business days
- **Approval and estimate**: If acceptable, EBS approves the application and provides a detailed connection cost estimate

3. Acceptance, detailed facility study, connection contract

- **Acceptance of the Connection Estimate:** Applicant has 90 days to accept or request changes, covering Facility Study costs
- **Detailed Facility Study:** EBS provides technical details, timelines, and fees within 90 days
- **Connection Contract:** Applicant has 60 days to sign, secure permits, and provide payment security, or the request is terminated

4. Realization of the facility

- **Start of construction**: After the contract is signed and the fee is paid, construction begins on the Connection Asset and Facility, to be completed by the estimated connection date

5. Facility inspection and meter installation

- **Final Inspection**: Once civil and electrical works are complete, EBS conducts an on-site inspection to ensure compliance with documentation and standards. If successful, EBS installs the meter(s) as per the connection contract

6. Operational agreement, energization, and operation

- **Operational Agreement:** Define responsibilities and facility characteristics, followed by notifications for energization and interim operation
- **Final Notification:** Certifies compliance with the Grid Code and authorizes full facility operation

Each step is described in more detail below.

Step 1: Connection Application

Preliminary studies and facility pre-application report

The Applicant is responsible for all preliminary studies related to the assessment of the costs of the Facility, the estimation of revenues, and the expected return period of investment. For connections that are not subject to the tendering process, as per Article 21 of the Electricity Act, EBS may support the potential Applicant in its decision-making process regarding the location and sizing of the Facility. This support may include providing data and/or developing tools that assess the available hosting capacity of the National Grid. These tools can also help identify areas of the grid with potential connection challenges, which could lead to higher connection costs or longer connection timelines.

Upon the Applicant's specific request and payment of a designated fee set by EBS, EBS may also choose to prepare a pre-application Facility report. This pre-application report will cover the information in Section 3.1.1 of the Connection Code, which includes detailed information on the National Grid conditions and the hosting capacity at the connection site specified by the Applicant, the proposed technology, and the primary energy source.

Connection application

To start the connection process, the Applicant shall submit a connection application, which can be a form EBS provides upon request or is publicly available on EBS's website. The application must be accompanied by proof of payment for the fee, which EBS estimates on a case-by-case basis to conduct the Connection Impact Study. The application should also include the customary list of documents specified in Section 3.1.2 of the Connection Code.[153]

Upon receipt of the connection application form, EBS shall check its validity and completeness and inform the Applicant of any missing documents.

Step 2: Application Review and Connection Impact Study

Upon receiving a valid and complete connection application and the Applicant's prepayment of the estimated connection study fee, EBS will conduct a Connection Impact Study to assess the proposed Facility's impact on the National Grid. This assessment will be completed within 120 business days of receiving the valid application.

Section 3.2 of the Connection Code specifies the minimum requirements of the Connection Impact Study. This includes an estimate of the connection fee with a detailed breakdown of the cost components and the fee for the Connection Assets required to integrate power into the National Grid at the connection point. The fee is calculated based on criteria established by EBS and should be publicly available.

If the Connection Impact Study reveals an acceptable impact on the National Grid, EBS will approve and send a connection estimate to the Applicant, who will approve the connection application and report the results of the Connection Impact Study.

Step 3: Acceptance, Detailed Facility Study, Connection Contract

Acceptance of the connection estimate

The Applicant must review, sign, and return the connection estimate within 90 days, either accepting the estimate as provided or requesting modifications. By doing so, the Applicant also agrees to pay EBS for the costs of conducting the Detailed Facility Study. If the Applicant neither accepts the estimate nor requests changes within this timeframe, the connection application will automatically expire.

Detailed Facility Study

EBS can determine whether or not a Detailed Facility Study is necessary for connection. If deemed necessary, EBS prepares the Detailed Facility Study and provides the Applicant with a detailed technical solution within 90 business days of receiving the application. The detailed technical solution for the connection shall contain:

- The list of the executive design phases for the work on the Connection Assets, and any work on the existing National Grid necessary to satisfy the connection application;
- An estimated timeframe for each of the design phases, indicating who will be responsible for each phase; and
- The final connection fee and the time required to construct the Connection Assets.

The detailed technical solution for the connection will be considered the reference document concerning executive planning and construction of the Connection Assets.

[153] Connection Code. "Section 3.1.2."

Connection Contract

Upon completing the Detailed Facility Study, EBS will provide the Applicant with a connection contract. The connection contract will detail:

- The terms and conditions for connecting the Facility or any equipment to the new connection point in the National Grid as determined by the Detailed Facility Study;
- The physical separation point and ownership;
- Responsibilities for the construction and the payment of the Connection Assets that will be required for the connection. These responsibilities will be designated either to EBS, the Applicant, or both. Standard practice is for the Applicant to be responsible for the costs of the Connection Assets from the Facility up to the physical separation of the connection point, while EBS is responsible for any reinforcement of the Grid beyond the connection point;
- The expected connection date; and
- The metering scheme to be used to meter the Facility.

The Applicant must accept the connection contract within 60 business days of receiving notification from EBS of the detailed technical solution for the connection. Failure to do so will result in the forfeiture of the detailed technical solution and the expiration of the connection request. During these 60 days:

- The approved connection application, related connection estimate, and the results of the Detailed Facility Study remain valid, and EBS shall book and assign the hosting grid capacity to the Facility; and
- It is the Applicant's responsibility to go through and obtain all other permitting procedures necessary for the Facility's construction, installation, and operation. Depending on the local regulatory framework, the characteristics of the Facility, and the primary energy source, these permitting procedures may involve one or more stakeholders.

When the Applicant signs and returns the connection contract to EBS, along with proof that all necessary construction permits have been granted, the Applicant must also provide EBS with a letter of credit or another acceptable form of security. This security must:

- Designate EBS as the beneficiary; and
- Be in an amount equal to the final connection fee outlined in the contract, covering the new Facility or upgrades for which the Applicant is responsible, in line with standard commercial practices.

If the Applicant fails to execute the connection contract or provide the required payment security in a timely manner, the connection request will be considered terminated and withdrawn. The Applicant will remain responsible for reimbursing EBS for any actual costs incurred before termination and withdrawal.

Step 4: Realization of the Facility

Once the parties sign the connection contract and pay the connection fee, construction of the required Connection Asset—by EBS or the Applicant, as specified in the connection contract—and the Facility—by the Applicant—can start. Construction should be completed by the estimated connection date indicated in the connection contract.

Step 5: Facility Inspection and Meter Installation

Once all the civil and electrical works for the Facility and the Connection Asset have been completed and the Facility is ready for energization, EBS will conduct an on-site inspection to verify that the Facility is built and installed according to the documentation and agreed terms and in compliance with the Connection Code and applicable standards.

If the Facility passes inspection, EBS will proceed to install the meter(s) as specified in the connection contract. These meters will be set up at the designated delivery point of the connection to monitor the Facility's energy production and consumption.

Step 6: Operational Agreement, Energization, and Operation

Upon successful completion of the Facility inspection and installation of the meter(s), the procedure for commissioning the Facility can begin, following these four phases:

- Define and sign the Operational Agreement with EBS. The Operational Agreement should contain:
  - The respective responsibilities in the context of the operation and control of the functional portions of the National Grid
  - The characteristics of the Facility and processes, as well as specific connection requirements, in addition to those given in the Connection Code and in the relevant national regulation, if deemed necessary
  - The relations between EBS's operating units of the National Control Center and the Grid User's personnel, and any third parties
  - Consideration of any derogation to the requirements of the Connection Code;
- The energization operational notification, which authorizes activation of the connection, understood as entry into operation of the internal loads and auxiliaries;
- The interim operational notification, which authorizes activation of the Facility, understood as energization, first parallel and interim operation in parallel with the network of the Facility. The purpose of the interim operational notification is to verify the conformity of the group with the requirements described in the Grid Code;
- The final operational notification, which certifies that the Facility is compliant with the Grid Code and authorizes the final activation and operation of the Facility.

6.2.2 Technical requirements

The general technical requirements for the interconnection of new generation units (regardless of whether or not they are subject to the tendering process of the Electricity Act[154]) and demand

[154] Electricity Act 2016. "Article 21."

facilities to the National Grid are specified in the Connection Code.[155] These requirements are designed to:

- Clearly define the physical and functional separation points between EBS and the Grid Users;
- Avoid any deterioration in the performance or the reliability of the National Grid;
- Avoid any negative influence in the operation of the National Grid;
- Avoid damages to other users; and
- Contribute to the safety and quality of the electricity service, according to the type of the Facility.

Moreover, the Grid User must design and build any Facility in full compliance with national and international safety standards for personnel, equipment, and property, adhering to the applicable IEC and ISO regulations. All apparatus and equipment must be built and installed using materials and components that conform to Good Utility Practices.[156]

Depending on the type of facility, the Connection Code defines the technical requirements as follows:

- Section 4 defines the specific performance requirements for generation units larger than 10MW and connected at voltages greater than or equal to 110kV;
- Section 6 defines the requirements for demand facilities; and
- Section 7 defines the requirements for smaller generation units connected at lower voltages (including microgrids).

This analysis includes a review of the Connection Code, which is considered to be in line with industry best practice.

7 Feed-in tariff methodology

A feed-in tariff is the tariff at which an off-taker (typically, a utility) buys electricity generated from a distributed generation system and injected into the grid. A feed-in tariff is one of the commercial terms that can be used to promote and regulate investment in distributed generation.

Commercial terms for the sale of electricity from distributed generation should encourage and enable a level of investment in distributed generation that is socially optimal, that is, a level where the benefits of distributed generation exceed its costs:

$$Avoided\ cost\ of\ generation + Reliability\ benefits + Reduction\ of\ GHG > Cost\ of\ installing\ PV$$

[155] Connection Code. "Section 4."

[156] Connection Code. "Section 4.1."

Where:

- Avoided cost of generation = the cost of fuel and other variable operations and maintenance (O&M) costs that EBS incurs when supplying an extra unit of electricity
- Reliability benefits = the economic value of having a reliable supply of electricity
- Reduction of greenhouse gases (GHG) = the economic value of reducing GHG emissions
- Cost of installing photovoltaic (PV) = the levelized cost of distributed solar PV.

Conversely, the commercial terms should discourage investment in distributed generation when its installation costs exceed its benefits.

At the same time, the commercial terms should ensure that the profits of EBS do not fall as an increasing number of customers install distributed generation. If distributed generation increases and commercial terms do not address this risk, EBS's profits may fall because of the following:

- The increase in distributed generation means EBS sells less electricity and thus earns less revenue while its fixed costs remain the same;
- EBS increases its tariffs to be able to recover fixed costs across its remaining customers and sales—this also poses a fairness issue as fixed costs shift from customers who install distributed generation (who are likely to be relatively higher income) to customers who do not own distributed generation; and
- As tariffs increase, distributed generation becomes cheaper than EBS's tariffs for an increasing number of customers who, in turn, switch to distributed generation, thus perpetuating the mechanism and making EBS increasingly insolvent.

Section 7.1 explains best practice principles to regulate distributed generation in a way that achieves a socially optimal level of investment in distributed generation, including principles on the level at which the feed-in tariff should be set. Section 7.2 describes Suriname's current legal framework and commercial terms for distributed generation. Lastly, Section 7.3 identifies areas for improvement in Suriname's current distributed generation framework by comparing the best practice principles with the current commercial terms.

7.1 Best practice principles for distributed generation regulation

Commercial terms for the sale of electricity from distributed generation should encourage and enable investment in distributed generation as long as its benefits exceed its costs. This section explains the best practice regulatory principles upon which the commercial terms should be based.

Marginal cost-reflective tariffs would encourage and enable a level of investment in distributed generation that is socially optimal and ensure EBS's profits do not fall as customers switch to distributed generation. This is because marginal cost-reflective tariffs reflect the cost of supplying an additional unit of electricity. If supplying an additional unit from the grid costs more than generating an additional unit from distributed generation, such tariffs would incentivize customers to use distributed generation. A marginal cost-reflective tariff structure can include, for example:[157]

- A per kWh, time-of-use charge to cover the avoided cost of generation. The charge would equal the short-run marginal cost of energy. In a conventional power system, the short-run marginal cost is usually the cost of the marginal generator, that is, the generator that supplies the last kWh needed to meet demand. The charge would be higher at peak times to reflect the investment cost in generation capacity.
- One or several fixed charges to cover various fixed costs. Fixed costs may cover, for example, distribution and transmission, demand, or ancillary services. The demand charge would be based on customers' maximum demand or coincident peak demand to pay for peak generation capacity.[158]

Besides marginal cost-reflective tariffs, the following regulatory measures can achieve an optimal level of investment in distributed generation and address the risk to EBS's financial sustainability:

- **Fixed distributed generation charge**: A fixed fee charged to distributed generation customers on monthly bills to cover the fixed costs of maintaining and operating the transmission and distribution (T&D) network for the services that such customers continue to receive from the National Grid (backup and ancillary services).
- **Net billing with a feed-in tariff set at the avoided cost of generation at the time of sale**: A mechanism whereby a distributed generation customer can buy electricity from EBS and sell its excess electricity to EBS at different rates (retail tariff for buying from EBS and feed-in tariff at the avoided cost of generation at the time of sale for selling to EBS).
- **Revenue cap**: A mechanism allowing EBS to compensate for a decrease in demand (and thus revenue) by raising tariffs in the next regulatory period up to the revenue cap. This mechanism is different than a price cap, which does not limit the revenue a utility may earn but sets a cap on the tariffs it may charge.
- **Cap on distributed generation capacity**: This is setting a limit on the size of individual distributed generation systems or on the total distributed generation capacity that may connect to the grid.

Other relatively common regulatory measures should be avoided as they are likely to increase the total cost of generation of the National Grid. These include:

- **Net metering**: A mechanism with a unique meter that measures the consumption and sale of electricity, and only the difference is billed to the customer or sold to the utility. This means the distributed generation customer sells excess electricity to the utility at the retail tariff. The retail tariff is higher than the value of distributed generation because the retail tariff covers costs for services that distributed generation does not provide, such as the

[157] Refer to the Tariff Manual for a more detailed discussion on cost-reflective tariffs.

[158] Coincident peak demand is the demand of a customer or group of customers at the time of the system's peak demand. Coincident peak demand measures how each customer or group contribute to the overall peak demand of the system.

cost of operating the T&D grid. Therefore, remunerating distributed generation at the retail tariff increases total system costs.

- **Net billing with a feed-in tariff set at the levelized cost of distributed generation**: Setting the feed-in tariff at this level will increase the total cost of generation if the levelized cost of distributed generation is higher than EBS's avoided cost of generation.

Table 7.1 summarizes the regulatory measures that should be implemented (✓) to achieve a socially optimal level of investment in distributed generation or avoided (✗) to prevent under or overinvestment in distributed generation and threats to EBS's financial sustainability. The recommended regulatory measures can be implemented to address each measure's shortfalls (for example, net billing can be coupled with the fixed distributed generation charge because net billing does not address the problem of under-recovery of fixed costs by the utility). The table also explains the pros and cons of each measure from an economic perspective.[159]

[159] The table does not include the pros and cons in terms of the safety of the power grid, which is discussed in Section 6

Table 7.1: Summary of recommended regulatory measures for distributed generation

Measure	Description	Pros	Cons
✓ **Marginal cost-reflective tariffs**	Utility tariffs that reflect the cost for the utility to supply an additional unit of electricity	Incentivizes optimal level of investment in distributed generation	May cause social disruption when transitioning to marginal cost-reflective tariffs leads to the increase of tariffs for low-income households
✓ **Fixed distributed generation charge**	▪ Fixed fee on the monthly bills of distributed generation customers ▪ Intended to cover the fixed costs of maintaining and operating the T&D grid because of the services provided by the grid that distributed generation customers continue to rely on	▪ Addresses the problem of under-recovery of fixed costs by the utility ▪ Decreases the risk of cost-shifting between customers that have distributed generation and customers that do not	On its own, a fixed distribution charge does not incentivize the socially optimal level of investment in distributed generation. This measure needs to be combined with other best practice measures in order to incentivize the optimal level of investment in distributed generation.
✓ **Net billing with FIT = avoided cost of generation at the time of sale**	Distributed generation customer buys electricity from the grid at retail tariff and sells its excess electricity to the grid at the avoided cost of generation at the time of sale	Incentivizes optimal level of distributed generation investment	▪ Does not address the problem of under-recovery of fixed costs by the utility ▪ Does not incentivize the socially optimal level of distributed generation investment for own consumption
✓ **Cap on distributed generation capacity**	This cap may take the following forms: ▪ Defining a cap on individual system size ▪ Defining a cap on the total distributed generation capacity that may connect to the grid	Limits the decrease in social welfare or under-recovery for the utility	Does not incentivize the socially optimal level of distributed generation investment (for own consumption or sale to the grid)
✓ **Contract with minimum FIT duration**	▪ Contract between the utility and the distributed generation customer guarantees the FIT over a certain period ▪ The minimum duration should correspond to the duration of the contract or the expected life of the distributed generation system	Promotes investment in distributed generation by providing revenue predictability	N/A
✓ **Revenue cap**	Mechanism that allows the utility to adjust tariffs in the next regulatory period to reach the revenue cap	Allows the utility to remain viable in case no other measure is implemented or the distributed generation charge is not enough to compensate for revenue loss	▪ Does not incentivize the socially optimal level of distributed generation investment

Measure	Description	Pros	Cons
			▪ Will not prevent risks to the utility's financial sustainability if the tariff structure remains the same ▪ Cost shifting between customers that use distributed generation and customers that do not ▪ May cause social disruption in case of a significant tariff increase to reach the revenue cap
✗ **Net metering**	Only the difference between consumption and energy sold to the grid is billed to the customer or sold to the utility; therefore, FIT = retail tariff	May be readily used without the need to replace unidirectional meters with bidirectional meters	▪ Risks over-incentivizing distributed generation investment for sale to the grid and increasing total system costs ▪ Does not solve the problem of utility under-recovery
✗ **Net billing with FIT = levelized cost of distributed generation**	Distributed generation customer buys electricity from the grid at retail tariff and sells its excess electricity to the grid at the levelized cost of distributed generation	Would encourage scaling up distributed generation quickly	▪ Risks over-incentivizing distributed generation investment and increasing total system costs ▪ Does not solve the problem of utility-under recovery

7.2 Framework for the sale of electricity from distributed generation

The Electricity Act permits households and businesses to install small-scale renewable energy systems for self-consumption.[160] The Act also stipulates that these distributed generation customers are eligible for compensation for any excess electricity they feed into the National Grid, with the commercial terms for compensation to be outlined in the ESP.[161]

The Electricity Act allows EBS customers to install distributed generation systems at a different location than the consumption point[162] and sell the energy fed into the National Grid to EBS. The distributed generation systems must use renewable sources.[163] The Act does not limit the amount of electricity that may be fed into the National Grid but limits the amount of electricity that is eligible for payment from EBS. Any amount fed into the grid by a distributed generation customer that is above the amount consumed by that customer is not eligible.[164] This means customers are not incentivized to oversize their systems and sell more electricity to EBS than they buy from EBS.

In 2021, Decree S.B.2021 no.88 mandated a net billing system with a feed-in tariff of 115 percent of the energy rate that applies to the consumer.[165] Before this decree, electricity fed into the grid was sold under a net metering arrangement whereby this electricity was discounted from the consumer's monthly bill. If the electricity fed into the grid exceeded the consumer's consumption for a given month, that surplus rolled over to the following month. Any surplus held by a customer was reduced to zero in the first month of EBS's financial year.[166]

As described in Section 6, customers who want to install and interconnect distributed generation must submit an application to EBS for approval.[167] If EBS determines that the distributed generation system will negatively impact grid operations, EBS may limit the size of the proposed system or require the customer to incur the costs to adjust the grid to support the proposed system size.[168] After the customer receives EBS's approval to interconnect, EBS installs a bidirectional meter between the generation and consumption installations.[169] Such a meter is required for net billing to record electricity consumed from the grid separately from the electricity fed into the grid. Once the system is installed, the Inspection Body inspects it to ensure all

[160] Electricity Act 2016. "Article 20."

[161] Electricity Act 2016, Notes to the Act, pg. xvii.

[162] Electricity Act 2016, Notes to the Act, pg. xvii.

[163] Electricity Act 2016, Notes to the Act, pg. xvii.

[164] Electricity Act 2016. "Article 20.4."

[165] Decree S.B. 2021 no.88. "Article 8.3."

[166] EBS. 2018. "General Terms and Conditions of Connection for Self-Generators" Article 12. https://nvebs.com/uploads/files/page/algemene-voorwaarden-zelfopwekkers.pdf

[167] EBS. 2018. "General Terms and Conditions of Connection for Self-Generators" Article 2.

[168] EBS. 2018. "General Terms and Conditions of Connection for Self-Generators" Articles 2 and 3.

[169] EBS. 2018. "General Terms and Conditions of Connection for Self-Generators" Article 12.

conditions have been met.[170] Other technical requirements include standard safety and security guidelines for system operation, voltage regulation, and frequency.

7.3 Assessment of Suriname's framework for distributed generation

Table 7.2 compares the best practice principles defined in Section 7.1 to Suriname's current commercial terms for the sale of electricity from distributed generation. The table identifies areas where Suriname can improve the commercial terms for distributed generation to enable a socially optimal level of investment in distributed generation. The Energy Efficiency Plan defines strategies that the Government can implement to promote distributed energy.

[170] EBS. 2018. "General Terms and Conditions of Connection for Self-Generators" Article 5. 2018.

Table 7.2: Assessment of Suriname's current commercial terms and recommendations

Recommend measure	Is it implemented in Suriname?	Recommendations
Marginal cost-reflective tariffs	Ongoing: The Government is gradually eliminating subsidies to bring tariffs to cost-recovery levels. Household tariffs will increase by 68 percent between April and November 2024. Further, all non-household tariffs will be cost-reflective by the end of 2024 (reflecting 2023 costs). The Government will partially subsidize some low-income households' electricity consumption partially under the new regulatory system.[171]	▪ Pursue the transition to marginal cost-reflective tariffs while maintaining affordability for low-income customers
Fixed distributed generation charge	No: Distributed generation customers are not required to pay a fixed monthly charge to EBS.	Add a fixed distributed generation charge to the monthly bill for distributed generation customers. This requires the EAS to determine the fixed charge for each customer category by: ▪ Calculating the total fixed costs that EBS incurs to provide backup and ancillary services to distributed generation customers; and ▪ Allocating these costs between customer categories
Net billing with FIT = avoided cost of generation at the time of sale	Unclear: The FIT is set at 115% of EBS's variable charge, but it is unclear how this FIT has been determined.	▪ Define a clear methodology for determining the FIT based on the avoided cost of generation at the time of sale ▪ Regularly update the FIT to reflect the avoided cost
Cap on distributed generation capacity	Partially: There is no cap on individual system size or the total capacity of distributed generation that may connect to the National Grid, but distributed generation customers must be net consumers.	▪ A clear cap may be set on individual system sizes or the total capacity of distributed generation that may connect to the grid to limit the financial risk to EBS based on the integrated resource plan ▪ EBS is considering setting a cap on individual system size[172]
Minimum tariff duration set in contract	No: The grid connection agreement between EBS and the distributed generation customer offers an unlimited duration guarantee for the FIT[173]	▪ Limit the feed-in tariff to the duration of the contract or the expected life of the distributed generation system

[171] Information gathered from meetings with EAS and key stakeholders during the inception visits during the week of 8 April 2024.

[172] Dave Abeleven/IDB. 2024. "Suriname Electricity Sector Regulatory Review & Minimum Regulatory Function Strategy."

[173] Dave Abeleven. IDB. 2024. "Suriname Electricity Sector Regulatory Review & Minimum Regulatory Function Strategy."

Recommend measure	Is it implemented in Suriname?	Recommendations
Revenue cap	No: The EAS has not set its approach to setting tariffs	▪ Define tariff periods and apply a revenue cap approach in the next tariff periods

8 Energy efficiency

This section reviews the current policies, regulations, and laws related to energy efficiency and evaluates the status of the implementation of energy-efficient equipment/appliances and distributed generation in Suriname. Section 8.1 discusses the advancements and challenges Suriname faces in energy efficiency and distributed generation from a policy and regulatory perspective. Section 8.2 describes the status of the implementation of energy-efficient equipment/appliances. The ESP's Volume II – Technical Plan covers the plan for energy efficiency.

8.1 Policy and regulatory overview

The Government has set out policies and regulations to improve energy efficiency. Some of these include:

- Electricity Act 2016;
- Feed-in Tariff policy;
- Nationally Determined Contribution (NDC);
- Street Lighting Retrofit and Advanced Metering Infrastructure Project;
- Regional Energy Efficiency Building Code; and
- The national public awareness campaign called Slim Met Stroom to inform consumers on ways to reduce electricity bills.

These energy efficiency policies, regulations, and laws are described in more detail below.

Electricity Act 2016

The Electricity Act of 2016 mandates including energy efficiency measures and guidelines in the ESP, integrating energy efficiency into the country's energy reform. The Act also empowers the Electricity Authority of Suriname (EAS) to conduct customer audits to evaluate their compliance with the energy efficiency guidelines outlined in the ESP. Non-compliance may result in the loss of eligibility for tariff subsidies.[174]

The Electricity Act mandates that expanding production capacity through public tenders must adhere to objective, transparent, and non-discriminatory criteria outlined in ESP, including the minimum energy efficiency values specified.[175]

Feed-in Tariff policy

The Electricity Act of 2016 also allows customers to install distributed generation systems for self-consumption, using the grid to exchange electricity through the net billing mechanism. In 2021, Decree S.B.2021 no.88 mandated a net billing system with a feed-in tariff of 115 percent of the

[174] Electricity Act 2016. Article 19.

[175] Electricity Act 2016. Article 21.

energy rate that applies to the consumer.[176] The Electricity Act limits net billing: the Consumer's annual energy production shall be lower than his annual consumption. Thus, EBS is not obliged to accept the surplus electricity generated by the Consumer.[177]

This still does not financially make distributed generation projects viable and is the primary reason the market has a very low penetration of distributed generation.[178] Energy policies such as subsidies, net metering, and net billing, implemented in several countries in Latin American and Caribbean countries to promote distributed generation sources, have led to increased distributed generation for self-consumption elsewhere. However, in Suriname, there are regulatory, technical, financial, and economic barriers, as well as market failures, that must be corrected to see the deployment of distributed generation increase, which is currently in an early stage of development.

Suriname's National Energy Policy 2013-2033

The National Energy Policy 2013-2033 supports the Sustainable Energy Framework for Suriname, which aims to increase the power sector's efficiency, transparency, sustainability, and accountability.[179]

One of the goals of this policy is to improve energy efficiency by addressing key issues such as:

- Relatively low levels of energy efficiency in key sectors such as power generation, mining, and transportation; and
- Relatively low levels of energy efficiency from building designs and electrical installations and high energy consumption levels by end-use devices.[180]

This policy outlines strategies to address energy efficiency challenges by:

- Assisting households and businesses to adopt energy conservation and efficiency practices aggressively;
- Reducing and/or eliminating barriers to the uptake of energy conservation and efficiency projects, technologies, etc.;
- Enabling the Government to lead the way in energy conservation and efficiency efforts and working in partnership with the private sector and civil society; and

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[176] Decree S.B. 2021 no.88. "Article 8.3."

[177] Electricity Act 2016. Explanatory notes: Offsetting electricity generated by Private Producers (net-metering/feed-in tariffs)

[178] Distributed solar PV systems are not widely used in Suriname. By 2022, only 12 residential consumers using distributed generation were connected to the grid, and limited installations were known in commercial, industrial, or public buildings.

Historically, low electricity tariffs have discouraged the implementation of distributed solar PV. However, as subsidies phase out, distributed solar energy can become a cost-effective alternative to traditional fossil fuel-based generation and be used to replace less efficient backup generation.

[179] Government of Suriname. 2012. "Suriname's National Energy Policy 2013-2033." p 2. SK 001323-15 Suriname's National Energy Policy 2013 - 2033.pdf

[180] Government of Suriname. 2012. "Suriname's National Energy Policy 2013-2033." p 21. SK 001323-15 Suriname's National Energy Policy 2013 - 2033.pdf

- Seeking to improve the efficiency of the energy infrastructure that supplies energy to all sectors of the economy.[181]

Nationally Determined Contribution

The NDC indicates that Suriname is working to establish an Energy Efficiency Framework to promote energy efficiency measures and raise awareness. The NDC emphasizes the Government's commitment to implementing fiscal sustainability measures to encourage energy efficiency investments.[182]

Street Lighting Retrofit and Advanced Metering Infrastructure Project

In 2018, the Government received a US$30 million loan from the Caribbean Development Bank (CDB) for the Street Lighting Retrofit and Advanced Metering Infrastructure Project. The project started in October 2019. The scope was to conduct a rapid climate risk assessment of the power sector infrastructure, including streetlights, poles, sub-stations, etc., and to recommend measures to increase the system's resilience.[183]

The CDB expects to replace approximately 40,000 high-pressure sodium streetlights with high-efficiency LED streetlights. Under this project, the CDB also expected EBS to establish an advanced metering system, including installing 21,000 smart meters.[184] As of 2024, the replacement of streetlights has largely been completed. However, the replacement of smart meters remains ongoing.[185]

Regional Energy Efficiency Building Code (REEBC)

Suriname is also part of regional initiatives to promote energy efficiency in the Caribbean. It is part of the Regional Energy Efficiency Building Code (REEBC), an initiative to create a clear and generally accepted framework for maximizing energy efficiency in buildings. This includes thermal performance requirements for walls, roofs, and windows; daylighting, lamps, and luminaire performance; energy performance of chillers and air distribution systems; the electrical wiring system; solar water heating appliances; renewable energy; zoning of buildings; climate classification and building energy management system.[186]

Consumer-level energy efficiency efforts

The Government has also made efforts to improve energy efficiency at the consumer level. For example, in 2014, EBS launched *Slim Met Stroom*, a national awareness campaign to inform consumers how energy efficiency measures could help reduce electricity bills. The campaign seeks to educate consumers on the benefits of energy saving and gives practical savings tips to help

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[181] Government of Suriname. 2012. "Suriname's National Energy Policy 2013-2033." p 21. SK 001323-15 Suriname's National Energy Policy 2013 - 2033.pdf

[182] Government of Suriname. 2020. "National Determined Contributions 2020." p 14-15.

[183] Caribbean Development Bank. "Street Lighting Retrofit and Advanced Metering Infrastructure Project." Downloads. STREET LIGHTING RETROFIT AND ADVANCED METERING INFRASTRUCTURE PROJECT | Caribbean Development Bank

[184] Caribbean News Now. 2018. "CDB funds US$30 million project to upgrade streetlights in Suriname." https://www.caribbeannewsnow.com/2018/02/06/cdb-funds-us30-million-project-upgrade-streetlights-suriname/

[185] Information obtained from EAS via email consultation on 2 December 2024.

[186] REEBC. 2017. *"CARICOM Regional Organization for Standards and Quality: Caribbean Application Document for the 2018 International Energy Conservation Code."* http://www.gnbsgy.org/wp-content/uploads/Draft-CROSQ-Standard-Caribbean-Application-Document-for-the-2018-International-Energy-Conservation-Code.pdf

reduce electricity bills. The campaign also took place in primary schools to raise children's awareness of consumption behavior. In addition, EBS created an appliance consumption calculator. The consumption calculator allows consumers to monitor their electricity consumption by calculating the consumption of electrical appliances.[187]

8.2 Market for energy efficient equipment/appliances

Implementing energy-efficient equipment/appliances in buildings can lower energy consumption while maintaining the same output. This also reduces environmental impact and helps decrease electricity bills. Customers can replace old appliances with efficient lighting, refrigerators, motors, air conditioning units, and solar water heaters.

Besides considerable progress in implementing LED technology, Suriname has been slow to adopt energy-efficient equipment and appliances elsewhere.[188] All sectors (residential, commercial, industrial, and public) have adopted LED technology for approximately 90 percent of interior lighting. However, opportunities for improvement still exist, with the potential of implementing Minimum Energy Performance Standards (MEPS)[189] and replacing inefficient equipment and appliances with top-tier equipment in the following areas:

- Refrigeration and freezers: most of this equipment in all sectors is of standard efficiency;
- Industrial motors: This equipment ranges from 1kW to 100kW, and most of these motors are of standard efficiency or below;
- Windows: All buildings audited had single-pane windows, with some using tinted windows;
- Building envelope: Most roofs and windows have the potential to improve insulation, use double glazing and tinted windows, install cool roof materials and coatings, incorporate shading devices, and enhance natural ventilation in both existing and new buildings; and
- Solar water heating: Solar water heating has not been adopted in the residential, public, or commercial sectors.[190]

Table 8.1 shows the status of energy equipment usage across these sectors.

[187] EBS. 2014. "Wat is SMS." http://www.nvebs.com/over-ons/slim-met-stroom/wat-is-sms/

[188] The IDB evaluated the implementation of energy-efficient equipment/appliances across the residential, public, commercial, and industrial sectors. This assessment involved analyzing the current use of lighting, refrigerators, motors, air conditioning units, and solar water heaters. For each piece of equipment, the IDB evaluated whether the technology used in each building was standard or top-tier, comparing its energy consumption to that of equipment that meets Minimum Energy Performance Standards (MEPS) (IDB. 2022. "Fostering energy efficiency and distributed generation in Suriname: Task 1 – EE/DG Diagnosis" p 46-54.)

[189] Minimum Energy Performance Standards specify the minimum level of energy performance that appliances and equipment must meet or exceed before they can be supplied or used for commercial purposes. (Energy Rating. "Minimum Energy Performance Standards." Link)

[190] IDB. 2022. "Fostering energy efficiency and distributed generation in Suriname: Task 1 – EE/DG Diagnosis." p 46-54.

Table 8.1: Status of energy equipment/appliances usage across sectors

Equipment	Analyzed sectors	Status
Lighting		
Interior lighting - lighting controls	All	▪ All sectors have adopted LED technology for approximately 90% of their interior lighting.
Interior lighting - lighting controls	All	▪ Use of occupancy and daylight sensors is minimal (<1% of lighting in all sectors).
Exterior lighting	All	▪ All sectors have adopted LED technology for approximately 90% of their exterior lighting
Lighting controls – exterior lighting	All	▪ More than 50% of residential and public buildings do not use occupancy and daylight sensors. ▪ About 65% of industrial buildings use daylight sensors, but none of the buildings use occupancy sensor
Refrigeration		
Residential appliances - refrigerators and freezers	Residential	▪ Most refrigerators and freezers in the residential sector are of standard efficiency, with an annual electricity consumption of 471kWh. In contrast, equipment that meets MEPS consumes only 263kWh annually, while top-tier models use just 131kWh.
Commercial appliances – refrigeration	Commercial and industrial	▪ Some refrigeration equipment of standard efficiency was found in the commercial and industrial sector buildings. There is potential to implement MEPS and top-tier equipment in these sectors.
Industrial equipment		
Motors	Industrial	▪ Motors were identified to range from 1kW to 100kW, with most of these motors being of standard efficiency or below. There is potential to implement MEPS and top-tier equipment.
Air conditioning and building envelope		
Building envelope	All	▪ All buildings audited had single-pane windows, with some using tinted windows. ▪ There is thus an opportunity to improve the insulation of roofs and windows (double glazing and tinted) and use cool roof materials and coatings, shading devices, and natural ventilation in both existing and new buildings.
Air-Conditioning - Split Air Conditioning (AC) Units	All	▪ Over 90% of buildings across all sectors are equipped with cooling systems. ▪ In public and commercial buildings, cooling systems cover 65% of the total surface area. ▪ Energy performance labeling is required for people to make an informed decision when purchasing new equipment.

Equipment	Analyzed sectors	Status
		▪ MEPS would also exclude low-quality and low-efficiency equipment from the market. ▪ Product lifetime for split AC units is about 12 years. Equipment subject to salty air may have a lower expected lifetime.
Solar		
Solar water heating	All	▪ There has been no adoption of solar water heating in the residential, public, and commercial sector. ▪ There is a company (Marsol) retrofitting electric boilers with solar hot water collectors, meaning that the technology is already available in the country.

Source: IDB[191]

[191] IDB. 2022. "Fostering energy efficiency and distributed generation in Suriname: Task 1 – EE/DG Diagnosis." p 46-54.

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WASHINGTON, DC
1747 Pennsylvania Avenue NW, Suite 1200
Washington, DC 20006
United States of America
+1 (202) 466-6790

SYDNEY
Suite 19.01, Level 19, 227 Elizabeth Street
Sydney NSW 2000
Australia
+61 (2) 9231 6862

AUCKLAND
Sinclair House, 3 Glenside Crescent
Auckland 1010
New Zealand
+64 (4) 913 2800

WELLINGTON
Level 2, 88 The Terrace
Wellington 6011
New Zealand
+64 (4) 913 2800

PARIS
3B Rue Taylor
Paris 75481
France
+33 (0)1 84 60 02 00

BOGOTÁ
Calle 81 #11-08, Piso 5, Oficina 5-121
Bogotá
Colombia
+57 (1) 508 5794

enquiries@castalia-advisors.com
castalia-advisors.com

Thinking for a better world.

Appendix A: Evolution of utilities' business models in the face of increasing distributed energy generation

Traditional power systems have been organized around centralized generation, with an unidirectional structure where customers are at the end of the electricity supply chain. Utilities own the distribution grid and sell power to customers, and are either vertically separated or part of a company that also owns transmission and/or generation.

In future decentralized markets, utilities are expected to have a different role because of bidirectional energy flows and the emergence of new market actors:

- Prosumers (customers who consume and generate electricity),
- Active customers (who actively manage their consumption),
- Aggregators (who buy and sell energy services which they produce by bundling and controlling DE resources (DER); which are electricity-generating resources or controllable loads connected to a local distribution system or to a host facility within the local distribution system), and
- Companies that create and manage embedded networks (a network that connects a group of customers to act as a single customer on the grid).

The role of active system operators is expected to increasingly be to coordinate between many small and large actors in the power market.

To respond to this evolution, utilities can adopt the business models in Table A.1. Utilities are likely to change their business models in the same order as shown in the table—first resisting increased distributed generation, then cannibalizing their own business, etc. However, these business models by themselves will not fix the challenges when tariff distortions exist. With tariff distortions, the growing use of distributed generation will lead to declining revenue to cover utilities’ fixed costs, and result in the death spiral. Therefore, regulatory reforms will be needed to decouple recovery of fixed costs from kWh sales, no matter what business models utilities adopt.

Table A.1: Business models for utilities to respond to increasing distributed generation

Business model	Description	Rationale for using business model
Resist change to distributed energy	▪ In the short term, a utility is likely to try to limit the uptake of distributed generation by customers, for example by requiring a license to install such systems, and making that license difficult to obtain, or setting a cap on the total distributed generation capacity that can be connected to the grid ▪ In the medium term, the utility can shrinking the its asset base voluntarily (e.g. not replacing decommissioned assets). To manage a shrinking asset base, the utility should be allowed to include stranded assets in the regulatory asset base, and earn a return on it to repay its debt	▪ The utility will lose revenue from the uptake of distributed generation, due to tariff distortions ▪ There is a risk of death spiral, as the utility would need to invest in the T&D networks to accommodate a growing capacity of distributed generation while earning less revenues due to decreasing customer base ▪ The utility will be unable to perform its social service of delivering electricity if regulations do not change and customers can freely install distributed generation systems
Cannibalize own business	▪ Customers that want to switch to distributed generation will need the help of a company to do so; the utility would be that company ▪ Services the utility would provide would include, for example: providing financing for distributed generation; designing distributed generation systems; offering installation services	The utility will earn revenue from this business, and lose less revenue than if they did not by being proactive and first entrants in the market
Provide regulated distribution services	The utility would provide the following services: ▪ Procuring flexibility services from their network users, such as voltage support and congestion management to defer network investments. These services would be regulated services, meaning the utility may include the investments required to provide flexibility services in its regulated asset base to replace other investments they would otherwise have to make on the grid. This could apply to commercial and industrial and residential customers with smart meters. ▪ Owning distributed generation resources, or having agreement with customers to have some degree of control over their resources (for example, to turn off a device when needed for demand side management); and ▪ Option to also expand that to electric vehicles and provide charging services	Utilities have a certain amount of control over equipment that is connected to the grid and have a way (contractually and technically) of taking full advantage of automated demand response, and customers' distributed generation resources
Become a distribution	▪ The utility becomes a market facilitator and platform provider for trading flexible energy resource, and acts as an intermediary between customers that buy and sell power to each other	The power system is evolving towards a two-way power flow, and new smart technologies will allow utilities to act as distribution system operators

Business model	Description	Rationale for using business model
system operator	▪ Services provided by the utility would include: planning, dispatch, coordination, settlement if there is trading; gather and store data, for example on price and actions of customers; and provide price signals to customers for their decision making in selling or buying electricity	

Appendix B: Practices to become a utility of the future

B.1 Technical operations

Table B.1: Practices to become a utility of the future – Technical operations

Area	Topic	Utility of the Future dimensions *Innovation*	*Inclusion*	*Market*	*Resilience*
Expansion and rehabilitation plans	Expansion and rehabilitation planning	The plan outlines the process for trialing and adopting new infrastructure technologies and innovations. It includes a research and development program.	The plan includes expansion to last-mile connections (e.g., slums). The planning process involves a representative group of community members.	Plan based on customer preferences. Collaborate with municipal road works and other utilities. Communicate with all stakeholders, including the neighborhood and other municipal services.	Plan includes investments in context/scenarios of uncertainty, such as redundancy infrastructure (including digital); plan includes development of distributed resources where economically optimal.
Asset Management	Strategic asset management plan	Proactive management and replacement of assets based on comprehensive data on aging assets. The asset management plan is regularly updated to incorporate the latest trends and technologies.	The plan includes an analysis of the local supply of goods and services that could be part of the plan.	The plan includes evaluating potential synergies with other utilities (e.g., water) and opportunities for private sector participation.	Coordination with other sectors in case a significant event is not immediately relatable to electricity.
	Asset records	Fully autonomous system that maps, inspects, and records the status of all infrastructure in the system (including underground) and flags any potential problems before they occur.	Records classify assets linked to service provision of the most vulnerable population.	Collaboration with other utilities, exchanging the underground records. Compliance with the latest data management regulations. Records aligned with data strategy when they exist, enabling flexibility and interoperability with other applications on the market.	Digital and secure backup of all records.
	Asset maintenance	Digitalized records support proactive maintenance (e.g., an autonomous system that issues	Includes locally supplied labor, goods, and services options.	Maintenance by manufacturer guidelines. Service level	Proactive asset management based on current and future shocks and stresses.

Area	Topic	Utility of the Future dimensions *Innovation*	*Inclusion*	*Market*	*Resilience*
		POs for needed items and tracks maintenance performed).		agreements with equipment and spare parts suppliers.	
	Maintenance records	Records are accessible on various supports and locations, leveraging cloud technologies and devices. Records/data are created in formats that can be exported and used for enhanced applications (big data, AI, etc.).	Includes population affected by the maintenance performed.	Include customer data if the work order derives from a request/complaint.	Digital and secure backup of all records.
Technical Operations Processes	Procedures	Digitalized and accessible handbooks that are reviewed, audited, and updated periodically.	HSEQ (health, safety, environment, and quality) policy/process in place to protect utility, staff, and customers from related issues. The process is communicated to all utility staff and the community; regular training sessions are held to ensure all staff and community members know the process. Comply with ISO 45001 (occupational health and safety standard).	Automated purchase orders when using a spare part from inventory. Process for identifying new trends in the market to improve, update, or modernize processes. The utility has a channel to send process improvement and optimization proposals. Ensures that recycled material is adequately treated and allocated to proper uses—training and education programs for customers on energy efficiency.	Procedures for implementing contingency plans for when the utility is not operating under normal conditions (e.g., emergencies).
Quality of electricity	Frequency of quality tests	Online monitoring and implementation in the SCADA system.	Not applicable (NA)	NA	Ability to implement quality control and quality assurance programs. Robust digital security measures are in place to protect data.
	Reporting of test results	Results are reported and published automatically.	Results are available via various media (e.g., online, SMS, community alerts) and a utility website.	Quality alert system for customers. Quality issues are communicated to customers in general or/and target a selection	NA

Area	Topic	Utility of the Future dimensions *Innovation*	*Inclusion*	*Market*	*Resilience*
				of users with specific requirements/needs (B2B).	
Commercial losses	Electricity theft strategy	Review and update the implemented electricity theft management strategy periodically. Strategy defines policies to identify and implement innovations.	The strategy includes community-led sensitization focused on all electricity theft reduction activities (e.g., the introduction of meters).	Performance-based contracts with set targets.	Ability to rapidly conduct an electricity theft analysis following a shock (e.g., an earthquake).
	Loss reduction activities	Use of innovation (e.g., smart meters) to identify illegal connections remotely.	Use of community partnerships to monitor and report illegal residential connections. Activities tailored for low-income areas.	Use of customer advisory groups to provide ongoing reviews of plans for commercial loss reduction.	NA

Source: adapted from World Bank. 2021. "Utility of the Future." https://documents1.worldbank.org/curated/en/796201616482838636/pdf/Utility-of-the-Future-Taking-Water-and-Sanitation-Utilities-Beyond-the-Next-Level.pdf

B.2 Commercial operations

Table B.2: Practices to become a utility of the future – Commercial operations

Area	Topic	Utility of the Future dimensions *Innovation*	*Inclusion*	*Market*	*Resilience*
Customer Relationship Management	Customer relationship/ engagement strategy	Customer experience strategy (CX)/customer-centric mindset (customers' holistic perception of their experience with the utility). Uses innovations to	Engages a representative group of customers in decision-making (e.g., on feedback, payment, affordability, and service level). Uses neighborhood advisory	Customers control how often and via what means the utility contacts them. The utility uses engagement as a cost-saving strategy (e.g., promoting energy-	Customer behavioral strategy plan for crisis and crisis management programs.

Area	Topic	Utility of the Future dimensions *Innovation*	*Inclusion*	*Market*	*Resilience*
		engage with customers (e.g., gaming, interactive website)—significant use of social media, including advertising for behavior change.	groups in lower-income areas to accompany utility activities.	efficient households, offering exchanges and rebates).	
	Customer engagement staff/team	NA	Strategy tailored to different groups of customers regarding accessibility, language, social norms, and preferred forms of communication.	Community liaisons build relationships with specific geographic areas and customer groups. They also support staff in building relationships and partnerships with trusted community leaders, NGOs, and institutions.	NA
	Communication strategy	Communication strategy analyzes behavioral psychology and implements innovative interventions to influence customer behavior.	Customized communication strategy for each audience and customer personas, considering culture, gender, age, needs, and priorities.	The branding strategy aligns with the communication strategy. The brand value proposition reflects the utility's strategy and the importance of the customer.	Crisis communication strategy to deal with unexpected or disruptive events that threaten the utility, stakeholders, or general public. Media / social-media crisis response plan. Reputation crisis management strategy.
	Customer satisfaction feedback	Automated collection through various channels and regular analysis with action plans to address issues.	Collects feedback to disaggregate customer preferences (quality, pressure, means of communication) by sub-group.	The results of feedback are publicly accessible. Feedback informs management and operational decisions, and the public is told how the feedback was acted upon.	NA
	Commercial processes and policies	NA	NA	The process of identifying new trends in the market to improve, update, or modernize processes. The utility team has a channel to send process improvement and optimization proposals.	NA

Area	Topic	Utility of the Future dimensions *Innovation*	*Inclusion*	*Market*	*Resilience*
	Customer records	Computerized customer database (in agreement with general data protection regulation, GDPR), integrated with the CRM system, and metering data.	Database disaggregated by location and demographic categories (e.g., age, employment status, gender, refugee, head of household); poverty mapping of current and potential customer base.	NA	Data security system, backups with redundancy in multiple servers.
	Records update frequency	Automatically updated as part of the CRM database. Data policy is in place, and data ownership is managed across the utility, including customer services.	Customers can update some data online and/or request changes by established data security/access levels.	Collaboration with other utilities (e.g., water utility) to exchange customer data by GDPR.	Automatic backups in predetermined cycles with redundancy across multiple servers.
Customer service	Methods for customers to make complaints and inquiries	CRM database automatically updates and integrates the recording, tracking, and resolution of customer complaints and inquiries; it also automatically links with other utility systems (e.g., technical and financial).	Methods are accessible to persons with disabilities and illiterate customers in local languages.	Use Chatbots for virtual assistance (software applications that use AI and natural language processing to understand and interact with customers). Utility tracks social media feeds to flag disruptions.	Methods for customers to escalate complaints if they represent a threat to the system (e.g., a burst of a main).
	Methods to record, track, and resolve complaints and inquiries	Records linked to GPS to geo-reference complaints.	NA	Management reports inform business decisions and evaluate staff or unit performance.	E-platform strategy for the crisis: Use E-platforms embedded in the official CRM site. Implement CRM through phones and social media.
	Procedures to record, track, and resolve complaints and inquiries	AI will analyze data and identify customer service improvements.	Omnichannel/multichannel approach that seeks to provide customers with a seamless interacting experience, whether they're interacting online, by telephone, or in the office.	Procedures exist to follow up with customers on their satisfaction level related to how the complaint was treated and resolved.	NA

Area	Topic	Utility of the Future dimensions *Innovation*	*Inclusion*	*Market*	*Resilience*
	Methods to communicate status updates to customers concerning complaints and inquiries	NA	NA	Complaints and response rates are publicly accessible.	NA
	Procedures before supply interruptions or service disruptions	Information on lost customer minutes is available on demand through various media.	Interruptions are scheduled, taking into account the differentiated needs of users.	NA	Robust contingency plans for electricity supply are in place.
Metering	Meter reading	Collaboration with mobile service providers for the Internet of Things (LoRa IoT, NB IoT). Providing meter readings through the mobile operators' network.	Methods for customers of all socio-economic statuses to access readings themselves.	The electricity demand profile and alarms regarding customer electricity consumption are available online.	Digital and secure backup of all records. Ability to access the customer database remotely for all meter readers.
	Data reconciliation (reading=billing =accounts)	Data is fully integrated with the CRM and financial systems.	NA	NA	NA
	Type of meter	Electronic meters with on-demand remote readings (e.g., on mobile devices and control rooms) that meet all ISO 4064 standards; automatic check for consistency of meter reading, billing, and accounts data.	Communication plan to inform end-customers of the advantages of having a meter installed. Range of metering solutions for customers (portfolio of metering systems for specific communities; different solutions for different areas, communities, etc., including pre-pay meter).	Differentiate customers depending on demand profile (customers or B2B) for meter selection.	NA

Area	Topic	Utility of the Future dimensions *Innovation*	*Inclusion*	*Market*	*Resilience*
	Testing and replacement	Proactive testing, calibration, and replacement based on exception reports from online meter data.	Deferred payment alternatives for meter replacement (if the customer pays for meter).	NA	Proactive testing, calibration, and replacement based on exception reports from online meter data.
Billing	Frequency	Automatized billing system with bills available on time and online (e.g., on mobile devices).	Flexible billing frequency.	Estimates of services to bill are available in real-time.	Billing contingency plan during a crisis. Record of historic data for billing using historical meter reading consumption in case of not being able to carry out the reading process for an extended period.
	Bill presentment	Customer preferences differentiate presentation methods. Paper bills are easily read (e.g., letter size, graphs, etc.) and clearly explain the cost components.	Bill presentation format based on customer consultation or feedback. Bills compare electricity consumption with previous months and/or with similar customers.	Bills are used as a demand-side management tool, e.g., educating customers on their consumption and ways to reduce it.	Customer preferences differentiate presentation methods. Paper bills are easily read (e.g., letter size, graphs, etc.) and clearly explain the cost components.
Collections	Payment methods	Use of prepay plans or pay in advance, no reading required; mobile wallets, mobile payment apps.	Flexible payment schedules and other accommodating measures. Payment support schemes (e.g., social tariffs and links to safety net programs) should be used when available.	Autopay bank transfer or credit card. Contactless payment onsite: Near-field communication (NFC) and magnetic secure transmission (MST) technology; quick response reader (QR Reader).	Payment plan during crisis. Eliminate in-person customer payments. Provide a grace period plan during a crisis. Provide solutions for customers on prepaid plans. Send customer reminders of payments through electronic payment platforms.
	System for following up on arrears (debts)	Clear policies and plans for non-payment (e.g., automated reminders).	NA	Automatic reminders.	Debt management plan during crisis. Processes to adopt supportive temporary billing measures for flexible payment and debt collection to reduce the financial burden faced by the population during a crisis.

Area	Topic	Utility of the Future dimensions *Innovation*	*Inclusion*	*Market*	*Resilience*
	Disconnection and reconnection process/policy	Remote disconnect and reconnect with guaranteed lifeline quantity of electricity for domestic households.	Considers the impact of inadequate debt control through shutoffs of susceptible populations. Utility helps customers manage payment (e.g., arrears forgiveness programs or low-interest payment plans).	Customer rights regarding disconnection are publicly accessible. The total annual resources expended for managing shutoffs and collections are assessed relative to resources recovered due to shutoffs.	A contingency plan to cover non-payers. A disconnection and reconnection plan during a crisis. Implement measures to support affordability during a crisis. This may require approval at the national level.

Source: adapted from World Bank. 2021. "Utility of the Future." https://documents1.worldbank.org/curated/en/796201616482838636/pdf/Utility-of-the-Future-Taking-Water-and-Sanitation-Utilities-Beyond-the-Next-Level.pdf

B.3 Financial management

Table B.3: Practices to become a utility of the future – Financial management

Area	Topic	Utility of the Future dimensions *Innovation*	*Inclusion*	*Market*	*Resilience*
Strategy & Management	Finance/ accounting processes and policies	Digitalized and accessible handbooks that are reviewed, audited, and updated periodically.	NA	Identifying new market trends to improve, update, or modernize processes. The utility has a channel to send process improvement and optimization proposals.	Procedures for implementing contingency plans for when the utility is not operating under normal conditions (e.g., emergencies).
	Organizational structure	The financial management function is streamlined (less human input and	NA	NA	NA

Area	Topic	Utility of the Future dimensions *Innovation*	*Inclusion*	*Market*	*Resilience*
		more emphasis on digital systems).			
Planning & Budgeting	Preparing the budget	The budget includes funds for innovation.	Budgeting decision-makers involve a representative group of community members when making capital planning decisions. The budget includes funds for creating a respectful and inclusive culture.	NA	The budget includes contingency funds for natural disasters, extreme weather events, global pandemics, etc.
	Monitoring actuals vs. budget	Automatic monitoring and utility use allocated funds for innovation.	Utility uses allocated funds to create a respectful and inclusive culture.	Financial monitoring reports are publicly accessible.	Contingency plan for significant variations in the budget due to unexpected crises.
	Cash flow management	Cash and debt management system with automatic links to other operating systems so that relevant budget holders remain up to date.	NA	NA	Cash management includes contingency funds for natural disasters, extreme weather events, etc.
	Budget system	The system automatically links to other operating systems so relevant line managers receive real-time notices about budget variances and risks.	NA	NA	The system protects and backs up data in case of shocks and stresses.
Accounting and Financial Reporting	Accounting method	Automated system integrated with the supply chain (e.g., automatic ordering and billing of chemicals; digital data from	NA	NA	NA

Area	Topic	Utility of the Future dimensions *Innovation*	*Inclusion*	*Market*	*Resilience*
		customers for automatic billing; systems for forecasting, planning, and reporting, etc.).			
	Accounting system	Integrated ERP system for all processes.	NA	NA	NA
	Financial statements			The system automatically publishes financial reports regularly (monthly, quarterly, etc.).	
	Asset register	Automated system fully populated with accurate asset data and connected to GIS. Data and systems integrated across digital solutions (e.g., operations and maintenance systems).	NA	System plus independent review to estimate asset replacement values.	NA
Control and Transparency	External auditing of financial statements	NA	The community can participate in/review the external audit process.	NA	NA
	Ethical financial policies	NA	NA	Transparency section on the utility's website (including ethics policy, management/financial reports, anonymous email/portal to report fraud, etc.).	NA
	Financial transparency	NA	NA	Audited financial statements are published on the utility's website.	NA

Area	Topic	Utility of the Future dimensions *Innovation*	*Inclusion*	*Market*	*Resilience*
Financial Modelling and Forecasting	Tariff analysis	Financial modeling and forecasting are centralized and accessible to all departments that can be updated frequently to support emergencies and responses.	Local communities consulted on different affordability solutions, including payment support schemes—and community partnerships to address the needs of lower-income groups when tariff changes are introduced.	Tariff analyses are used to estimate the impact of proposed tariffs on customers.	Tariff structure for use in emergencies ready in case the utility needs them.
	Financial forecasting	Use of data-driven solutions for financial modeling.	NA	NA	Financial analysis of resiliency measures (e.g., insurance premium customers would pay for greater supply reliability).

Source: adapted from World Bank. 2021. "Utility of the Future." https://documents1.worldbank.org/curated/en/796201616482838636/pdf/Utility-of-the-Future-Taking-Water-and-Sanitation-Utilities-Beyond-the-Next-Level.pdf

B.4 Human resources management

Table B.4: Practices to become a utility of the future – Human resources management

Area	Topic	Utility of the Future dimensions *Innovation*	*Inclusion*	*Market*	*Resilience*
Human Resources Management	Human resources management strategy	HR strategy includes innovation as part of its values.	HR strategy includes diversity as part of its values. Includes gender balance strategy.	HR strategy includes customer focus as part of its values.	Strategy has a contingency plan in case of a significant disruption to utility staff (e.g., disease affecting most staff).

Area	Topic	Utility of the Future dimensions *Innovation*	*Inclusion*	*Market*	*Resilience*
	Staffing analysis and plan	Ongoing analysis of future trends in the labor sector, the future of current jobs/roles/profiles, the impact of technology on current jobs, and preferences of the new generations (remote work, flexibility, etc.).	The potential/future supply of local labor is permanently evaluated to determine how it can meet the demand of staff needed by the utility. Specific plan to meet gender balance goals.	Private sector practices are evaluated to define an optimal number of employees (e.g., full-time equivalent employees based on revenue per employee).	Contingency plans in place to move staff between different departments to meet changing requirements.
	HR system	Digitalized system that has all staff records and all processes and policies, updated on demand and accessible online (following GDPR).	The system disaggregates data by gender and diversity parameters.	The system automatically links to commercial, technical, and financial systems.	The system automatically backs up records.
	HR processes and policies	NA	Processes are in place to effectively mitigate the risks to the health, safety, and well-being of employees, customers, and community members—process to ensure gender balance primarily in recruitment, promotion, training, and development.	The process of identifying new trends in the market to improve, update, or modernize processes. The utility team has a channel to send process improvement and optimization proposals.	Human resource crisis plans minimize the risk resulting from a reduced labor force and ensure continuity of operations during a crisis. Definition of an Emergency Command Task Force. Communication strategy (internal and external)
Attraction & Recruitment	Attraction & recruitment policy	The policy enables automated recruitment systems to sift candidates. Vacancies are posted on the utility's website and automatically on specialized social networks.	The policy requires gender-balanced recruitment and interviewing panels. It also outlines different outreach programs to recruit typically underrepresented groups (e.g., female engineers). Recruitment is open and published.	Working conditions are attractive and are competitive with the local labor market, whether in the public or private sector.	Contingency plan to recruit staff to fill vacancies during a crisis and/or hire outsourced services on demand during the crisis.
	Job descriptions	NA	Job advertisements target diverse audiences (including women) and include non-discriminatory statements.	Job descriptions and profiles aligned with staff objectives, performance measurement, training, and development.	All critical staff job descriptions account for their temporary replacement in case they cannot

Area	Topic	Utility of the Future dimensions *Innovation*	*Inclusion*	*Market*	*Resilience*
					perform their duties during a crisis.
	Evaluation & selection	AI during the selection process. Remove names, pictures, and birth dates from CVs when assessing applications and propose pre-screened candidates to management for further consideration to reduce unconscious biases.	Gender-blind AI reflects strategy during recruitment by utilizing screening software to avoid gender, race, and other biases. The selection panel has at least one woman.	Inclusion of outsiders in the selection committee (where permitted).	Clear messaging to non-chosen female candidates that they were not excluded by gender and they could apply to other positions.
	Onboarding	Family is included during the onboarding plan to introduce the employee's workplace to family members.	Match women entering the utility with a colleague from an operational or technical field to reduce barriers and make technical areas more accessible; encourage buddies to bring their protégés to their workplace and/or introduce the new employee to his/her informal network.	Partner with an external specialist to provide diversity training that covers hands-on approaches to recognizing, respecting, and leveraging differences and similarities within the utility and among customers.	Matching employees from different organizational and job backgrounds will enforce cross-departmental learning and allow new hires to get more insight into the utility and business aspects.
	Entry-level/young professionals programs	Conduct outreach programs targeting secondary school students to raise awareness of water's value and encourage young women to pursue careers in the sector. Outreach programs can include field visits to water treatment plants and pumping stations.	Youth Professional Program (YPP), at least 70% are women and minorities.	YPP program is competitive in the local market. At the same level as similar programs offered by private companies.	YPP program provides special training in emergency management, crisis management, risk management, and/or damage control.
	Internship and apprenticeship	A designated day allows parents to bring their daughters to work to inspire girls about their future career prospects.	The utility has a well-assessed pool of interns, of which at least 50% are women, and also	The internship program is competitive in the local market, at the same level as similar	NA

Area	Topic	Utility of the Future dimensions *Innovation*	*Inclusion*	*Market*	*Resilience*
			proportionally represents diverse social identities.	programs offered by private companies.	
Training & Development	Training programs	Training and development program aligned with employees' job competency framework. Use of innovative training (e.g., augmented reality, gamification). Special training in innovation and design thinking. Multiple formats (e.g., virtually, in person).	Staff training on how to work in a diverse environment (e.g., gender equality, implicit or gender bias, sexual harassment, disability inclusion, codes of conduct, etc., some of them mandatory every two years). A train-the-trainer program is in place to promote women and minorities.	The development program has allocated resources to develop high-performance teams (e.g., funds to bring in external consultants). Partnerships with local educational institutions/universities for knowledge exchange (e.g., exchange of onsite training for students for staff attendance at the institution's programs/courses).	Staff trained in how to identify and address slow-onset risks. Staff trained in how to identify and address uncertain risks.
	Mentoring and networking	Female entrepreneurs and innovators within the utility were identified and given support.	Training for mentors is expanded to include gender equality, diversity, and non-discriminatory practices. Peer career coaching for women	Cross-mentoring programs with other utilities or private sector companies	NA
	Development and promotions	Participation in innovation activities (innovation events, proposals of innovative solutions, implementation of innovations, etc.) is considered in the staff promotion process.	Diverse and gender-balanced selection committee in the promotion process.	NA	NA
	Succession plan	NA	The succession plan actively encourages female and minority successors.	NA	Definition of an "active prevention status" for critical staff teams to ensure that team members can be replaced by others if needed during a crisis
Performance Management	Planning and target setting	Targets for innovation achievements are defined: innovative proposals for process	NA	Performance indicators are defined for all staff and linked to customer management	NA

Area	Topic	Utility of the Future dimensions *Innovation*	*Inclusion*	*Market*	*Resilience*
		improvement, participation in innovation contests, implementation of innovations, etc.		indicators (customer satisfaction index, complaints attended, complaint resolution time, etc.).	
	Performance evaluation	Employees who propose or develop innovative projects have additional points in their performance evaluation.	Staff performance evaluation is done equally for all, with clear and unbiased rules, regardless of gender, culture, religion, etc.	Employees have an indicator of "customer satisfaction" as one of the components of their evaluation (regardless of the area where they work).	Incentives in performance evaluation related to the effort to maintain the continuity of the operation during an emergency
Remuneration, Incentives & Benefits	Direct financial compensation	Includes bonuses, profit sharing, stock options, insurance (health, family), etc.	Opportunities for performance-based compensation communicated to men and women and offered on an equal basis (including by establishing gender-neutral guidelines for allocation of bonuses, etc.).	HR teams conduct benchmarks and surveys to position compensation against the market.	Contingency budget for a potential crisis to ensure continuity of service delivery through salary supplements to compensate for potential additional workloads.
	Work-life balance	NA	Mental and emotional health and counseling support to all staff.	NA	Procedures for work arrangements during emergencies, including flexible work time and / or location arrangements. Mental and emotional health and counseling support during crisis.
	Awards & recognition	Special awards for innovative initiatives.	Special awards for females and minorities are based on performance, results, and added value.	Special awards for initiatives that positively impact customer service and customer satisfaction.	NA
Culture & Values	Organizational culture	Programs to encourage and promote innovative culture within the utility. Internal events to collect, evaluate, and implement innovative ideas.	Internal programs to expose women to other work areas and duties to achieve skill parity in traditionally male-dominated functions and roles. Programs and training for staff and	Staff rotation programs from different departments to the commercial department to strengthen their soft skills in customer orientation.	NA

Area	Topic	Utility of the Future dimensions *Innovation*	*Inclusion*	*Market*	*Resilience*
			management, tackling gender stereotypes, to promote a gender-friendly work environment.		
	Staff surveys	Staff surveys include opportunities for staff to propose innovative ideas.	Forums exist where employees can propose new ideas, and management genuinely considers them. Men and women are given equal opportunities to participate in forums.	NA	NA
	Prevention of Workplace Harassment	A fair and non-biased tribunal deals with harassment confidentially and promptly and provides support and recommendations to the utility. Survey to assess levels of workplace harassment and bullying and adopt policies, procedures, and training based on information derived from the survey; implementation of policies to address domestic violence.	NA	NA	Independent mental and emotional health and counseling support for overcoming harassment cases.

Source: adapted from World Bank. 2021. "Utility of the Future." https://documents1.worldbank.org/curated/en/796201616482838636/pdf/Utility-of-the-Future-Taking-Water-and-Sanitation-Utilities-Beyond-the-Next-Level.pdf

B.5 Organization and strategy

Table B.5: Practices to become a utility of the future – Organization and strategy

Area	Topic	Utility of the Future dimensions *Innovation*	*Inclusion*	*Market*	*Resilience*
Business Strategy	Strategic architecture	Strategic architecture includes the aspiration to be a Utility of the Future and is aligned with SDGs.	Mission and vision promote inclusion, internal diversity, community engagement, and social equity as organizational values.	Mission and vision reflect the considerations of customers.	The mission and vision include ensuring the utility's resilience by providing services despite shocks and stresses experienced. Includes robust scenario analysis.
	Strategic objectives	Strategy and objectives aim for innovation and a circular economy approach.	Strategy and objectives recognize the needs of different groups of customers, including underserved communities and the SDGs.	Strategy and objectives reflect customers' needs, priorities, values, and interests and promote stakeholder engagement (including policymakers, technology developers, NGOs, contractors, investors, researchers, community groups, etc.).	Utility is implementing a strategic plan to secure electricity supply for all under changing environmental conditions, population growth, urbanization, etc.
	Business plan	Business plan accommodates innovation and outlines incentives that facilitate the transition to a circular economy.	The business plan includes actions to address the expressed needs of underserved areas (e.g., slums) and vulnerable groups (e.g., low-income, women, and people with disabilities).	The utility has secured long-term contracts to deliver the business plan.	Business plan establishes long-term strategies that account for uncertainties.
Monitoring and Reporting	Monitoring process	An automatic monitoring and reporting system is equipped with dashboards that present real-time utility performance and are available remotely.	NA	NA	Identification of performance metrics for resiliency, such as recovery and robustness; listing of known unknowns.
	Utility process & policies	Formalized processes to find, assess, and support innovation, including from external sources, such as other sectors.	NA	NA	Formalized processes to monitor the development of slow-onset events. Utility processes and manuals consider the lessons learned post-crisis—identification of all non-

Area	Topic	Utility of the Future dimensions *Innovation*	*Inclusion*	*Market*	*Resilience*
					successful actions implemented during the crisis and analysis of the reasons for failure.
	Internal and external reporting	NA	Individual dashboard reports as required (e.g., on access disaggregated by neighborhood, gender, demography).	Monitoring mechanisms incorporate independent customer feedback.	Reports highlight any relevant risks related to resiliency.
Efficiency & Continuity	Process optimization	Machine learning tools to identify process optimization.		Incentives to personnel who propose and implement process optimizations (e.g., bonuses for savings generated by optimizing the procurement process).	
	Holistic approach	Information systems integrate all the processes and utility SLAs.	SLA integrates external stakeholders (suppliers, government agencies, etc.).	NA	SLAs are defined for key crisis management processes.
	Business continuity	NA	Community involvement in business continuity planning.	Agreements with other utilities and private sector companies to create synergies regarding business continuity (e.g., rotation of personnel, use of equipment, information systems, training, etc.).	IT teams should be able to activate backup and disaster recovery protocols remotely, consolidating lessons learned and new processes implemented in previous business continuity experiences.
Strategic Capabilities	Project management	Simulation process (low impact and low cost) as part of project evaluation.	The project plan includes community participation, local suppliers for project goods and services, and local labor (men and women).	NA	Project management plan during a crisis.
	Technology management	Early adopters of new innovative technologies with no proven business case; digital transformation plan.	NA	Technologies to better engage customers (e.g., online platforms) are proactively pursued and deployed.	Digital tools for improved prediction capacity are proactively pursued and deployed. Data management (data analytics, remote control

Area	Topic	Utility of the Future dimensions *Innovation*	 *Inclusion*	 *Market*	 *Resilience*
					and automation of infrastructure systems, utility analytics supporting management and operational decisions). Multi-location of data centers.
	Procurement management	Electronic bidding documents follow the internationally recognized process with a defined, transparent, and fair scoring system. The purchase order generation system is used every time an item leaves the warehouse or when a maintenance order is generated.	Programs to develop local suppliers of goods and/or services; invitations to bid advertised through various channels to reach a diverse audience (including minority—and female-owned companies).	Defined framework for considering circular economy, which accurately accounts for social, health, environmental, and economic aspects when assessing new business opportunities. Environmentally preferable purchasing (EPP) or green purchasing of products and services that have a lesser or reduced effect on human health and the environment.	Procurement strategy for emergencies: emergency stock, emergency supply of fuel for 2 months, suppliers' agreements, regular updates from suppliers on status and capacity to supply, alternative suppliers, suppliers' communication strategy, emergency stock of all inputs required for 3 to 4 months. Any missing inputs should be ordered immediately. Risk analysis of suppliers of goods and services. Established predictive analytics capabilities.
Utility Governance	Utility governance & decision making	Use AI to support the management, administrative, and operational decision-making process.	The Board of Directors has at least one member from the community.	The Board of Directors has at least one member from the private sector.	The crisis management decision committee is composed of people from different backgrounds (technical, administrative, financial, etc.) to ensure continuity of operations.

Source: adapted from World Bank. 2021. "Utility of the Future." https://documents1.worldbank.org/curated/en/796201616482838636/pdf/Utility-of-the-Future-Taking-Water-and-Sanitation-Utilities-Beyond-the-Next-Level.pdf

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