BELIZE ELECTRICITY, LTD

Integrated Resource Plan

Revision History

Date	Rev.	Description
6/3/2022	1	Initial draft with the foundational elements and capacity expansion plan.
7/21/2022	2.0	Updated version with introduction, reviews of foundational elements and capacity expansion reflecting comments from client obtained in presentations, generation capital expenditures and transmission expansion plan.
7/23/2022	2.1	Updated version with stability results.
8/09/2022	2.3	Updated version updated generation resources action plan, transmission capital expenditures and action plan, total cost of supply, executive summary, and considerations for the Chen Cycle.
8/26/2022	2.4	Final draft addressing BEL comments including the need for bringing up to standards certain substations in the system, separating the interconnection costs for new generation from the PPA to be funded by BEL and providing additional details on the expected flows from the Mexican Marked under the recommended Belize Centric Strategy and the Reference Strategy.

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1. Executive Summary

Siemens PTI was engaged by Belize Electricity Limited (BEL) to develop a least cost and least risk system expansion plan (LCEP).

The LCEP is a roadmap that will guide how BEL generates, transmits, and supplies electricity in a way that balances Affordability, Reliability, and Sustainability through 2042. To develop this road map Siemens followed a five-step process presented in this document that was used to analyze candidate portfolios derived from two central development strategies, one that favored the development of in country resources and another that relied on international purchases as part of the expansion plan.

1.1 Objectives

Following the 5-step process a preferred a Preferred Portfolio, which is a set of supply- and demand-side resources, as well as transmission expansions was identified as the one that best meets the BEL's defined objectives, which include the following key objectives:

- **Least Cost / Least Risk:** This objective is BEL's ability to procure, produce and deliver energy at a least cost with minimal price fluctuations and in support of quality of life, productivity of enterprise and national development. This objective is measured in terms of the net present value (NPV) of the Revenue Requirements (NPVRR), Rate Stability measured using the concept of "regret" that evaluates for each Portfolio its worst outcome (measured by the NPVRR) on an adverse Scenario (Future), Energy Security, i.e., avoiding over dependence single source (wind / solar),Spot Market Exposure and Fuel Dependency.

- **Sustainability:** Measure BEL's ability to produce/procure energy in a way that is sustainable and does not degrade the environment. It is measured as the percentage of energy requirements covered by renewable energy, with a minimum target of 75% of the energy to come from renewable by 2030 and carbon minimization with the objective to allow Belize to become zero carbon by 2050.

- **Reliability, Quality of Service and Resiliency:** This objective measure BEL's system ability to effectively produce/procure and deliver the energy required by customers with minimal interruptions to enhance quality of life and productivity and manage high impact /low probability events. It has the following components and metrics.

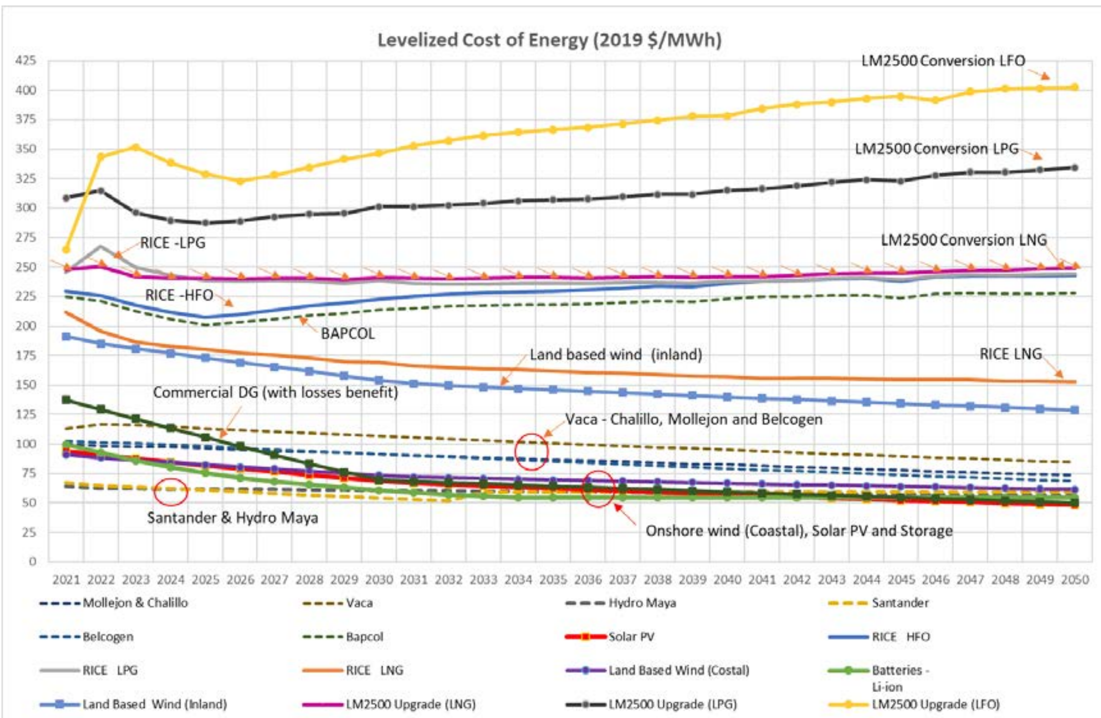
1.2 Forecasts and Candidates

For the identification of the Preferred Portfolio Siemens created a load forecast the planning period 2022 – 2042 including the forecasted new Electric Vehicles (EV) charging load and a forecast for the delivered prices for current and future fuels (natural gas) for Belize.

The load is projected to grow at 2.3% average for the next twenty years with a low band of 1.7% and a high band of 2.6% before the impact of EVs which represent about 8.7% of additional energy by the end of the planning period on the base case and 17.5% on the high case. For fuels, the forecast identified that the lowest cost for Belize is likely to be containerized LNG.

On the supply side, Siemens assessed the existing generation resources as well as the candidate generation resources that can be selected for the expansion plan. This includes conventional resources as is the case of reciprocating internal combustion engines (RICE) and repowering of the LM2500 at Mile 8 as well as renewable and storage.

Solar PV and Wind Generation (coastal region) was identified as the most economic utility scale resources for energy delivery, however for capacity needs the integration of renewable, Reciprocating Internal Combustion Engines, Storage, and the conversion of the LM2500 were identified as good alternatives. The figure below shows the Levelized Cost of Energy for all resources considered, including the distributed PV, which was also forecasted.



International Interconnections were considered including the current and expected cost and conditions to purchase power and energy from Mexico and the possibility of contracting directly with generators located in that country.

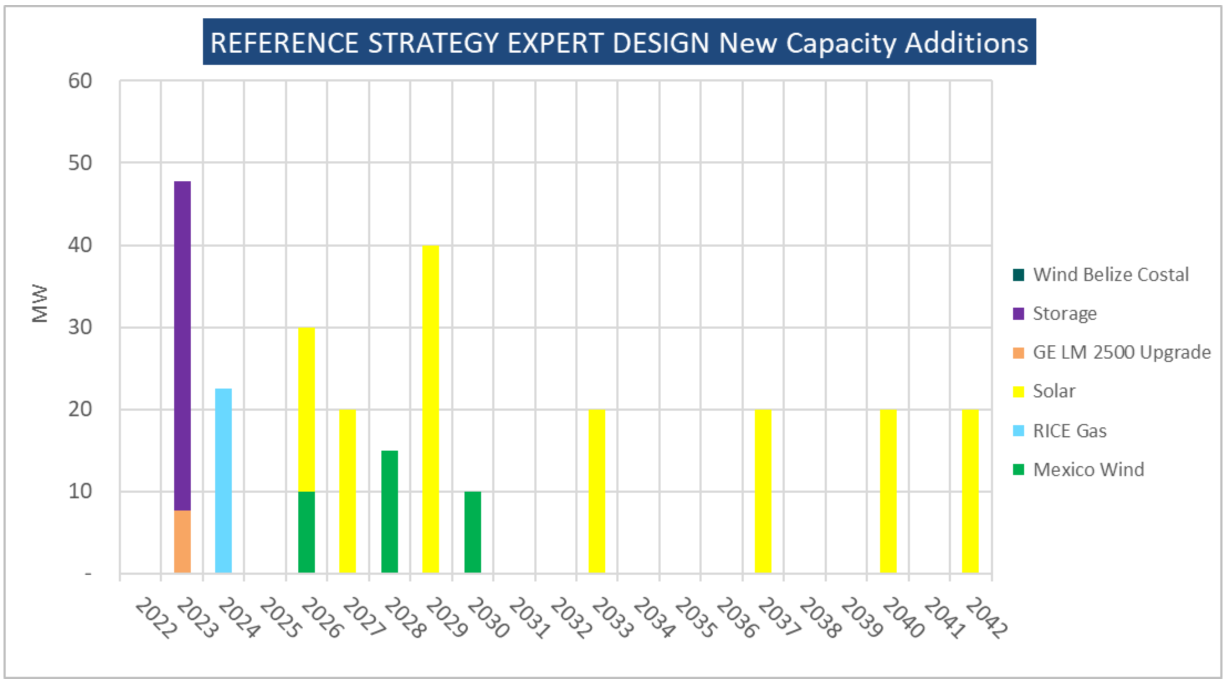
The current contract with CFE Calificados was modeled with its limit of 55 MW and the benefits of BEL entering with Calificados or other parties for a larger value was assessed and found convenient, particularly if the transmission limitations of the interconnection between the Oriental area of Mexico's power system and the Peninsular area, where BEL connects, are resolved. This improvement was modeled effective by 2030, although sensitivities for it not happening were carried out.

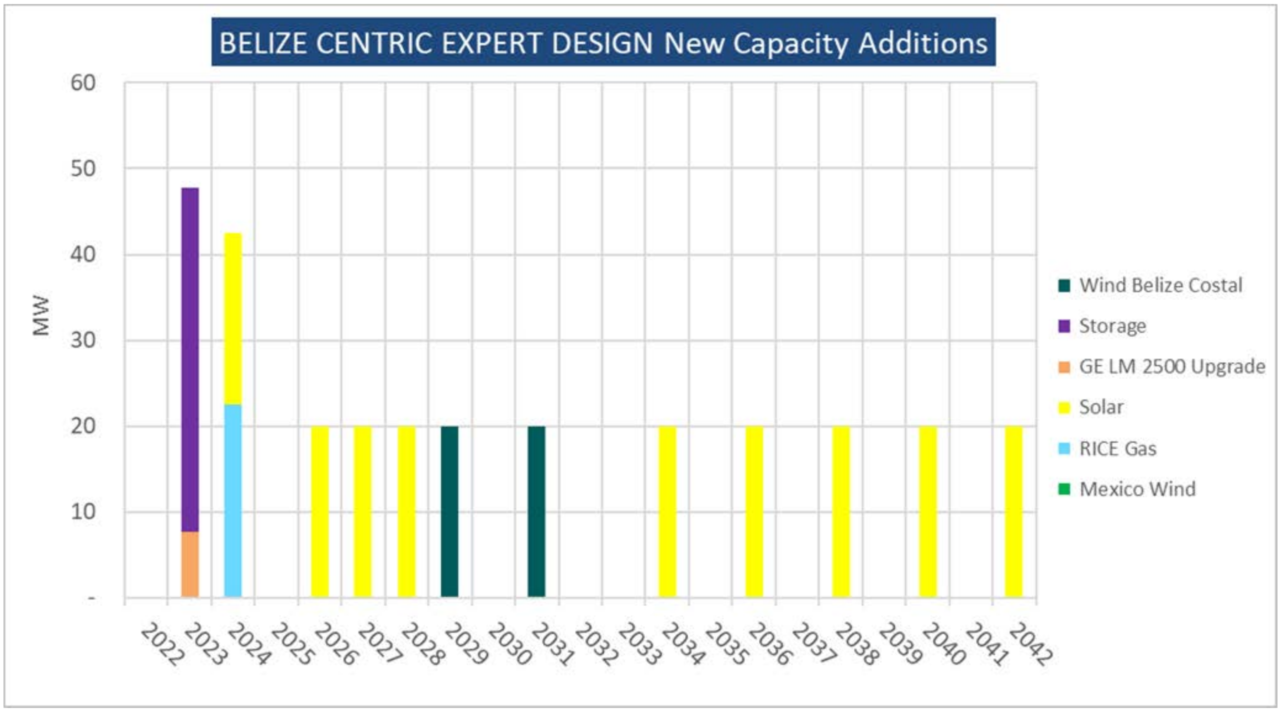
A project located in Mexico connected to BEL via a direct line, was modeled as a candidate. This project benefited from economies of scale as it was to be built as part of a larger project. This is expected to have 200 MW of wind generation and will be developed a few miles north of the Belize border and will interconnect to Xul-Ha.

Increases on the transmission interconnection with Mexico were assessed but not found convenient.

1.3 Portfolio Formulation

Multiple expansion plans were developed following the Reference Strategy that balanced internal resources with international purchases and the Belize Centric that gave preference to in country resources. This analysis resulted in two selected portfolios, the Reference Strategy Expert Design, and the Belize Centric Strategy Expert Design. The graphs below show the corresponding expansion plans, where we observe that in both plans there is the LM2500 conversion, 40 MW of Storage and one 22.5 MW RICE.



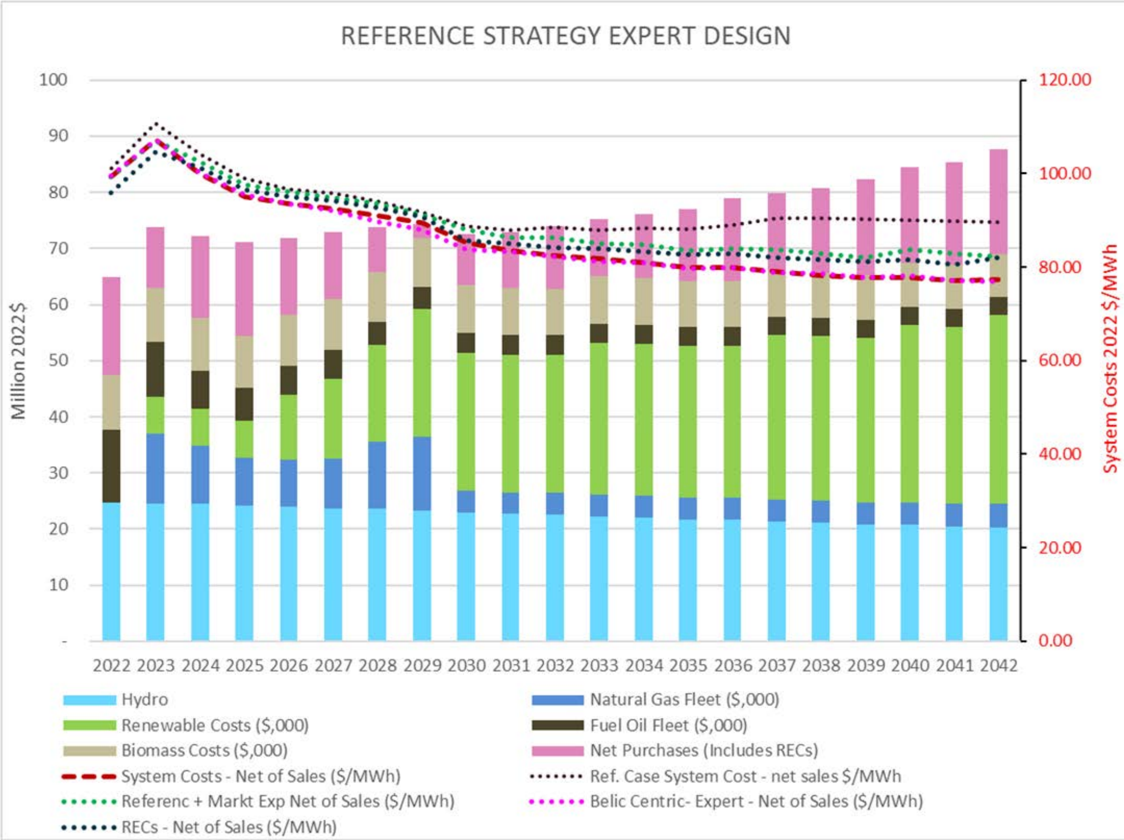


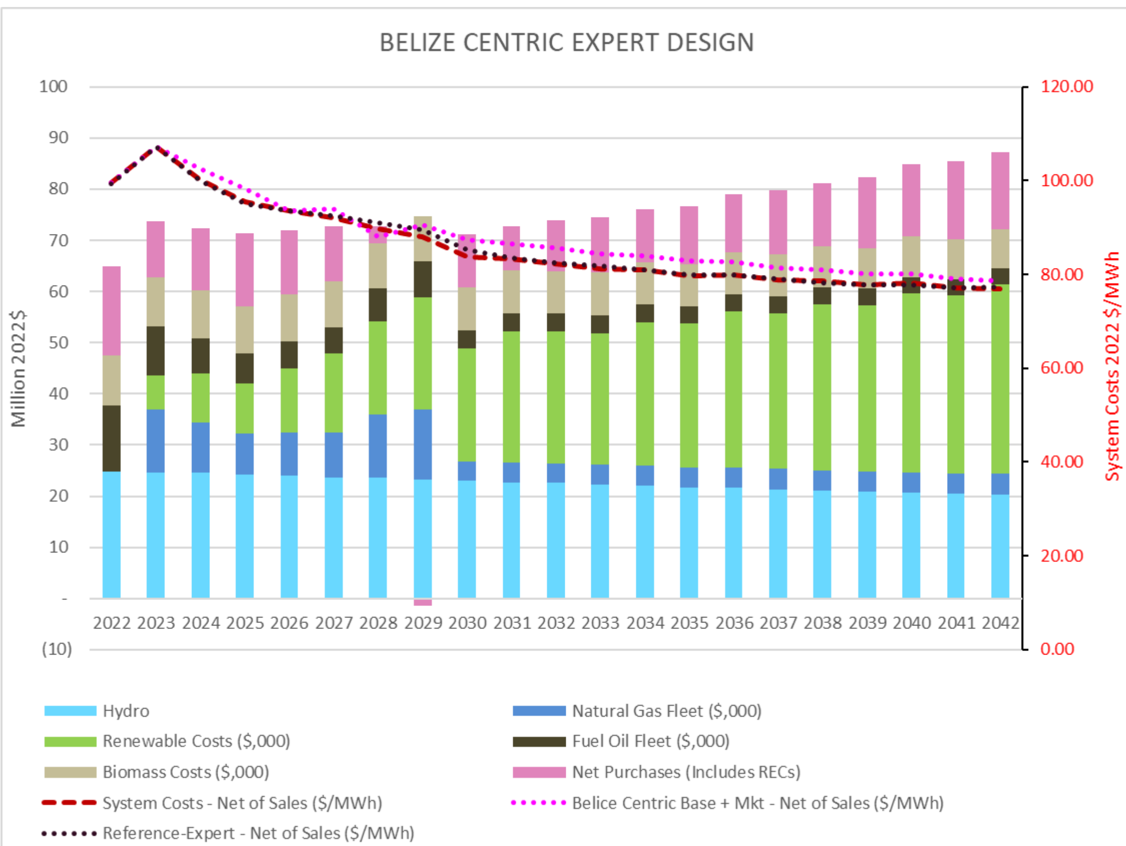
Both portfolios meet the 75% renewable by 2030 and largely stay around that value until the end of the planning period, although the Belize Centric achieves 80% by the end.

From a cost perspective both portfolios have similar Net Present Value of the Revenue Requirement as shown below, with less than 0.3% difference. However, the Belize Centric has lower Mexican market purchases and higher Mexican market sales. That makes it less vulnerable to cost increases in Mexico as well as increases in the Belize load.

NPV $000 (2022$)	Reference Expert Design	Belize Centric Expert Design
Variable	57,677	61,160
Fixed	670,178	684,182
Purchases	168,537	159,460
Total Costs before sales	896,393	904,803
Market Sales	18,497	29,502
Total after sales	877,896	875,301
Total Load (MWh)	10,007,705	10,007,705
Mkt + RECS Purchases (MWh)	3,651,218	3,509,257
Energy Sales (MWh)	196,758	346,392
Total Costs $/MWh	87.72	87.46
Purchase Costs $/MWh	45.05	44.91
Sales Price $/MWh	94.01	85.17

Both scenarios' costs are expected to decline in real terms during the planning horizon. See figures below, where we note the increasing role of renewable energy.


REFERENCE STRATEGY EXPERT DESIGN
Million 2022$
System Costs 2022 $/MWh
2022 2023 2024 2025 2026 2027 2028 2029 2030 2031 2032 2033 2034 2035 2036 2037 2038 2039 2040 2041 2042
Hydro
Natural Gas Fleet ($,000)
Renewable Costs ($,000)
Fuel Oil Fleet ($,000)
Biomass Costs ($,000)
Net Purchases (Includes RECs)
System Costs - Net of Sales ($/MWh)
Ref. Case System Cost - net sales $/MWh
Referenc + Markt Exp Net of Sales ($/MWh)
Belic Centric- Expert - Net of Sales ($/MWh)
RECs - Net of Sales ($/MWh)


BELIZE CENTRIC EXPERT DESIGN
Million 2022$
System Costs 2022 $/MWh
2022 2023 2024 2025 2026 2027 2028 2029 2030 2031 2032 2033 2034 2035 2036 2037 2038 2039 2040 2041 2042
Hydro
Natural Gas Fleet ($,000)
Renewable Costs ($,000)
Fuel Oil Fleet ($,000)
Biomass Costs ($,000)
Net Purchases (Includes RECs)
System Costs - Net of Sales ($/MWh)
Belice Centric Base + Mkt - Net of Sales ($/MWh)
Reference-Expert - Net of Sales ($/MWh)

The Belize Centric Portfolio has higher capital cost for the entire planning period, which is driven by the higher renewable installations after 2030 and driving the reduced dependence on Mexican Imports.

Capital Investment Costs Reference and Belize Centric Expert Portfolios 2022 to 2042

	Reference Strategy Expert Design		Belize Centric Expert Design	
	Capacity MW	Capital Costs (2022US$ Millions)	Capacity MW	Capital Costs (2022US$ Millions)
Mexico Wind	35	$50.6	0	$0.0
RICE Natural Gas	23	$25.4	23	$25.4
Solar PV	160	$183.6	180	$208.3
GE LM 2500 Upgrade	8	$11.5	8	$11.5
Battery Storage	40	$50.2	40	$50.2
Wind Belize Costal	0	$0.0	40	$56.1
Total	**265**	**$321.3**	**290**	**$351.5**

When the initial 10 years are considered, the investments are lower in this plan.

Capital Investment Costs Reference and Belize Centric Expert Portfolios 2022 to 2030

	Reference Strategy Expert Design		Belize Centric Expert Design	
	Capacity MW	Capital Costs (2022US$ Millions)	Capacity MW	Capital Costs (2022US$ Millions)
Mexico Wind	35	$50.6	0	$0.0
RICE Natural Gas	23	$25.4	23	$25.4
Solar PV	80	$100.9	80	$105.0
GE LM 2500 Upgrade	8	$11.5	8	$11.5
Battery Storage	40	$50.2	40	$50.2
Wind Belize Costal	0	$0.0	20	$28.6
Total	**185**	**$238.6**	**170**	**$220.8**

1.4 Portfolio Selection and Balanced Scorecard.

For the selection of the Recommended Portfolio the portfolios are assessed under multiple scenarios and sensitivities: three sensitivities were Low Hydro Production, Low Demand Growth and High Demand Growth as well as seven scenarios: High International Pricing, Low Capital and Low International Pricing, High Technology, High Regulation, Low Regulation, Climate Crisis, and Low Hydro – High Demand.

The results of the analysis above were reflected in a Balanced Scorecard, which identified the Belize Centric as the Preferred Portfolio. The Belize Centric Expert Design Portfolio had lowest NPV of cost by $2.6 million compared to the Refence Expert Design Portfolio. The NPV of energy market purchases is also lower and the capital investment requirements through 2030. In terms of sustainability, it has larger emissions reductions compared to the Reference Expert Design Portfolio and meets the 75% renewable mandate by 2030 and exceeds it by 2042.

In terms of energy security, both portfolios rely about one third of their total generation from solar power in the long-term (post 2030) with the Belize Centric having a bit more dependency than the Reference Expert Design. Prior to 2030, both portfolios rely on Hydro with about one third of the total generation.

When both portfolios were tested for varied long-term energy demand conditions and low hydro conditions, the Belize Expert Design also performs better in terms of costs (lower NPV of costs), lower market exposure to Mexico imports and slightly lower fuel costs. CO2 emissions reductions are larger for the Belize Centric Expert Portfolio, given the reduced dependency on Mexico imports which given the expectations for future generation mix in the Yucatan Peninsula, have a higher emissions content compared to Belize's internal generation mix (Peninsula is expected to have more dependency on fossil fuel).

The Belize Centric Expert Portfolio also has lower NPV of costs under the Climate Crisis, High International Energy costs, High Regulation, High Technology and Low Regulation conditions. However, the portfolio has slightly higher NPV of costs under Low Capital and International Energy costs. The Belize Centric also has a lower reliance on market purchase costs from Mexico. Belize Centric has slightly higher fuel costs under the High International Energy costs scenario, High Regulation and Low Regulation cases, which could imply higher commodity price risk.

The Belize Centric has larger emissions reductions under most scenarios except under High International Energy costs and Low Regulation Scenarios.

1.5 Supply Action Plan.

The Action Plan for the Belize Centric is separated in Thermal Investments, Solar Investments and Wind Turbine Generation and detailed below.

Belize Thermal Investments and Storage – Preferred Portfolio

Belize Preferred Portfolio Investments by Year						
In Service Year	Technology	MW	CapEx (2022$ Millions)	Common To Reference Strategy	RFP Issue date	Developer / Owner
2023	LM2500 Upgrade	7.74[1]	$11.47	Yes	On Going	BEL
2023	Storage	40	$50.21	Yes	ASAP	BEL
2024	RICE	22.5	$25.39	Yes	2023	Private

[1] This is the added capacity on top of the nominal capacity of 23.2 MW. The expected dependable capacity after the upgrade is 30.9 MW when burning Natural Gas delivered in containers.

Solar PV Investments – Preferred Portfolio

Belize Preferred Portfolio Investments by Year						
In Service Year	Technology	MW	CapEx (2022$ Millions)	In Reference Strategy	RFP Issue date	Developer / Owner
2024	Solar	20	$27.84	Delayed to 2028	2023 (1)	Private
2026	Solar	20	$26.42	Yes	2024	Private
2027	Solar	20	$25.73	Yes	2025	Private
2028	Solar	20	$25.06	Yes but 40 MW	2026 (2)	Private
2034	Solar	20	$22.01	Yes but 2033	2032 (3)	Private
2036	Solar	20	$21.31	Yes but 2037	2034 (4)	Private
2038	Solar	20	$20.63	NO	2036 (4)	Private
2040	Solar	20	$19.97	Yes	2038 (4)	Private
2042	Solar	20	$19.35	Yes	2040 (4)	Private

(1) Issue as soon as possible given the state of the renewable industry
(2) Could include more than 20 MW to achieve a total of 80 MW by 2028
(3) The 2034 project can be advanced to 2033, thus the RFP could be issued in 2031
(4) Consider reviewing the state of the Mexican Market and delay further (beyond 2042) the last 20 MW block and align with the Base Strategy.

Wind Turbine Generation Investments – Preferred Portfolio

Belize Preferred Portfolio Investments by Year						
In Service Year	Technology	MW	CapEx (2022$ Millions)	In Reference Strategy	RFP Issue date	Developer / Owner
2029	Belize Wind	20	$28.63	Earlier Mx Wind 25MW by 2028	2027 (1)	Private
2031	Belize Wind	20	$27.46	Earlier Mx Wind 10 MW in 2029	2029 (1)	Private

(1) Consider issuing the RFP earlier and open to Mexican wind for increased competition

We examined the potential for increased purchases from Mexico and based on this we recommend that an increase in the contract be pursue with a target between 80 and 85 MW as well as the opportunity to purchase RECs for compliance.

1.6 Transmission.

BEL transmission system being largely made up of single transmission lines interconnecting substations, without the possibility of an alternative path in what is called a radial system, is particularly vulnerable, as a single outage (called N-1) results in the interruption of flow to important sections of the system and results in load being interrupted (shed).

The system was analyzed both in steady state and dynamic stability and an expansion plan was developed that will transition BEL's transmission system to a reliable state-of-the-art system by the implementation of targeted investments in the system and leveraging the assets that are recommended from the capacity expansion plan.

Two level of investments were identified: a) the Minimum Investments and b) the Recommended Investments which expand the first group to achieve recommended performance.

The Minimum Investments are those necessary to address expected overloads under normal operating conditions that, in this case, are defined overloads beyond the ONAF (emergency rating) of the transformers, although in general this rating is reserved for contingencies or unforeseen increases in load.

The Recommended Investments are those necessary to provide firm capacity (N-1 Security) at the substations to address the loss of a transformer and prevent the parallel (if one is present) to overload beyond its maximum emergency (ONAF) ratings. In addition, in some cases these investments also address loadings above the normal (ONAN) rating.

The table below provides a summary of the minimum required investments and the in-service dates to address the projected overloads. BEL should use these dates as guide for starting the engineering and procurement process. The 2023 projects are associated with ongoing projects or require replacement of an asset inside a substation. The only exception to this is the Santander substation standardization that is central for the availability of the generating plant. Other projects have at least two years leeway or three in the case of new transmission additions.

Minimum Required Investments US$ 2022

Investment	Capital Costs 2022 M$	Overload Required Date	Load Affected MW	Notes
San Pedro 2 34.5/22 kV transformer	$0.49	2023	5.48	This is the smaller 5.4/7 MVA transformer to be replaced by BEL in 2023
Orange Walk transformer 1 34.5/22	$0.12	2023	6.03	San Pedro relocated here
Santander standardization	$1.75	2023	N/A	The substation layout is not up to code and standards (BEL reported)
La Democracia to Dangriga 115 kV transmission line	$15.67	2024	18.20	Required for RICE interconnection & reliability
San Pedro standardization	$1.75	2024	13.33	The substation layout is not up to code and standard (BEL reported)
Corozal standardization	$1.25	2025	7.33	The substation layout is not up to code and standards (BEL reported)
Orange Walk standardization	$1.25	2026	10.33	The substation layout is not up to code and standard (BEL reported)
Independence Transformer 1	$1.78	2026	9.01	N-1 main concern. ONAN currently exceeded
Belmopan 115/22 kV	$1.07	2035	16.97	N-1 main concern. ONAN currently exceeded
Maskall to San Pedro 69 kV Supply	$18.85	2025	17.51	by 2025 the cable will overload
San Pedro to Caye Caulker 34.5 kV cable	$5.46	2023	17.51	Ongoing project BEL
San Pedro 1 34.5/22 kV transformer	$1.63	2030	7.85	Existing XFR currently loaded above ONAN
San Ignacio transformers	$2.10	2036	8.96	N-1 main concern and loaded above ONAN by 2025
Chan-Chen transformers	$1.57	2041	5.95	N-1 main concern and loaded above ONAN by 2034
Total	**$54.73**			

The Recommended Investments include the investments above, but they may be advanced in this table as for example to provide firm capacity (N-1 security) before the overload is present. We note below that all investments that require new transmission have in service dates of 2024 or 2025, although it is recognized that investments like the new Dangriga 115 kV line may experience further delays.

Recommended Investments US$ 2022

Investment	Capital Costs 2022 M$	Planning Recommended Date	Load Affected MW	Notes
San Pedro 2 34.5/22 kV transformer	$0.49	2023	5.48	This is the smaller 5.4/7 MVA transformer to be replaced by BEL in 2023
Orange Walk transformer 1 34.5/22	$0.12	2023	6.03	San Pedro relocated here
Santander standardization	$1.75	2023	N/A	The substation layout is not up to code and standards (BEL reported)
Corozal Transformer	$1.15	2023	3.78	N-1 main concern
Orange Walk transformers 34.5/6.6	$1.15	2023	5.19	N-1 main concern
Orange Walk transformer 2 34.5/23	$1.15	2023	6.03	N-1 main concern. ONAN exceeded by 2030
La Democracia to Dangriga 115 kV transmission line	$15.67	2024	18.20	Required for RICE interconnection & reliability
San Pedro standardization	$1.75	2024	13.33	The substation layout is not up to code and standard (BEL reported)
Corozal standardization	$1.25	2025	7.33	The substation layout is not up to code and standards (BEL reported)
Orange Walk standardization	$1.25	2026	10.33	The substation layout is not up to code and standard (BEL reported)
Dangriga transformers	$1.61	2024	7.02	N-1 main concern. ONAN exceeded by 2035
Independence Transformer 1	$1.78	2024	9.01	N-1 main concern. ONAN currently exceeded
Belmopan 115/22 kV	$1.07	2024	16.97	N-1 main concern. ONAN currently exceeded
Santander tap to Belmopan 115 kV line section and substation upgrade	$1.25	2024	16.97	N-1 main concern
Belmopan 22/11 kV second unit	$1.10	2024	6.33	N-1 main concern
North Ladyville to Belize II 115 kV Transmission line	$10.66	2025	9.28	Reliability of Belize Metropolitan District
Switching substation North Ladyville	$1.42	2025	18.44	
New Belize II 115/22 kV substation	$7.10	2025	18.44	
Maskall to San Pedro 69 kV Supply	$18.85	2025	17.51	by 2025 the cable will overload
San Pedro to Caye Caulker 34.5 kV cable	$5.46	2023	17.51	Ongoing project BEL
San Pedro 1 34.5/22 kV transformer	$1.63	2026	7.85	Existing XFR currently loaded above ONAN
San Ignacio transformers	$2.10	2026	8.96	N-1 main concern and loaded above ONAN by 2025
Chan-Chen transformers	$1.57	2026	5.95	N-1 main concern and loaded above ONAN by 2034
Belcogen transformers	$1.72	2026	10.31	N-1 main concern. ONAN exceeded by 2027
Independence Transformer 2	$0.49	2026	9.01	Existing XFR currently loaded above ONAN
Belmopan 115/22 kV second unit	$0.49	2035	20.53	Replacing existing with larger capacity unit
Total	**$84.02**			

The cost for interconnection of new generation to the system, i.e., the gen-tie or line from the project to a BEL's substation and the cost of a new breaker bay at that substation, are normally included in the project's unit costs. However, as these costs will be funded by BEL and included in the rate-base instead of the PPA price, for the estimation of the delivery costs they were extracted from the PPA and added to the rest of transmission costs. A gen tie of 5 miles at 34.5 kV and one 34.5 breaker bay was assumed for each project with a cost 2022$ of $1.23 million.

Finally, from the stability analysis the following recommendations are derived:

a) The LM 2500 at Mile 8 should be modified so that it can easily transition from regular CT to a Synchronous Condenser with the use of a clutch. Also, its minimum load should be set up as low as possible as in the long term this unit will provide largely spin reserves at night.

b) The storage must have frequency controls much like the governors in a conventional generator with adjustable droop.

c) Solar PV and wind generation must also have frequency controls much like the governors in a conventional generator with adjustable droop. Although most of the time this governor will actuate to reduce generation, the positive direction (reg-up) must also be available in case the resource is being curtailed.

1.7 Cost of Delivery Impacts.

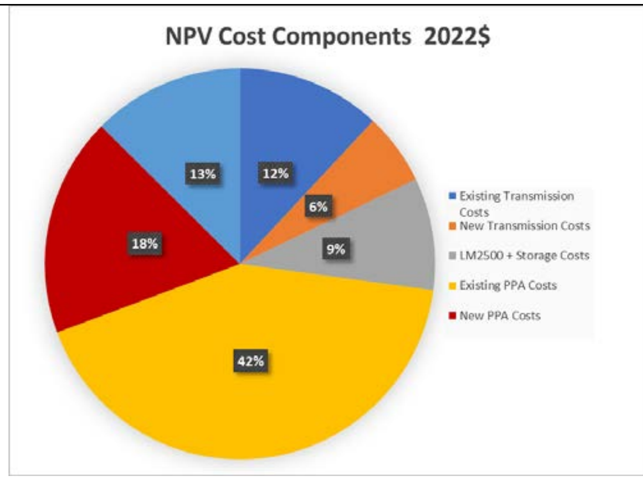
An estimation of the total expected cost of delivery combining the transmission and supply costs presented was produced. For supply side we used the recommended Belize Centric Expert Plan whose capital expenditures were discussed above and for transmission we considered both the minimum investments and the recommended investments.

1.7.1 Minimum Transmission

The table below shows the NPV of the various revenue requirement streams and the effective costs in $/MWh, where we note that the New Transmission, which is the minimum in this case, represents 4% of the costs.

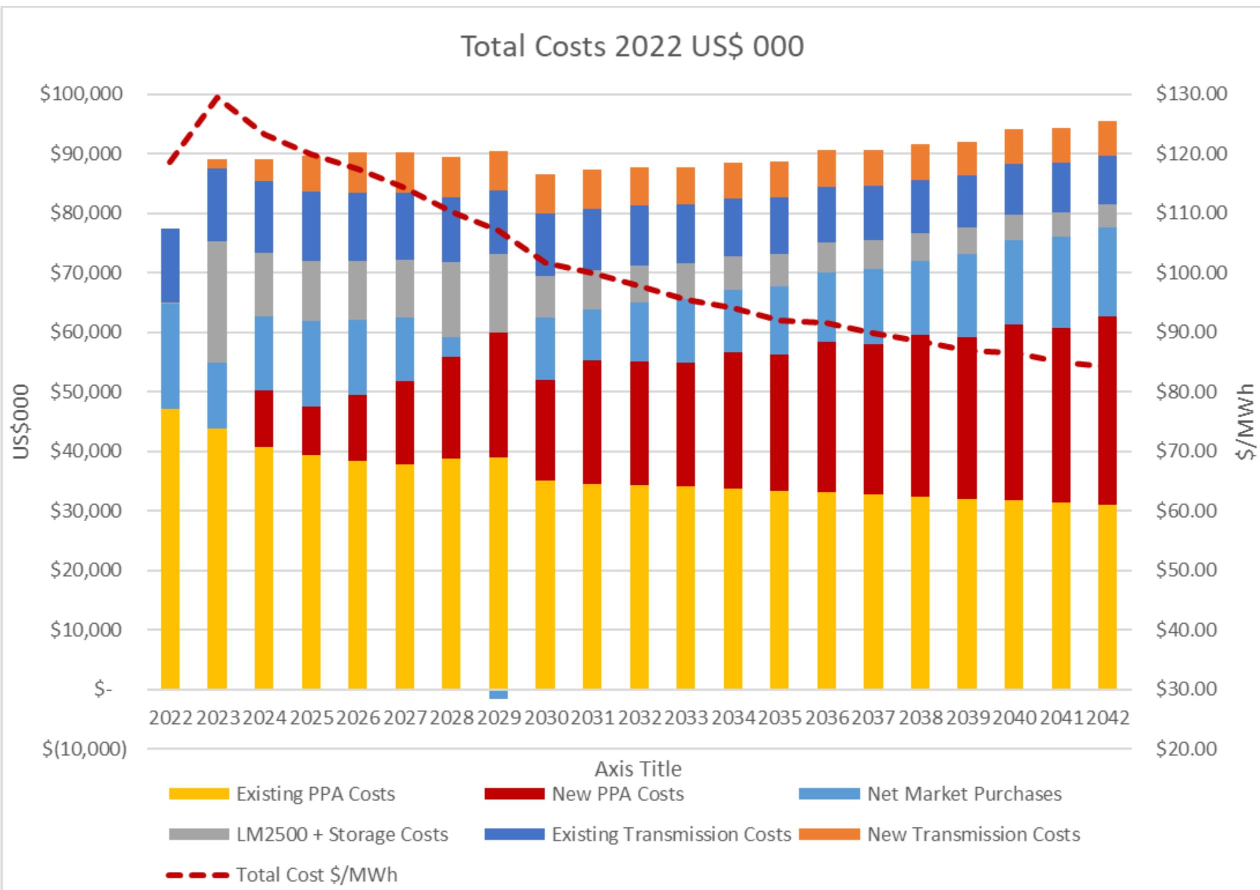
2022$ NPV Revenue Requirement for total delivery costs with minimum transmission

Total Costs Rate Impact (2022 000$)	NPV
Existing Transmission Costs	$124,684
New Transmission Costs	$61,793
LM2500 + Storage Costs	$96,811
Existing PPA Costs	$439,806
New PPA Costs	$189,254
Net Market Purchases	$131,111
Total	**$1,043,460**
Effective Cost $/MWh	**$104.3**



The figure below shows the total costs over time for the planning period in 2022$, where we observe the decline overtime of the cost of supply in real terms and that by the end of the planning period the largest component of costs are the New PPAs, Existing PPAs and Market Purchases in that order.

Total Delivery Costs 2022 US$ with Minimum Transmission



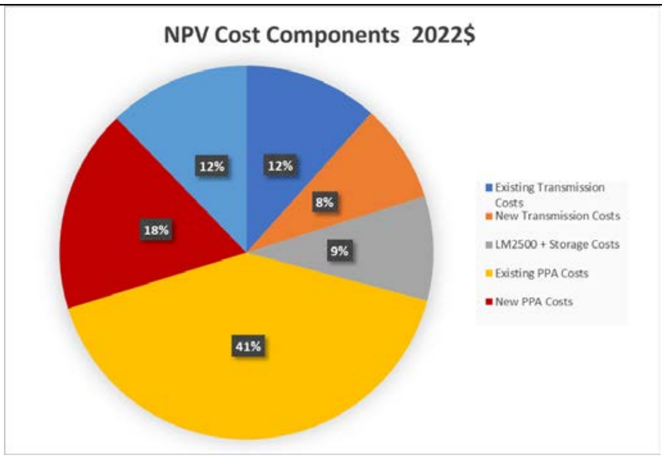
In the report the costs above are also presented in Nominal Terms.

1.7.2 Recommended Transmission

The table below shows the NPV at a real discount rate of 6% of the revenue requirements in 2022 US$ for all components of supply, for the case that transmission is developed as recommended. In this case the recommended new transmission has a participation of 7%, up from 4% with the minimum investments.

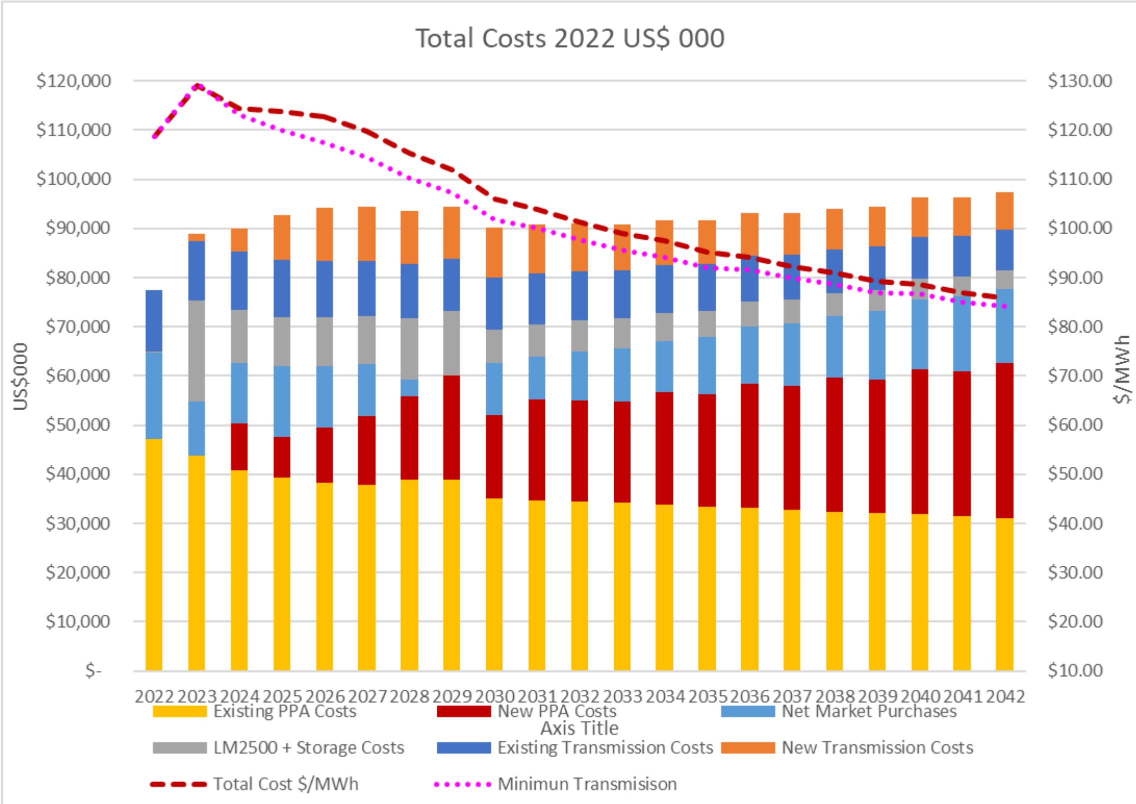
2022$ NPV Revenue Requirement for total delivery costs with Recommended Transmission

Total Costs Rate Impact (2022 000$)	NPV
Existing Transmission Costs	$124,684
New Transmission Costs	$91,366
LM2500 + Storage Costs	$96,811
Existing PPA Costs	$439,806
New PPA Costs	$189,254
Net Market Purchases	$131,111
Total	**$1,073,033**
Effective Cost $/MWh	**$107.2**



The figure below shows the total costs over time for the planning period in 2022$, where we also observe the decline overtime of the cost of supply in real terms. In this figure we also added the cost of supply with the Minimum Transmission investments, and we note that in average the costs are about 3% higher or about $3.2/MWh with the recommended transmission investments. The main components of the cost remain the PPA (new and existing) and the market purchase.

Figure 1-1: Total Delivery Costs 2022 US$ with Recommended Transmission



2. Introduction

Siemens PTI was engaged by Belize Electricity Limited (BEL) to develop a least cost and least risk system expansion plan (LCEP).

The LCEP is a roadmap that will guide how BEL generates, transmits, and supplies electricity in a way that balances Affordability, Reliability, and Sustainability through 2042. To develop this road map Siemens followed a five-step process presented in this document that was used to analyze candidate portfolios derived from two central development strategies, one that favored the development of in country resources and another that relied on international purchases as part of the expansion plan.

Following the 5-step process a preferred a Preferred Portfolio, that is a set of supply- and demand-side resources, as well as transmission expansions was identified as the one that best meets the central objectives of least cost and least risk while meeting the policy objectives of the Government of Belize (GoB) with respect of renewable generation penetration and results on a reliable power system. This Preferred Portfolio will be a planning tool to inform future resource actions and transmission additions to serve the expected load for the period 2022-2042

The LCEP presented in this document is the result of a collaborative effort between Siemens and Belize Electricity Limited (BEL), the Belize Ministry of Energy (MoE) and the Belize Public Utilities Commission (PUC).

The balance of this document is organized in the following sections:

LCEP Process and Considerations: In this section the overall procedure followed for the identification of the LCEP is presented. In this section the project objectives and metrics used for the assessment are presented, followed by the strategies used for the formulation of the Portfolios and the scenarios and sensitivities used for their assessment. Finally in this section the concepts used for the portfolio selection and balanced score card is presented.

Load Forecast: The load forecast for the planning period 2022 – 2042 is presented including the forecasted new Electric Vehicles charging load. Recommendations for a future Energy Efficiency study is made.

Fuel Forecast: The delivered prices for current and future fuels (natural gas) for Belize are provided.

Existing Generation Resources: The main considerations regarding the performance of the in country existing resources and costs are presented.

In country Candidate Generation Resources: Cost and performance of candidate future in country resources that can be selected for the expansion plan are presented. This includes conventional resources as is the case of reciprocating internal combustion engines (RICE) and repowering of the LM2500 at Mile 8 as well as renewable and storage. The expected incorporation of distributed generation is also presented.

International Interconnections: The current and expected cost and conditions to purchase power and energy from Mexico is presented. This also includes the possibility of contracting directly with generators located in that country. Not enough information was available to assess the convenience of interconnection with Guatemala at this time. This interconnection can be assessed in the future; however, it is expected to be an enhancement to the recommended plan, rather than a major modification.

Portfolio Development: The various portfolios (plans) for electricity to supply Belize are developed and presented.

Scenarios and Sensitivities: The portfolios are assessed under multiple scenarios and sensitivities and their performance compared.

Balanced Scorecard and Portfolio Selection: The scorecard of each portfolio is presented, and a portfolio recommended for implementation. The expected capital costs are provided.

Capital Expenditure: The capital expenditures of the two best portfolios are presented.

Preferred Portfolio Selection and Action Plan: In this section the preferred portfolio is selected, and the action plan is provided.

Transmission System Assessment: The BEL transmission system under current and future conditions is assessed with the preferred deployment of the new resources to enhance reliability. Investments are recommended as well as the in-service dates. Capital expenditures are provided

Transmission Action Plan: In this section we provide the transmission action plan.

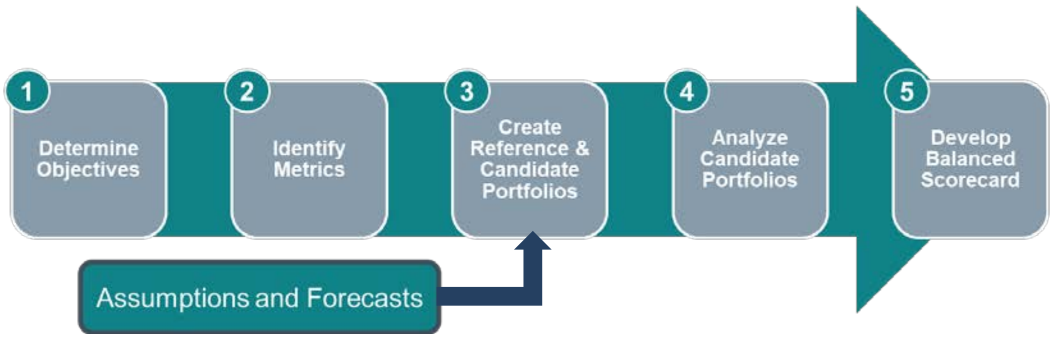
Cost Delivery Impacts: This last section provides the impact in the cost of delivery of the generation and transmission investments recommended.

3. LCEP Process and Considerations

Siemens PTI uses a 5-Step process for modeling, identifying, and analyzing Candidate Portfolios and the associated transmission plans leading to the selection of the identification of the Least Cost Expansion Plan. The process, detailed below, provides a holistic approach to identifying the Preferred Portfolio and transmission investments that best meets BEL's defined Objectives as measured by the Metrics over a wide range of potential future conditions.

Step 4 is the central analytical step where the optimization procedure considers both the least costs long term capacity expansion plan (utility scale and load side resources) as well as the associated transmission, ensuring that the combined least cost / least risk plan is identified.

Figure 3-1: Siemens PTI: Approach to Integrated Resource Plan Modeling



3.1 Objectives and Metrics

The objectives are the policy objectives that the selected generation and transmission expansion plan (i.e., the Preferred Portfolio) must best achieve. Some of these objectives have a floor that must be meet by all candidate portfolios (e.g., 75% renewable energy by 2030) and other are relative (e.g., which one has the least cost, or which one has the maximum level of renewable energy).

We present below the objectives that were used to identify and assess the portfolios.

3.1.1 Least Cost / Least Risk

This objective is BEL's ability to procure, produce and deliver energy at a least cost with minimal price fluctuations and in support of quality of life, productivity of enterprise and national development. This objective is also known as Affordability and has the following components and metrics.

- **Least Cost:** This is measured by the Portfolio net present value (NPV) of the Revenue Requirements (NPVRR) for the new and existing generation, the current transmission system and its expansion as defined in each of the Portfolios. The generation revenue requirements for the existing generation include the capacity and energy payments as defined in the PPAs as well as the fixed and variable costs of BEL owned generation. All future generation is be assumed to be developed by third parties and the revenue requirement includes the annualized return on capital estimated using the expected Weighted Average Cost of Capital (WACC) for a private developer plus fuel (if applicable) and fixed and variable O&M expenditures. Transmission is assumed to be developed by BEL and includes the return on the capital invested using BEL's WACC as well as O&M. The is calculated using BEL's WACC as the discount rate.

- **Rate Stability:** This measures the degree by which the Portfolio costs can vary by changes in uncertain variables outside of BEL's control; for example, changes in fuel prices, lower/higher demand, low/high CFE market prices, etc. It will be measured using the concept of "regret" that evaluates for each Portfolio its worst outcome (measured by the NPVRR) on an adverse Scenario (Future).
- **Energy Security:** Heavy dependence on a single source is to be avoided (e.g., hydro, solar, wind fossil fuel, biomass or international interconnections). Participation of each source type on the supply matrix to be assessed and the more diverse mixing, solar, hydro, wind, thermal and imports the better.
- **Secondary Objectives:** In addition to the central objectives above there are secondary objectives that can be used to differentiate between two otherwise close Portfolios. These include:
  - **Market Exposure**: Percentage of energy procured or sold in spot market (international). Spot Markets can be volatile and add risk to the portfolio when compared with the situation where the energy is procured via bilateral contracts (PPA). The lower spot market exposure the better.
  - **Fuel Dependency:** NPV of Imported fuels cost expressed as a percentage of NPVRR, lower the better

- **Intensity of Construction:** Capital requirements over time or number of new plants by year. Lower the better and there could be a limit on new utility scale plants by year (e.g., no more than 6 plants) to account for the complexity of managing multiple contracts at the same time and interconnecting the plants to the system.

3.1.2 Sustainability

This objective measure BEL's ability to produce/procure energy in a way that is sustainable, does not degrade the environment and minimizes pollution and impacts on the ecosystem. It has the following components and metrics.

- **Renewable Energy:** This is the percentage of energy requirements to be covered by renewable energy. The current target is 75% of the energy to come from renewable by 2030 as defined in Belize's National Determined Contribution (NDC). The imported energy from Mexico, is be considered as included in this goal. Hence in as much as Mexico energy is considered thermal, given that the marginal energy produced in the Yucatan Peninsula is from gas fired CCGTs, then the expansion plan would need to reduce Mexico's participation to less than 25% from the current 44% average. An alternative to this is direct purchases with a RE provider in Mexic (via a dedicated line), if possible, and/or acquire REC (Renewable Energy Certificates).
- **Zero Carbon:** Belize is committed in accordance with it NDC becoming zero carbon by 2050 in line with COP-26. The IRP Preferred Portfolio is to put Belize on the path to achieve this goal. A sensitivity to 100% renewable by 2030 was also carried out.

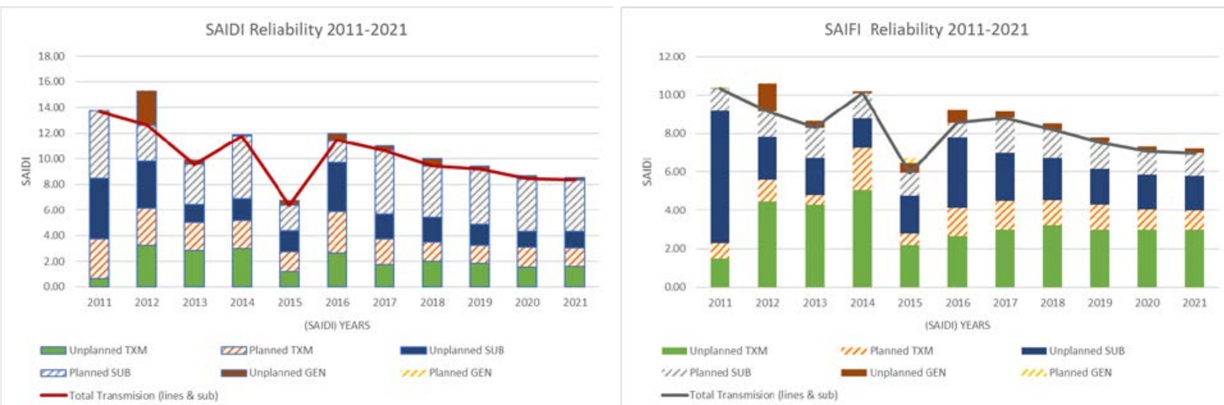
3.1.3 Reliability, Quality of Service and Resiliency

This objective measure BEL's system ability to effectively produce/procure and deliver the energy required by customers with minimal interruptions to enhance quality of life and productivity and manage high impact /low probability events. It has the following components and metrics.

- **Reliability:** System to reach at least the SAFI and SADI as defined in BEL's business plan. These indices can be separated in generation, transmission and distribution. Distribution is outside the scope of the IRP that is to define the expansion of generation and transmission and generation has a fairly small contribution and it is measured by resource adequacy, thus the focus of the reliabilty analisis is to define a system that minimizes the customer interuptions and its duration by adequate develoment of the transmission system as defined by the planing criteria (see section 14.3.2) and location of the generation resources.

  Historical statistics, see below, indicate a steady improvement of SAIDI and SAIFI with transmission and subtransmission, as expected, as the leading contributor with 8.35 hours/yr. SAIDI and 6.99 times/yr. SAIFI (1.2 hours CAIDI).

Figure 3-2: SAIDI and SAIFI Transmission and Generation 2011 to 2021



  When the distribution system is added for 2021 it is expected 14.5 hours SAIDI and for the entire system and 11.3 times SAIFI for 1.3 hours CAIDI. Note that the main driver of these statistics is the SAIFI, i.e., the number of interruptions to the load that exceed the 5 minutes threshold and are considered permanent, and it is directly a function of the level of redundancy in the system. Hence in transmission planning we focused on minimizing the required level of load shed resulting of a single outage.

  Comparable values in developing countries can vary widely, depending on the investment in the transmission and distribution system, historically we had observed SAIFI average values of 11~ 12 times/year, however recent statistics showed an improvement for example El Salvador has a SAIFI target value of 8.3 times/Year (16.6 SAIDI)[2] and according to a presentation by the Costa Rican Regulator[3] (based on World Bank statistics) Colombia has a SAIFI of 4.2 (4.6 SAIDI), Guatemala 2.4 (3.7 SAIDI), Chile 1.7 (2.3 SAIDI), Panama 1.5 (1.6 SAIDI) and Costa Rica 1.0 (1.8 SAIDI). In the case of Mexico, we see a SAIFI target of 0.2 for transmission and 0.94 distribution (1.14 total) and the

[2] Reporte de Sostenibilidad 2021.indd (delsur.com.sv)
[3] Roberto 20191001 ARESEP Eficienciaa 01-10-19.pdf

four worst divisions reported a total SAIFI of 1.33 times/year including transmission and distribution[4]. In developed countries these values are similar to the lowest values reported and in the order of 1.1 times/year SAIFI and 130 min/year (2.2 hours/year) SAIDI, including distribution transmission and generation (feed) but excluding major events[5]. Based on the above the SAIFI of Belize could be significantly improved over time and by the end of the planning period the interruptions should be aligned with those observed in other Latin-American countries and under 4.0 times/year.

- **Adequacy:** This is a metric directed basically to the generation system and measures the energy not served (ENS) and the loss of load hours (LOLH). In as much as there are no targets for BEL they could measured and compared with other developing countries targets (e.g. 2 hours/year). However as shown later in this report given the distributed nature of the future resources the probability of having ENS is very small (no ENS was ideitified).

- **Quality of supply, Sequrity and resiliency:** Meets planning standards on voltage / frequency, the system to be designed such that no N-1 contingency or N-2 event results in system collapse and minimizes the load interrupted during outage of longer transmission lines whose restoration may take several weeks to perform. This is defined in the Planning Standard in Section 14.3.2.

3.1.4 Economic Development

This objective measure How much the IRP's investments support employment and the economy. It is measured by the capital investment located in country and the estimated employment.

3.1.5 Customer Engagement

Customer engagement consists of the initiatives that customer may take to self-supply and include Energy Efficiency (EE) effectively reducing their consumption and Distributed Energy Resources (DER). In this IRP DER will be based on a forecast that will be used on all portfolios analyzed, thus this metric (the level of customer engagement) can be reported but will not be differentiator. There was not enough information to make an adequate EE forecast and recommendations are included in this report for the required studies to be carried out.

3.1.6 Decision Making Support

BEL needs to make decisions on Decisions on future generation including new solar and the repowering of the Mile 8 LM2500 and new thermal generation (LNG based). The capacity expansion plan includes these options and guides BEL on making its decisions.

3.2 Create Candidate Portfolios

Siemens PTI develops in this step the Candidate Portfolios based on a series of inputs that are informed by the IRP objective, strategic alternatives, and Scenarios / Sensitivities.

[4] Reporte_de_confiabilidad_de_Electricidad_.pdf (www.gob.mx)
[5] See for example https://cmte.ieee.org/pes-drwg/wp-content/uploads/sites/61/2019-IEEE-DRWG-Benchmarking-Results.pdf

Siemens PTI uses scenario analyses, optimization techniques, expert judgement, practical considerations, and stakeholder input to craft the Candidate Portfolios that adequately reflect the IRP strategic considerations and objectives. The IRP's Preferred Portfolio is identified by the comparison and contrasting of two Candidate Portfolios.

Section 9 presents the portfolio development carried out based on the following strategies:

3.2.1 Base Case or Reference Case Strategy.

This strategy seeks to minimize the costs and manage the hydro risk by a combination of:

- Increased international (Mexico) purchases
- New thermal generation (LPG/LNG)
- New Renewable generation/storage (existing proposed projects and new generic projects)

The new generation candidates were pre-screened using the Levelized Cost of Energy (LCOE) metric to rule out uneconomic / unfeasible options (usually limited to types of thermal generation and fuel) and the best performing were provided as "Options" to be selected economically by Aurora's Long Term Capacity Expansion (LTCE). In other words, beyond any committed project, the generation additions must be a result of the Aurora optimization.

The increase of international interconnections was limited to Mexico as there was not enough information for Guatemala, and was analyzed using a two-step process, as elaborated later in this document, designed to co-optimize transmission with generation. First the options for interconnection expansion are defined to achieve a transmission transfer level increase with Mexico. With these inputs the actual amounts of energy / capacity purchases (or sales) are economically selected by Aurora LTCE balancing with in country generation developments. If the economic amounts were to hit frequency the limits of the interconnection capacity making it a severe binding constraint, then an increase in capacity would be investigated. However as shown later in this report the increase on the interconnection capacity with Mexico was found not to be economic.

Finally, note that the Portfolio must meet the 75% renewable by 2030 (75x30) and place Belize on the path to achieve by 2050 zero carbon. In as much as greater renewable goals are achieved it will be a result of the least cost long term capacity expansion plan as optimized by AURORA.

3.2.2 Belize Centric Strategy.

This strategy seeks to minimize the costs and manage the hydro risk by:

- Focusing on local generation
- International purchases should not surpass current levels.
- New thermal generation and new Renewable generation/storage options as in the Base Strategy and it is possible that larger plants will be selected.

As before, the pre-screened generation candidates will be provided as "Options" to be selected economically by Aurora's Long Term Capacity Expansion (LTCE). And the initial LTCE will be discussed and adjusted as necessary, including levels of sales to Mexico (which will be allowed) and convenience to firm energy and capacity purchases via PPAs.

3.2.3 Scenarios and Sensitivities.

The Candidate Portfolios are created via the LTCE that receives as inputs the key variables of load growth, fuel prices, capital costs, emission costs, etc., as well as renewable energy requirements and reliability requirements, normally given by a Planning Reserve Margin requirement. A consistent combination of these variables is a Scenario or Future state of the world. The Candidate Portfolios are first designed considering Reference Conditions and as discussed in the next step its performance is tested under other Scenarios (Futures) and Sensitivities that may result in further refinement (postponement or advancement of a decision).

The following scenarios are used for analysis:

- **Reference:** Demand modeled with the central projection, renewable and storage modeled with the expected (base) cost projection, expected cost of LPG and NG. Hydro production modeled with base projection. No CO2 prices applied to Belize.
- **High Technology:** Demand modeled with the high projection, assumed driven by high economic growth and electrification, renewable and storage will be modeled with the lower cost projection, low cost projection of LPG and NG as driven by lower demand for these fuels. Hydro production modeled with base projection. No CO2 prices applied to Belize.
- **High Regulation:** Demand modeled with the low projection, renewable and storage modeled with the base cost projection, high cost of LPG and NG as driven by high regulation of fuels. Hydro production modeled with base projection. CO2 prices apply to Belize.
- **Low Regulation:** Demand modeled with the high projection, renewable and storage modeled with the base cost projection, high cost of LPG and NG as driven by high demand. Hydro production modeled with base projection. No CO2 prices apply to Belize.
- **Climate Crisis:** Demand modeled with the low projection, renewable and storage modeled with the low cost projection, high cost of LPG and NG. Hydro production modeled with low projection. CO_2 prices apply to Belize.

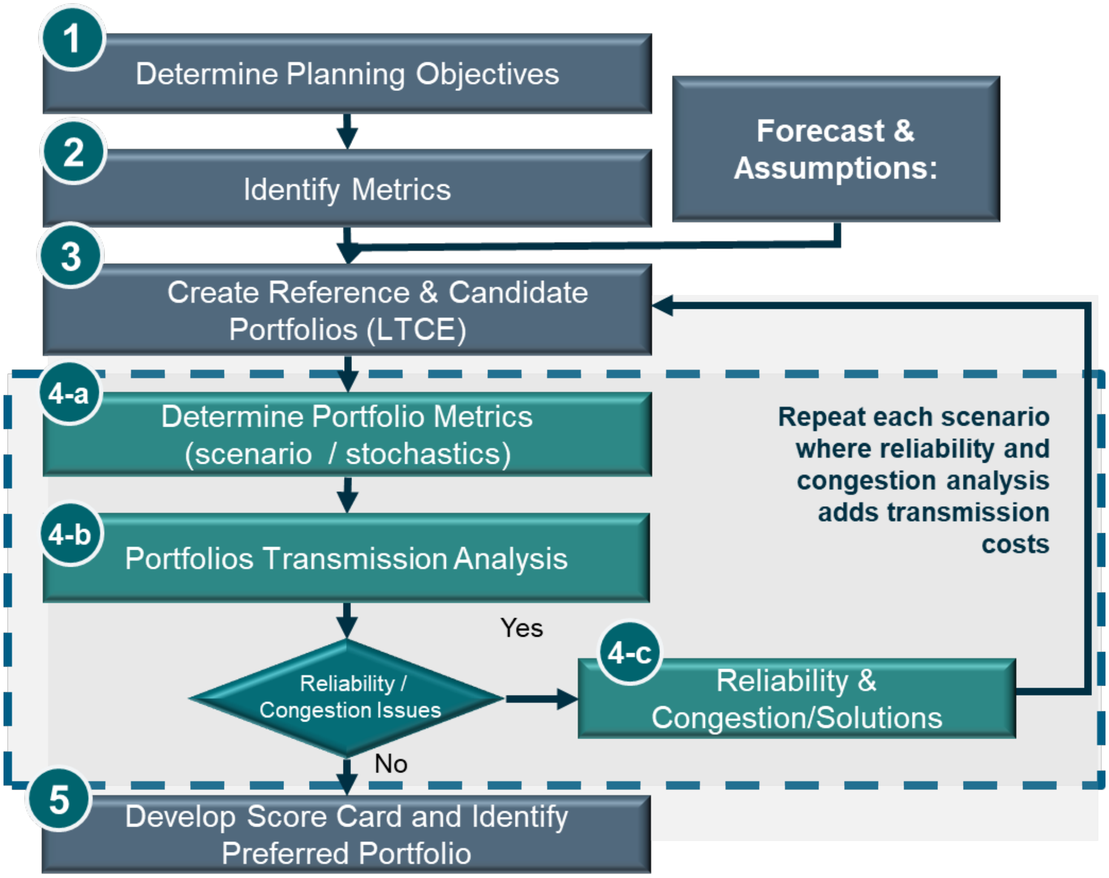
Sensitivities consist of changing only one variable at the time while leaving the other variables at their expected value. The objective is to assess how the portfolio is dependent or manage this variable. The following sensitivities are considered:

- **High Demand Forecast:** A high demand growth sensitivity to be assessed.
- **Low Demand Forecast:** A low demand growth sensitivity to be assessed.
- **Low Hydro:** This sensitivity considers the periodic repetition of low hydro availability years as observed in 2019.
- **Low Capital and Low International Energy Prices:** Low capital, fuel, and international purchase prices.
- **High Capital and International Energy Prices:** High capital, fuel, and international purchase prices.

3.3 Portfolios Analysis

Candidate Portfolios are analyzed in this step with an expanded procedure that includes for the identification of the least cost / least risk plan, the transmission impacts (see Figure 3-3 below).

Figure 3-3: Expanded Procedure to account for transmission



Step 4-a is where all the Metrics that define the Portfolio performance are assessed. In this critical step the performance under the base case conditions and the various scenarios and sensitivities identified is caried out. The step is carried out for base conditions before proceeding to the transmission analysis in Step 4-b and repeated considering the scenarios and sensitivities after the transmission impacts are considered.

The analysis consists of modeling the security constrained economic dispatch / security constrained unit commitment for the 8760 hours (8784 for leap years) for all the years within the planning horizon (2022 to 2042) and assess the performance of the portfolios with respect of the objectives presented above using the metrics provided. The result of this analysis for base, scenarios and sensitivities are provided as inputs to the score card assessment.

In Step 4-b the initial Candidate Portfolios created in Step 3 are modeled using our load flow modelling software (PSS®E) and its performance (steady state and stability) is assessed. If performance violations are found, then reinforcements are identified under Step 4-c and the LTCE (Step 3) would be repeated to assess that if with the new transmission costs the LTCE remains the same or options are dropped. This loopback ensures that both generation and transmission impacts are considered. However, as shown later in this report, the generation expansion due to its distributed nature supported transmission with the possibility to include non-wires-alternatives (NWA) deferring or eliminating reliability investments, rather than dictate expansions.

3.4 Preferred Portfolio Selection and Balanced Scorecard

These steps consist via regret analysis and a balance score card select the Preferred Portfolio and if applicable hedging strategies / pivot points to address uncertainty.

3.4.1 Regret Analysis

The regret is defined as the difference between a Portfolio outcome under a given scenario or sensitivity and the outcome of the best performing Portfolio for that scenario or sensitivity.

This is usually measured in term of the NPVRR for the portfolios and it allows identifying the best performing portfolio and the severity of the outcome for the other portfolios.

The best performing Portfolio under most scenarios / sensitivities is likely the Preferred Portfolio, but as other objectives are important this is assessed via the scorecard below.

Additionally in this step, depending on the outcomes hedging strategies can be identified to address a particularly adverse outcome, example delaying construction until there is clarity on the load growth or prices / development on an external market.

Regret can be applied to any metric and can result is adjustment of the Portfolios for better performance.

3.4.2 Score Card

In this step a scorecard is developed that will compare the performance of each portfolio against the objectives and metrics defined in the initial steps of the IRP Planning Process.

The balanced scorecard allows assessing the tradeoffs between portfolios (i.e., lease cost and environmental stewardship) and enables the team to determine the best performing portfolio. Weights will be used to produce a final score of the portfolios.

4. Load Forecast

Siemens developed a load forecast by customer class and service areas. This section provides the details on the forecast that was performed including the sales forecast regression analysis, non-coincident peak, and coincident peak forecast as well as the seasonal peak breakout. Each process is forecasted monthly by class going out through 2042 which is then broken out by load center (load centers). The load centers include Belize, Ladyville, San Ignacio, Belmopan, Corozal, Orange Walk, San Pedro, Dangriga, Independence and Caye Caulker and regional splits are assumed to remain constant.

4.1 Energy Sales Forecast

The energy forecast was created using a regression analysis based on historical sales by class dated back to 2015. Each class had their own set of unique variables that contributed to the regression based on the statistics that best fit that specific class. The variables included the following and their sources:

a. Temperature – Forecasted using historical averages going back to 2016
b. Population – Total and split between urban/rural forecasted out to 2025 by Belize PHC, 2000 & 2010. Growth rate after 2025 based on Average annual rate of population change graph from United Nations, Department of Economic and Social Affairs, Population Division (https://population.un.org/wpp/Graphs/1_Demographic%20Profiles/Belize.pdf)
c. GDP – Forecasted through 2026 by Statistical Institute of Belize. Split into sectors including Primary Industries, Secondary Industries and Tertiary Industries. All growth after 2026 based on average growth rate from 2010-2026.

The residential and commercial classes were forecasted using an excel based regression analysis based on historical relationships with independent variables. Each of these regressions were analyzed and verified to have over a 90% statistical fit. Residential class forecast used average temperature, GDP, and population variables as well as monthly binaries to account for seasonal variation in the forecast. Social rate used independent variables of CDD65 and urban population along with monthly binaries. Commercial Rate 1 used population and tertiary industries along with monthly binaries. Commercial rate 2 used urban population, GDP, a "previous month" binary and seasonal monthly binaries.

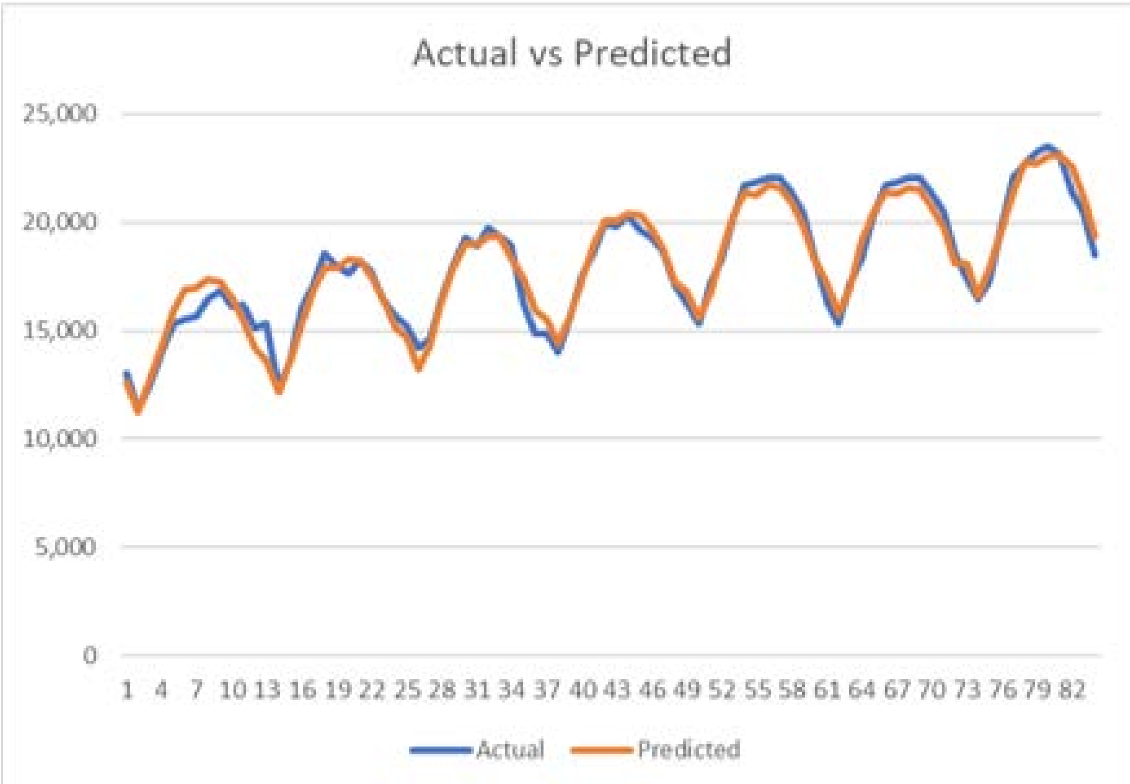
Streetlights, COP, and Industrial were forecasted using manual calculations as their regressions were not cohesive with the independent variables available. The street light forecast was created with simple calculations which had expected decreases through 2026 due to LED light replacement programs that are expected to continue over the next 4 years. After this decrease was assumed to stop, the street light forecast was then escalated at the same growth rate as population. COP sales were expected to remain flat and used a historical 7-year average going forward. There is currently no known large industrial growth or retirements, therefore industrial sales were expected to remain at the latest historical values (2021). These regressions and calculations are further described in the workpapers "1_MonthlySalesRegression.xlsx" and "2_MonthlySalesForecast.xlsx". The figures below provide the energy forecast resulting from the application of the methodology described.

4.1.1 Residential

The residential customer class (including social) are expected to represent 43% of the load in 2022 and this is forecasted to grow to be 51% of the load by the end of the planning period (2042).

The main variables contributing to the residential forecast are population, GDP, average temperature, and seasonality. The regression model using these variables show good correlation, as shown in the figure below.

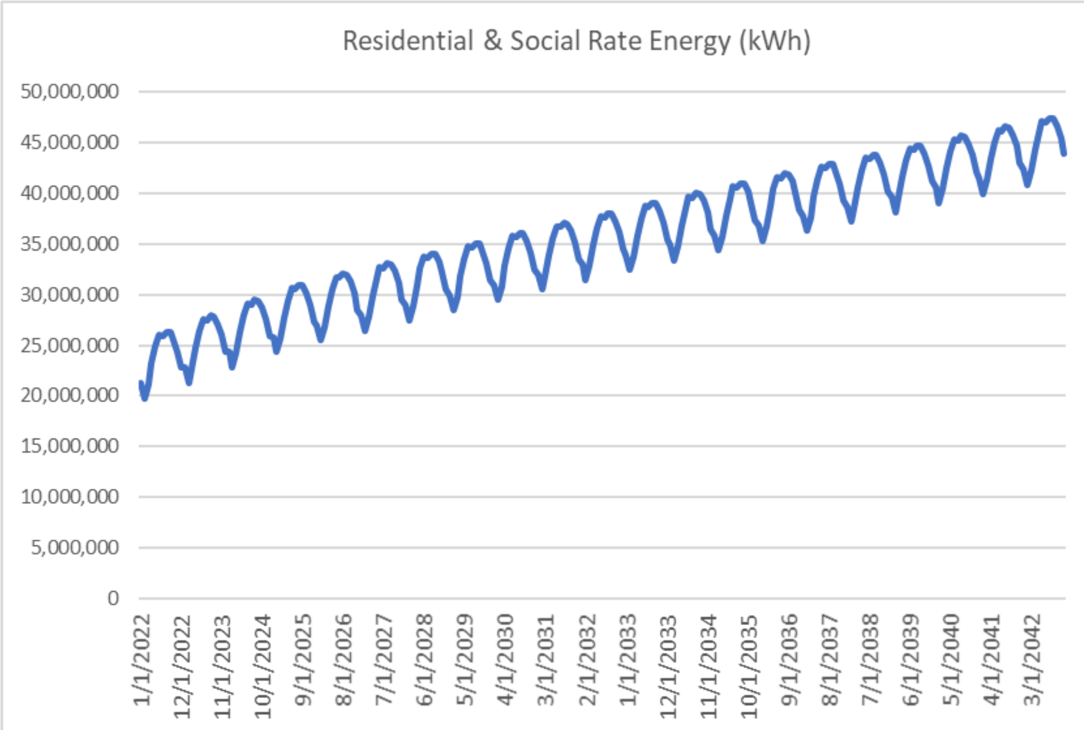
Figure 4-1: Residential Regression Comparison



Source: workpaper 1_MonthlySalesRegression.xlsx

The expected growth rates are 3.2% for the residential sector and 2.3% for the social class, largely driven by population growth estimates.

Figure 4-2: Residential and Social Energy Forecast (kWh)



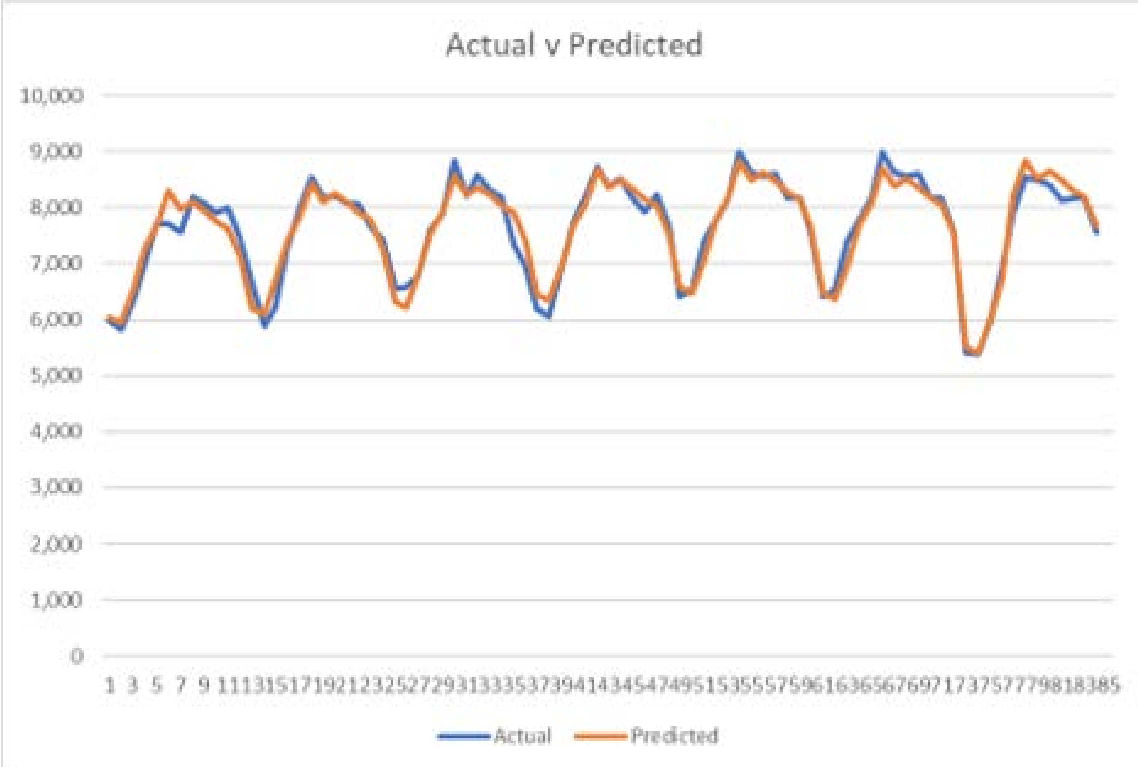
Source: workpaper 3_EnergyAreaSplits.xlsx

4.1.2 Commercial

The commercial energy forecast is split into 2 separate billing classes, Commercial 1 and Commercial 2.

The main variables affecting the Commercial 1 class growth are population, Tertiary Industries GDP, and seasonality, which proves good correlation against historical billing data.

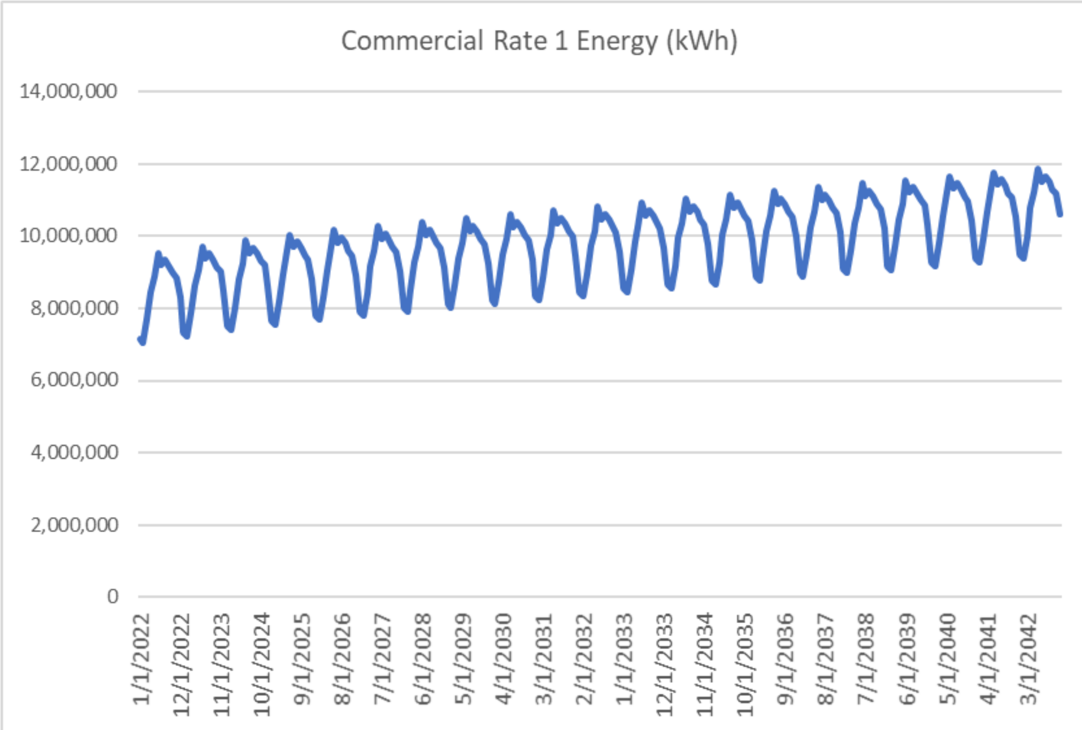
Figure 4-3: Commercial Class 1 Regression Comparison



Source: workpaper 1_MonthlySalesRegression.xlsx

The Commercial 1 customer class are expected to represent 14.4% of the load in 2022 and is forecasted to only contribute 12.5% of the total load by the end of the planning period. The expected growth rate is an average 1.2%, starting and 1.8% in the near term and decelerating to 1.0% for the long-term growth.

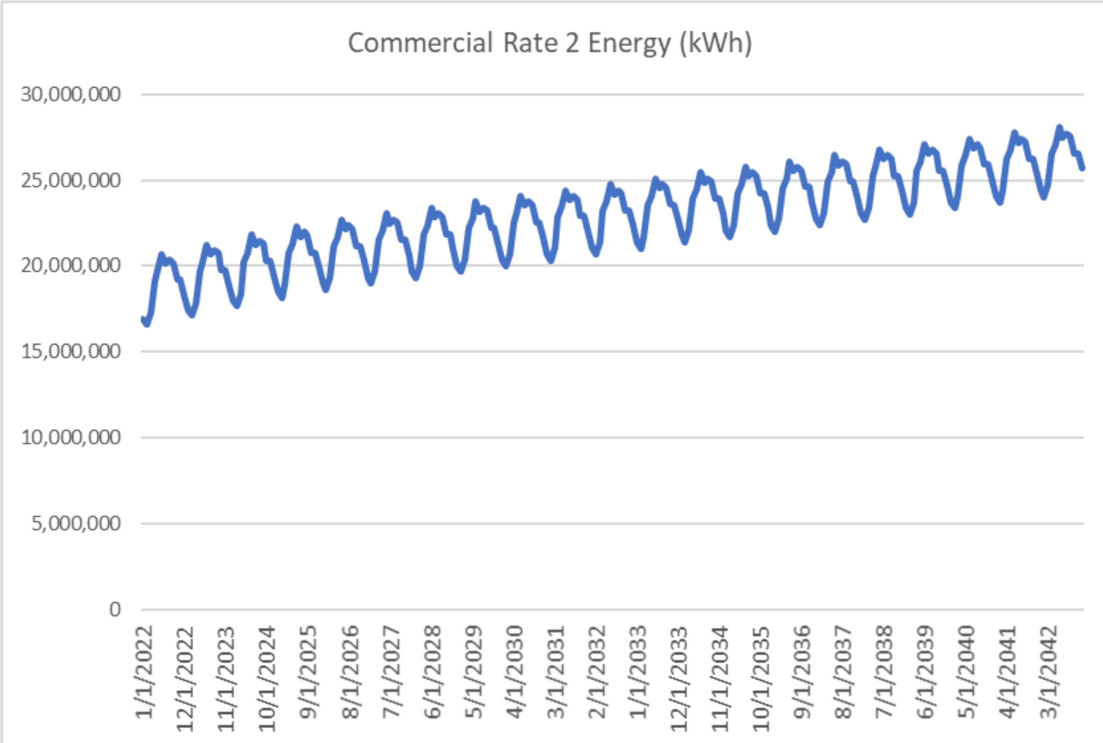
Figure 4-4: Commercial Rate 1 Energy Forecast (kWh)



Source: workpaper 3_EnergyAreaSplits.xlsx

The commercial 2 customer class is expected to represent 34.2% of the load in 2022 and forecasted to drop to 30.4% of the total load by 2042. The expected growth rate is an average 1.7%, decelerating over time like the Commercial 1 class forecast. The main variables affecting the Commercial 2 class include Urban population, GDP, prior month, and seasonality.

Figure 4-5: Commercial Rate 2 Energy Forecast (kWh)

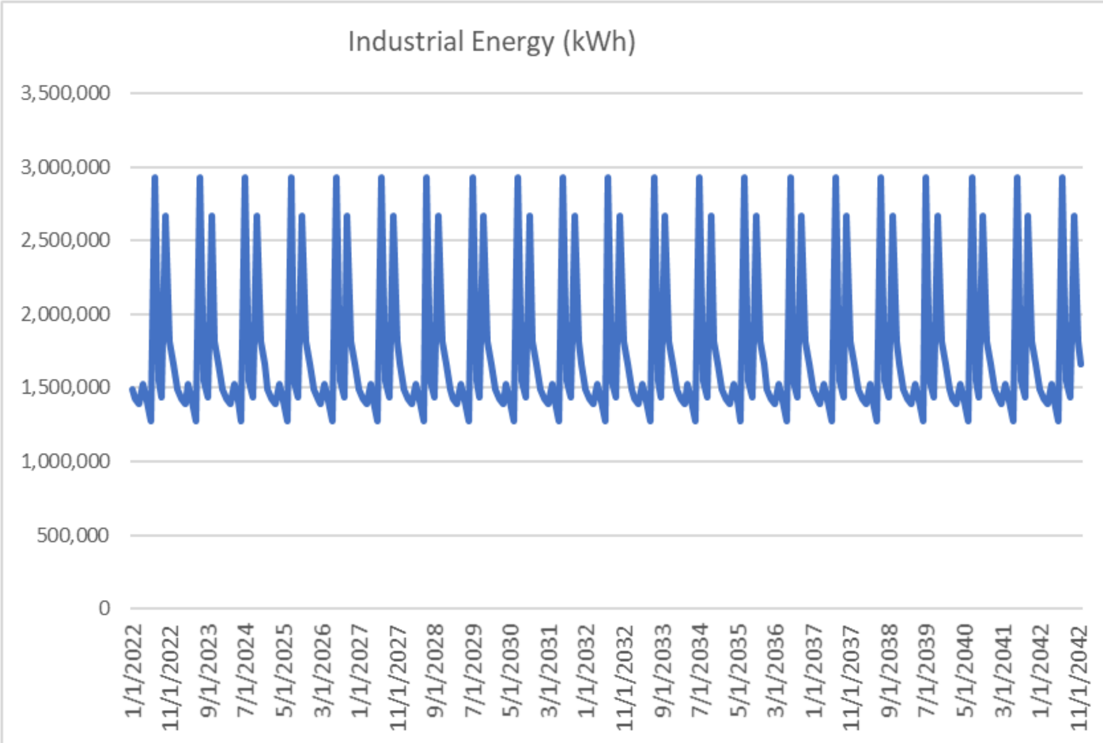


Source: workpaper 3_EnergyAreaSplits.xlsx

4.1.3 Industrial, Street Lights and COP

Large Industrial load currently represents 3.1% of the total BEL load. Large industrial loads are currently modeled as existing load with no growth or decline over time. Potential growth is expected to be captured in other categories and sensitivities.

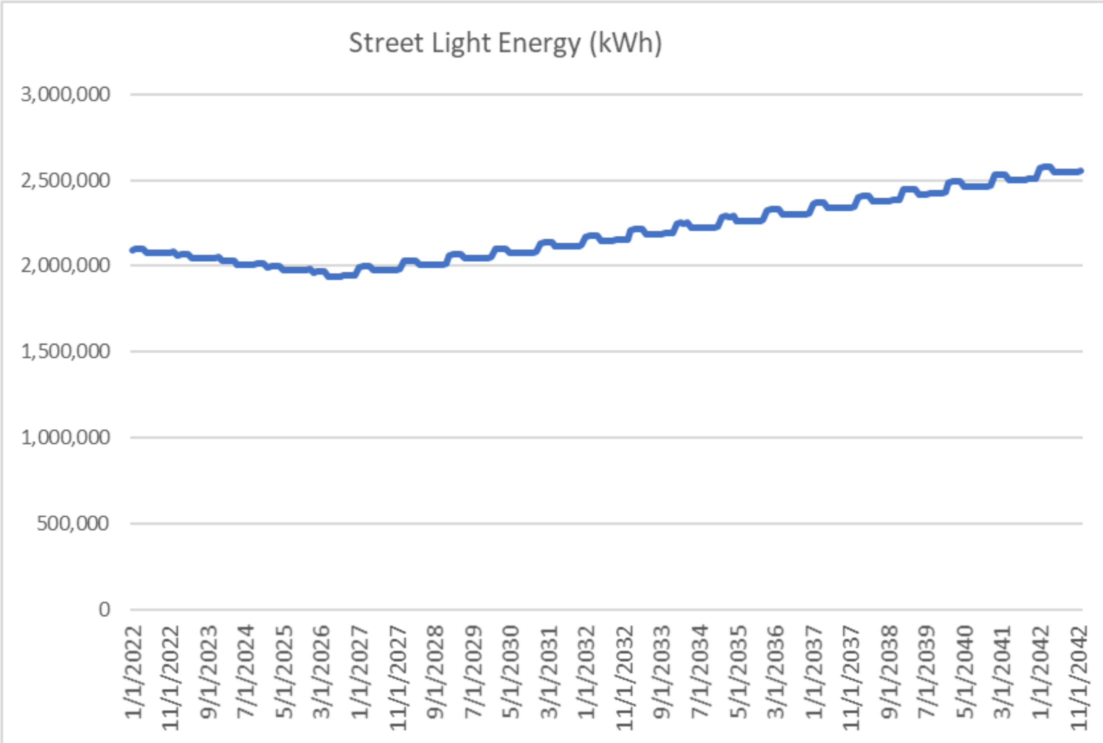
Figure 4-6: Industrial Energy Forecast (kWh)



Source: workpaper 3_EnergyAreaSplits.xlsx"

Streetlights energies are expected to represent 3.8% of the load in 2022 and forecasted to drop to 3.50% of the load by 2042. It is expected to drop in the near term as a result of LED conversion and upon completion, expected to begin growing in line with population.

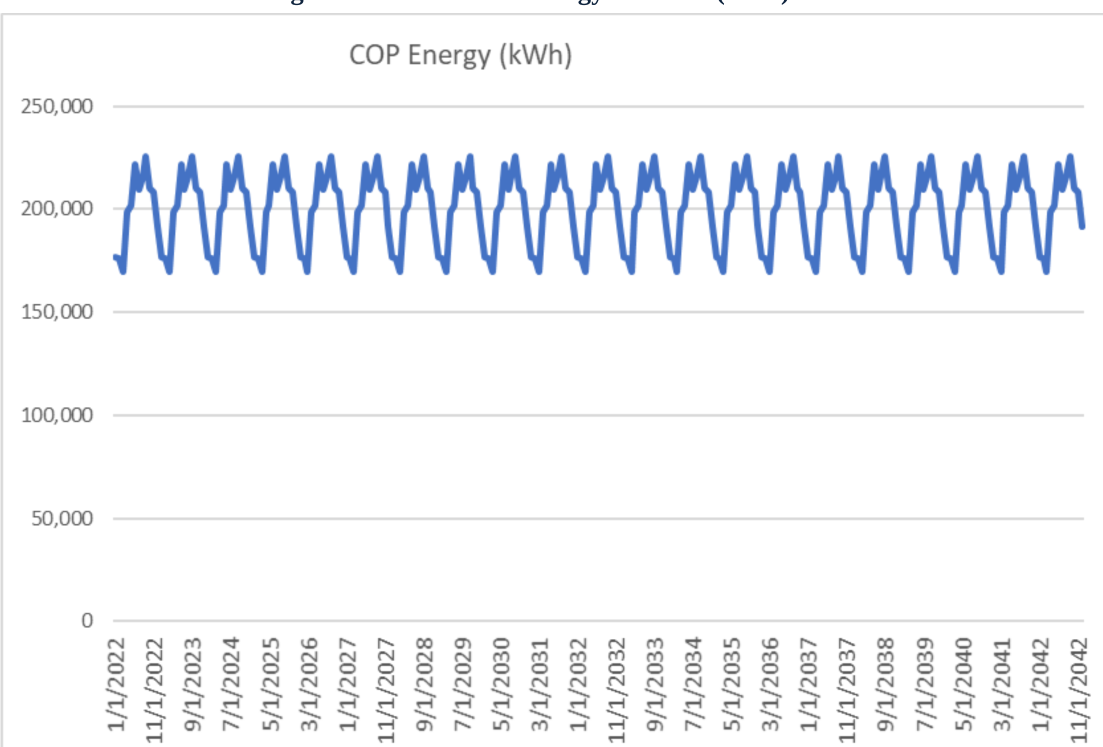
Figure 4-7: Street Light Energy Forecast (kWh)



Source: workpaper 3_EnergyAreaSplits.xlsx"

COP load is modeled as a constant load with no change in the future, similar to Large Industrials. This class only represents 0.4% of current total load and expected to only represent 0.2% of total load by 2042.

Figure 4-8: COP Energy Forecast (kWh)



Source: workpaper 3_EnergyAreaSplits.xlsx"

4.1.4 Total Energy Forecast

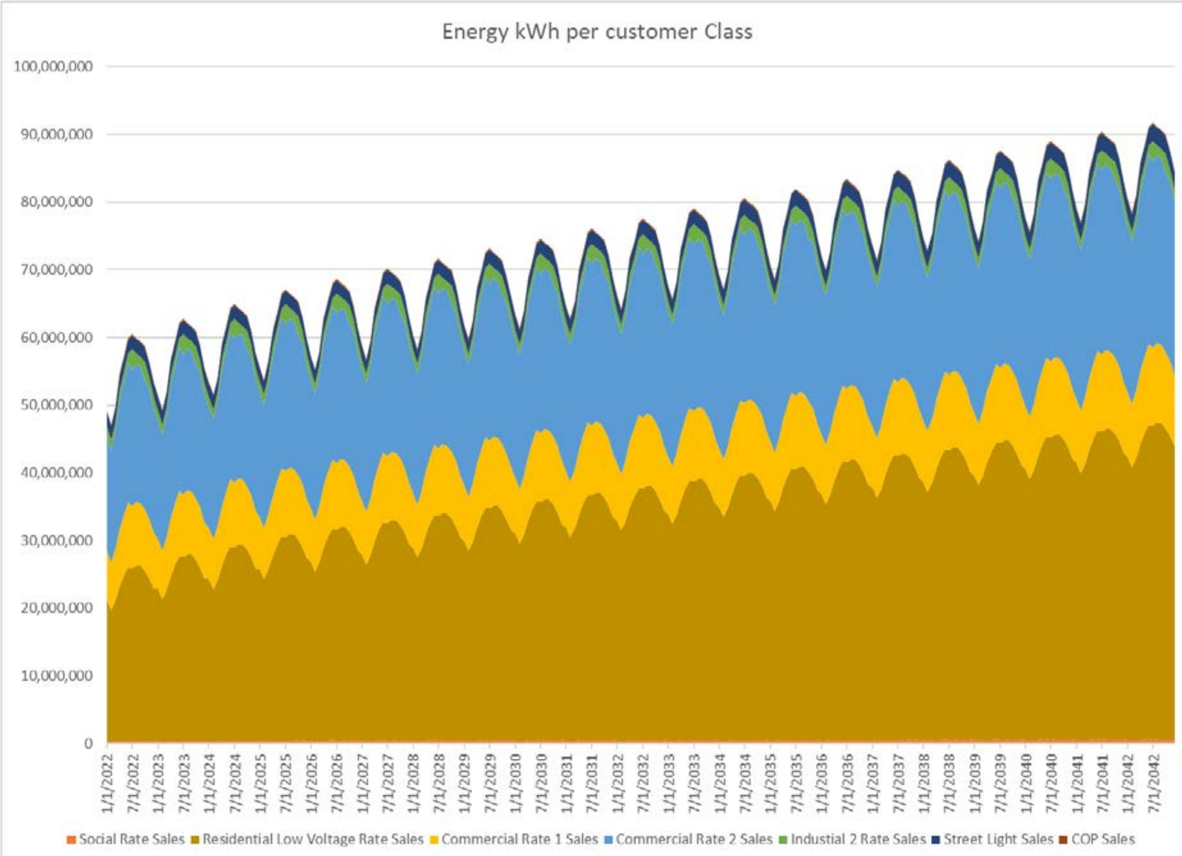
Combining these forecasts, the table and figure below provides the energy forecast for the entire BEL system, where we note that the energy is expected to grow from 604,938 MWh in 2021 to 871,441 by 2032 (3.3% CAGR) and to 2042 to 1,041,095 MWh (2.6% CAGR)

Table 4-1: Total Energy Forecast with customer contribution (MWh)

	Social	Res	Com 1	Com 2	Ind	Streetlight	COP	Total
2022	4,405	283,097	102,656	227,996	20,595	25,020	2,406	666,175
2023	4,581	301,504	104,741	234,424	20,595	24,614	2,406	692,864
2024	4,760	320,035	106,780	240,909	20,595	24,208	2,406	719,694
2025	4,945	337,748	108,653	246,934	20,595	23,803	2,406	745,084
2026	5,076	350,807	110,064	251,747	20,595	23,397	2,406	764,092
2027	5,207	362,815	111,377	255,960	20,595	23,797	2,406	782,157
2028	5,336	374,786	112,689	260,120	20,595	24,204	2,406	800,136
2029	5,465	386,711	114,000	264,272	20,595	24,618	2,406	818,067
2030	5,592	398,582	115,309	268,413	20,595	25,039	2,406	835,936
2031	5,718	410,389	116,615	272,542	20,595	25,467	2,406	853,732
2032	5,843	422,123	117,918	276,654	20,595	25,902	2,406	871,441
2033	5,967	433,777	119,215	280,747	20,595	26,345	2,406	889,052
2034	6,088	445,340	120,508	284,819	20,595	26,796	2,406	906,552
2035	6,209	456,804	121,794	288,867	20,595	27,254	2,406	923,929
2036	6,327	468,161	123,074	292,888	20,595	27,720	2,406	941,170
2037	6,443	479,400	124,345	296,880	20,595	28,194	2,406	958,264
2038	6,557	490,514	125,609	300,840	20,595	28,676	2,406	975,197
2039	6,669	501,495	126,863	304,765	20,595	29,166	2,406	991,959
2040	6,779	512,332	128,107	308,652	20,595	29,665	2,406	1,008,537
2041	6,886	523,019	129,341	312,500	20,595	30,172	2,406	1,024,919
2042	6,991	533,546	130,563	316,306	20,595	30,688	2,406	1,041,095

Source: workpaper 3_EnergyAreaSplits.xlsx”

Figure 4-9: Total Energy Forecast with customer contribution (kWh)



Source: workpaper 3_EnergyAreaSplits.xlsx

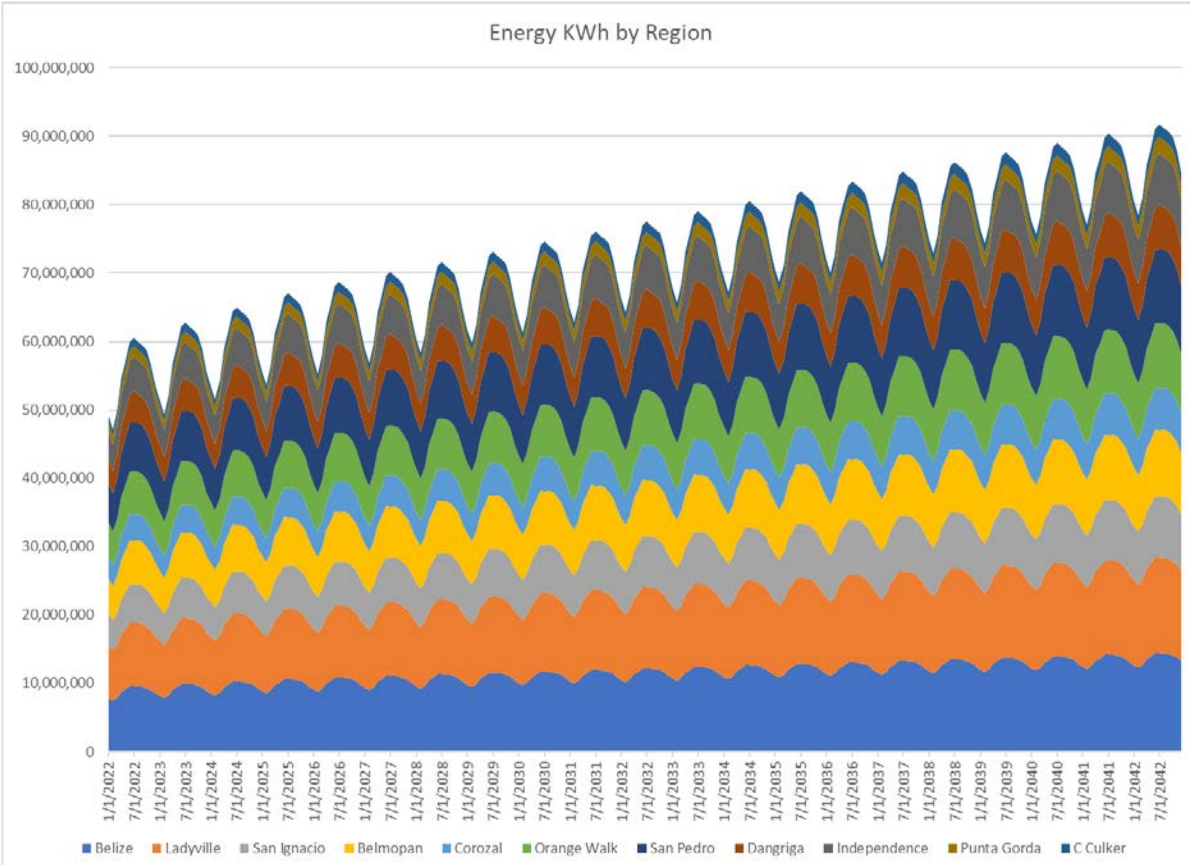
The forecast by customer class was allocated by load center (load center) using the factors in the table below and summarized in Figure 4-10

Table 4-2: Percentage of customer classes by load center

	Social	Residential	Commercial I	Commercial II	Industrial I1	Streetlight	Commercial P
Belize	11%	11%	11%	11%	11%	11%	11%
Ladyville	10%	10%	10%	10%	10%	10%	10%
San Ignacio	12%	12%	12%	12%	12%	12%	12%
Belmopan	9%	9%	9%	9%	9%	9%	9%
Corozal	15%	15%	15%	15%	15%	15%	15%
Orange Walk	13%	13%	13%	13%	13%	13%	13%
San Pedro	1%	1%	1%	1%	1%	1%	1%
Dangriga	9%	9%	9%	9%	9%	9%	9%
Independence	10%	10%	10%	10%	10%	10%	10%
Punta Gorda	9%	9%	9%	9%	9%	9%	9%
Caye Caulker	1%	1%	1%	1%	1%	1%	1%
Total	100%	100%	100%	100%	100%	100%	100%

Source: workpaper 3_EnergyAreaSplits.xlsx

Figure 4-10: Total Energy Forecast by Load center (kWh)

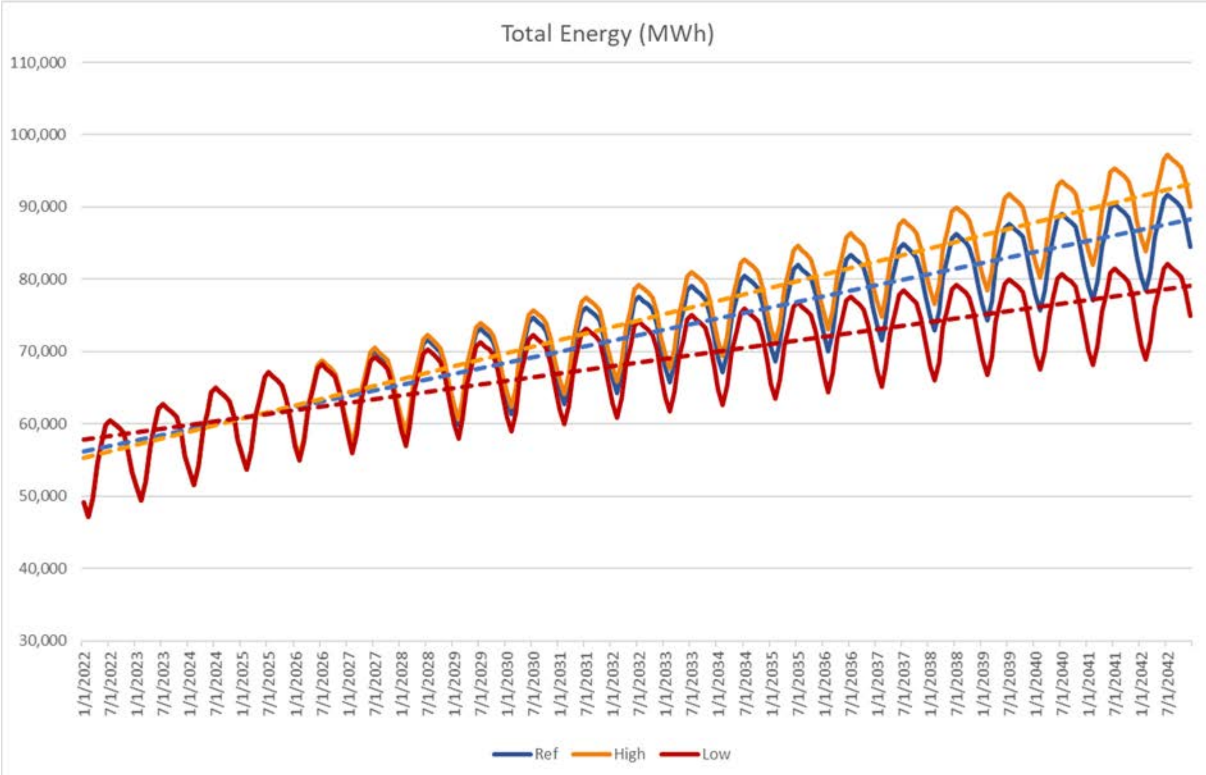


Source: workpaper 3_EnergyAreaSplits.xlsx"

The energy forecast shown above includes a 6% distribution loss assumption. From the differences between billed sales and historical generation, the distribution and transmission losses are calculated to be ~11.5%. A historical average of 5.5% has been noted for transmission losses, therefore the distribution losses are assumed to be at approximately 6% throughout the forecast. This is constant across all classes.

High and Low forecasts were also developed. These sensitivities were derived by adjusting 2 key independent variables after 2025, population forecast and GDP variables. For population, growth rates were adjusted using the upper/lower range of the estimated Belize growth rates from United Nations, Department of Economic and Social Affairs, Population Division (https://population.un.org/wpp/Graphs/1_Demographic%20Profiles/Belize.pdf). GDP variables growth rates were increased or decreased 25% going forward. See figure below for the total energy forecast comparison for all sensitivities.

Figure 4-9: Total Energy Forecast, High and Low Sensitivities



Source: High_Low_Ref_Compare.xlsx workpaper and 3_HighEnergyAreaSplits.xlsx,

Growth rate differences between these sensitivities are shown in the table below.

Table 4-3: Sensitivity Growth Rates

	Ref	High	Low
2022 - 2044 CAGR	2.3%	2.6%	1.7%
2022-2025 CAGR	3.8%	3.8%	3.8%
2025-2030 CAGR	2.3%	2.6%	1.5%
2031 -2042 CAGR	1.8%	2.2%	1.1%
2015-2019 CAGR	2.5%	2.5%	2.5%

4.2 Peak Load Forecast

The coincident peak forecast was calculated using a combination of energy to peak ratio based on class as well as a coincident peak factor assumption obtained from the "DNVGL Phase 1 Report – Load Profiling" report.

4.2.1 Non-Coincident Peak

A non-coincident peak per customer call forecast was calculated using the energy forecast by customer class from the analysis above and the monthly load factors by class taken directly from various tables in the DNVGL Phase 1 Report and shown in the table below.

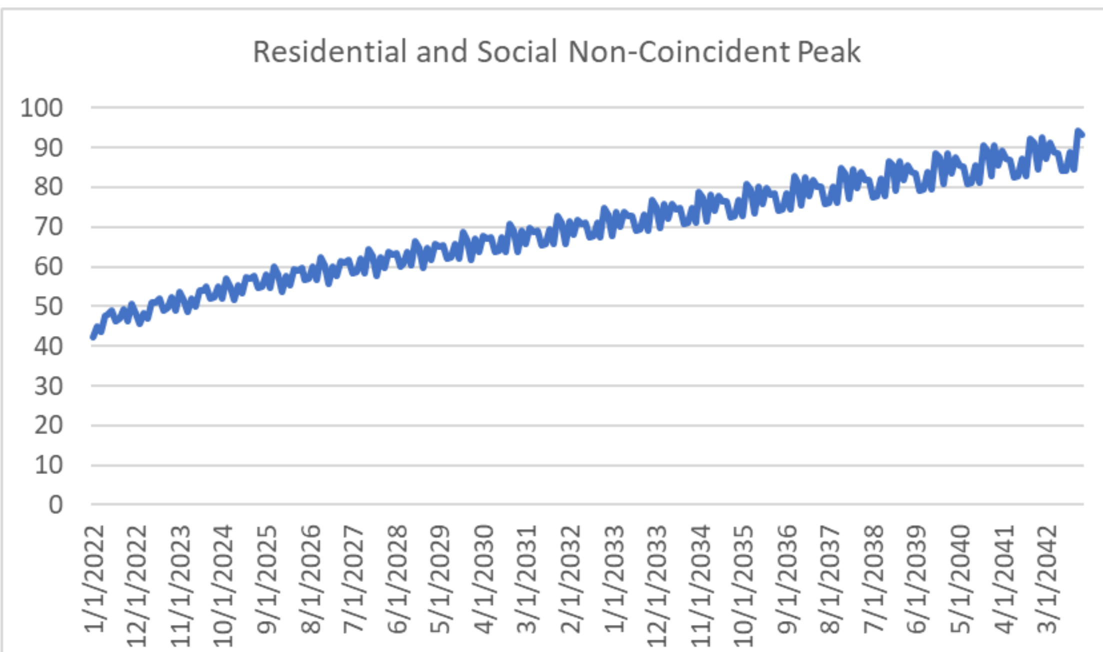
Table 4-4: Load Factors by Customer Class

Month	Res	Com1	Com2	Ind1	Ind2	COP	Streetlight
January	67%	59%	51%	75%	72%	59%	53%
February	61%	64%	49%	76%	71%	64%	52%
March	65%	65%	51%	79%	73%	65%	50%
April	67%	71%	50%	74%	74%	71%	48%
May	69%	74%	50%	74%	74%	70%	46%
June	74%	73%	53%	70%	71%	73%	45%
July	75%	73%	56%	71%	74%	73%	46%
August	76%	73%	54%	70%	76%	73%	47%
September	74%	71%	54%	71%	75%	77%	49%
October	74%	69%	53%	73%	70%	69%	51%
November	67%	65%	51%	76%	70%	65%	53%
December	63%	65%	52%	83%	74%	65%	54%

Source: DNVGL Phase 1 Report

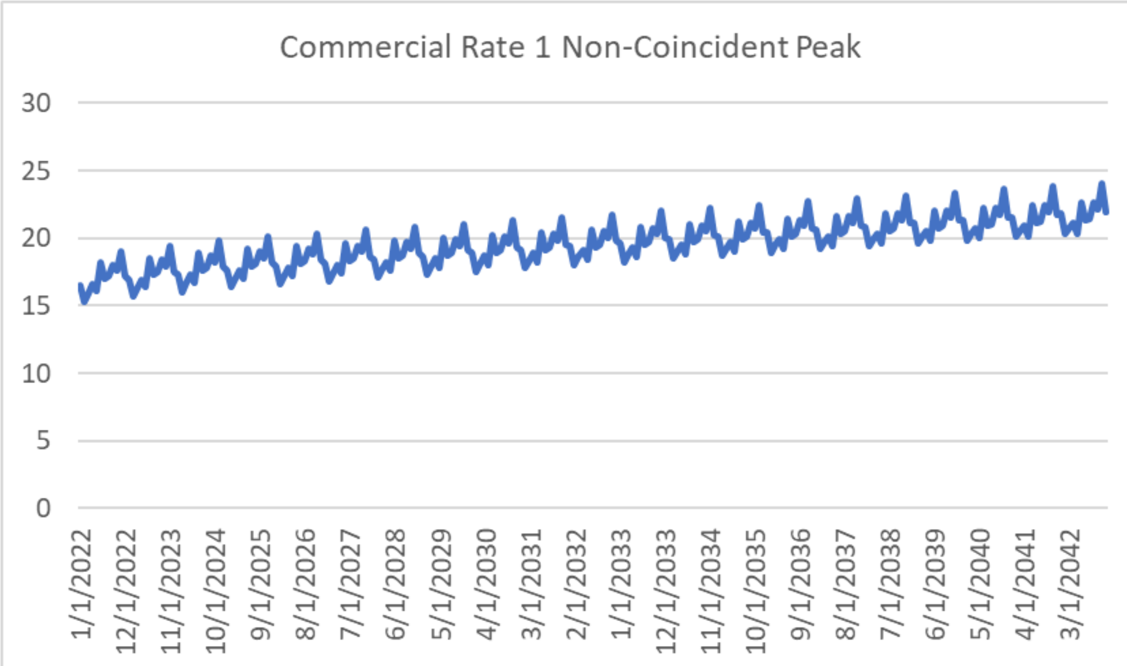
The figures below show the non-coincident peak load projection by customer class resulting from the analysis described above

Figure 4-11: Residential and Social Peak Load Forecast (non-coincident)



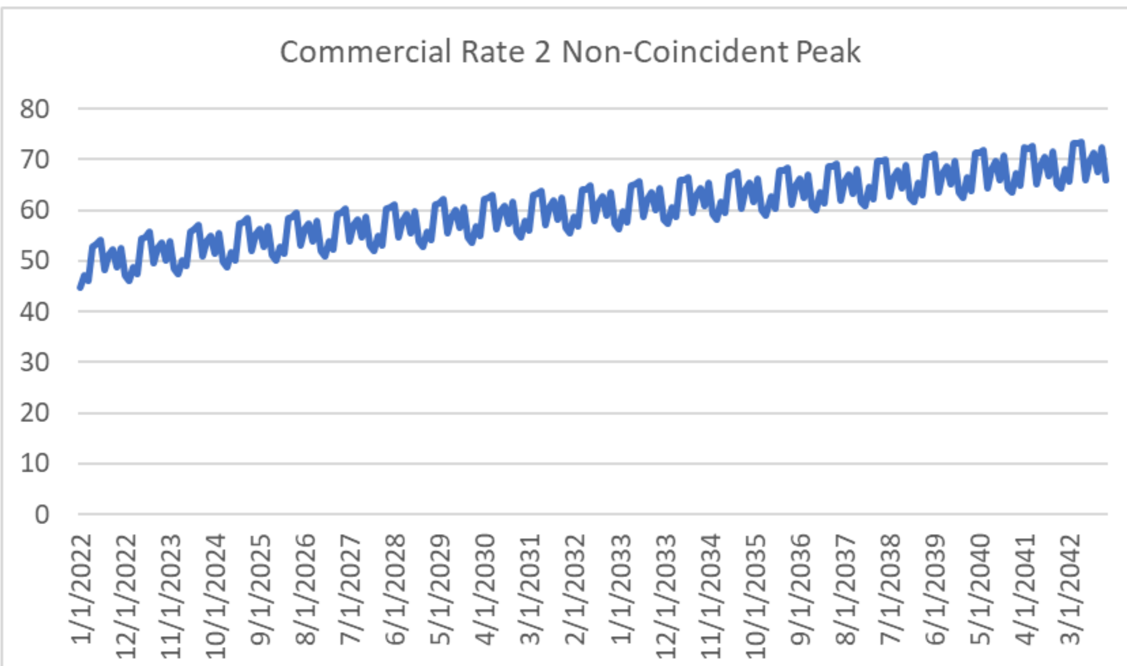
Source: 4_MonthlyPeakForecast.xlsx workpaper

Figure 4-12: Commercial Rate 1 Peak Load Forecast (non-coincident)



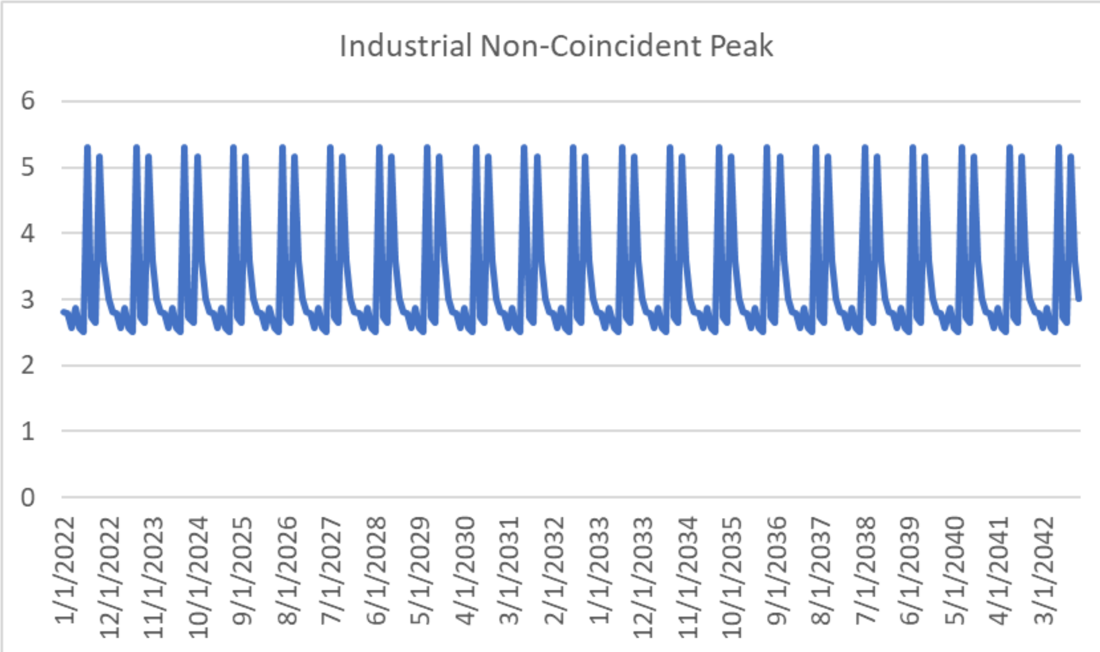
Source: 4_MonthlyPeakForecast.xlsx workpaper

Figure 4-13: Commercial Rate 2 Peak Load Forecast (non-coincident)



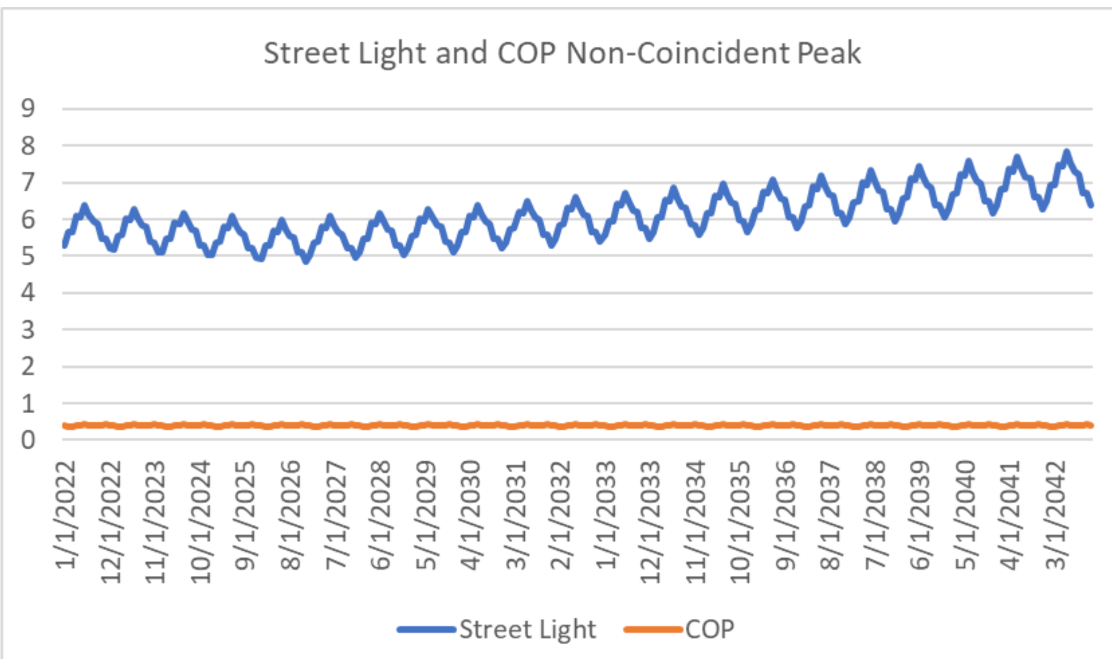
Source: 4_MonthlyPeakForecast.xlsx workpaper

Figure 4-14: Industrial Peak Load Forecast (non-coincident)



Source: 4_MonthlyPeakForecast.xlsx workpaper

Figure 4-15: Street Light + COP Peak Load Forecast (non-coincident)



Source: 4_MonthlyPeakForecast.xlsx workpaper

4.2.2 Coincident Peak

After a class non-coincident peak was created, the system peak was determined using a coincidence factor by customer class to determine its contribution to the system's peak.

The first step in the process is to identify a time for the system peak by month is this was derived from the information on Figure 4-16 and summarized in the table below.

Table 4-5: System Peak Hour by Month

Month	Hour
January	18
February	20
March	20
April	20
May	20
June	20
July	15
August	15
September	20
October	18
November	18
December	18

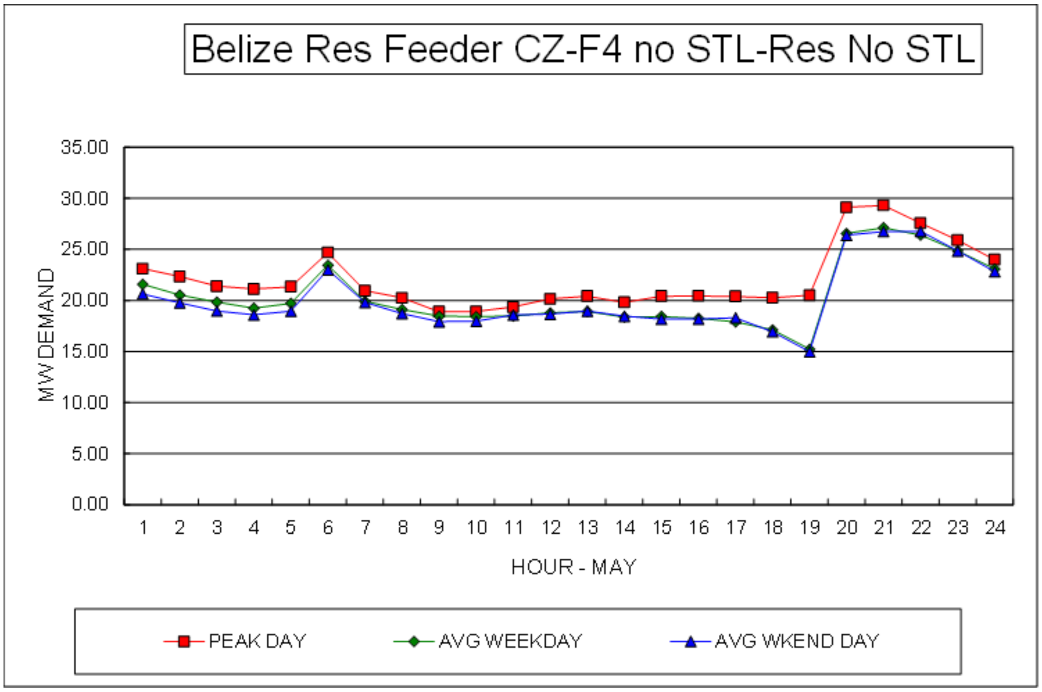
Figure 4-16: Representative System Load Curves by Month

Source: DNVGL Phase 1 Report

The next step was to identify the coincidence factors using various load characterization graphs throughout the DNVGL report and finding the ratio of the load at the time of the system peak, identified in the prior step to the customer class peak as shown in the graph.

An example of the residential graph used to create this scaling factor is shown below, where we see that the residential load peaks at the same time as the system in the months that peak in hour 20, so it has a coincidence factor of 1.0 for those months.

Figure 4-17: Residential Load Hourly Profile (May)



Source: DNVGL Phase 1 Report

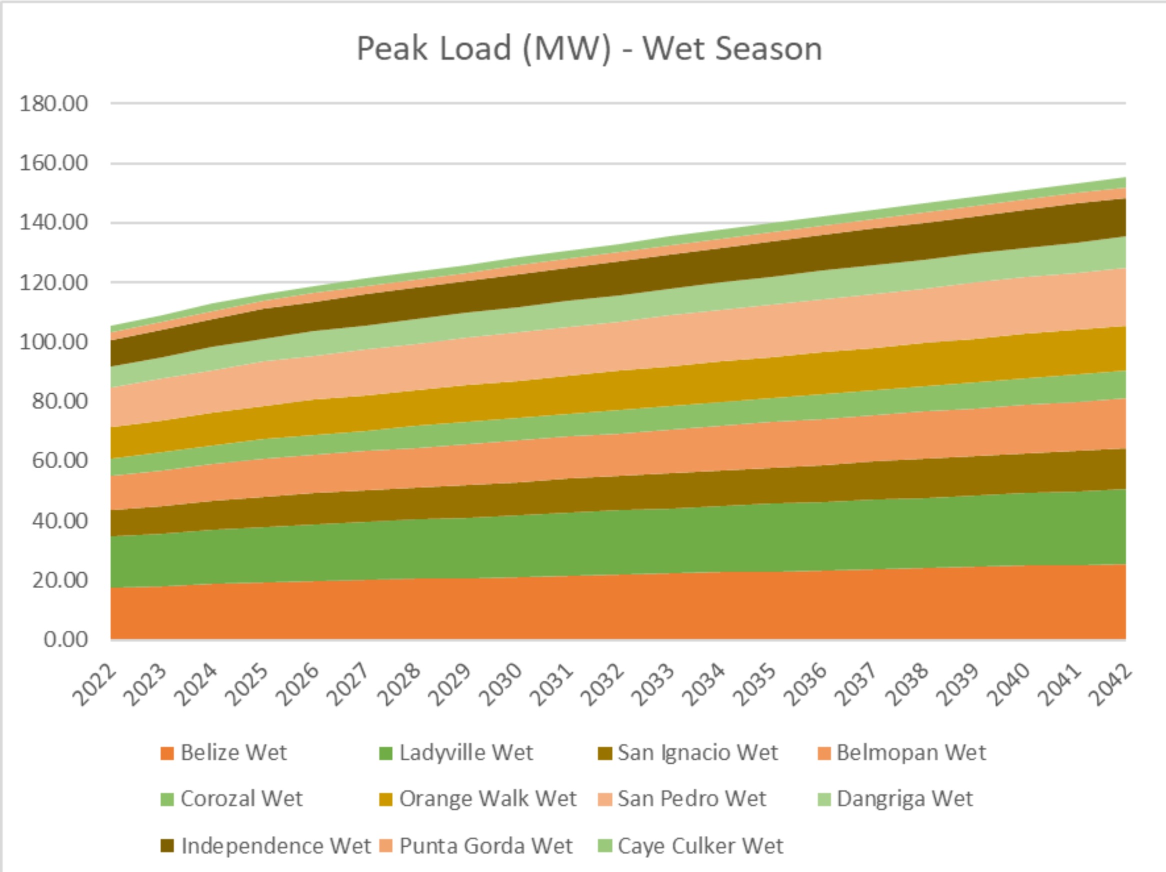
The table below provides a summary of the monthly coincident peak factors by customer class.

Table 4-18: Class Coincident Peak Factors by Month

Month	Social	Res	Com1	Com2	Ind1	Ind2	COP	Streetlight
January	70%	72%	99%	74%	100%	100%	95%	100%
February	100%	100%	85%	47%	100%	100%	83%	100%
March	100%	100%	85%	47%	100%	100%	83%	100%
April	100%	100%	85%	47%	100%	100%	83%	100%
May	100%	100%	85%	47%	100%	100%	83%	100%
June	100%	100%	85%	47%	100%	100%	83%	100%
July	70%	72%	100%	100%	100%	100%	100%	0%
August	70%	72%	100%	100%	100%	100%	100%	0%
September	100%	100%	85%	47%	100%	100%	83%	100%
October	70%	72%	99%	74%	100%	100%	95%	100%
November	70%	72%	99%	74%	100%	100%	95%	100%
December	70%	72%	99%	74%	100%	100%	95%	100%

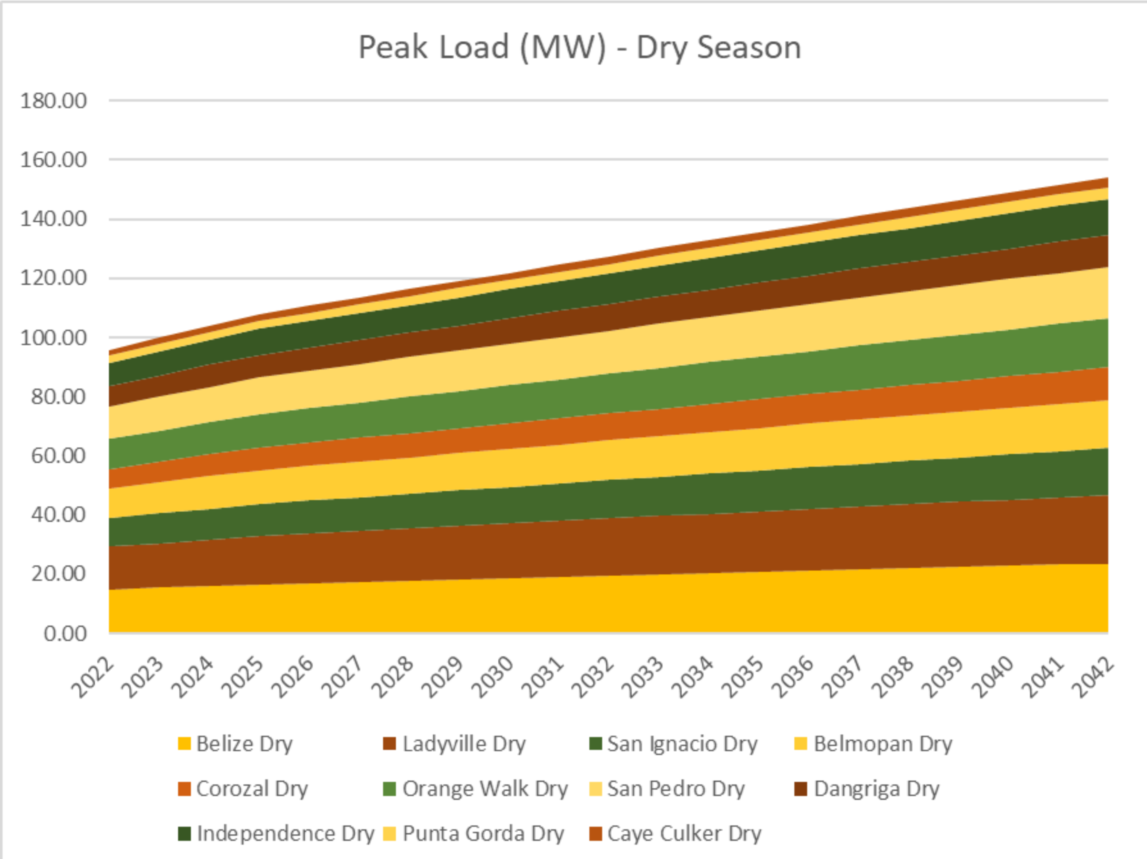
Once all coincident peaks by class and month were calculated, each were added to create the total system peak which was then split out by load center. These were then split out into wet and dry seasons (wet being July-October and dry being March-May) to then find the wet and dry season peaks. The figure below shows this forecast for the coincident peak load by load center for the dry season and the wet season. The forecast shown does not include the transmission losses but does include distribution losses. The result of this analysis is shown in the graphs and table below

Figure 4-19: System Peak Load Forecast wet season



Source: 5_PeakAreaSplits.xlsx workpaper

Figure 4-20: System Peak Load Forecast dry season



Source: 5_PeakAreaSplits.xlsx workpaper

Table 4-6: Peak Demand Wet/Dry Season Coincident Peaks by Load Center (Dry-Mar-May, Wet -July-October)

	Belize		Ladyville		San Ignacio		Belmopan		Corozal		Orange Walk		San Pedro		Dangriga		Independence		Punta Gorda		Caye Caulker		Total	
	Wet	Dry	Wet	Dry	Wet	Dry	Wet	Dry	Wet	Dry	Wet	Dry	Wet	Dry	Wet	Dry	Wet	Dry	Wet	Dry	Wet	Dry	Wet	Dry
2022	17.51	14.86	17.05	14.49	8.96	9.57	11.46	10.09	5.95	6.66	10.31	10.15	13.33	10.87	7.15	6.94	9.01	7.75	2.45	2.49	2.24	1.90	105.43	95.76
2023	18.10	15.47	17.64	15.10	9.31	10.00	11.86	10.52	6.19	6.97	10.67	10.58	13.78	11.35	7.38	7.19	9.31	8.07	2.54	2.59	2.32	1.99	109.11	99.83
2024	18.68	16.09	18.22	15.71	9.67	10.44	12.26	10.95	6.44	7.27	11.04	11.01	14.24	11.84	7.61	7.45	9.62	8.40	2.63	2.69	2.40	2.07	112.78	103.93
2025	19.23	16.68	18.77	16.28	10.00	10.86	12.63	11.36	6.67	7.56	11.38	11.42	14.66	12.30	7.82	7.70	9.90	8.71	2.71	2.79	2.47	2.15	116.24	107.80
2026	19.65	17.12	19.19	16.71	10.25	11.16	12.92	11.67	6.84	7.78	11.64	11.72	14.98	12.64	7.98	7.88	10.11	8.94	2.77	2.86	2.53	2.22	118.86	110.68
2027	20.03	17.54	19.57	17.13	10.48	11.47	13.17	11.96	7.00	7.99	11.88	12.02	15.27	12.96	8.13	8.06	10.31	9.15	2.83	2.93	2.58	2.27	121.23	113.49
2028	20.41	17.96	19.95	17.55	10.70	11.78	13.43	12.26	7.15	8.21	12.11	12.31	15.56	13.28	8.27	8.24	10.50	9.37	2.89	3.01	2.63	2.33	123.60	116.30
2029	20.79	18.38	20.32	17.97	10.93	12.08	13.69	12.55	7.31	8.43	12.35	12.61	15.85	13.59	8.42	8.42	10.70	9.59	2.94	3.08	2.68	2.38	125.97	119.10
2030	21.16	18.80	20.70	18.39	11.16	12.39	13.94	12.85	7.46	8.65	12.58	12.91	16.14	13.91	8.56	8.60	10.89	9.81	3.00	3.15	2.73	2.44	128.32	121.88
2031	21.54	19.21	21.07	18.81	11.38	12.69	14.20	13.14	7.62	8.86	12.82	13.20	16.43	14.22	8.71	8.77	11.08	10.03	3.06	3.23	2.78	2.50	130.66	124.66
2032	21.91	19.63	21.44	19.22	11.60	12.99	14.45	13.43	7.77	9.08	13.05	13.50	16.71	14.53	8.85	8.95	11.27	10.24	3.11	3.30	2.82	2.55	133.00	127.42
2033	22.28	20.04	21.81	19.63	11.83	13.29	14.70	13.72	7.93	9.29	13.28	13.79	17.00	14.84	8.99	9.13	11.46	10.46	3.17	3.37	2.87	2.61	135.31	130.17
2034	22.65	20.45	22.18	20.04	12.05	13.59	14.95	14.01	8.08	9.50	13.51	14.08	17.28	15.15	9.13	9.30	11.65	10.67	3.22	3.44	2.92	2.66	137.62	132.90
2035	23.01	20.86	22.54	20.45	12.27	13.89	15.20	14.30	8.23	9.71	13.73	14.37	17.56	15.45	9.28	9.48	11.84	10.88	3.28	3.51	2.97	2.72	139.90	135.62
2036	23.38	21.26	22.90	20.85	12.48	14.18	15.44	14.58	8.38	9.92	13.96	14.65	17.84	15.76	9.41	9.65	12.02	11.09	3.33	3.59	3.02	2.77	142.17	138.31
2037	23.73	21.66	23.26	21.26	12.70	14.48	15.69	14.86	8.53	10.13	14.18	14.94	18.11	16.06	9.55	9.82	12.21	11.30	3.39	3.66	3.06	2.82	144.42	140.98
2038	24.09	22.06	23.62	21.65	12.91	14.77	15.93	15.14	8.67	10.34	14.40	15.22	18.39	16.35	9.69	9.99	12.39	11.50	3.44	3.73	3.11	2.88	146.65	143.62
2039	24.44	22.45	23.97	22.05	13.12	15.05	16.17	15.42	8.82	10.54	14.62	15.50	18.66	16.65	9.83	10.16	12.57	11.71	3.49	3.79	3.16	2.93	148.85	146.24
2040	24.79	22.84	24.32	22.43	13.33	15.34	16.40	15.69	8.96	10.74	14.84	15.77	18.93	16.94	9.96	10.33	12.75	11.91	3.55	3.86	3.20	2.98	151.03	148.83
2041	25.14	23.22	24.66	22.82	13.54	15.62	16.64	15.96	9.10	10.94	15.05	16.05	19.19	17.22	10.09	10.49	12.93	12.11	3.60	3.93	3.25	3.03	153.18	151.39
2042	25.47	23.60	25.00	23.20	13.74	15.89	16.87	16.23	9.24	11.14	15.26	16.32	19.45	17.51	10.22	10.65	13.10	12.30	3.65	4.00	3.29	3.08	155.30	153.92

Source: 5_PeakAreaSplits.xlsx workpaper

4.3 Electric Vehicle forecast.

Siemens PTI developed a forecast for the expected electric vehicle charging load in Belize. This forecast is considered representative, and it is based on the information available at this time.

4.3.1 Assumptions and Considerations.

The forecast was carried out considering the following:

a) There are approximately 75,000 vehicles in Belize or 174 vehicles per 1000 habitants[6]

b) The vehicle additions per year is estimated as the average of two methods:

   1. As population grows new vehicles are added to maintain the 174 vehicles per 1000 habitants approximately constant and a vehicle in Belize lasts in average 10 years after importation[7] and then needs to be replaced. Thus, total new vehicle additions are the sum of the new vehicles added to maintain the 174 ration as the vehicle replacement.

   2. Each year approximately 13% of the fleet are newly imported vehicles into the country[8].

c) Approximately 25 % of the vehicles imported are new or have 1 year or less and are candidate to be electric[8].

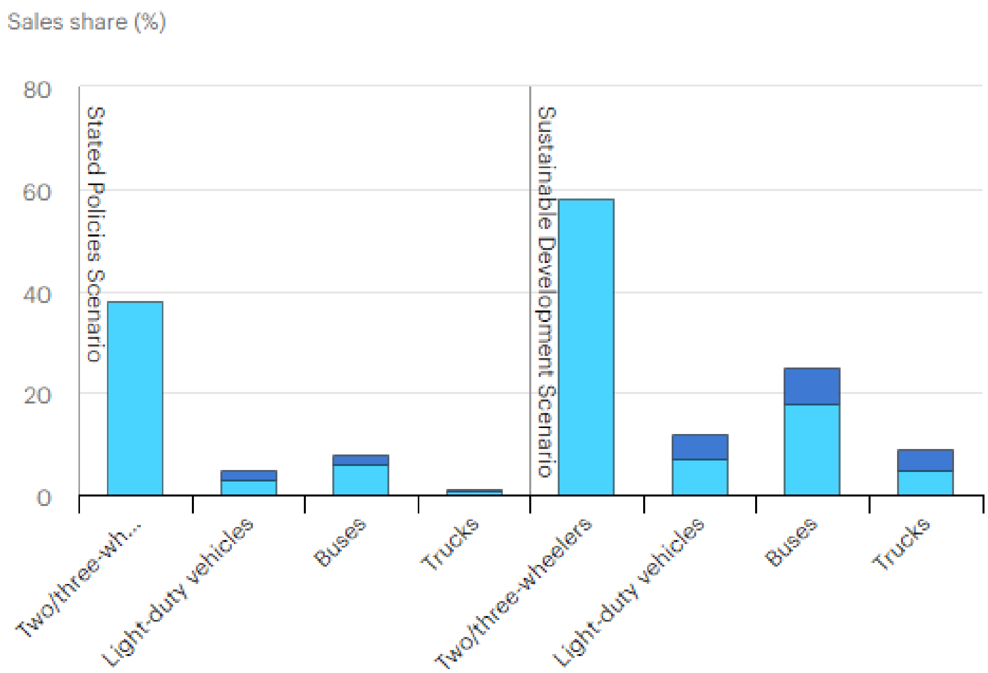
d) By 2030 10% of the vehicles imported will be electric rising to 12% by 2032 and 24% by 2042 when most of the vehicles (95%) will be electric. This assumption is derived from the 2021 IEA study under the "Sustainable Development Scenario" that indicates that in the "rest of the world"[9] EV fleet will reach 12% of all light duty vehicle sales by 2030 with a min of 5% (Stated Policies Scenario or Base)[10]. See table and figure below.

Table 4-7: Share of EV of new vehicles sales in Belize

	2030	2032	2042
Battery Operated	6%	7%	14%
PIHV	4%	5%	10%
Total	**10%**	**12%**	**24%**

[6] Source: ourworldindata.org.
[7] The average age of vehicles imported to Belize is already 6 years, source: CLEANER AND MORE EFFICIENT FUELS AND VEHICLES IN BELIZE, Establishment of a baseline for the fuel economy of light duty vehicles (2013 - 2016)
[8] source: CLEANER AND MORE EFFICIENT FUELS AND VEHICLES IN BELIZE, Establishment of a baseline for the fuel economy of light duty vehicles (2013 - 2016)
[9] Rest of the world is defined countries outside China, Europe, India, Japan, and the US
[10] See Prospects for electric vehicle deployment – Global EV Outlook 2021 – Analysis - IEA and Global EV Outlook 2021 (windows.net)

Figure 4-21: Electric Vehicle Share by Mode and Scenario in the rest of the world[10]



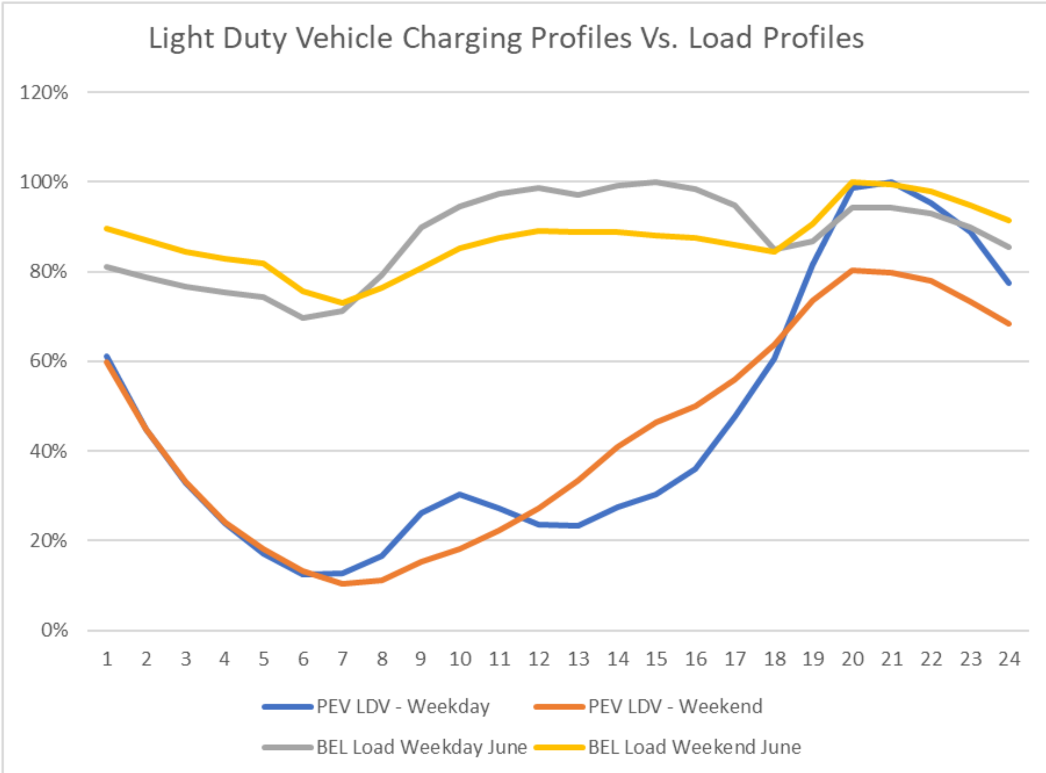
e) The mix of EV is assumed to be 70% Battery operated (BEV) and 30% plug in hybrids (PPHEV) and the energy consumption is estimated with an average economy of 270.6 Wh/mile (ref InsideEVs) and projected to improve at a rate of 0.57% reduction per year. With this assumption and the projected number of electric vehicles in country by year (from the considerations above), the total energy consumed for charging can be estimated by year if the miles driven by vehicle is known. This information was provided by BEL for two scenarios the Base and High consumption and summarized in the table below.

Table 4-8: Belize vehicle utilization assumptions

Miles / year per vehicle	Per Week	Per Year	Implied 1000's passenger miles per capita
Base	250	13,000	2.26
High	350	18,200	3.17

f) The PV charging profiles assume that the peak charging is coincident with the night peak. This is conservative as it maximizes the impact. The alternative option was to assume delayed charging, so the EV are charged and ready to roll out by 7:00 am. The profiles and impact are shown in the figure below.

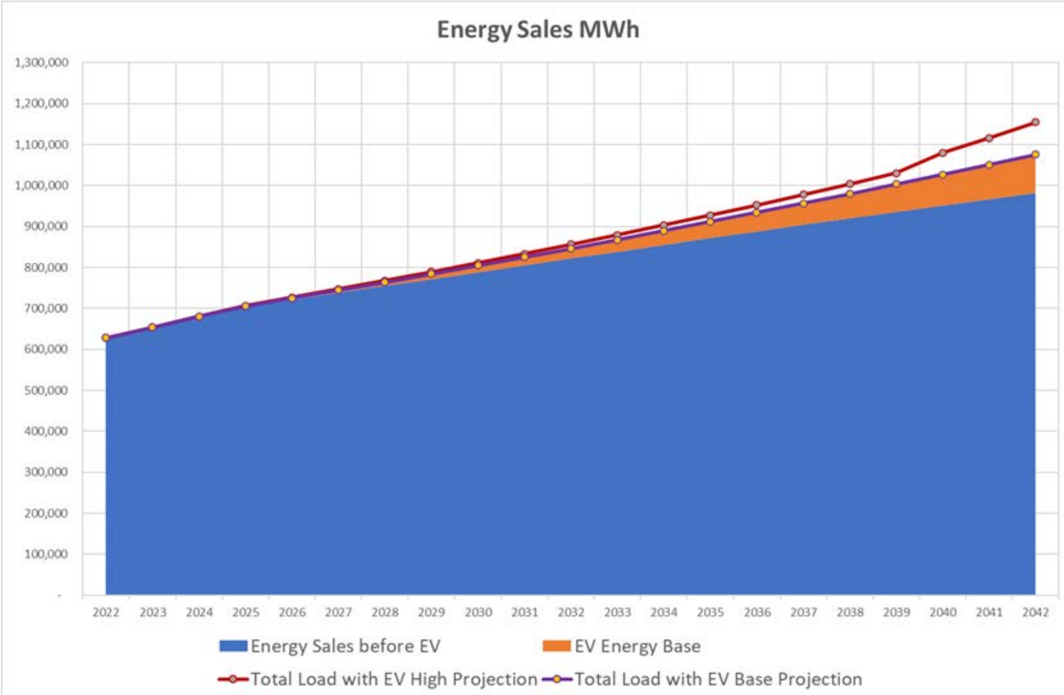
Figure 4-22



4.3.2 Forecast.

Using the assumptions above and with the Base forecast, EV are projected to represent 8.7% of the total energy load by the end of the planning period 2042 and 17.5% with the high forecast. See figure below

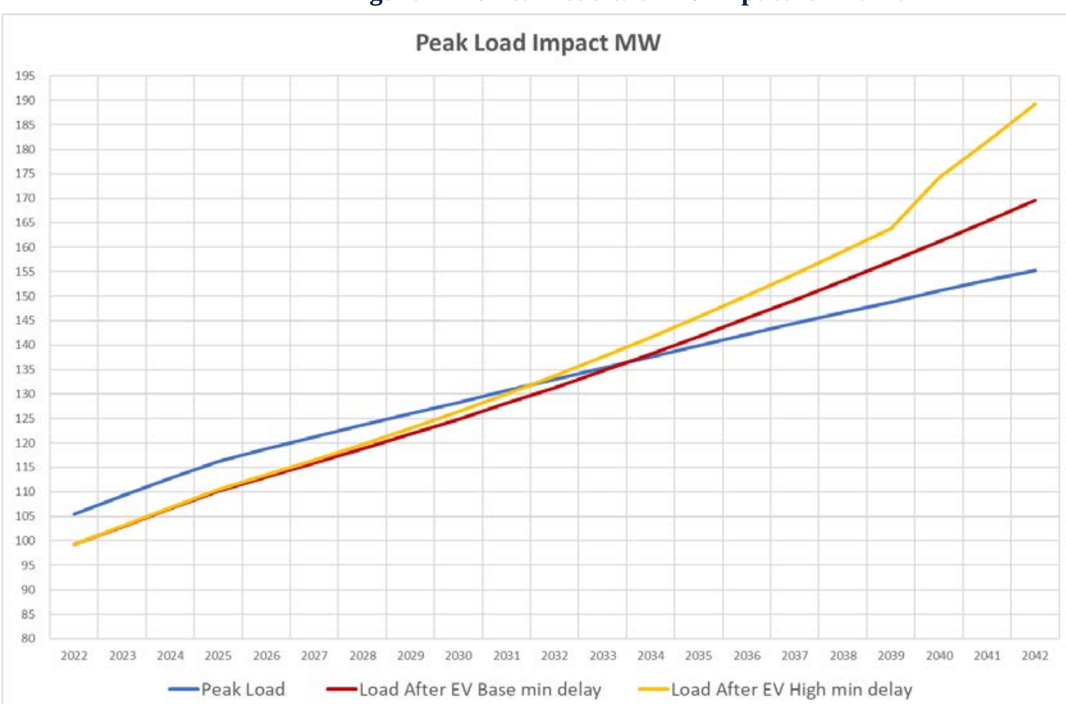
Figure 4-23: Energy Consumption with EV impact for Belize



Source: EV_Projection_2_28_2022_V1.1

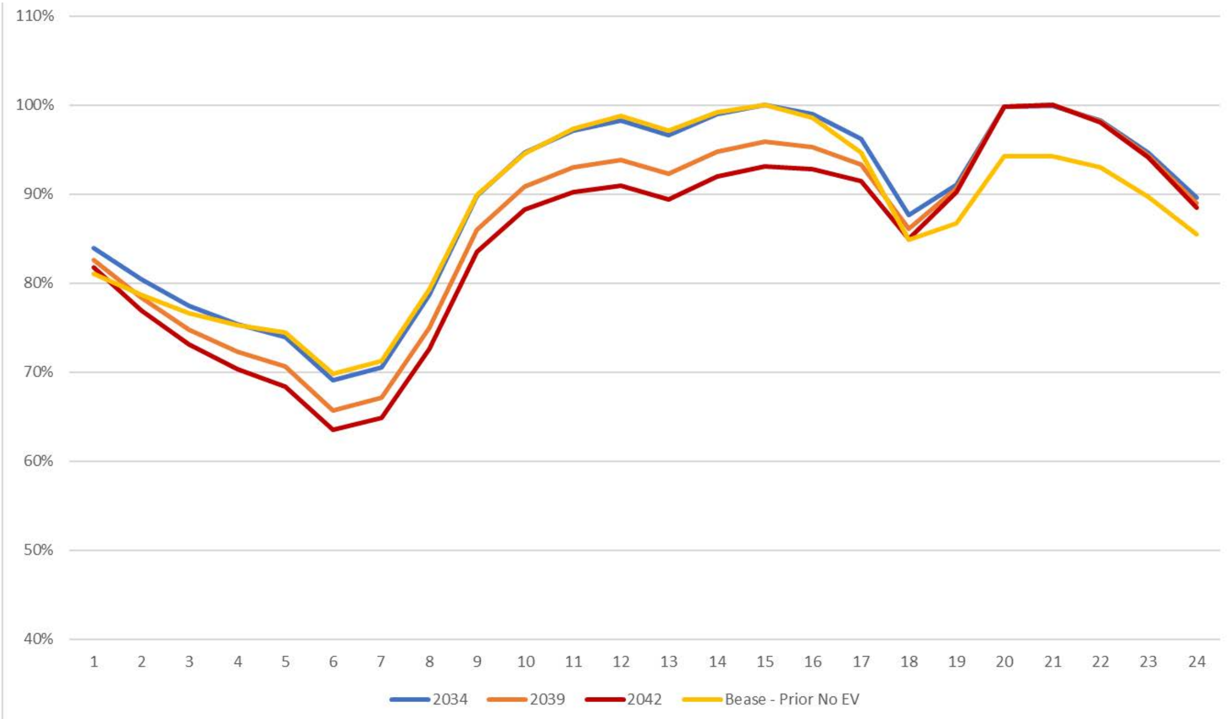
This is projected to increase the annual peak by 9.2% on the Base Forecast and 21.8% on the High Forecast as shown in the next figure.

Figure 4-24: Peak load with EV impact for Belize



By 2032 ~ 2033 the EV charging is expected to shift the peak from day peak to a night peak, as shown in the figure below that shows the load profiles with the impact of EV and we see that the net impact is shifting from a profile where the day peak is approximately 6% higher than the night peak (yellow trace - current profile) to a profile by 2042 where the night peak is 7% higher than the day peak (red trace). However, regardless of the EV the dual peak nature of the system will remain.

Figure 4-25: Load Profiles with EV Impact



4.4 Energy Efficiency and Demand Response.

Energy Efficiency, which is the replacement of large consumption appliances as is the case of air conditioning and lighting for more efficient appliances and the weatherization of buildings, is a cost-effective way to meet the customers' needs without having to invest in the electric system to attend inefficient consumption. Also demand response, which is shifting the demand from times of high consumption or making the loads interruptible during emergencies, helps manage the capacity costs of the system.

It is recommended that Belize initiates Energy Efficiency / Demand Response programs that via energy audits, rebate programs and improvements of codes and standards result in a reduction of the consumption under that is currently forecasted.

These efforts should start with the definition of a baseline and potential by answering some of the example questions below.

a) Determine on average how much of the residential consumption corresponds to lighting (we see an average total consumption of ~250 kWh/month) and is still use incandescent lighting and if so the percentage of the lights. Same question for fluorescent lighting. This information is necessary to assess the potential impact of a LED program.

b) For the average residential, what percentage of the demand would be air conditioning (AC) and are predominantly use window units, mini-split or other?

c) Same questions as above for the Commercial 1

d) For the Commercial 2 similar question but in lighting there would be also Halogen lighting and for Fluorescent if the T8 is being still used, VS T12

e) For water heating, is there electric water heating and if so type and % of the residential load.

f) Is there a program like the “Energy Star” in the US for efficient appliances and how much is the penetration?

g) Do Belize codes address weatherization, i.e., avoiding loss of cooling.

5. Fuel Forecast

Siemens PTI developed fuel price forecasts for four different fuels including the following: ultra-low sulfur diesel (ULSD), No.6 Heavy Fuel Oil (HFO), Propane, and Liquified Natural Gas (LNG). Since each fuel is unique, different methodologies were employed for each fuel. Those methodologies and the developed forecasts for each fuel are presented below and are inclusive of transportation charges to Belize.

5.1 Ultra-Low Sulphur Diesel (ULSD)

Siemens PTI forecast the delivered price for ULSD based on our proprietary US Gulf Coast (USGC) ULSD forecast. Given the ULSD fuel volume available in the USGC refining complex, we assume ULSD delivered to Belize will originate along the USGC from one of the refineries. Siemens PTI developed our USGC ULSD forecast from a proprietary model which employs the historical correlation of ULSD and West Texas Intermediate (WTI) crude.

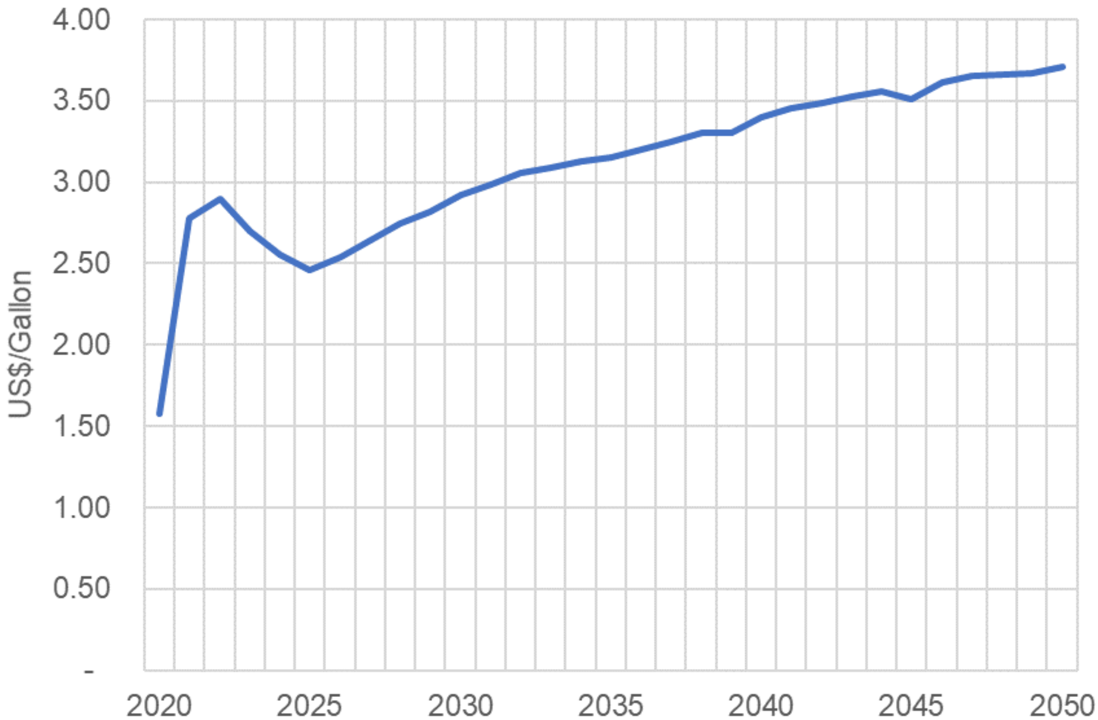
To estimate the cost to deliver USGC ULSD to Belize, Siemens PTI estimated the transport, ship loading and unloading, local storage, and local delivery to end customer by calculating historical difference on a monthly basis between USGC ULSD commodity price and delivered the price BEL paid. This cost was estimated to represent an adder of 34.3% to the commodity price, which was added to Siemens PTI's ULSD USGC commodity forecast to obtain the delivered ULSD price.

Figure 5-1 shows the ULSD forecast that is expected to decline into the mid-2020s in line with WTI before increasing steadily thereafter.

5.2 No. 6 Heavy Fuel Oil (HFO)

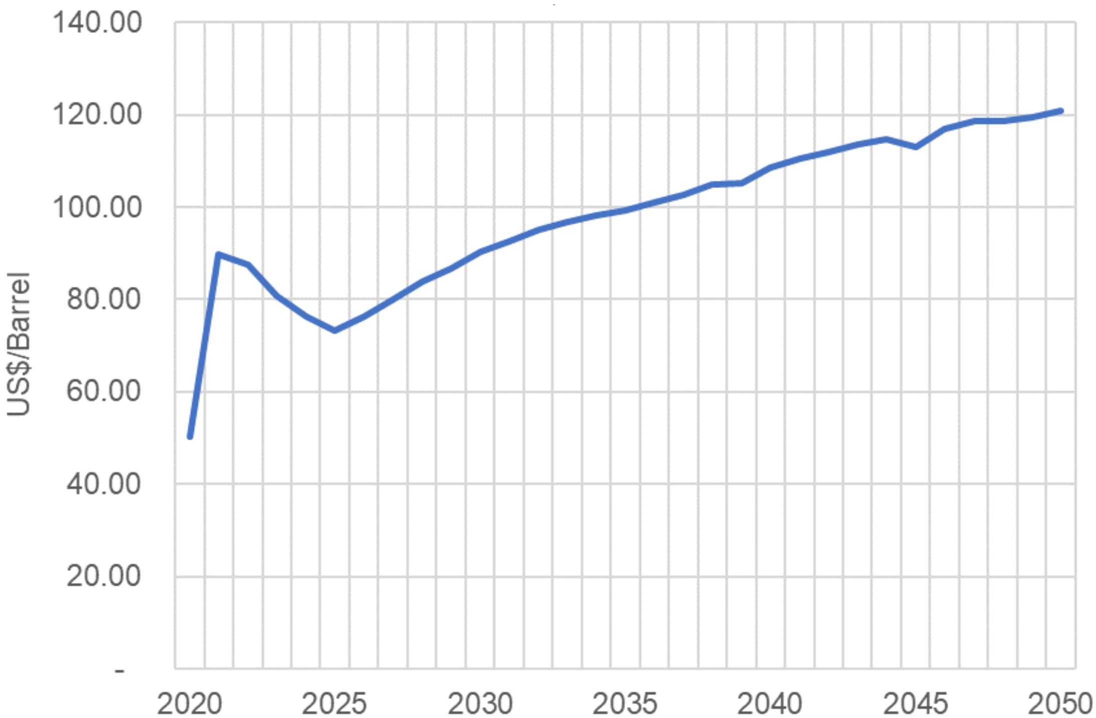
Siemens PTI forecasted the delivered price for HFO following the same methodology employed for forecasting the ULSD price. Again, the HFO is assumed to originate along the USGC from one of the many refineries with a price highly correlated with WTI. The commodity cost adder representing the delivery costs was derived by comparing historic USGC and local delivered prices and represents 36.2% of the commodity price. The HFO forecast follows a similar trend to that observed in the ULSD forecast because it too is linked to the WTI price forecast. The delivered price forecast is presented below.

Figure 5-1: Delivered ULSD Forecast (2021$/Gallon)



Source: Fuel Forecast_BEL_delivered.xlsx workpaper

Figure 5-2: Delivered HFO Forecast (2021$/barrel)



Source: Fuel Forecast_BEL_delivered.xlsx workpaper

5.3 Propane

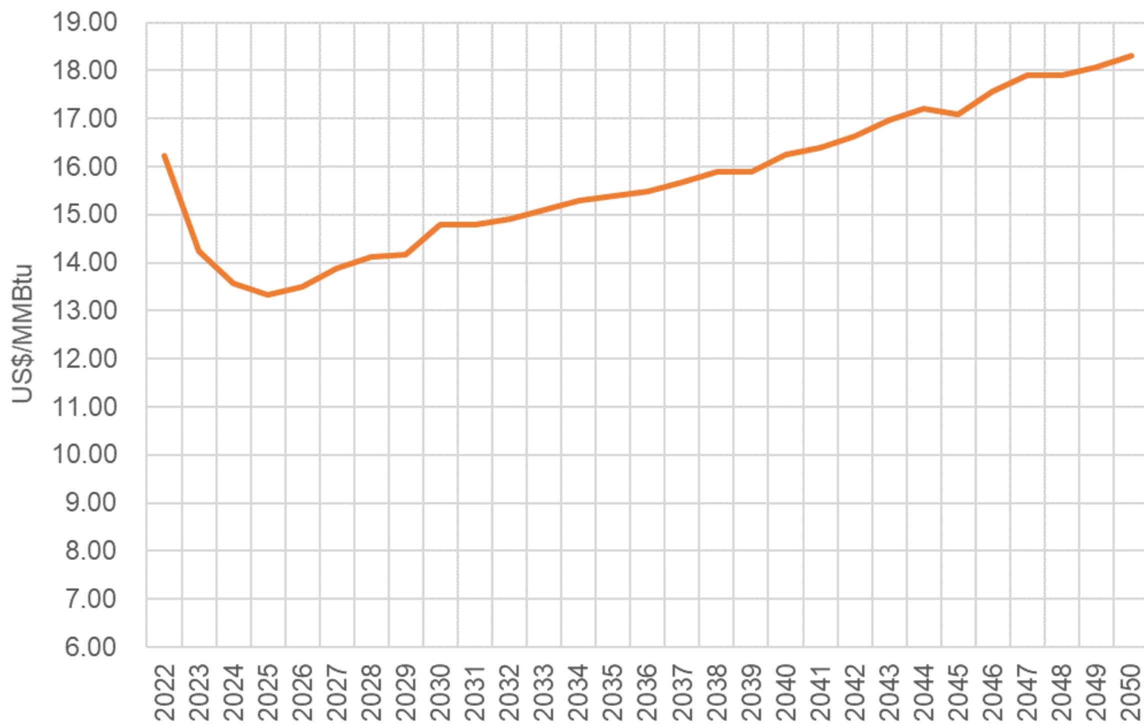
In general, Siemens PTI followed a fuel price forecasting methodology similar to that noted in the ULSD discussion. Once again, historical price correlations were developed in order to develop a commodity price forecast to which delivery and infrastructure cost were added to craft a delivered price forecast. However, for propane Siemens PTI develop a multi-variable regression rather than a single variable regression

Before the discovery/ development of large volumes of low-cost shale gas, propane typically correlated well with WTI, and the resulting regression factor resulted in robust models as tested via back casting. However, the propane/ WTI correlation has weakened over time as gas and oil production is increasingly linked. Thus, Siemens PTI now forecasts propane based on the aforementioned multi-variable regression which includes both natural gas and WTI. This regression provided the factors for a more robust forecasting model.

Siemens PTI estimated the delivery and local infrastructure related costs based on recent fuel supply offers. Several offerors provided detailed supply chain costs from which Siemens PTI estimated an incremental delivery cost of 2021$ 3.7 per MMBtu, that we applied to the US commodity forecast.

This resulted in delivered prices to a local port. The forecast indicates a near-term price decline followed by a gradual long-term increase, see figure below.

Figure 5-3: Delivered Propane (LPG) Forecast (2021$/MMBtu)

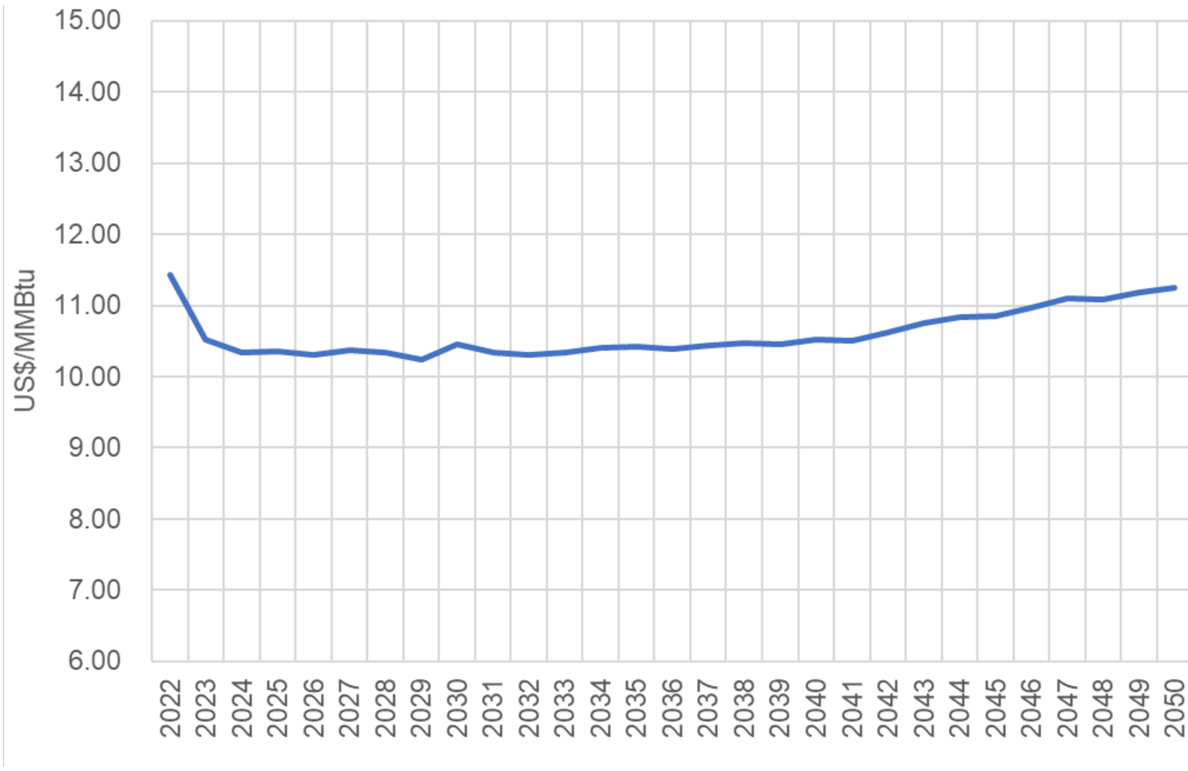


Source: Fuel Forecast_BEL_delivered.xlsx workpaper

5.4 Containerized Liquified Natural Gas (LNG)

To forecast the delivered LNG price, Siemens PTI added our proprietary natural gas price forecast (also used in the propane forecast), and a local delivery and infrastructure adder derived from recent fuel supply offers provided to BEL. For our forecasts, Siemens PTI applies our own unique insight through the Gas Pipeline Competition Model (GPCM) to derive our fundamentals based natural gas forecasts. The GPCM model is a common industry tool used by utilities and infrastructure providers to forecast natural gas prices at different trading hubs along the U.S. natural gas system. We integrate our view of gas demand across the U.S., which includes exports to Mexico via pipeline and exports to other countries via LNG. By combining the U.S. commodity forecast with the delivery costs that were estimated to represent and incremental delivery cost of 2021$ 6.79 per MMBtu for container delivery, Siemens PTI developed the forecast for LNG delivered to a local port as depicted below.

Figure 5-4: Delivered Containerized LNG Forecast (2021$/MMBtu)

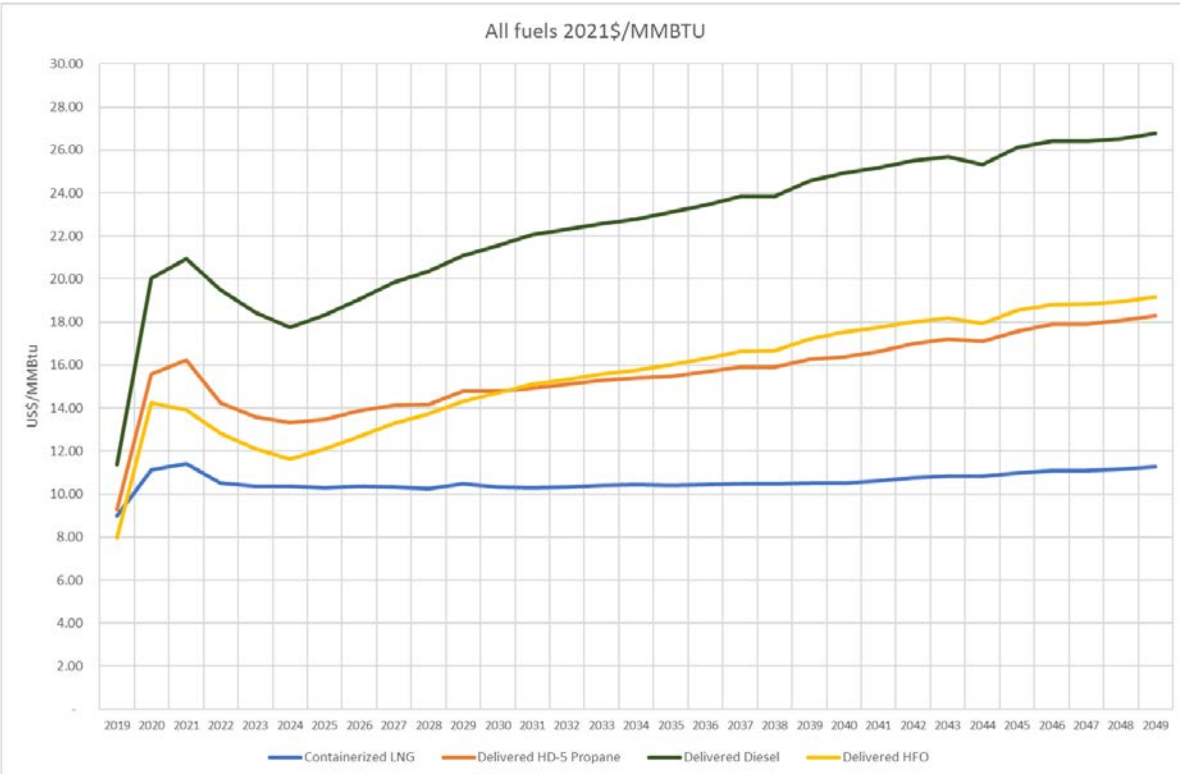


Source: Fuel Forecast_BEL_delivered.xlsx workpaper

5.5 Fuel Forecast Summary

Using the heat conversion for ULSD of 138,490 Btu/Gallon and 6,304,620 Btu/ Barrel for HFO, the figure below shows the forecasted prices for the various fuels in US$/MMBtu (2021). As can be observed containerized LNG is projected to be the least cost resource for Belize

Figure 5-5: Delivered Fuel Forecast (2021$/MMBtu)



Source: Fuel Forecast_BEL_delivered.xlsx workpaper

A range of high and low fuel prices were also created to be analyzed within scenarios and sensitivities.

Figure 5-6: High and Low Delivered LNG Forecast

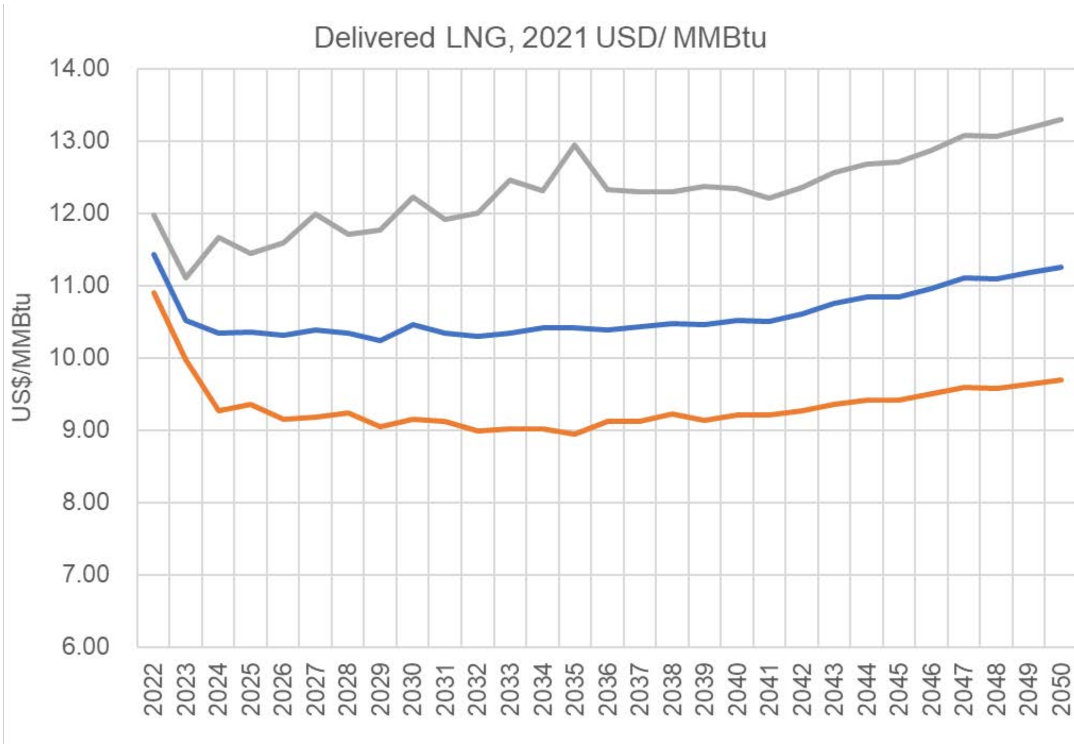
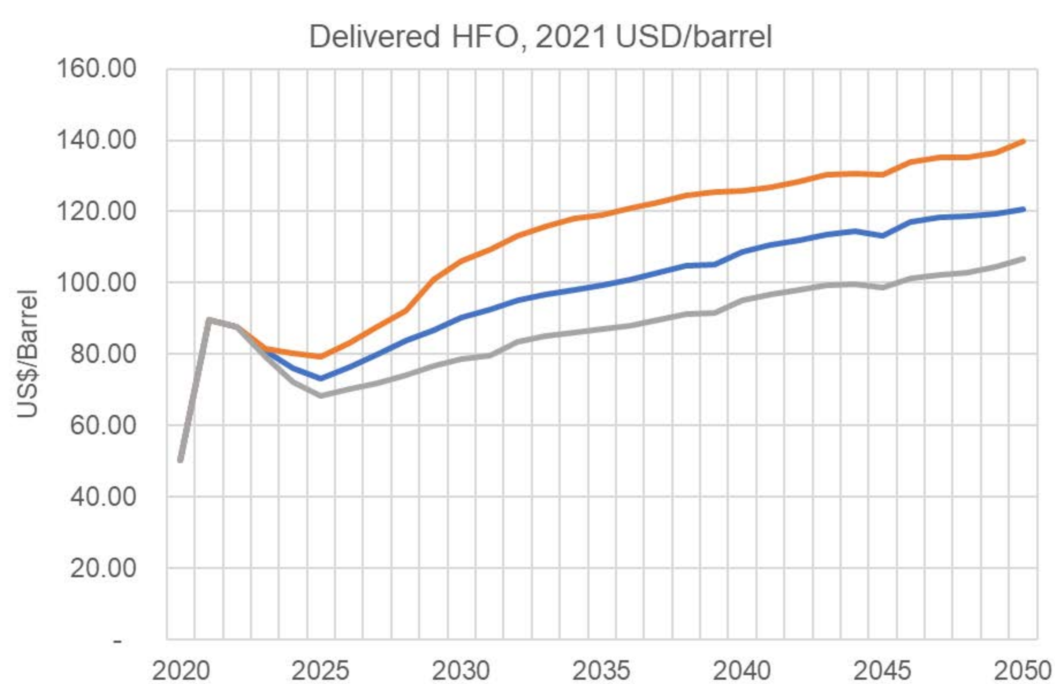


Figure 5-7: High and Low Delivered HFO Forecast



6. Existing Generation Resources

This section provides the parameters used for modeling the existing generation resources for the transmission analysis and the capacity expansion plan as well as the projection of the PPA prices for the planning period.

The table below shows a summary of the existing generation discussed in this section of the report, including the contractual capacity (or available capacity), the PSS®E capacity modeled, and the historical maximum reported (2008 to present).

Table 6-1: Existing Generation

Power Plant	Type	Contractual Capacity MW	PSSE Model MW	Historical MW
CFE		55	100	60.3
Mollejon	Hydro	25.2	3x8.4	32.8
Vaca	Hydro	19	2x9.5	24.2
Chalillo	Hydro	7	2x3.5	9.7
Hydro Maya	Hydro	3.4	1x3	3.8
Belcogen	Biomass	12.5	1x12.5	20.0
Santander	Biomass	8	1x8	13.7
Bapcol	HFO	22.5	3x7.86	23.1
LM2500(Mile 8)	LFO	19	1x20.25 (2021) 1x30.9 (2023)	22.5

6.1 Hydro Generation Energy and Prices

6.2 Overview

Hydro generation will be modeled considering the historical production as provided by BEL for the period 2008 to 2021. As shown below we assessed this production and determined the probability of the monthly output being exceeded (percentiles). We propose to use the 50th percentile for reference case conditions. This is the energy that has 50% probability of being exceeded and use a lower value, e.g., 20th percentile for the "Low Hydro" sensitivity.

With respect of the dispatch of the hydro, our model Aurora considers the monthly available energy and dispatches it against the net load (after renewable), thus minimizing the thermal and international interconnections energy production.

Hydro generation has a near zero marginal cost for Belize and water spillage is a loss for the Country. In principle however, BEL could reduce purchases to the hydro projects and buy from a lower cost source at the time as is expected to be Mexico[11], this can result in a situation where hydro energy would have to be curtailed (read spillage) and thermal energy imported from Mexico. To avoid this situation the hydro projects will be modeled as “must run” and the purchases to Mexico would be reduced ahead of these projects.

We provide details on energy modeled and rates by group of projects below.

6.3 Mollejon and Chalillo

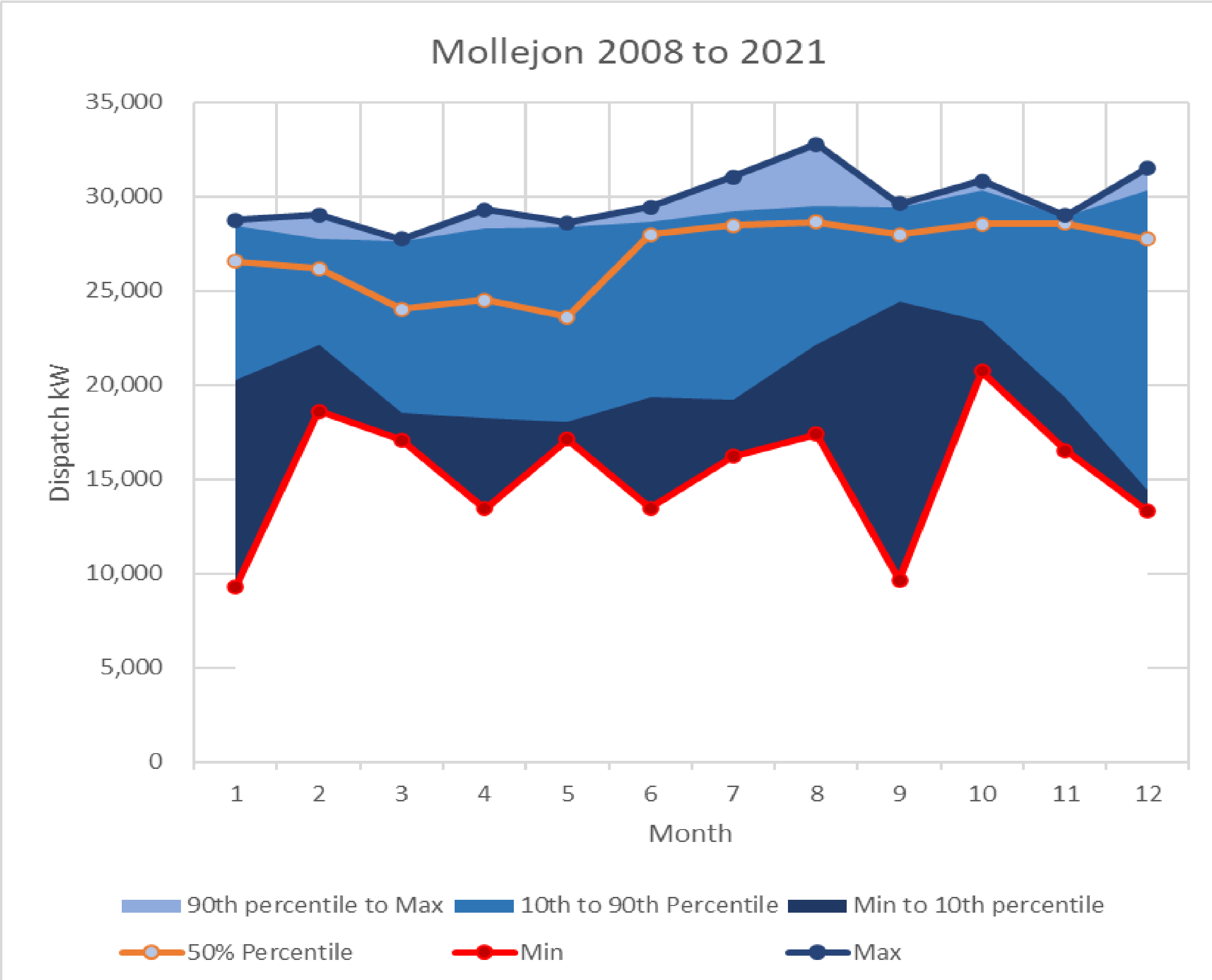
These two projects are under the same PPA. Chalillo is upstream of Mollejon, it has the largest reservoir in the hydroelectric chain and provides annual regulation. Downstream is Mollejon that has a smaller reservoir that would allow for daily regulation.

6.3.1 Mollejon and Chalillo Capacity

For the modeling of the capacity availability, we examined the dispatch by month considering the available history and observed that Mollejon in average was dispatched at 28.4 MW in the period August to November and a low of 24 MW in March to May. The figure below shows these averages together with the max and min values by month and the 10th and 90th percentiles. It is to be noted that these values represent the expected dispatch level, not the maximum output that can be achieved that is a function of the head and that for Mollejon that can be maintained fairly constant during the year using the local upstream reservoir. Hence no difference in capacity for load flow modeling (short term dispatch) is required and the units are assumed to be able to ramp up for short duration to its max in case of emergencies.

[11] We understand the BEL is in discussions with BECOL on a contract that would effectively make the generation at the hydro power plants “take or pay” unless the spill is caused due to reliability considerations. Water is spilled because there is not enough load and the generation in BEL is already at the minimum levels for reliability considerations.

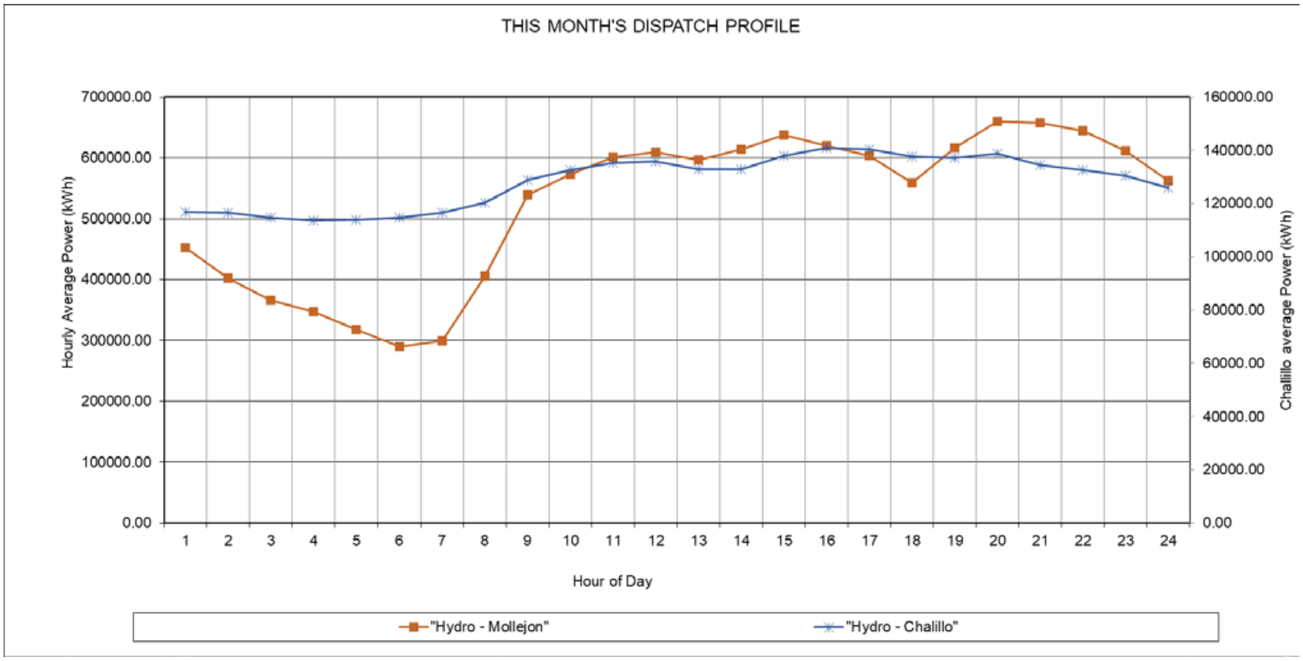
Figure 6-1: Mollejon Dispatch



Source: Hydro&Biomass Model.xlsx workpaper

We also observed that Mollejon can be dispatched hourly according to the economics of the day with low dispatch in the earlier hours of the day and increasing as the loads picks up, with a maximum in the evening. As an example of this we show below the August 2021 Mollejon production profile and we compare with that of Chalillo, which is fairly constant and shows that the reservoir at Mollejon can be used for the daily regulation. Another example of this is provided later when we discuss Vaca.

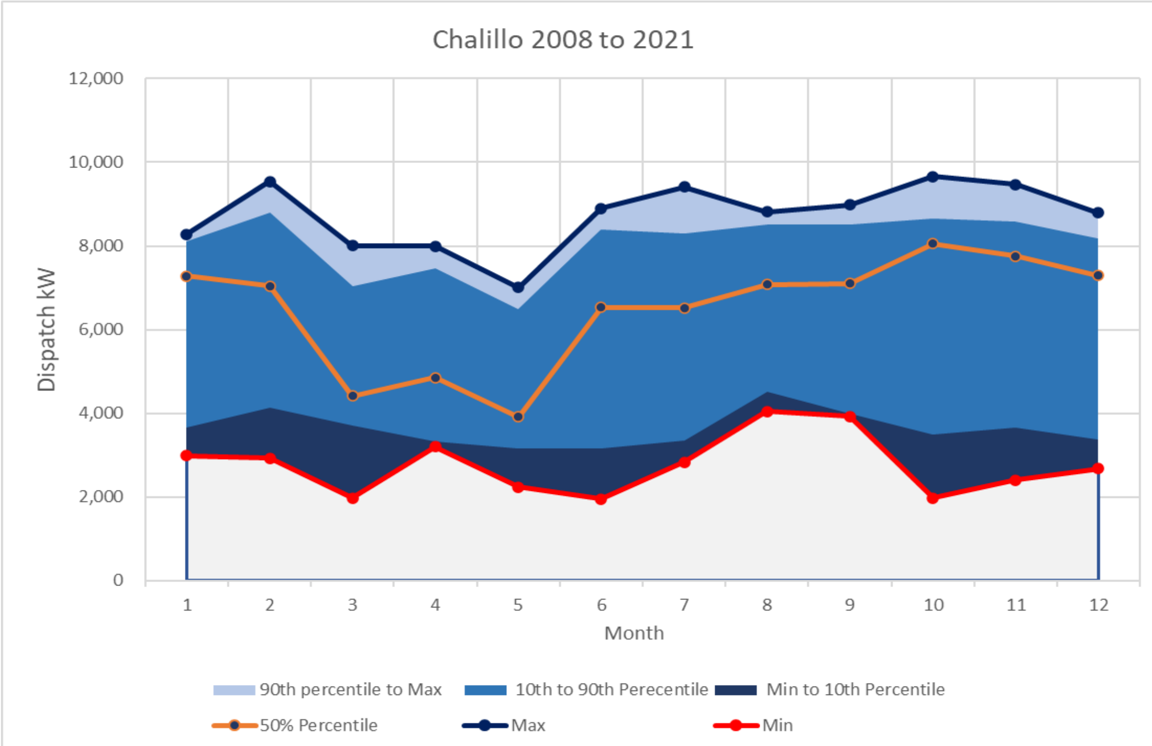
Figure 6-2: Mollejon and Chalillo daily average dispatch August 1021



Source: BEL_Cost_of_Power_08_21.xlsx

Similarly, we examined the hydro generation for Chalillo and found that in average achieved 7.5 MW in the period August to November and a low of 4.4 MW in March to May. The figure below shows these averages together with the max and min values by month and the 10th and 90th percentiles. Chalillo max output can be affected by the reservoir level that tends to be minimum by start of September and according to the information below does not seems to affect the dispatch levels of the project. Hence for load flow it will be assumed to be able to reach its max for short duration for emergency conditions.

Figure 6-3: Challillo Dispatch

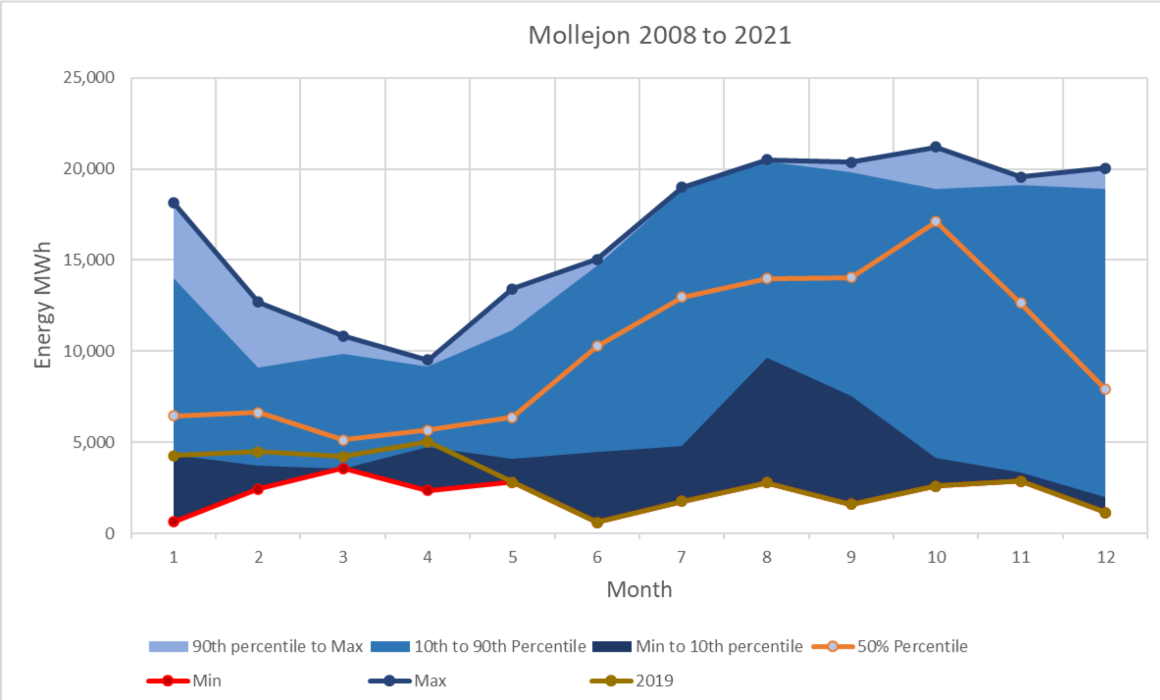


Source: Hydro&Biomass Model.xlsx workpaper

6.3.2 Mollejon and Chalillo Energy

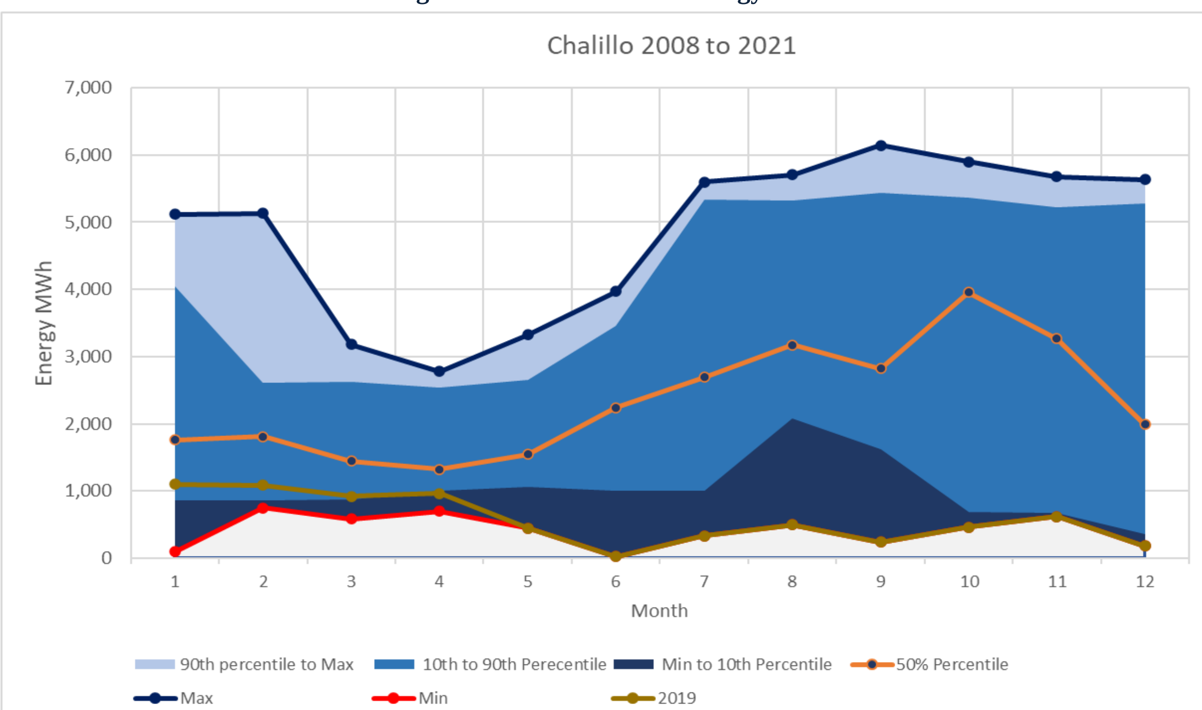
The figures below show the energy by month in kWh highlighting the 50% percentile as well as the bands between minimum and 10th percentile (low band), between 10th and 90th and 90th to max. In these figures we also show 2019, that as can be seen was one of the driest on record. As indicted above the 50th percentile was used for modelling.

Figure 6-4: Mollejon Energy in kWh



Source: Hydro&Biomass Model.xlsx workpaper.

Figure 6-5: Chalillo Energy in kWh



Source: Hydro&Biomass Model.xlsx workpaper.

6.3.3 Mollejon and Chalillo PPA

Chalillo and Mollejon has the same rate, which is an energy only rate with two values one that is charged for energy produced up to 100 GW and the second for any excess energy. The tables below show the energy to be modeled by month using the 50th percentile and to be priced using the Base Rate (under 100 GW) and the Secondary Rate (above 100 GW)

Table 6-2: Chalillo and Mollejon Base Rate modeled production

	Chalillo Base		Mollejon Base		Cha + Moll Cum
Contractual Capacity MW:	**7**		**28.4**		
Month	KWh	CF	KWh	CF	KWh
1	1,761,840	34%	6,458,098	31%	8,219,937
2	1,807,139	38%	6,654,367	35%	16,681,443
3	1,444,209	28%	5,125,126	24%	23,250,778
4	1,319,190	26%	5,670,763	28%	30,240,730
5	1,543,137	30%	6,372,587	30%	38,156,454
6	2,238,811	44%	10,286,624	50%	50,681,888
7	2,691,689	52%	12,968,910	61%	66,342,487
8	3,173,449	61%	13,984,375	66%	83,500,311
9	2,759,340	55%	13,740,350	67%	100,000,000
10	0	0%	0	0%	100,000,000
11	0	0%	0	0%	100,000,000
12	0	0%	0	0%	100,000,000
Total	**18,738,802**	**30.5590%**	**81,261,198**	**33%**	

Source: Hydro&Biomass Model.xlsx workpaper.

Table 6-3: Chalillo and Mollejon Secondary Rate modeled production

	Chalillo Second		Mollejon Second		Cha + Moll Cum
Contractual Capacity MW:	7		28.4		
Month	KWh	CF	KWh	CF	KWh
1	0	0%	0	0%	0
2	0	0%	0	0%	0
3	0	0%	0	0%	0
4	0	0%	0	0%	0
5	0	0%	0	0%	0
6	0	0%	0	0%	0
7	0	0%	0	0%	0
8	0	0%	0	0%	0
9	62,754	1%	312,486	2%	375,239
10	3,956,985	76%	17,114,741	81%	21,446,965
11	3,262,653	65%	12,628,481	62%	37,338,098
12	1,987,623	38%	7,918,164	37%	47,243,885
Grand Total	**9,270,014**	**15 %**	**37,973,871**	**15%**	

Source: Hydro&Biomass Model.xlsx workpaper.

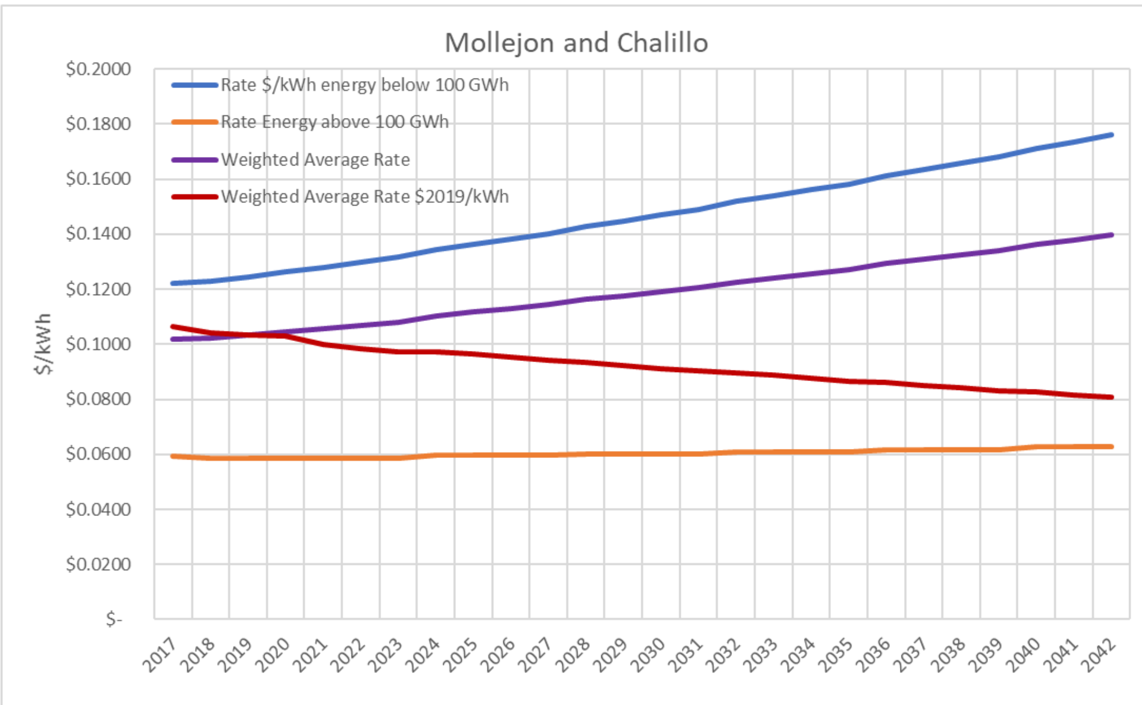
The rates BEL pays to the projects is an energy only rate in US$/kWh constructed with a Base Rate of $0.1214 US$/kWh for the Energy Below 100 GWh as indicated above and a Secondary rate of

$0.0500 US$/kWh for Energy Above 100GWh (paid only after the yearly production reaches this value). The Base Rate and Secondary Rate were stablished in the year 2000 and the Base Rate has a contractual adjustment of 1.5% per year. The Secondary Rate is not adjusted.

In addition to the above there is an O&M fee is 5% of the average BEL Rate times a factor that accounts for the losses. For the projection Siemens estimated that BEL rates would remain constant in nominal terms in four-year blocks with an adjustment on the fifth year to capture the effects of inflation.

The workpaper BEL_PPA_Assumptions_v1.2.xlsx has the details of the rates forecast that is depicted in the figure below that shows: the Base and the Secondary rates (Nominal) and an energy weighted average rate. This graph also shows the weighted average rate in real 2019$ and we see that there is a steady decline due to the fact that the Base Rate is adjusted less than the expected inflation and the Secondary Rate is not adjusted at all.

Figure 6-6: Mollejon and Chalillo PPA Rates



Source: BEL_PPA_Assumptions_v1.2.xlsx workpaper.

6.4 Vaca

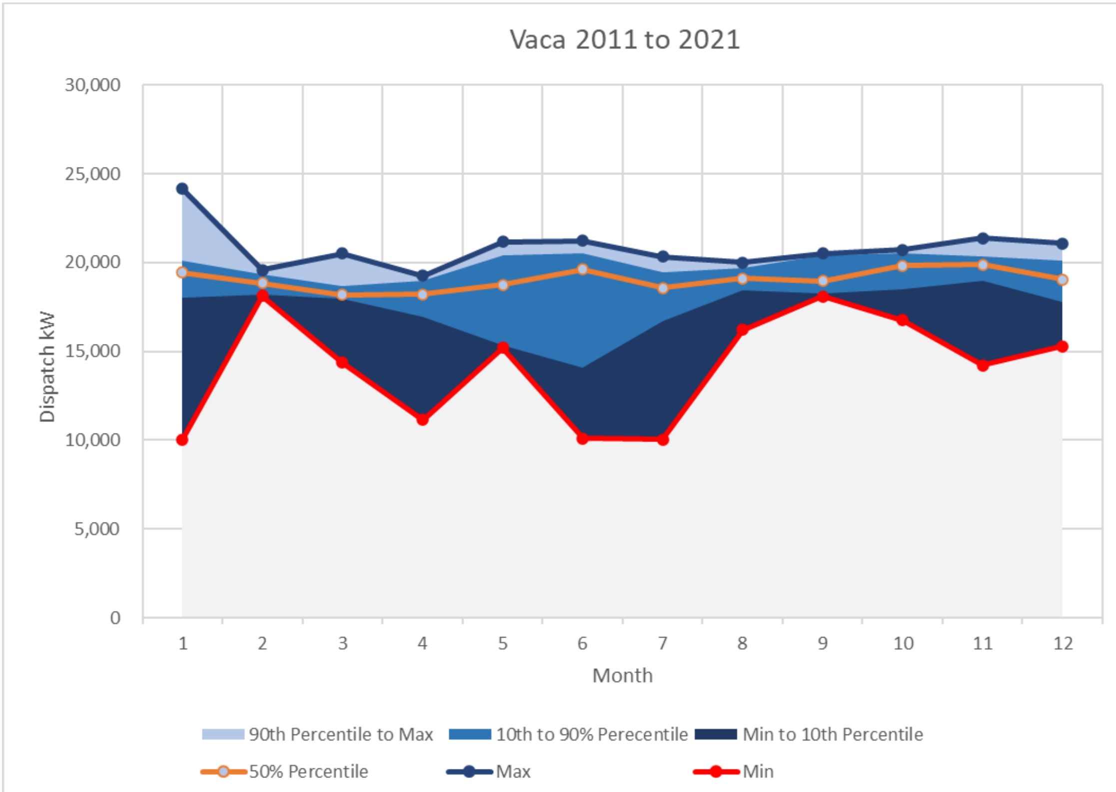
Vaca is located downstream from Mollejon it has a smaller reservoir that could be used for daily regulation.

6.4.1 Vaca Capacity

For Vaca, we examined the hydro generation and found that in average it was dispatched at 19.5 MW in the period August to November and a low of 18.4 MW in March to May. The figure below shows these averages together with the max and min values by month and the 10th and 90th percentiles. Like

Mollejon the maximum capacity is a function of the head that can be maintained fairly constant during the year using the local upstream reservoir.

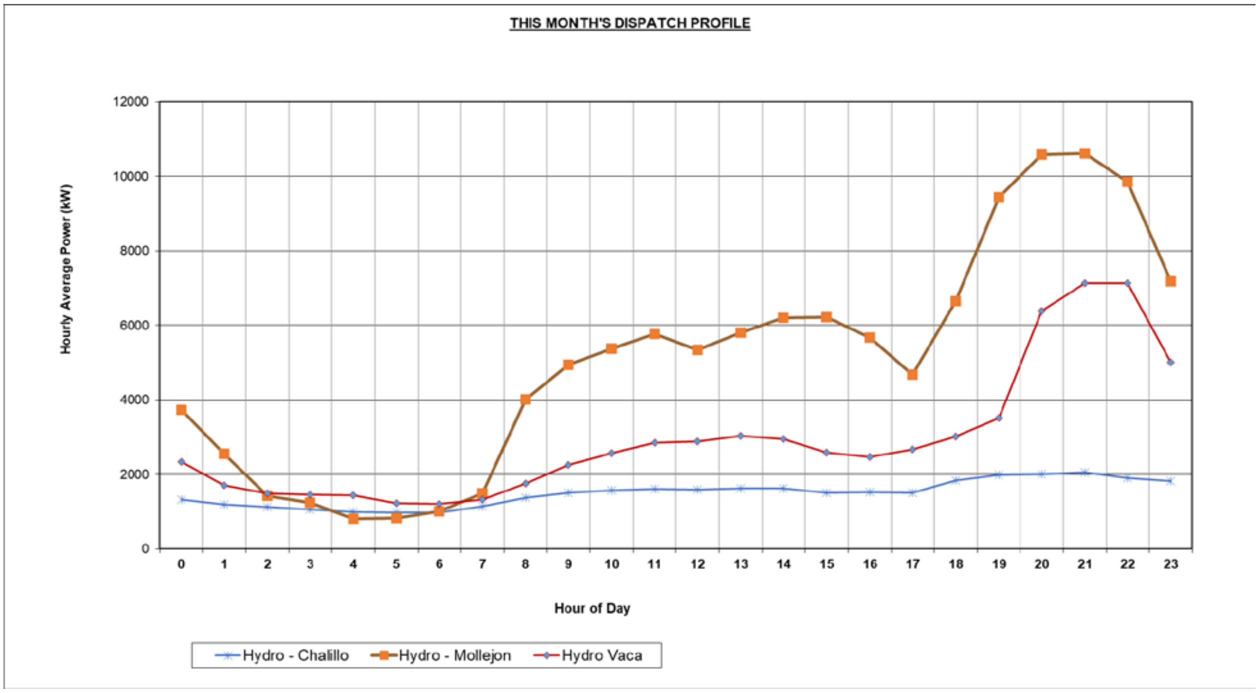
Figure 6-7: Vaca Dispatch



Source: Hydro&Biomass Model.xlsx workpaper

Vaca has a smaller reservoir and largely follows the production at Mollejon. However, as can be observed below where we show the May 2020 production profile, we note that the production at Vaca has its own profile and while Mollejon picks up the generation at hour 17, Vaca picks this up at hour 19 and both reduce at hour 22.

Figure 6-8: Mollejon, Vaca and Chalillo daily average dispatch May 1020

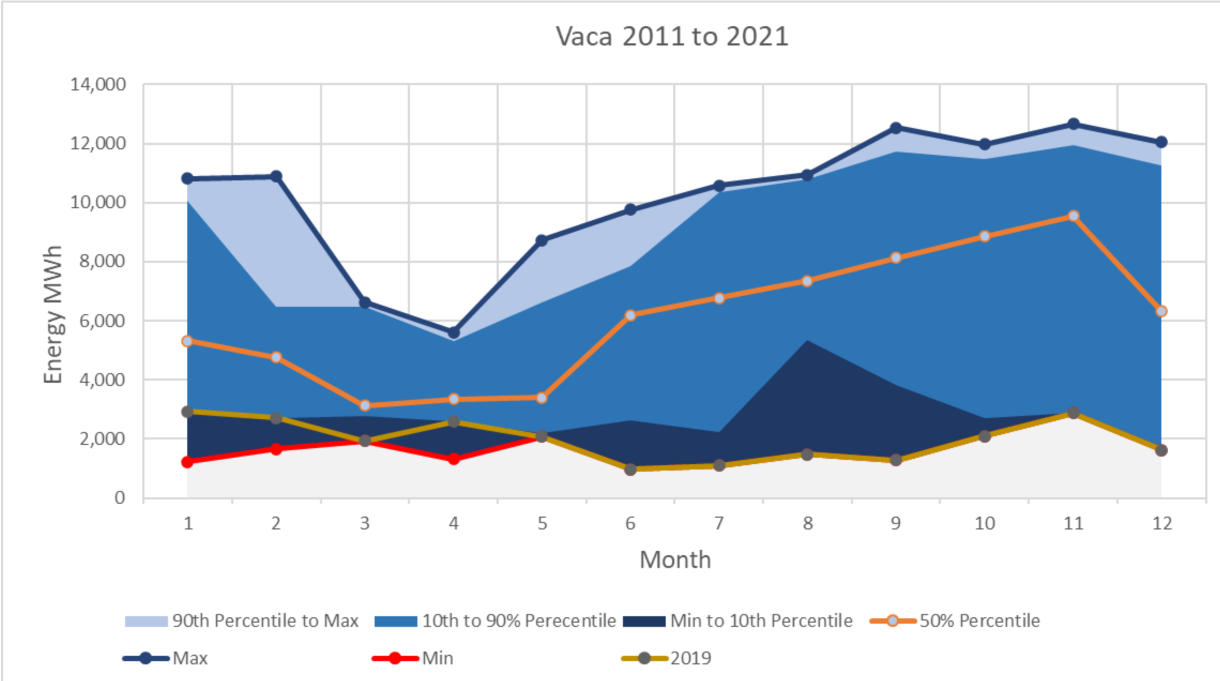


Source: BEL_Cost_of_Power_0520

6.4.2 Vaca Energy

The figures below show Vaca energy by month in kWh highlighting as before the 50% percentile as well as the bands between minimum and 10th percentile (low band), between 10th and 90th and 90th to max. Again, we note that 2019, was one of the driest on record

Figure 6-9: Vaca Energy in kWh



Source: Hydro&Biomass Model.xlsx workpaper.

As indicted above the 50th percentile is recommended for modelling, and this is shown in the table below.

Table 6-4: Vaca modeled production

	Vaca	
Contractual Capacity MW:	19	
Month	KWh	CF
1	5,320,712	38%
2	4,761,608	37%
3	3,125,086	22%
4	3,352,510	25%
5	3,395,340	24%
6	6,197,811	45%
7	6,780,198	48%
8	7,345,392	52%
9	8,127,356	59%
10	8,851,735	63%
11	9,551,978	70%
12	6,325,757	45%
Grand Total	73,135,483	44%

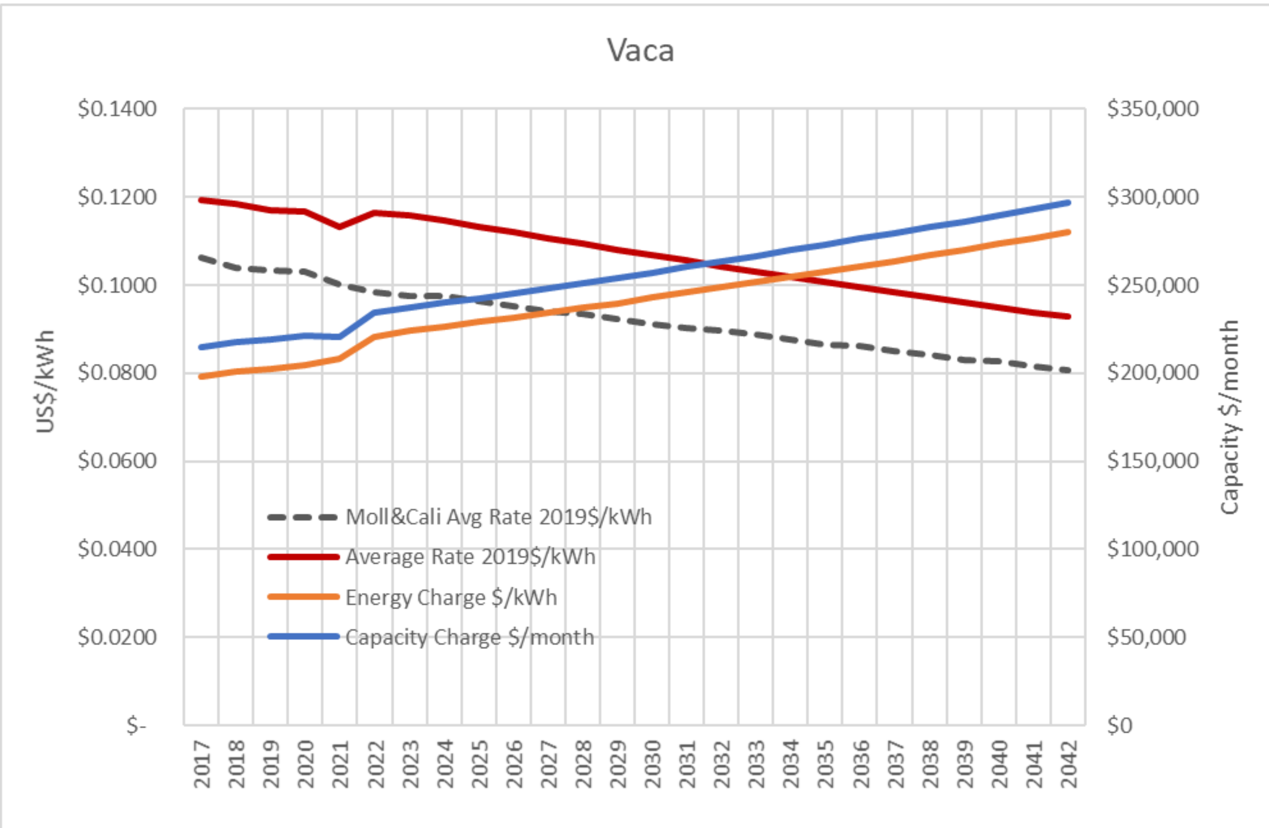
Source: Hydro&Biomass Model.xlsx workpaper.

6.4.3 Vaca PPA

Vaca contract has a capacity charge of $ 200,000 month and an energy charge of 0.0755 $/kWh, both values in 2010 US$. These values are adjusted using 50% of the year over year change in the PPI Commodity Data Index (WPUFD49207). The BEL_PPA_Assumptions_v1.2.xlsx workpaper provides the historical values of this contract and our projection based on inflation expectations.

The figure below shows the forecasted energy and capacity rates and the average rate in 2019 $ resulting from these rates. As we see there is a declining rate in real terms due to the fact that only 50% of the inflation is reflected in the rate adjustment. Also, as can be observed in the figure Vaca rates are about 1 cent per kWh higher than those of Mollejon and Chalillo in real 2019$

Figure 6-10: Vaca PPA Rates



Source: BEL_PPA_Assumptions_v1.2.xlsx workpaper.

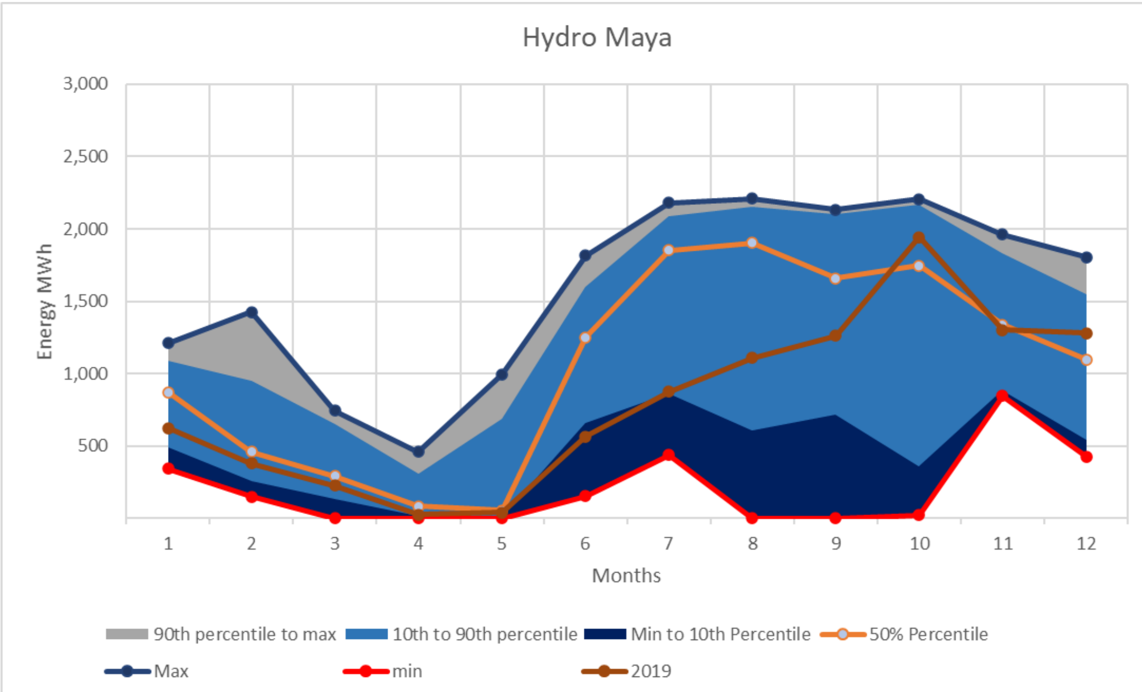
6.5 Hydro Maya

6.5.1 Hydro Maya Energy and Capacity

Hydro Maya is a small hydro plant in the south of Belize, separated from the plants above.

Its capacity was assumed to remain fairly constant (any variations would have negligible impact of the load flow analysis), and the figures below show Hydro Maya energy by month in kWh highlighting the 50% and bands. As the hydrology of Hydro Maya is different than the plants above, 2019 while dry was not as extreme.

Figure 6-11: Vaca Energy in kWh



Source: Hydro&Biomass Model.xlsx workpaper.

The table below shows 50th percentile that is recommended for modelling.

Table 6-5: Hydro Maya modeled production

	Hydro Maya	
Contractual Capacity MW:	2.5	
Month	KWh	CF
1	869,926	47%
2	458,241	27%
3	289,592	16%
4	81,790	5%
5	53,831	3%
6	1,248,942	69%
7	1,851,224	100%
8	1,903,823	102%
9	1,658,540	92%
10	1,745,988	94%
11	1,339,412	74%
12	1,095,403	59%
Grand Total	12,596,707	58%

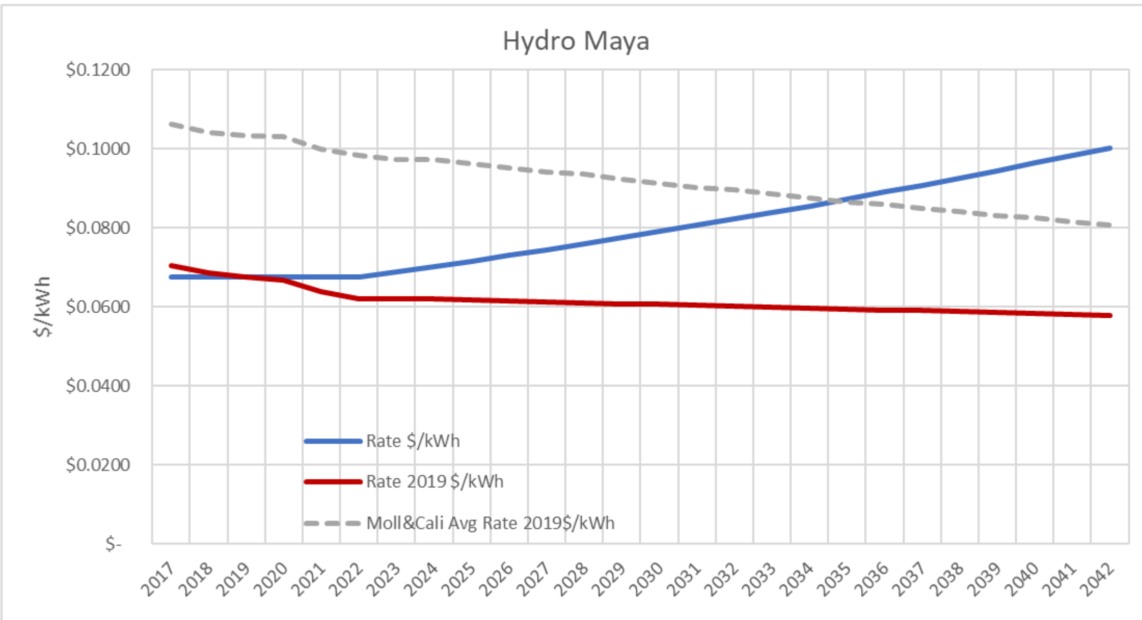
Source: Hydro&Biomass Model.xlsx workpaper.

6.5.2 Hydro Maya PPA

Hydro Maya contract is energy only at a constant price of $0.0675/kWh (nominal) until 2022. At that time, the contract will be renegotiated and only for the purposes of modelling an adjustment of 2% per year was adopted.

The figure below shows the forecasted Hydro Maya energy rate (nominal) and in 2019 $. The 2019$ average rate for Chalillo and Mollejon is also shown, where we see that the Hydro Maya rate is about 3 to 4 2019 cents lower.

Figure 6-12: Hydro Maya rates



Source: BEL_PPA_Assumptions_v1.2.xlsx workpaper.

6.6 Biomass Generation Belcogen & Santander

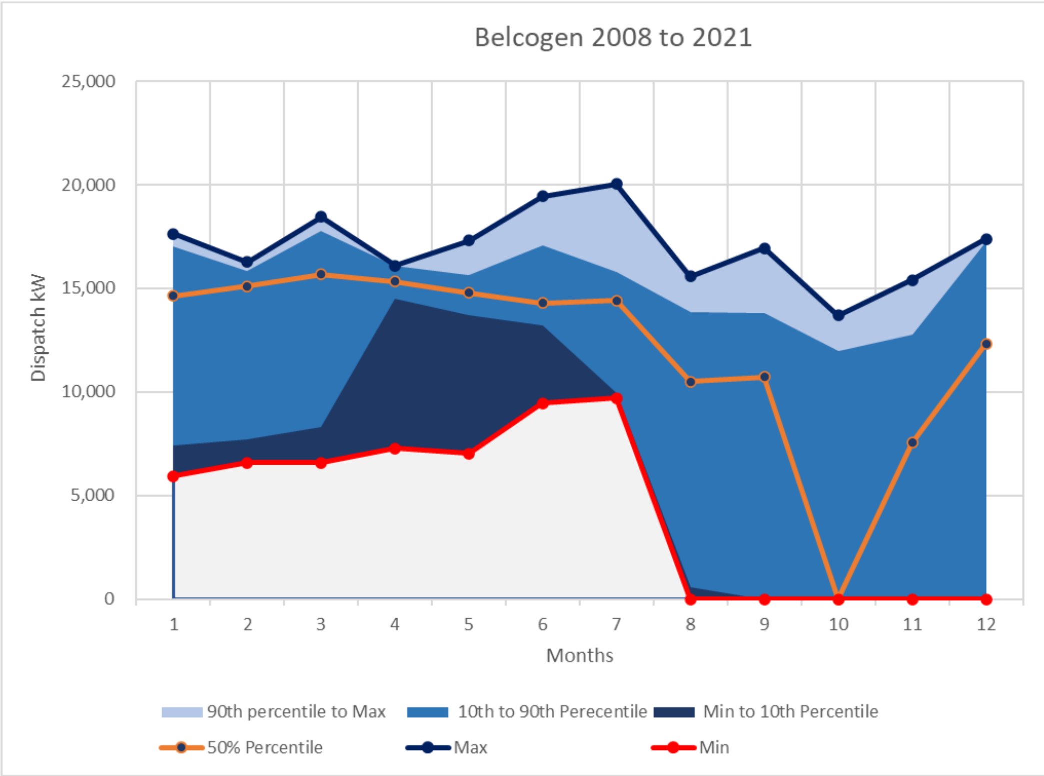
There are two biomass projects in Belize, Belcogen and Santander. Similar to the hydro energy the biomass production is subject to variability depending on the harvest conditions.

The Biomass contracts are take-or-pay, thus will be modeled as “must run” units, regardless of price. Below are the details on energy modeled and rates for the two projects.

6.6.1 Belcogen and Santander Capacity

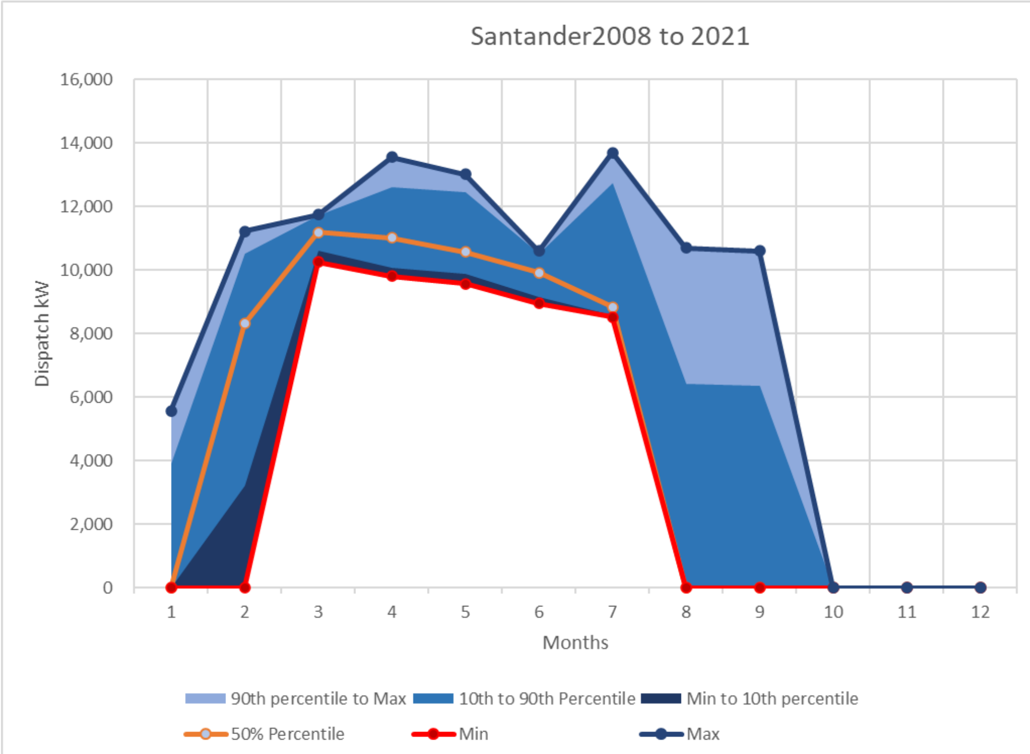
The biomass generation also presented seasonality as can be observed below, where we note that there are periods of maximum output in March to May (15.3 MW Belcogen, 10.9 MW Santander) followed by a decline to zero / near zero output starting in August to October. The zero-output period is more pronounced for Santander, but we expect that this will be expanded by the addition of another harvest season. From the below we selected for the modeling of biomass dispatch Belcogen with possibility to be dispatched to is max and Santander at zero output.

Figure 6-13: Belcogen Dispatch



Source: Hydro&Biomass Model.xlsx workpaper

Figure 6-14: Santander Dispatch (total period)



Source: Hydro&Biomass Model.xlsx workpaper

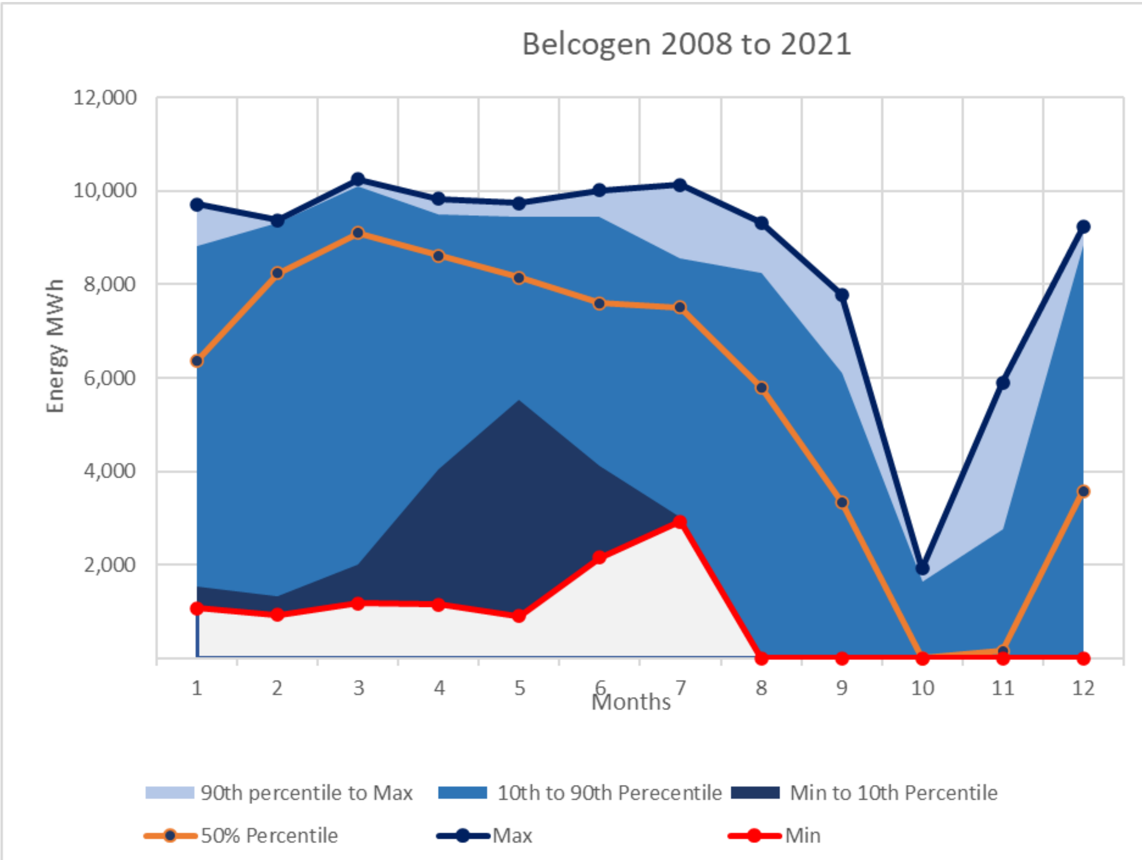
Figure 6-15: Santander Dispatch (2020 to 2021)

Source: Hydro&Biomass Model.xlsx workpaper

6.6.2 Belcogen Energy

The figure below shows the energy by month in kWh produced by Belcogen as derived from the historical data. This energy as mentioned earlier has significant variability as can be seen in Figure 6-16 and will be modeled as was the case of the hydro, using the 50% percentile detailed in Table 6-6

Figure 6-16: Belcogen Energy in kWh



Source: Hydro&Biomass Model.xlsx workpaper.

Table 6-6: Belcogen modeled production

	Belcogen		
Contractual Capacity MW:	12.5		
Month	KWh	CF	
1	6,368,463	68%	744
2	8,235,072	98%	672
3	9,101,964	98%	744
4	8,625,905	96%	720
5	8,155,023	88%	744
6	7,603,199	84%	720
7	7,510,005	81%	744
8	5,795,046	62%	744
9	3,343,662	37%	720
10	0	0%	744
11	158,225	2%	720

12	3,577,250	38%	744
Grand Total	**64,896,561**	**59%**	**8,760**

Source: Hydro&Biomass Model.xlsx workpaper.

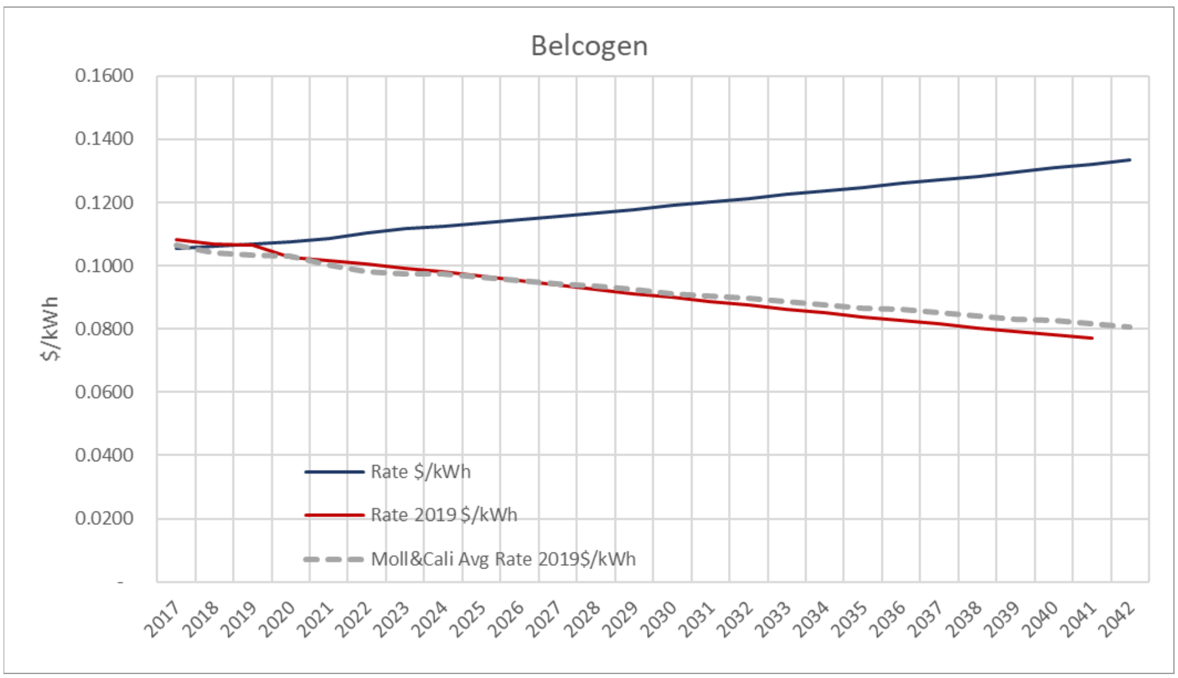
6.6.3 Belcogen PPA

BEL pays to Belcogen an energy only rate determined based on an initial contractual value for Operations, Capital and Finance cost 60% of which remains constant and 40% are adjusted using the "Price Indices for Gross Domestic Product and Related Measures: Percentage Change with respect of Preceding Period" These costs are converted to a cost in $/kWh dividing by a deemed energy produced of 128GWh. The projections to the end of the planning period were carried out using our expectations of inflation as an approximation to the changes in the index above.

The figure below shows the projected rates that are applicable for production using bagasse. In case that fossil fuels are used there would be additional charges, but this is not included in our model.

In the case of Hydro, there is a reduction in real terms 2019$, due to the partial consideration of inflation (40%) also we note that Belcogen rate is very similar to that of Mollejon and Chalillo.

Figure 6-17: Belcogen PPA Rate

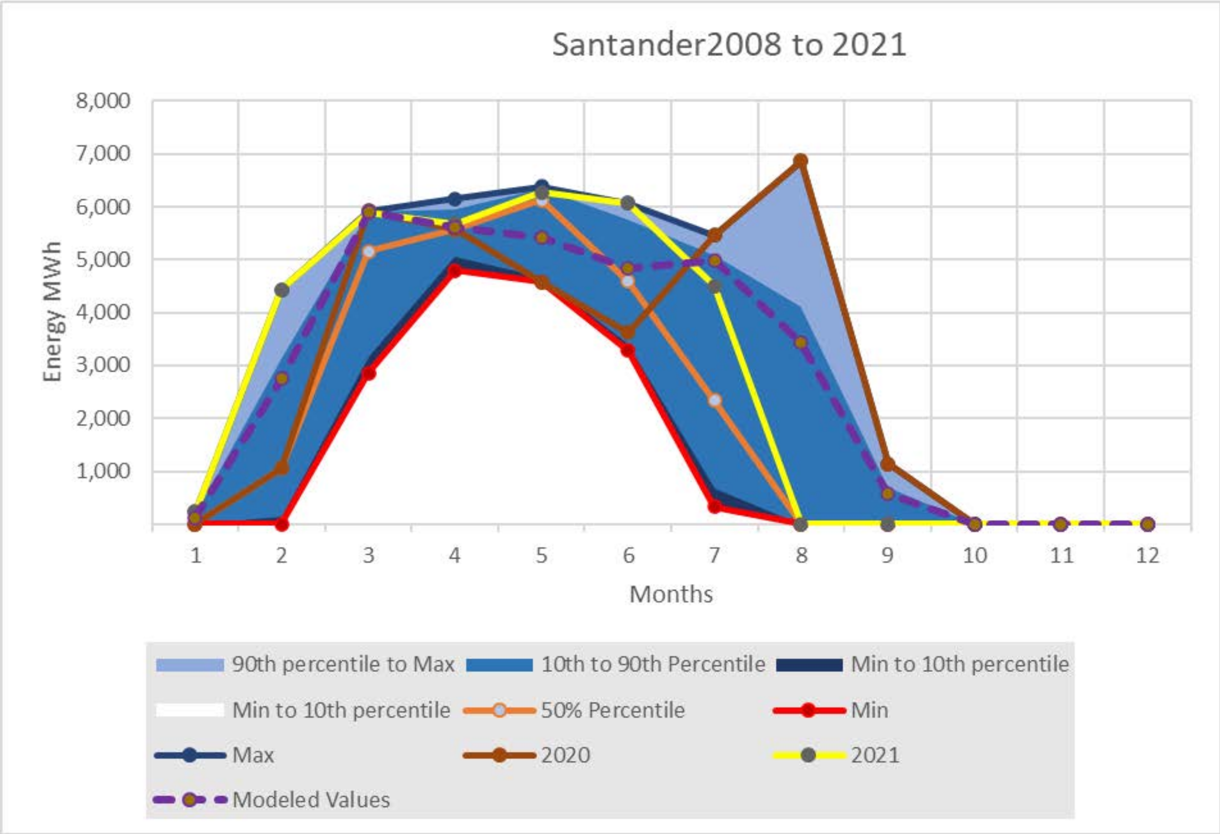


Source: BEL_PPA_Assumptions_v3.xlsx workpaper.

6.6.4 Santander Energy

The figure below shows the energy by month in kWh produced by Santander as derived from the historical data. Santander. As can be observed during 2020 and 2021 the production has been expanded and this is expected to continue in the future due to programs put in place by Santander. Hence the production will be modeled using the average of these two years and as detailed in Table 6-7.

Figure 6-18: Santander Energy in kWh



Source: Hydro&Biomass Model.xlsx workpaper.

Table 6-7: Santander modeled production

	Santander	
Contractual Capacity MW:	8.0	
Month	KWh	CF
1	115,268	2%
2	2,747,667	45%
3	5,906,267	88%
4	5,622,447	87%
5	5,425,047	81%
6	4,845,624	75%
7	4,983,746	74%
8	3,435,603	51%
9	572,563	9%
10	0	0%
11	0	0%
12	0	0%
Grand Total	33,654,230	48%

Source: Hydro&Biomass Model.xlsx workpaper.

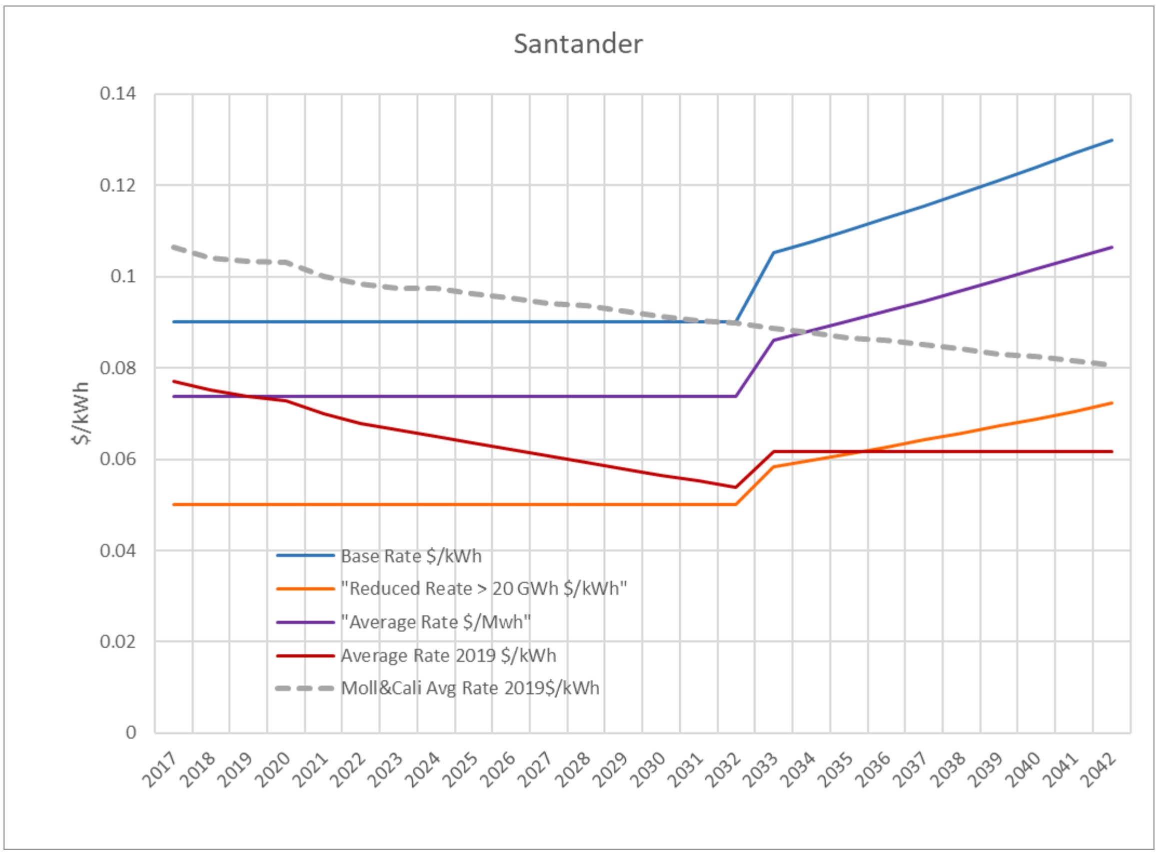
6.6.5 Santander PPA

Santander has two rates, a Base Rate of 0.09 $/kWh for energy delivered up to 20GW and a reduced rate (0.05 $/kWh) for energy above this value. There is a possibility of this rate change of $0.085/kWh up to 22.5 GWh and $0.08 thereafter.

We used the later rates that are nominal and are assumed to stay in place until the end of the contract by 2033. At that time, we are assuming conservatively that both rates will increase to 80% of the inflation adjusted rate and keep growing with inflation to the end of the planning period. This was done for conservative modeling only and should not be construed as an expectation of a contractual outcome.

The figure below shows the Base and Reduced rate projection for Santander as well as an energy weighted average in nominal and 2019$. We observe that this rate is about 2 cents lower than Mollejon & Chalillo rate.

Figure 6-19: Santander PPA Rate



Source: BEL_PPA_Assumptions_v3.xlsx workpaper.

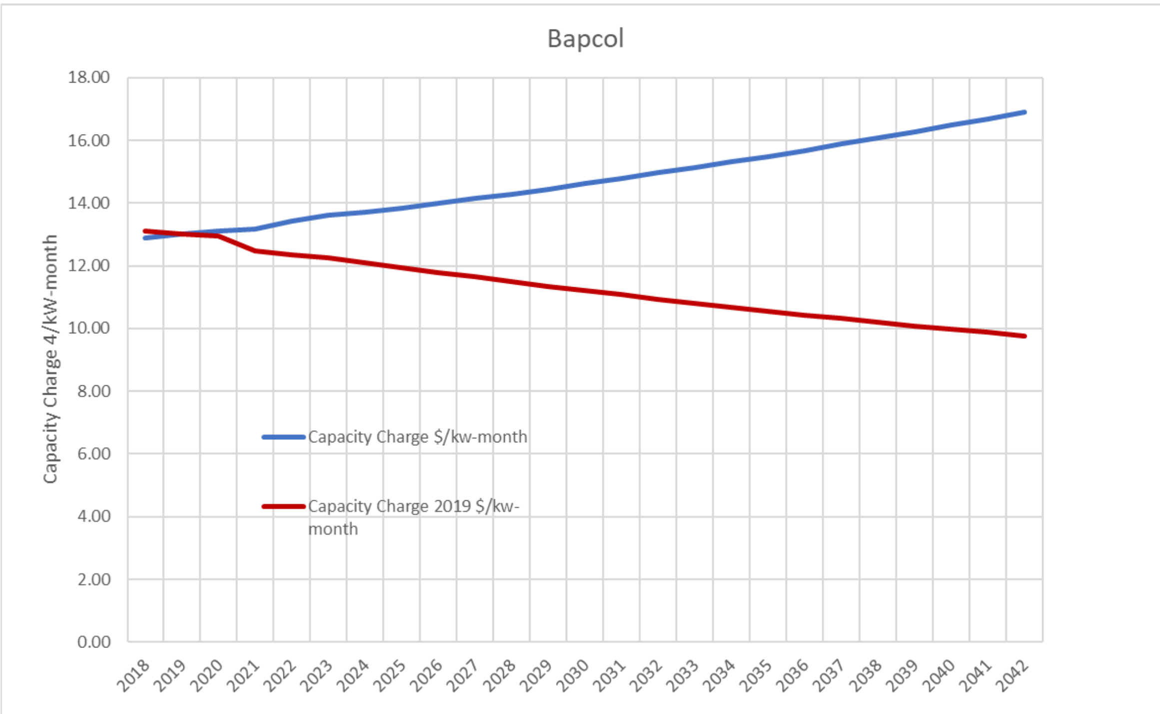
6.7 Thermal PPA BAPCOL

BAPCOL is a fully dispatchable plant hence its capacity was assumed constant as well as its capability to produce energy

BEL has a tooling agreement with BAPCOL according to which BEL owns the fuel and BAPCOL charges for the conversion to electricity. The plant is expected to operate on a peaking basis with a dispatch of 10 to 15% and will be dispatched economically considering the cost of fuel and the variable costs.

The rate structure has a capacity charge in of 12.71 $/kW-month (2018) of which 60% remains constant and 40% is adjusted using the US CPI. This charge is shown in the figure below both in nominal and 2019 $, where we see the decline due to the partial consideration of inflation.

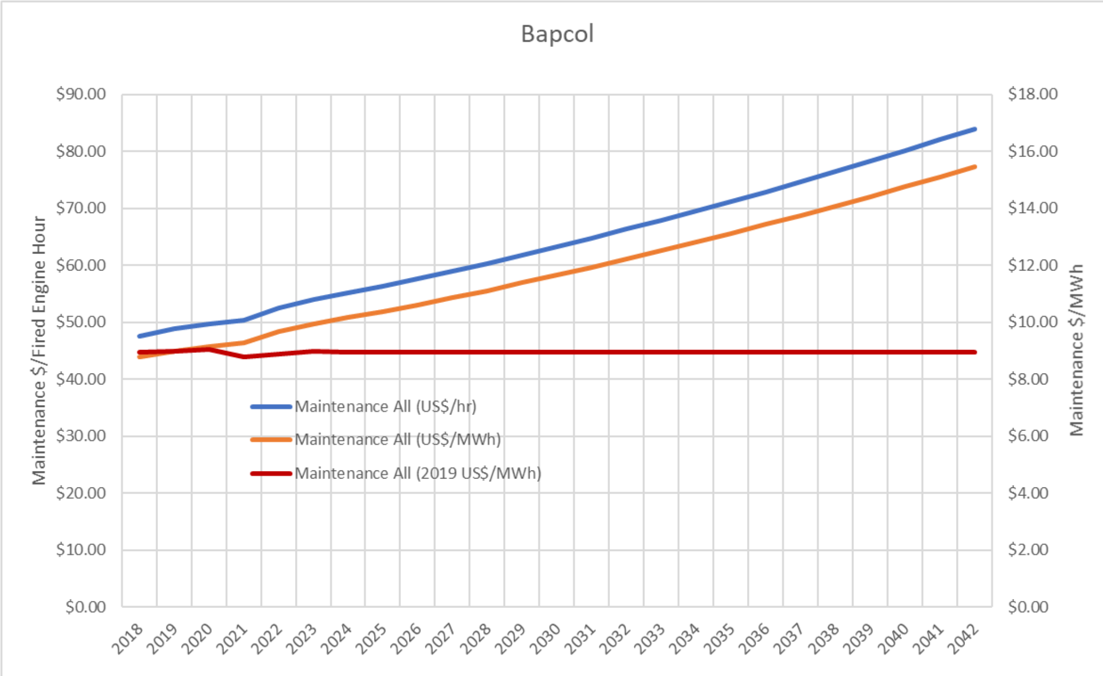
Figure 6-20: BAPCOL Capacity Charge Rate



Source: BEL_PPA_Assumptions_v1.2.xlsx workpaper.

The rate has another component to cover the maintenance and that is expressed in $/ engine-run-hour and it is fully adjusted using the US CPI. As variable maintenance is more commonly expressed as a function of the MWh, we determined using the historical data that the whenever the plant is online it operates in average at 72% of the installed capacity and using this, we estimated the cost in $/MWh. These values are shown in the figure below and the cost in $/MWh is presented in nominal and real terms.

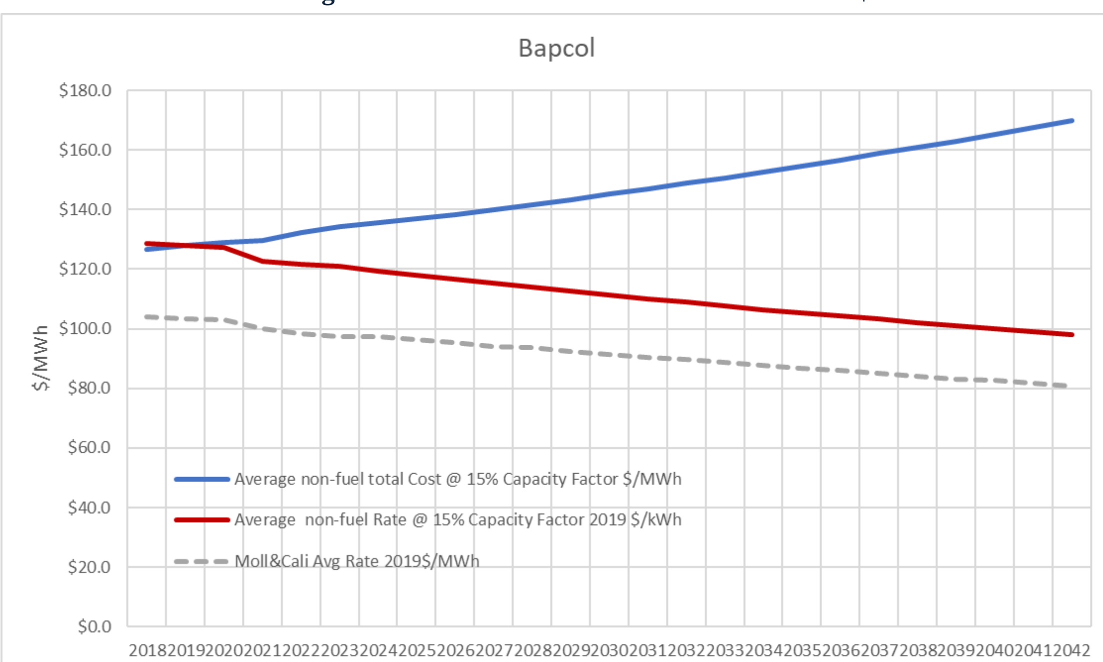
Figure 6-21: BAPCOL Maintenance Costs



Source: BEL_PPA_Assumptions_v1.2.xlsx workpaper.

Finally, considering a dispatch of 15% the figure below shows the total non-fuel costs in $/MWh for the project. It should be noted that the main service of this unit is to provide reserves and has a low-capacity factor, which results in a relatively high cost per MWh produced.

Figure 6-22: BAPCOL Total Non-Fuel Costs $/MWh.



Source: BEL_PPA_Assumptions_v1.2.xlsx workpaper.

7. In country Candidate Generation Resources

7.1 New Renewable and Storage Generation

7.1.1 Capital and O&M Costs

Siemens maintains an extensive database of capital and O&M costs for wind and solar resources that reflect the expected reduction in cost as the technologies mature and improve as well as increases in the capacity factors for the same levels of wind speed or solar irradiation. These cost and improvements are derived from various sources including NREL's 2021 ATB forecast and EAI generation forecasts. However, to convert to Belize's installed costs two corrections need to be made a) account for the differences for capital and operating costs in Belize with respect of the US average (Belize Regional Factor) and b) account for different project size, as in Belize smaller plants in the order of 20 MW are expected in contrast with the much larger plants in the US.

To estimate the Belize regional factor, we investigated three sources; two projects; Airport II Solar Project and Ambergris Cay Wind project cost forecasts as developed with the support of the USTDA, and a project prosed by BAPCOL (8 MW)12. For these projects BEL provided detailed cost that were compared it with the costs that our database would predict for a similar sized project.

These calculations are included in the workpaper Candidate Projects_Multiplier_1_v2.xlsx and the table below provides a summary. The first column for Solar and for Wind shows the capital cost in $/kW for the respective projects in Belize (BEL) and the row below the Siemens estimated cost for a project of similar size. Hence the ratio of these costs is the Belize cost multiplier that the project would imply. Next the second column shows the costs for a 20 MW project that is to be offered as candidate in Aurora and the Belize cost is derived by multiplying Siemens estimate for a 20 MW project times the Belize load regional factor. Finally, the third column shows what the price would be for a larger typical project using the same approach and multiplier.

Table 7-1: Renewable and Storage Capital Costs for Belize

	Solar			Wind		
	South Airport	Model	Base	Ambergris C	Model	Base
Capacity, MW	7.26	20.00	100.00	16.00	20.00	100 - 200
Belize, $/kW	2,077.30	**1,938.57**	1,552.63	2,456.81	**2,142.56**	2,097.87
US (Siemens), $/kW	1,498.47	1,398.40	1,120.00	1,781.24	1,553.40	1,521.00
Belize Cost Multiplier	1.39			1.38		

	Solar		
	BAPCOL	Modeled	Base
Capacity, MW	8.0	20.00	100.00
Belize, $/kW	1,236.50	**1,140.94**	913.80
US (Siemens), $/kW	1,515.52	1,398.40	1,120.00
Belize Cost Multiplier	0.816		

12 BAPCOL Solar consists of two project 7 MW at Chan Chen and 8 MW at Maskall.

Source: Candidate Projects_Multiplier_1_v2.xlsx workpaper

As can be observed above there is a large difference between the regional factors depending on whether the USTDA study is used or BAPCOL.

To further evaluate this the implied LCOE needs to be determined for which the Capital Cost Recovery (CCR) Factor, the O&M Costs and the expected capacity factor needs to be determined.

To determine the O&M costs, we compared the costs of the provided projects with our own internal estimations and found that the USTDA study costs for solar and wind were similar to our projection, and we selected these values for the model. The table also shows the values for batteries.

Table 7-2: Renewable and Storage O&M Costs for Belize

	Solar				Wind			Batteries
	South Airport	BAPCOL	Siemens	Model	Ambergris C	Siemens	Model	Modeled
Variable O&M $/MWh	-	-	-	-	-	-	-	-
Fixed O&M $/kW-year	14.01	13.34	14.00	**14.01**	44.88	44.53	**44.88**	**35.03**

Source: Candidate Projects_Multiplier_1_v2.xlsx workpaper

The CCR factor is a function of the cost of equity and the cost of debt, Siemens working with BEL identified that a cost of equity of 15% and a cost of debt of 6% (nominal) represents appropriately the implied added risk of investing in Belize with BEL (Utility) as the counterpart. The table below shows the CCR for Belize and as a reference a comparable value for the US, with the effects of the Investment Tax Credit and without it.

Table 7-3: CCR Calculations US VS. Belize

	USA	No ITC	Belize
Technology	Solar	Solar	Solar
Type	Utility	Utility	Utility
Book Life/Useful Life	20	20	20
Depreciation Schedule*	5	5	5
Cost of Equity	7.2%	7.2%	15.0%
Cost of Debt	4.3%	4.3%	6.0%
Equity %	50%	50%	50%
ITC	10%	0%	0%
CCR (real)	6.4%	7.1%	10.6%
CCR (nominal)	7.7%	8.5%	12.4%

* Accelerated depreciation for taxes over 5 years

We note that the cost of investing in Belize is approximately 45 to 49% higher before accounting for the ITC.

Finally, as will be shown in the next sections we expect that the solar in Belize should have a capacity factor of 22% to 23%.

Table 7-4 shows the total costs, the CCR, the Capacity Factor and the implied LCOE. We note that the USTDA project South Airport results in an LCOE much higher than those observed in Mexico just across the northern border, even using the US CCR or accounting for a larger size (Model 1). For BAPCOL our calculations show an LCOE of $85.3/MWh, which is almost the same as that indicated by the developer $85.0/MWh, which confirms the selection of the CCR. However, this cost could be optimistic as we note that using the US CCR and the multiplier implied by the BAPCOL Solar project, a 20 MW Solar Project (Model 2) would have a cost of $50/MWh which is expected for much larger projects in the 100 MW range.

We note that using a multiplier of 1.00 (Model 3) we would have costs somewhat between USTDA and BAPCOL and the cost for a larger project (Model 4) using lower cost of capital (US CCR) reproduces costs aligned with those observed in Mexico, which has a multiplier close to 1. Finally, as will be shown later in this report, using the same cost of equity of 15% and debt of 6% (as in the CCR factor below) and with our CapEx estimate for a RICE, we require a multiplier of 1, to reach the same Capacity Costs as those charged by BAPCOL for their project.

Table 7-4: LCOE for Comparable Projects

	South Airport	Model 1 (USTDA/DNVGL Base)	BAPCOL	Model 2 (BAPCOL Base)	Model 3 Unit Multiplier	Model 4 Unit Multiplier	
Capacity	7.26	20.00	8.00	20.00	20.00	100.00	
CapEx $/KW	2,077	1,939	1,237	1,141	1,398	1,120	
O&M $/kW-month	14.01	14.01	13.34	14.01	14.01	14.01	
Multiplier	N/A	1.39	N/A	0.82	1.00	1.00	
CCR	12.4%	12.4%	12.4%	12.4%	12.4%	12.4%	
CF	22%	23%	22%	23%	23%	23%	
LCOE	**140.9**	**126.3**	**85.3**	**77.2**	**93.0**	**75.9**	**-18%**
LCOE with US CCR	**90.0**	**80.8**	**55.4**	**50.4**	**60.3**	**49.6**	**-18%**
					-54%	-53%	**-47%**

In summary, based on the above we recommend using a multiplier of 1. The table below shows the base (2021 $) for Solar, Wind and the estimated the cost for a 20 MW / 4 hours Battery Energy Storage in Belize.

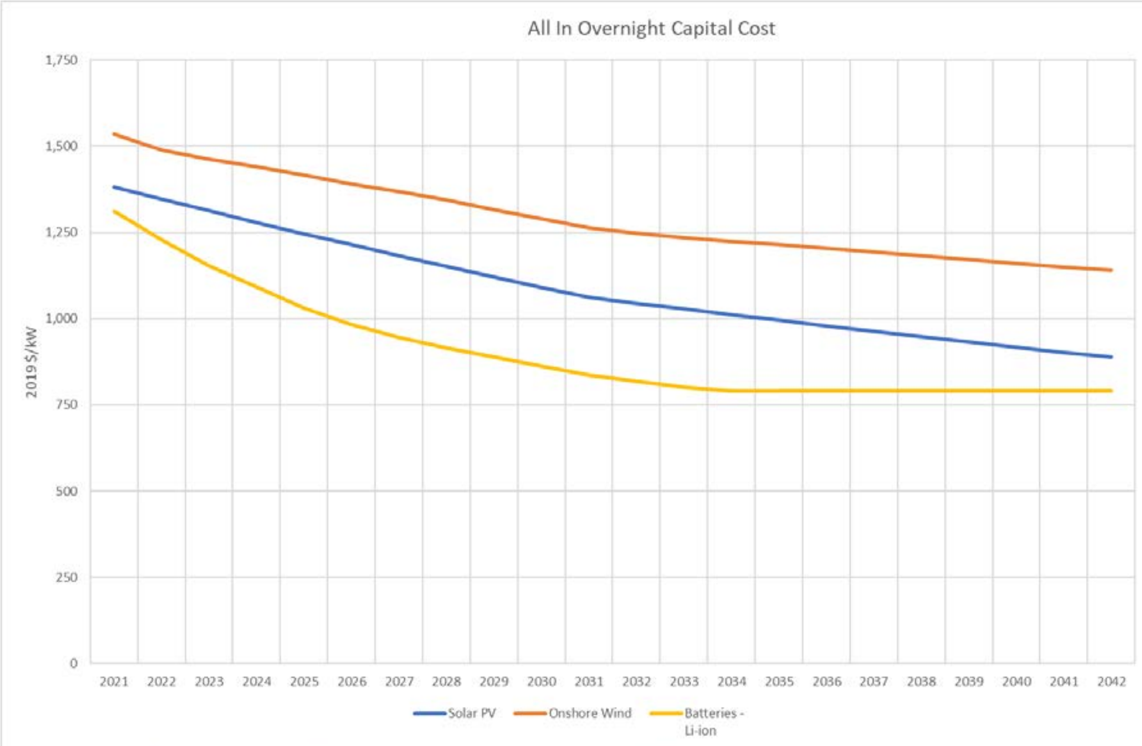
Table 7-5: CapEx for Solar, Wind and Solar

	Solar	Wind Onshore	Batteries
Capacity MW	20.00	20.00	20 & 4 hours
BEL Cost Multiplier	1.00	1.00	1.00
Model $/kW (2021 $)	**1,398.40**	**1,553.40**	**1,328.00**

Source: Candidate Projects_Multiplier_1_v2.xlsx workpaper

These capital costs are expected to decline over time as the technologies mature and the figure below shows the projected decline depending on the year the project is commissioned.

Figure 7-1: Solar, Wind and Storage (4 hours) Capital Costs



Source: Candidate Projects_Multiplier_1_v2.xlsx workpaper

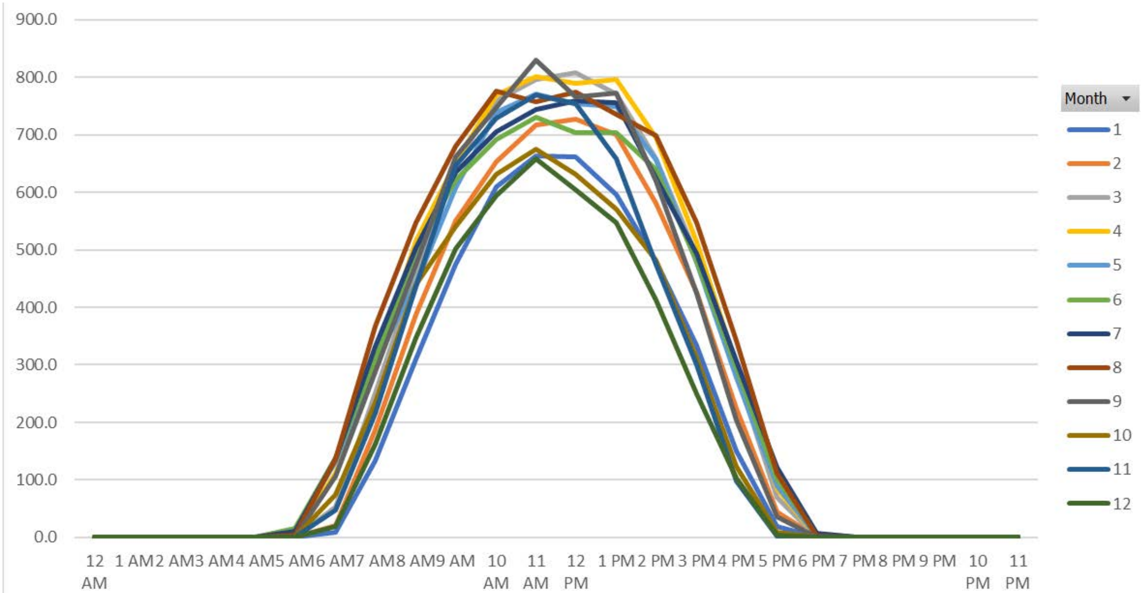
7.1.2 Production Profiles

To model the renewable generation, it is necessary to define the expected yearly energy production for each project considering the availability of the resource (wind speed and solar irradiation) and the technology for its conversion to electric energy (PV cells and invertors / wind turbines).

For Solar BEL provided measurements at the Airport (1732) site that were used to estimate the power output and capacity factor of a project at this site. As power density was provided kWh/m2 on a 10 min interval, instead of irradiance (normal / diffuse), a typical conversion factor was used to convert this information into a PV project energy output and the resulting CF (22.5%) was very close to the Airport II project, confirming the adequacy of the parameter.

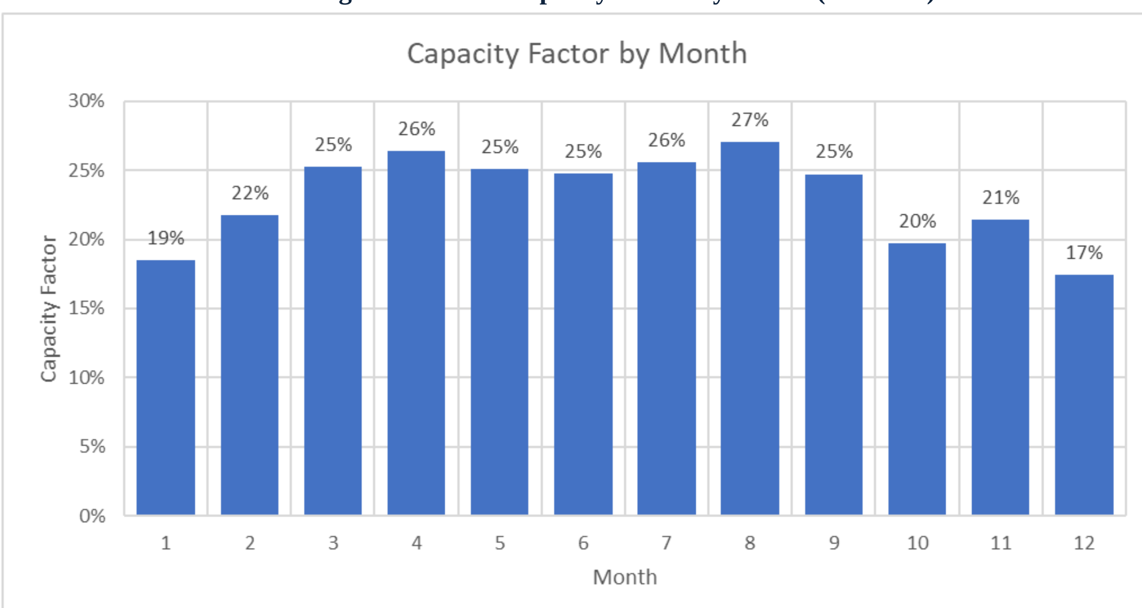
The figures below show the production profile for an average day by month for a reference 1,000kW project and the changes in the capacity factor by month. These results can be found in the workpaper Airport 1732 Irradiance.xlsx

Figure 7-2: Average Day Production by Month (1000 kW)



Source: workpaper Airport 1732 Irradiance.xlsx

Figure 7-3: Capacity Factor by Month (1000 kW)

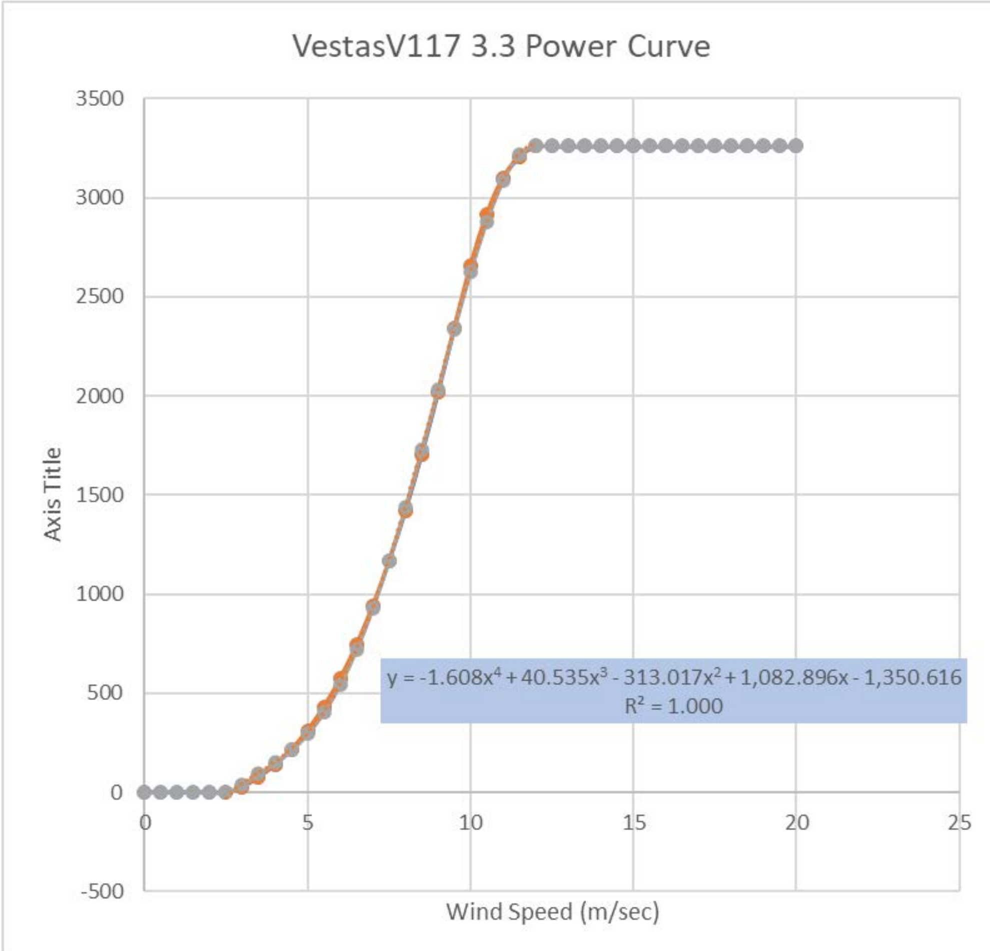


Source: workpaper Airport 1732 Irradiance.xlsx

For wind we received two profiles one in San Pedro representative of wind speed on offshore islands (called coastal wind) and one for Maskall representative of wind speed inland.

To convert wind speed into generation we considered the VestasV117 3.3 a 3.26 MW turbine and used its power curve for an air density of 1.175 kg/m3 which is in line with the expected value for Belize. The figure below shows the power curve for this turbine.

Figure 7-4: Wind Turbine Power Curve.

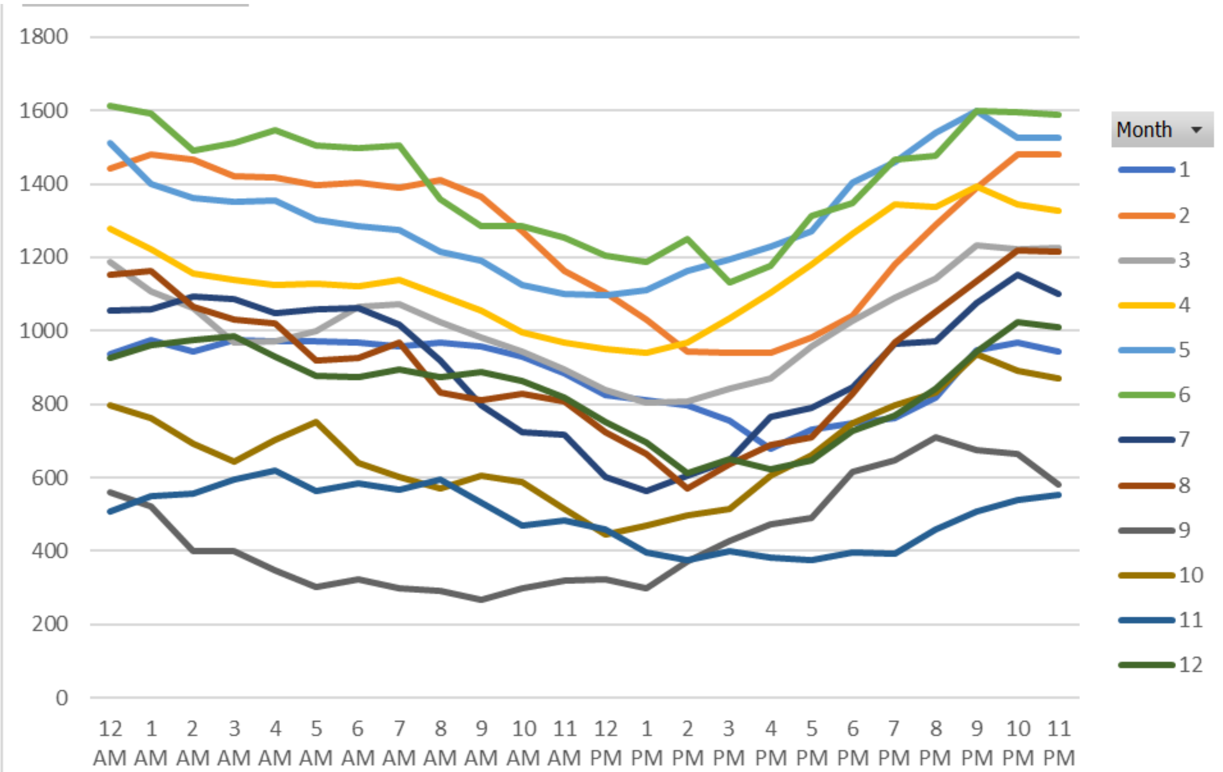


Source: Vestas and see workpaper San Pedro 1758-Wind Speed.xlsx

Finally, to convert the gross output of the wind turbine a reduction factor needs to be considered that takes into account local wind shading effects and losses in the collector system. A factor on 15% reduction was conservatively selected.

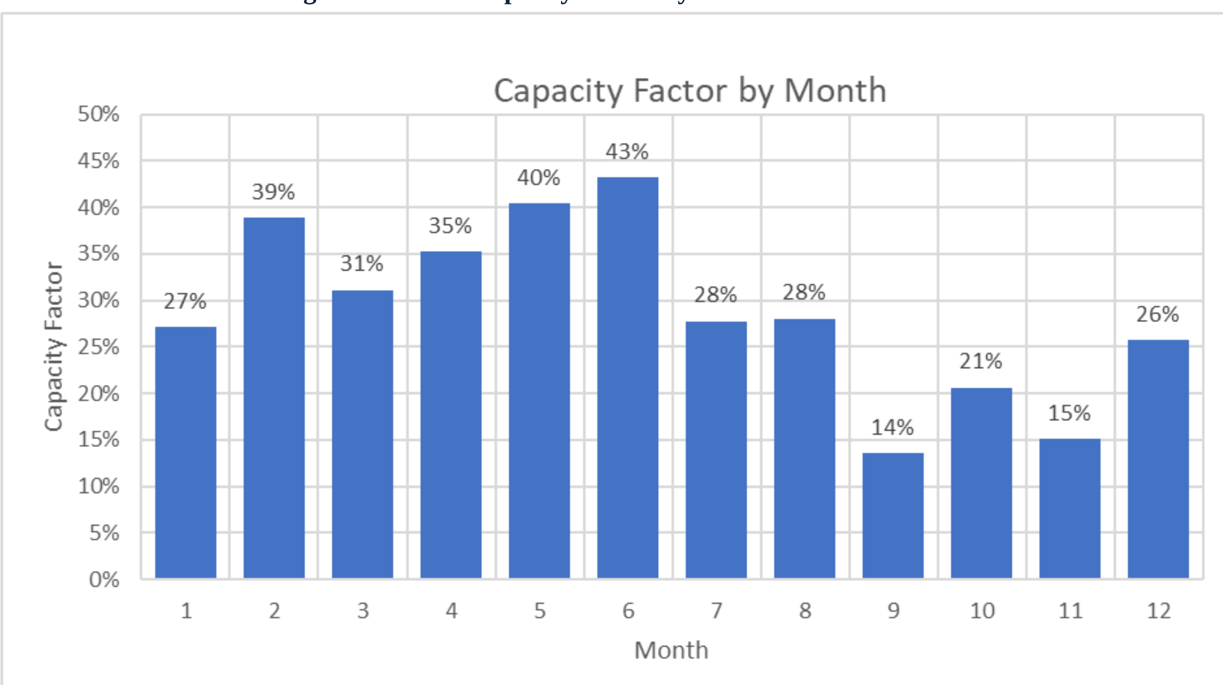
Using the above and the measured wind speed at San Pedro (coastal wind) an average capacity factor of 29.4% was determined and the figures below show the average day production by month and the capacity factor. We observe that the wind production is somewhat complementary with that of the solar. See workpaper San Pedro 1728 Wind Speed.xlsx for details.

Figure 7-5: Average Day Production by Month San Pedro Wind



Source: workpaper San Pedro 1728 Wind Speed.xlsx

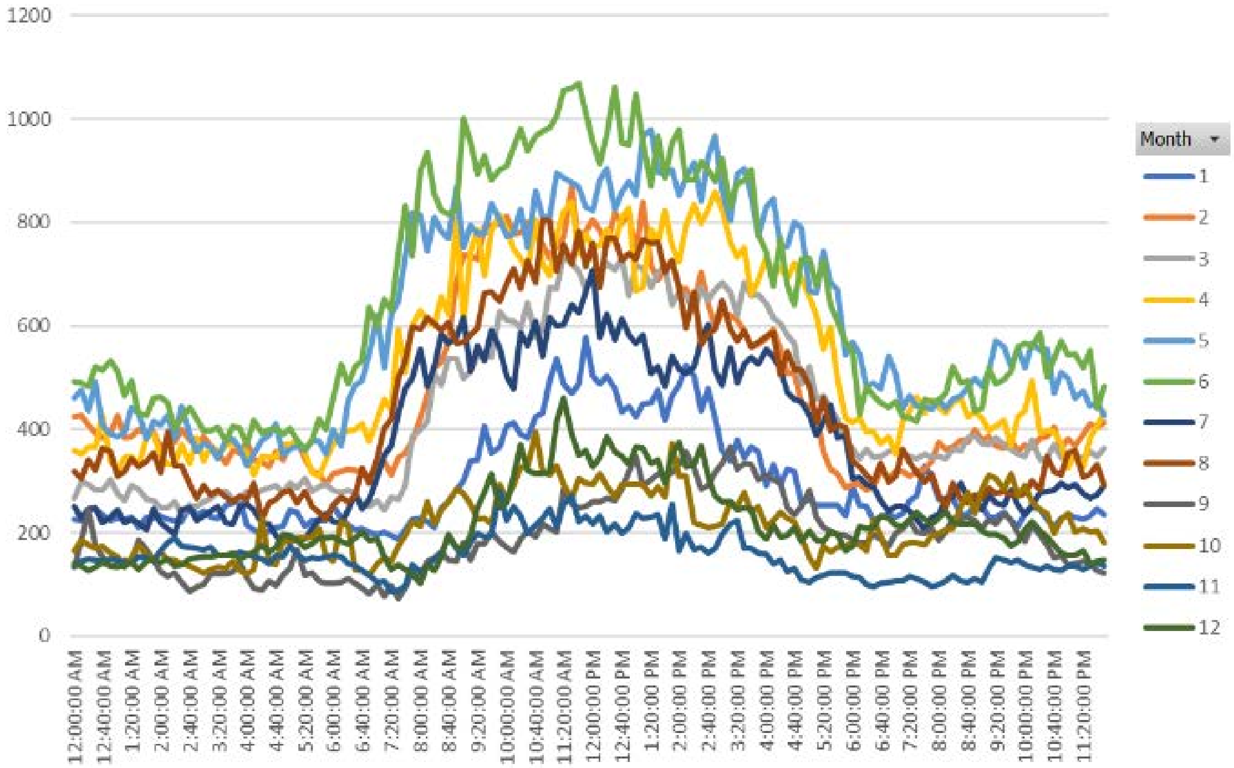
Figure 7-6: Capacity Factor by Month San Pedro Wind



Source: workpaper San Pedro 1728 Wind Speed.xlsx

This calculation was repeated for Maskall, and a much lower capacity factor was identified of 14% or less and as shown below there is not good complementary with solar.

Figure 7-7: Average Day Production by Month Maskall Wind



Source: workpaper Maskall 1754_wind.xlsx

7.1.3 LCOE & PPA Costs

The Levelized Cost of Energy (LCOE) can be used to screen resources and identify those that are likely to be selected by Aurora as part of the capacity expansion plan for Belize. Also, this LCOE is a good proxy for the expected cost that BEL will incur when contracting the selected resources.

Using the capital costs, O&M cost, the expected capacity factors and the CCR factors the LCOE of solar photovoltaic (PV), land-based wind for coastal locations (based on San Pedro); LBW-C and land-based wind inland (LBW-I) can be determined.

The CCR used in the capacity expansion plan is summarized by technology in the table below that reflects the final assumptions made with respect of the cost of debt and equity as well as the debt-to-equity structure. In this table for completeness, we provide the CCR for thermal generation and for the Mexico Wind that is presented later in this report.

Table 7-6: Final Funding Assumptions and Capital Cost Recovery Factors used.

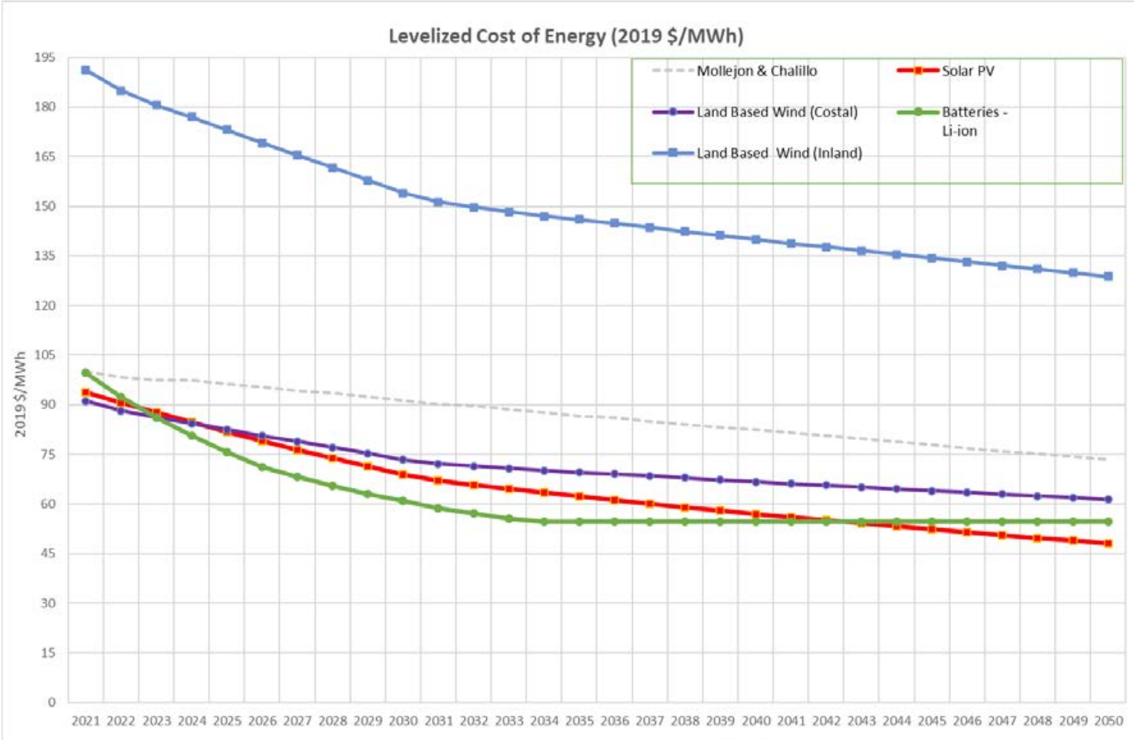
Technology	Thermal	Solar / Wind	Storage	Mexico Wind
Book Life/Useful Life	30	20	20	20
Depreciation Schedule	15	5	7	5
Cost of Equity	15%	15%	15%	13.9%
Cost of Debt	7.2%	7.2%	7.2%	7.2%
Equity %	40%	40%	40%	40%
Debt %	60%	60%	60%	60%
CCR (real)	9.4%	10.2%	10.3%	10.2%
CCR (nominal)	11.5%	11.9%	12.1%	11.9%

A referential LCOE for Battery Energy Storage System (Storage) can also be determined. In this case for the LCOE calculation an expected arbitrage benefit is subtracted to the carrying costs. This benefit is assessed by the difference between the marginal cost of energy when the Storage is discharging and when it is charging. This is modeled as $40/MWh representative of for example as the cost of HFO burned at a RICE (e.g., BAPCOL) $102/MWh being displaced by the Storage during peak hours using energy that was used to charge the Storage at a cost of $65/MWh (e.g., Mexico at $55/MWh after 15% round trip Storage losses). The capacity factor is estimated considering that the Storage cycles once every day from zero to full charge and back to zero (16.7% for a 4-hour battery).

The result of this analysis is shown in the figure below where we observe that the LBW-C, PV, and Storage are likely to be economic with costs below those of Mollejon and Chalillo (used as the reference for PPA analysis) and that a project with the profile at Maskall (LBW-I) is not likely to be economic and is screened out.

Note that if Storage is developed by BEL a different capital recovery structure would apply as the CCR assumes a uniform recovery (mortgage style) for the life of the asset (i.e., levelized PPA prices), while regulated assets receive a return on the undepreciated portion which declines overtime. However, this difference has a minor impact on the selection of the least cost capacity expansion plan, and it is the way Aurora expects the information to be entered. Later in this report when we assess the Cost of Delivery impacts, we take this difference into account (see Section 16).

Figure 7-8: Levelized Cost of Energy Solar, Land Based Wind (Coastal and Inland) and Battery Energy Storage



Source: Candidate Projects_Multiplier_1_v2.xlsx workpaper

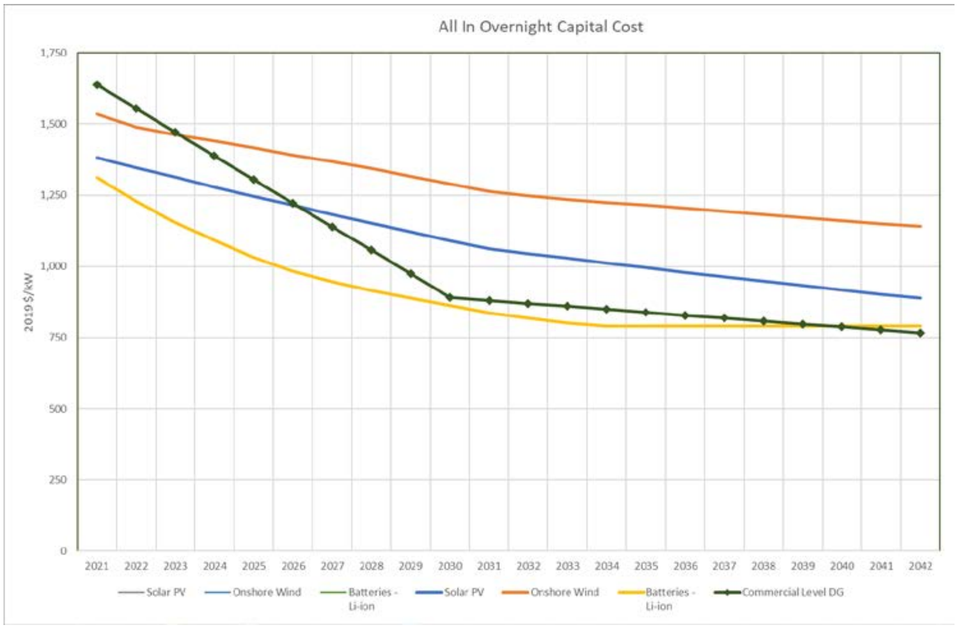
7.2 Distributed Generation

7.2.1 Distributed Generation as a resource

Distributed generation and in particular that associated with commercial customers installations is projected to decline significantly in costs making it a competitive alternative as it is at the load thus has a beneficial impact in transmission and distribution losses and if paired with storage could differ investments. The figure below shows NREL's projection for Commercial Level PV with a "moderate" decline in costs[13]. As it can be observed the costs are expected to become similar to those of utility scale over time.

[13] NREL also provides an Advanced forecast that declines more rapidly and a conservative with very little decline.

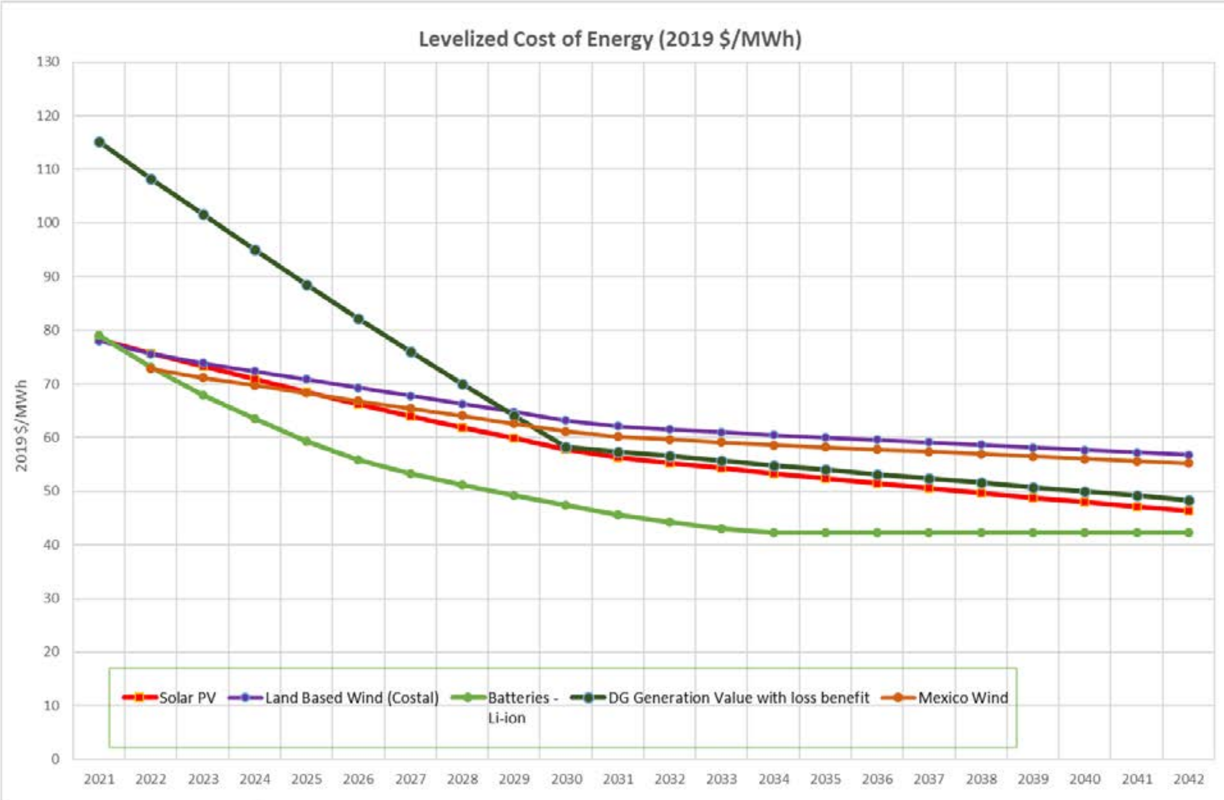
Figure 7-9: Distributed PV Capital costs and comparison with Utility Scale.



Source: NREL ATB 2021 and Candidate Projects_Multiplier_1_v2.xlsx workpaper

The distributed PV has, and it is expected to continue having lower capacity factors (CF) than utility scale facilities that can have tracking and are located in favorable areas. To estimate the LCOE of distributed generation we considered the NREL's Class 4 that has CF in the order of 16% and in line with favorable climates like Belize. Additionally, we considered the fixed O&M of $18/kW-year (2019$) declining over time and the same capital cost recovery (CCR) factor as for utility PV. This last consideration was made under the assumption that a developer would be able to finance in similar terms and that there is 10.5% in avoided technical losses savings, i.e., 10.5% more energy would have to be produced at the utility level for the same energy to be delivered to the load. The figure below shows the distributed generation LCOE including the losses benefits.

Figure 7-10: Distributed PV LCOE and comparison with Utility Scale.



Source: Candidate Projects_Multiplier_1_v2.xlsx workpaper

As can be observed the distributed level DG, from a supply point of view, is not currently competitive with other forms of renewable energy, but overtime, by 2031, with the reduction in CapEx and gains in capacity factors it is expected to become competitive with utility scale resources when losses are taken into consideration.

7.2.2 Distributed Generation from a customer's perspective.

Customers when deciding to install PV for self-supply should consider the cost of the service received from BEL versus the cost of installing these resources. Thus, the design and values of the BEL rates are central to this decision making. The main elements to take into consideration are:

a) **Demand Component of the rate:** this cost is not totally avoidable with solar DG as it will be based on the peak measured demand, and it may just be displaced to later in the day or occur on a cloudy day. Storage can mitigate this, and it is evaluated later in this report. Ideally should reflect the investments in the power system to be available to supply the customer's demand.

b) **Energy Component of the rate:** this cost is completely avoidable and represents the reduction in energy purchased from BEL

c) **Feed In Tariff:** this is the payment that the customer will receive for the energy injected to the grid when it exceeds its consumption. It should reflect the marginal cost of the energy at the time of injection.

d) **Fixed Costs:** reflects the administrative cost of keeping the customer active including measurements and billing.

The customers that are most likely to self-supply are the Commercial 2 customers, given their consumption, levels and rates. This can be observed in the table below that shows the current rates for these customers and compares it with the Industrial customers. We note that there is no Demand Component and the average all in rate is $235/kWh, 54% higher than Industrial.

I this table, a proposed rate that addresses some of the issues with the Commercial rate by adding a Demand Component is also shown. This second rate would address some of the undue incentives for these customers to self-supply and use BEL system as a backup without fully paying for this service, but not all.

Table 7-7: Belize Rates in US$

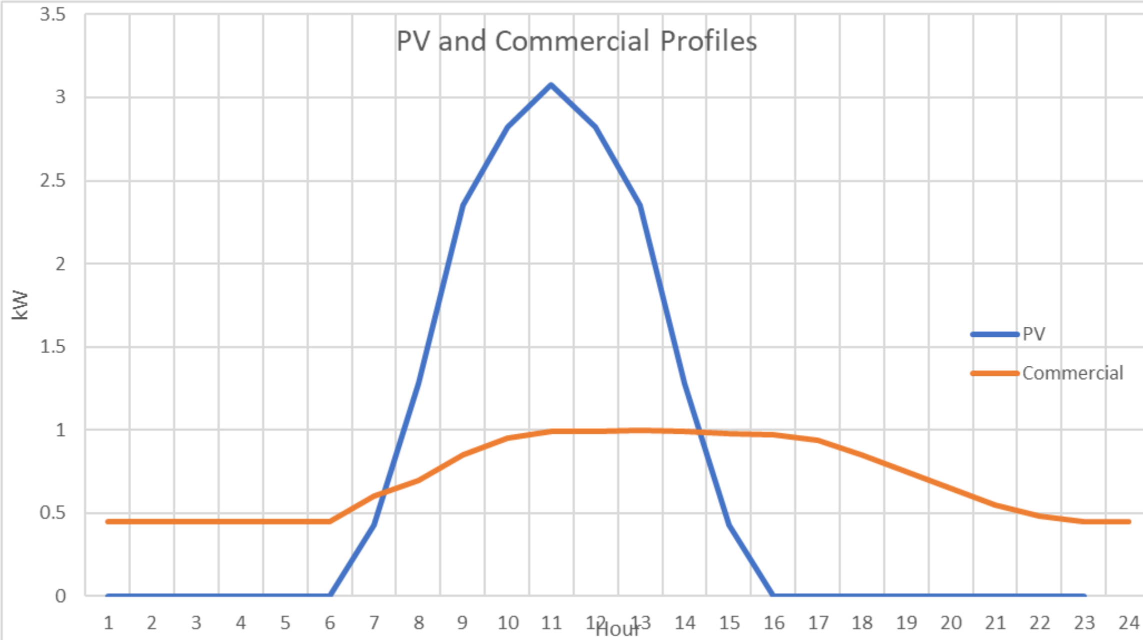
	Energy US$ / kWh	Demand US$/kVA-month	Fixed US$/month	All In @ 70% LF $/kWh
Commercial 2 Current	$0.190	$0.000	$75.000	$ 0.235
Industrial Current	$0.130	$11.500	$125.000	$ 0.153
Commercial 2 Proposed	$0.143	$42.515	$0.000	$ 0.226
Industrial Proposed	$0.138	$42.515	$0.000	$ 0.221

Exchange rate of 2 BZ$ per US$ assumed

Currently BEL is offering a feed-in rate estimated at US$ 130/kWh for the excess energy that the customers produce beyond their self-consumption and inject back the BEL's system. This feed-in rate is possibly above the marginal cost of production even after including the effect of avoided losses.

For the assessment of the impact of the cost that the customers will incur when injecting energy during the day and receive the feed-in rate to consume later at night and pay the BEL rate (the energy deferral costs), we considered two typical profiles, one for PV (with a 16% capacity factor) and one for a Commercial 2 customer with a 70% capacity factor. These profiles are shown below for 1 kW of demand at 70% load factor and the equivalent PV that would produce 100% of the energy consumed, which is injected to the grid during daytime.

Figure 7-11: PV and Commercial profiles to produce/consume the same energy equivalent to 70% Load Factor for 1kW peak demand.



Source: DG_Forecast_V1.xlsx

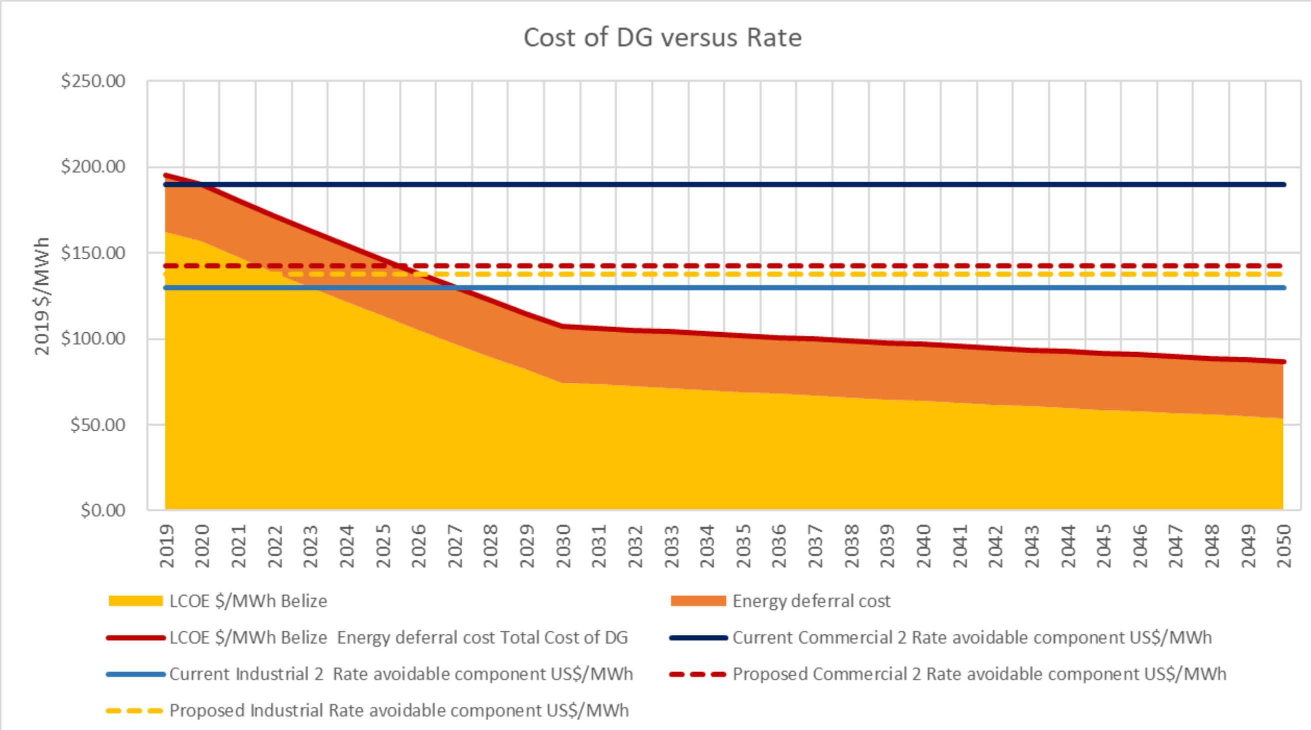
Considering these effects, Figure 7-12 shows the total cost that a customer would face (including the deferral cost) for self-supply and compares it with the rates that they would be facing when purchasing from BEL, the avoidable rates, largely the energy costs[14]. We observe that it is expected that there will be important and increasing incentives for the commercial customers and to a lesser extent the industrial customers to self-supply. I this figure we also show the impact of the proposed rates presented above and while we see that the "avoidable" component while lower, there will be still incentives for the Commercial 2 but starting later in time.

Based on this for modeling purposes, we will assume that over time 50% of the current Commercial 2 customers will switch to self -supply and the speed of conversion will increase as the savings become larger (see Figure 7-13). Customers are assumed to self-supply 100% of its load, injecting to BEL during the day and extracting at night. The figure also shows the savings with the proposed rate and in this case the savings achieved by the conversion to self-supply occur later, by 2026.

The 50 % of current Commercial 2 assumption above is conservative as it is possible that more customers will elect to self-supply, given the expected rates and the PV costs. However, for self-supply the commercial customer will require to make an investment or enter into a long-term obligation with a developer and if we overestimate the customers moving to self-supply, the long-term plan may miss in identifying the utility scale resources that BEL will require to supply the load.

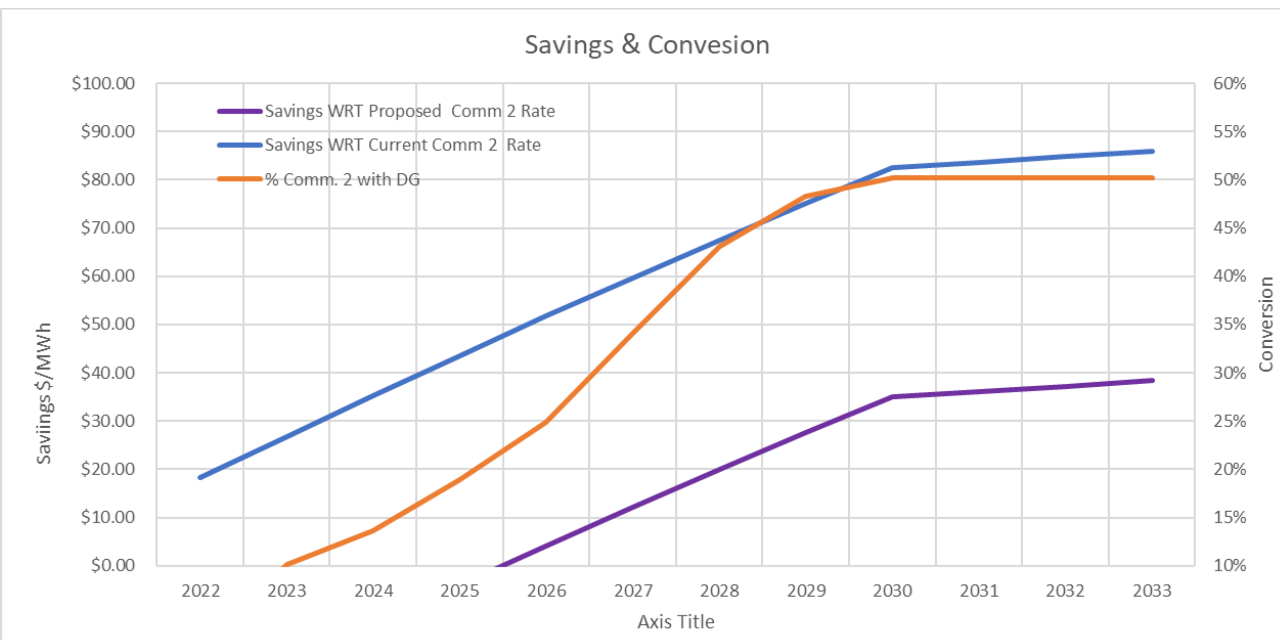
[14] The avoidable rate is assumed to be limited to the energy component and customers will be fully responsible for the Service Charge and the Demand Charge and the demand is just shifted to the time when PV is not producing (e.g., after 5 PM). In as much as they can also avoid some percentage of the demand charge the incentive will be greater

Figure 7-12: Competitiveness of Self-Supply vs. Belize Rates.



Source: DG_Forecast_V1.xlsx

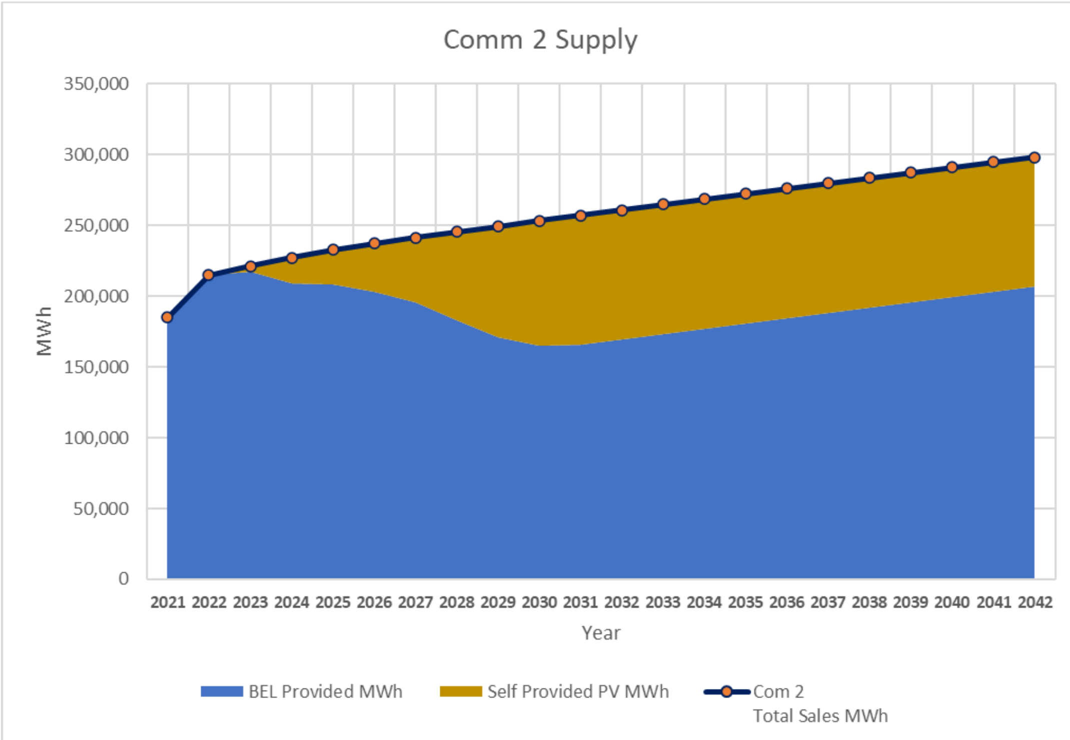
Figure 7-13: Percentage of Current Commercial 2 Customers with self-supply and savings achieved with the conversion



Source: DG_Forecast_V5.2.xlsx

The figure below shows the Customer 2 consumption overtime with the 50% of the currently existing Commercial 2 customers moving to PV self-supply. As can be observed this implies given the projected load growth, that about 31% of these customers demand by 2042 will be self-supplied or and 10% of the total BEL demand.

Figure 7-14: Commercial 2 customers supply mix.



Source: DG_Forecast_V1.xlsx

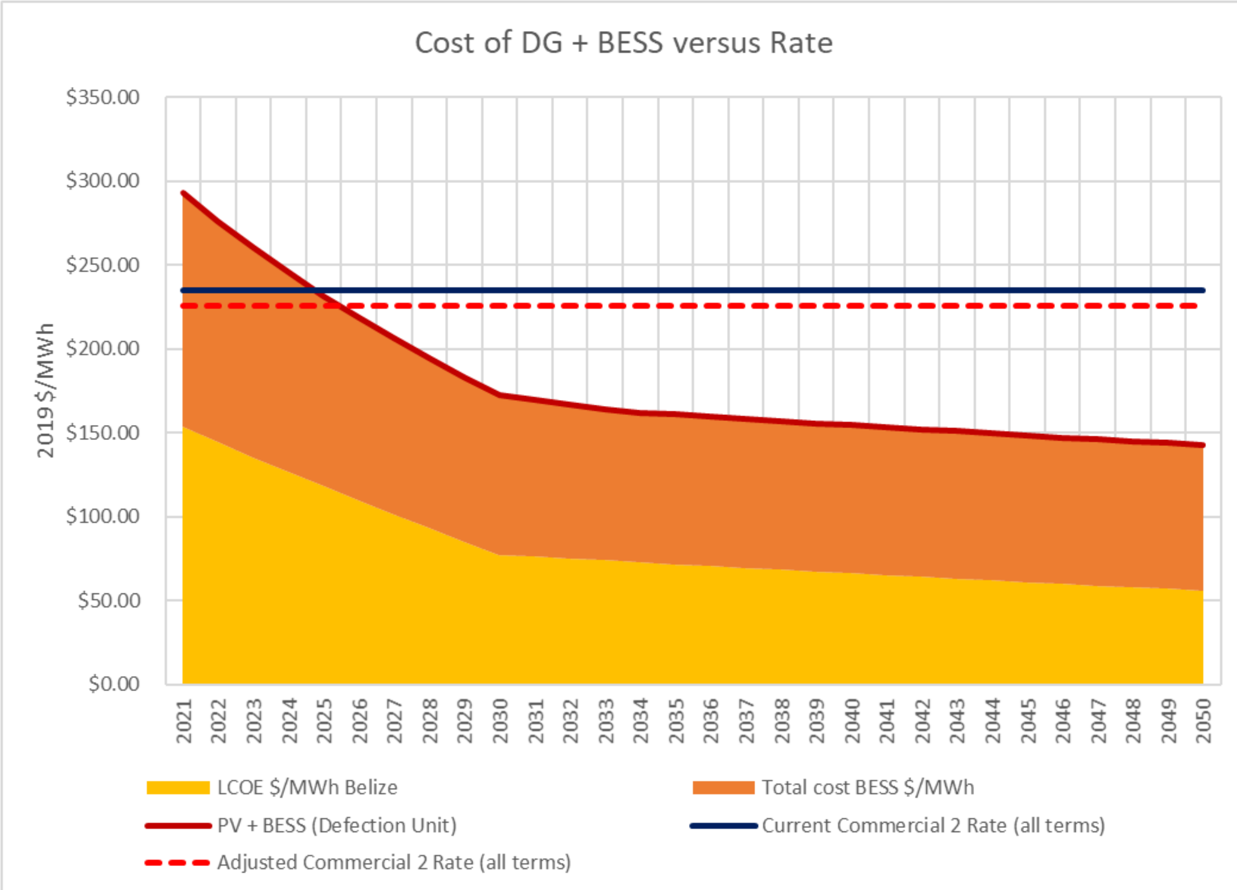
In the prior comparison we only considered the energy component of the rate, as with PV there would likely remain a demand charge as there is demand after the sun sets and the sun is not always shining.

However, with storage, the demand charge can also be avoided, and for this we assessed the benefits that the customer would realize by adding storage.

The figure below shows the result of this assessment, where to the cost of the PV plus a storage sized to move the surplus energy from day to night is compared with the BEL rates including the demand component (spread over the energy with a CF to 70%).

We see that there still will be incentives to conversion even with revised rates.

Figure 7-15: Competitiveness of Self-Supply with Storage vs. Belize Rates.



7.2.3 Modeling of Distributed Generation.

For the distributed generation (PV) modeling in the load flow and Aurora capacity expansion, Siemens used the information provided by BEL on the location for each of the Commercial 2 assumed to self-supply and identified the load centers and substations where this distributed PV will be located. This is shown in the tables below

Table 7-8: PV Installed by Load Center MW

Load Center	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	Total
Belmopan	-	1.79	-	2.01	0.69	1.11	1.30	0.73	0.20	-	7.84
Belize City	-	-	2.27	1.63	2.14	2.98	2.46	1.55	0.41	-	13.44
Caye Caulker	-	-	-	-	-	0.57	0.30	-	-	-	0.87
Corozal	-	-	-	0.93	-	-	0.34	0.22	0.20	-	1.69
Dangriga	-	-	-	-	0.73	0.88	1.14	0.52	-	-	3.26
Independence	-	-	-	1.83	-	1.42	1.42	0.23	-	-	4.90
Ladyville	2.64	8.74	1.13	0.86	1.35	2.00	1.05	0.52	-	-	18.30
Orange Walk	-	-	-	-	1.48	0.47	1.38	0.25	0.62	-	4.20
Punta Gorda	-	-	-	-	-	-	-	0.47	-	-	0.47
San Ignacio	-	-	-	-	-	0.97	-	-	0.42	-	1.39
San Pedro	-	-	1.12	-	1.34	1.52	2.52	2.24	0.61	-	9.36

Total	**2.64**	**10.53**	**4.52**	**7.26**	**7.73**	**11.93**	**11.91**	**6.73**	**2.47**	**0.00**	**65.71**

Table 7-9: PV Installed by Substation

Substation	2023	2024	2025	2026	2027	2028	2029	2030	2031	Total
Independence	-	-	-	1.83	-	1.42	1.42	0.23	-	4.90
Belmopan	-	1.79	-	2.01	0.69	1.11	1.30	0.73	0.20	7.84
Corozal	-	-	-	0.93	-	-	0.34	0.22	0.20	1.69
Ladyville	2.64	8.74	1.13	0.86	1.35	1.16	1.05	0.52	-	17.46
Belize City	-	-	2.27	1.63	2.14	2.98	2.46	1.55	0.41	13.44
Orange Walk	-	-	-	-	1.48	0.47	1.38	0.25	0.62	4.20
Dangriga	-	-	-	-	0.73	0.41	1.14	0.52	-	2.79
San Pedro	-	-	1.12	-	1.34	1.52	2.52	2.24	0.61	9.36
Cay Caulker	-	-	-	-	-	0.57	0.30	-	-	0.87
San Ignacio	-	-	-	-	-	0.97	-	-	0.42	1.39
Mullings River	-	-	-	-	-	0.47	-	-	-	0.47
West	-	-	-	-	-	0.84	-	-	-	0.84
Punta Gorda	-	-	-	-	-	-	-	0.47	-	0.47
	2.64	**10.53**	**4.52**	**7.26**	**7.73**	**11.93**	**11.91**	**6.73**	**2.47**	**65.71**

7.3 LM2500 upgrade and new RICE Thermal Generation

New thermal generation is expected to be limited to RICE and the LM2500 MW upgrade including conversion to LPG or Natural. This section provides our projected costs for these technologies.

The review of the BAPCOL thermal generation project allowed confirming that a Belize Regional multiplier of 1 was adequate for the conversion of RICE capital cost. Using a cost of equity of 15%, cost of debt of 7.2%, Debt / Equity 60%/40% structure and 30-years book life (15 years tax depreciation) the CCR factor for RICE generation is 11.5 % (also see Table 7-6) and as shown below this results in a Fixed Cost in $/kW-month very similar to BAPCOL considering Siemens projected capital costs in $/kW and a multiplier of 1.

Table 7-10: Determination of Multiplier for RICE

US CapEx $/KW 2021 US$	1,363
BEL Cost Multiplier	1.00
Belize CapEx $/KW 2021 US$	1,363
CCR	11.5%
Capacity Costs CapEx annuity $/kW-month	13.04
BAPCOL Capacity Costs 2021	13.18
Difference	-1.06%

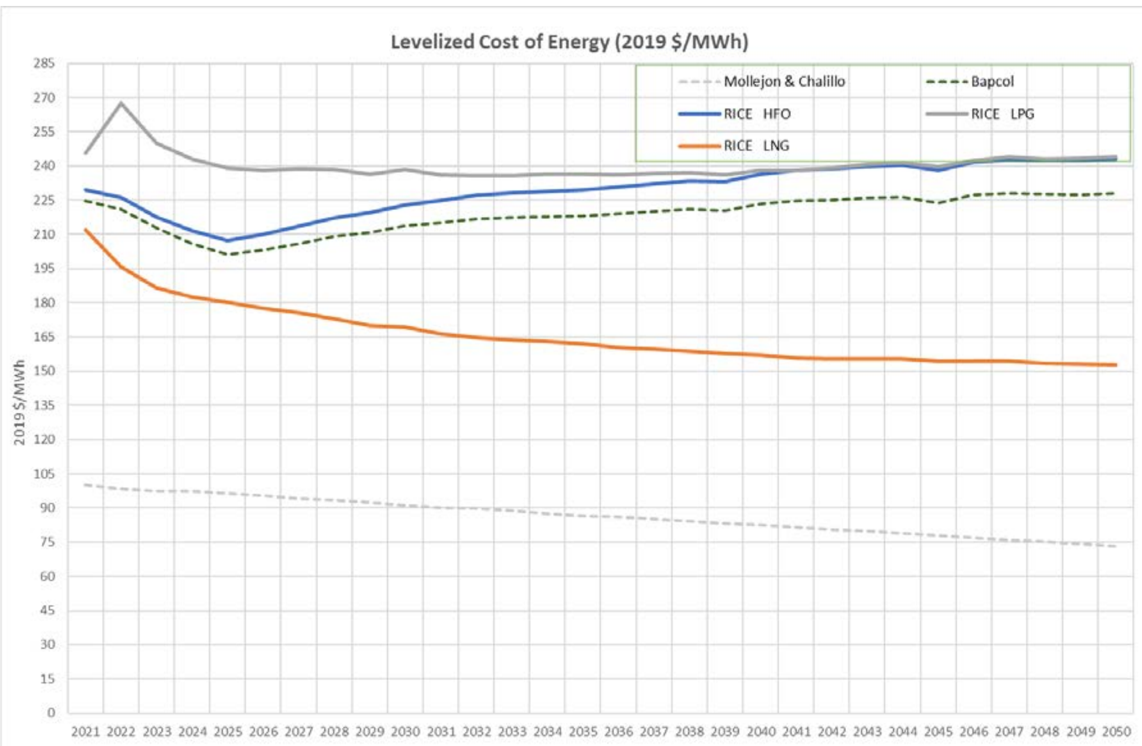
The determination of the LCOE for the BAPCOL project is a function of the capacity cost presented in this document (section 6.7), the fuel costs and an expected capacity factor (15%). In the workpaper Candiate_Projects_Multiplier_1_V2.xlsx this LCOE is presented (Resources Tab).

Similarly, in this workpaper the assumed costs for the RICE burning HFO, LPG and LNG (Containerized) are provided and shown in the figure below. We note that these resources have an LCOE substantially higher than energy resources like Mollejon / Chalillo as they have relatively low CF and high variable cost. However, we note that the LNG option has the lowest costs.

Table 7-11: RICE modeling parameters

Technology	RICE HFO	RICE LNG	RICE LPG
Fuel	HFO	LNG (Containers)	LPG
Construction Time (Yrs.)	2	2	2
Size (MW)	22.5	22.5	23
Baseload Heat Rate, HHV (Btu/kWh)	7,787	8,016	8,016
VOM (2019$/MWh)	5.20	5.20	5.20
FOM (2019$/kW-yr.)	4.41	4.41	4.41
Capacity Factor	30%	30%	30%
Capex $/kW (2019)	**1,291**	**1,291**	**1,291**

Figure 7-16: LCOE for BAPCOL and Generic RICE generation.



Source: Candiate_Projects_Multiplier_1_V5.1.xlsx

7.3.1 LM2500 Conversion

BEL in communications with GE assessed the repowering of the LM2500 Combustion Turbine to approximately 30 MW and become dual fuel: diesel (LFO) and LNG (in containers) or Propane (LPG).

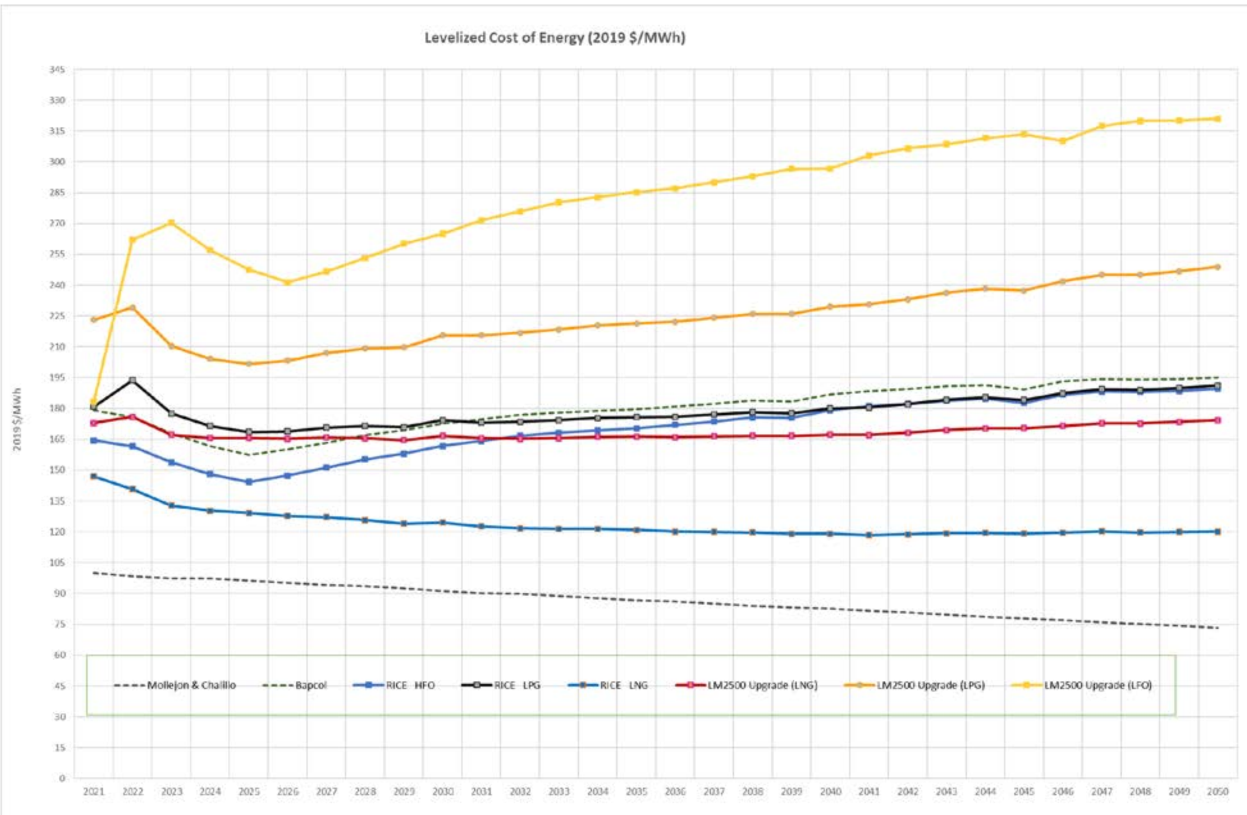
Table 7-12: LM2500 Conversion Parameters and Costs

	VOM (2019$/MWh)	FOM (2019$/kW-yr.)	Heat Rate HHV Btu/kWh	Capacity kW	Incr. kW	Incr. Cost $/kW
LM2500 Base	5.70	6.30	10,256	23,159	Base	
LM2500 Upgrade (LNG)	5.40	6.10	10,103	30,900	7,741	1,409
LM2500 Upgrade (LPG)	5.60	6.30	9,996	29,900	6,741	1,618
LM2500 Upgrade (LFO)	5.70	6.30	9,889	29,500	6,341	1,720

Source: Candiate_Projects_Multiplier_1_V2.xlsx

Based on the above, the same CCR Factors as for the RICE (11.5%) and a reference CF of 25%, the figure below shows the LCOE of this conversion and a comparison with the cost of RICE and BAPCOL that also provide peak service. We observe that the LNG conversion is the most competitive and it is competitive with RICE burning HFO, but it is more expensive with respect of the RICE burning LNG.

Figure 7-17: Levelized Cost of Energy



Source: Candiate_Projects_Multiplier_1_V5.1.xlsx

Diesel (LFO) is the costliest option and should be used only when other fuels are not available.

7.3.2 LM2500 Conversion to Cheng Cycle

The Aeroderivative turbines like the LM2500 have the option to be converted to a Cheng Cycle, which uses the heated exhaust gas from the turbine to make steam in a heat recovery steam generator (HRSG) that is then injected into the gas turbine's combustion chamber to increase power output and efficiency.

According to the information reviewed the following capacity and heat rate improvements could be theoretically achieved with the Cheng Cycle, with an investment of approximately US$ 1,329 per KW gained.

Table 7-13. Cheng Cycle Improvements and Capital Costs

LM2500PC	Capacity MW	Heat Rate (HHV) with Natural Gas, HHV, NG
Pre Cheng	19.1	10,730
Post Cheng	27.5	8,450
% Improvement	44.0%	21.2%
Capacity Increase, MW	8.4	
EPC Cost, 2019$/kW of Cap. Increase	953	
Overhead, installation, financing, etc.	30%	
Overnight Cost, 2019$/kW of Cap. increase	1,239	

Source: https://www.powermag.com/cheng-cycle-flirts-with-2-ppm-nox-and-co/

In addition to the above, there will be an increase on the O&M costs for the boiler and this is captured in the table below.

Table 7-14. Cheng Cycle O&M Costs

Base Variable O&M $/MWh	5.70
Incremental Boiler O&M Cost, $/MWh	4.20
Total, Variable O&M $/MWh	**9.90**
Fixed O&M $/kW-yr.	**6.30**

Based on the above and using the same CCR for thermal generation the graph below compares the LCOE of the LM2500 with the repowering to LNG presented above, with the same considering the Cheng Cycle and the RICE with LNG.

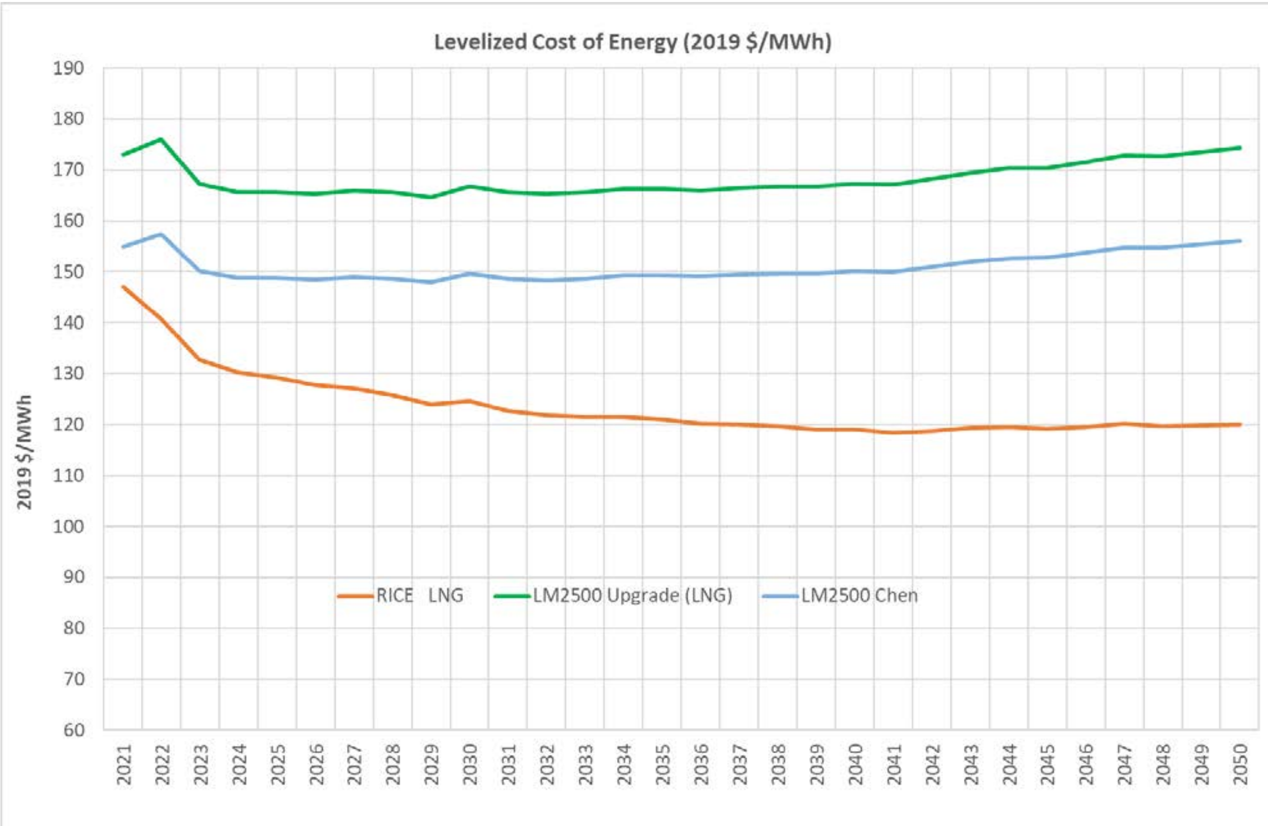
As can be observed the Cheng Cycle is in principle more cost-effective than the standard LM2500 upgrade, but not more effective than the RICE.

Moreover, the results above consider ideal conditions where the plant is operated at a levelized output as would be the case for industrial applications and there is supplemental use for the steam, that otherwise would need to be independently condensed and return to the HRSG.

These conditions are very different to the intended use of the LM2500 in Belize that is expected to cycle daily, dispatch close to its minimum when online and the steam would have to be condensed using chillers (dry cooling) which would add to the costs.

Based on these considerations we do not expect the Chen Cycle to be a competitive for the upgrade of the L2500 at Mile 8.

Figure 7-18: LM2500 (Cheng and Conventional) and RICE Levelized Cost of Energy



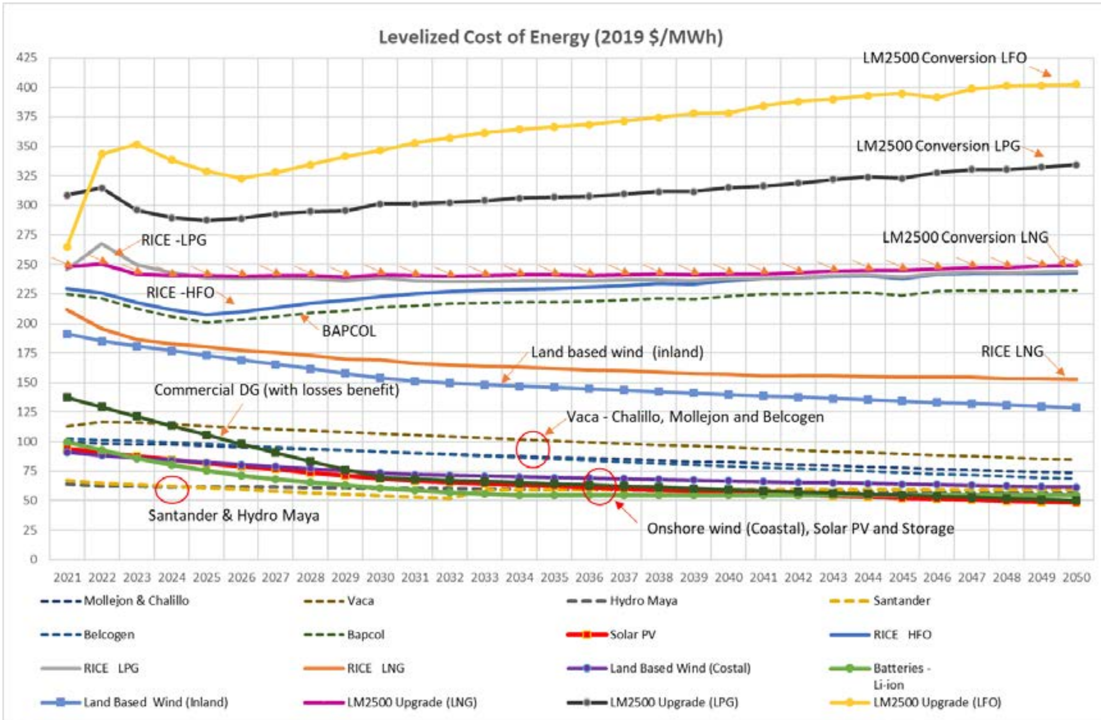
7.4 Summary of Resources Competitiveness

The figure below provides a summary of the LCOE of all resources discussed as well as the cost of the existing PPAs.

As can be observed the renewable resources, with the exception of inland wind, (Maskall) are expected to be the least cost source of electric energy and is under the costs of all existing PPA's, with the exception of Santander and Hydro Maya.

All existing and future thermal resources are expected to have much higher costs than the renewable and it is expected to provide peaking service only, with LNG in containers being the preferred fuel.

Figure 7-19: All Resources LCOE



8. International Interconnections

8.1 Mexico

8.1.1 Overview

BEL purchases from the Mexican Market economy energy on the 2nd day ahead. This energy is only committed on the day ahead market and there is no guarantee that at any time in the future beyond the second day that it will be available, as it does not have firm capacity associated with it. This energy also cannot be considered renewable.

The spot energy purchases above, however, can be made renewable if Renewable Energy Certificates (the RECs) are acquired in addition as discussed in this section.

With respect of the possibility of acquiring firm capacity and energy, an investigation of the regulation in Mexico made it evident that the existing interconnection with the Mexican market can only be used for spot market transactions and the only way to gain firm capacity and energy from a project located in Mexico would be via a dedicated line connecting BEL system directly to the project. This was the assumption for the Vientos del Caribe Project presented later in this section.

8.1.2 Contractual Conditions and RECs

BEL purchases from the Mexican Market economy energy on the 2nd day ahead with a markup from Calificados (15%) and a wheeling charge of approximately US$9.2/MWh.

This contract has a limit of 55 MW limit and was considered as the base case, but the benefits of BEL entering with Calificados or other parties for a larger value are assessed. Note that reportedly there were transformation limitations at Xul-Ha, but these are likely to be resolved with the Vientos del Caribe project discussed below. Moreover, any increase in the limit can be made interruptible, as BEL will have enough local capacity and the increase limit is just for economy.

With respect of the possibility of making the market purchases renewable, there is a market in Mexico for I-REC (International Renewable Energy Certificates) that are tied with a renewable source, which can be used to guarantee the clean nature of the energy purchased.

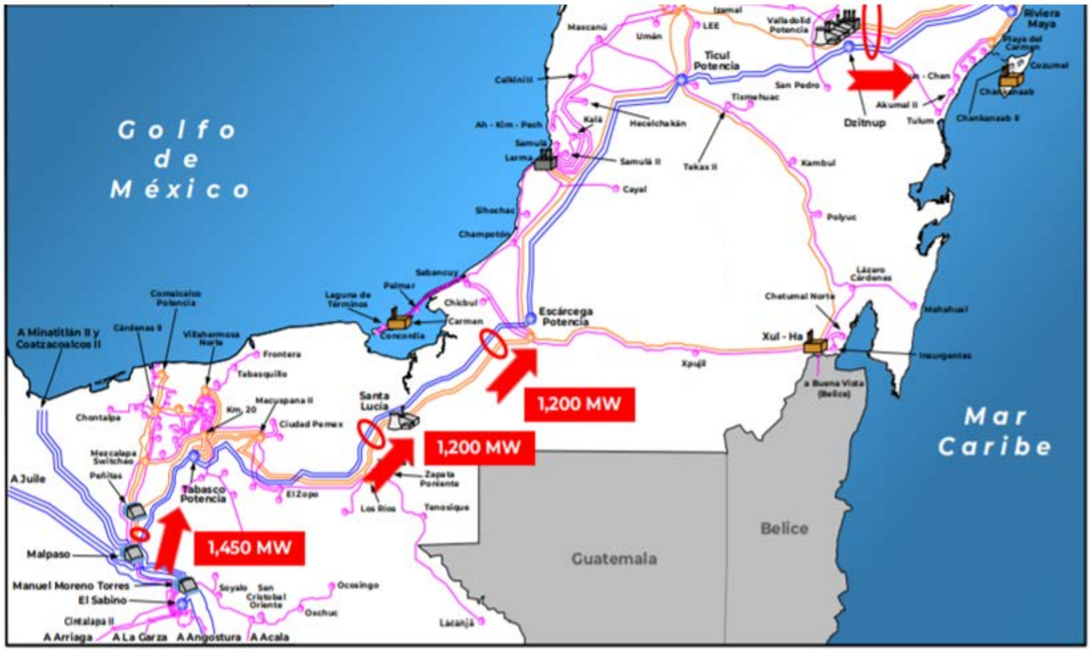
There are uncertainties with respect of this market in Mexico as the only binding by regulation is for the Clean Energy Certificates (CEL) and the attitudes towards private investments in renewable. However, it is expected that the renewable producers will converge to selling I-RECs / CELs at same prices.

In this study we assessed the use of RECs to make the Mexico Market Energy as counting towards the 75% renewable by 2030, with a conservative price of 2022 $ 15/MWh (CELs were traded at $10-14/MWh on the last auctions 2015, 2016 and 2017. However, given the uncertainties we preferred to use this tool in the longer term (2030 onwards) rather than short term.

8.1.3 Transmission limitations

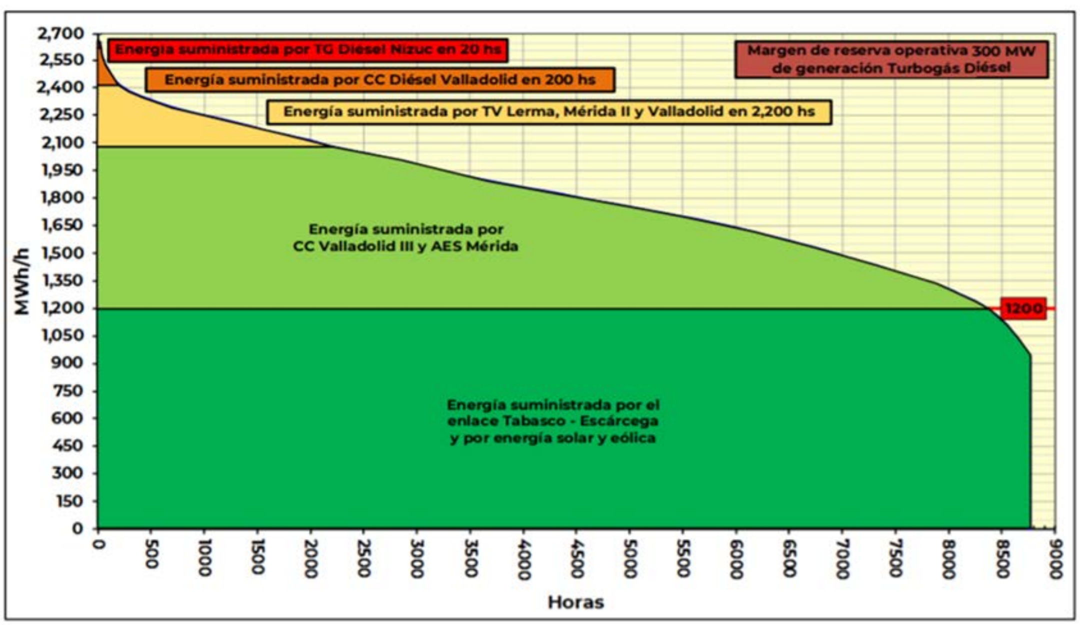
The market prices in the Peninsular area are expected to remain relatively high due to transmission limitations between the renewable rich Oriental region of CFE and the Peninsular region where Xul-Ha is located. The flowgate between these regions is limited to 1200 MW. See figure below.

Figure 8-1: Transmission limitations to the Peninsular Region



Two new CCGTs (Merida II & Valladolid III) are projected to enter in the short term (2024), but this is not enough to supply the projected load that is expected to grow between 5 to 8% and more costly thermal generation is required.

Figure 8-2: Load Duration Curve for the Peninsular Region 2025



8.1.4 Transmission Expansion Plans

According to CENACE, there are two options to increase the transfer capability to the area Peninsular one with a new HVDC line and a second with two new 400 kV lines. See figures below.

Figure 8-3: HVDC Option

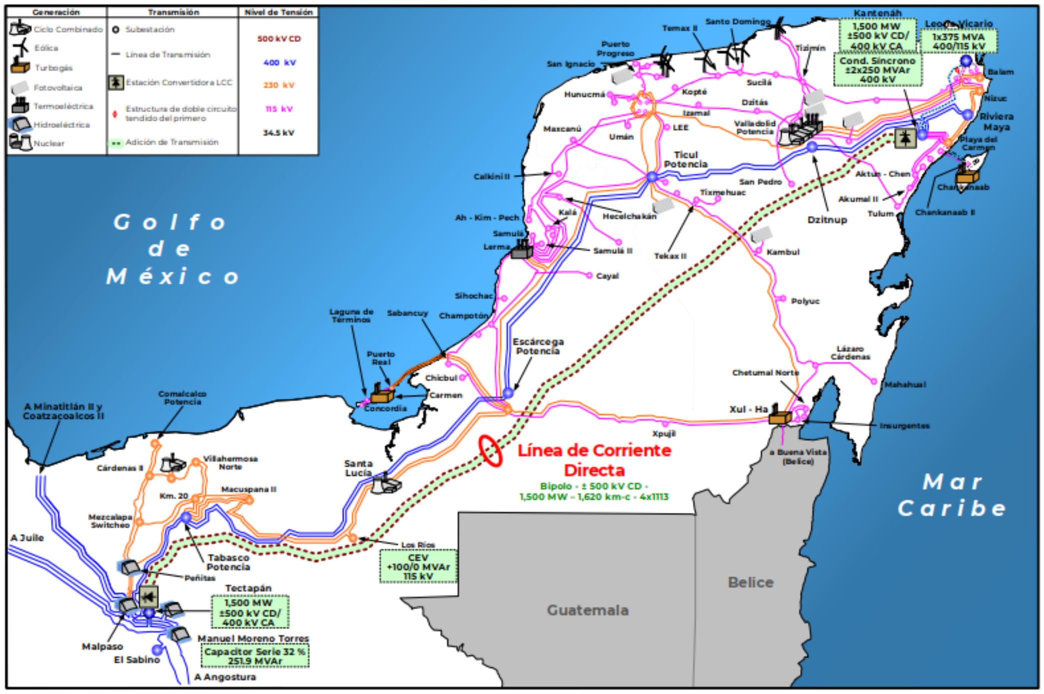
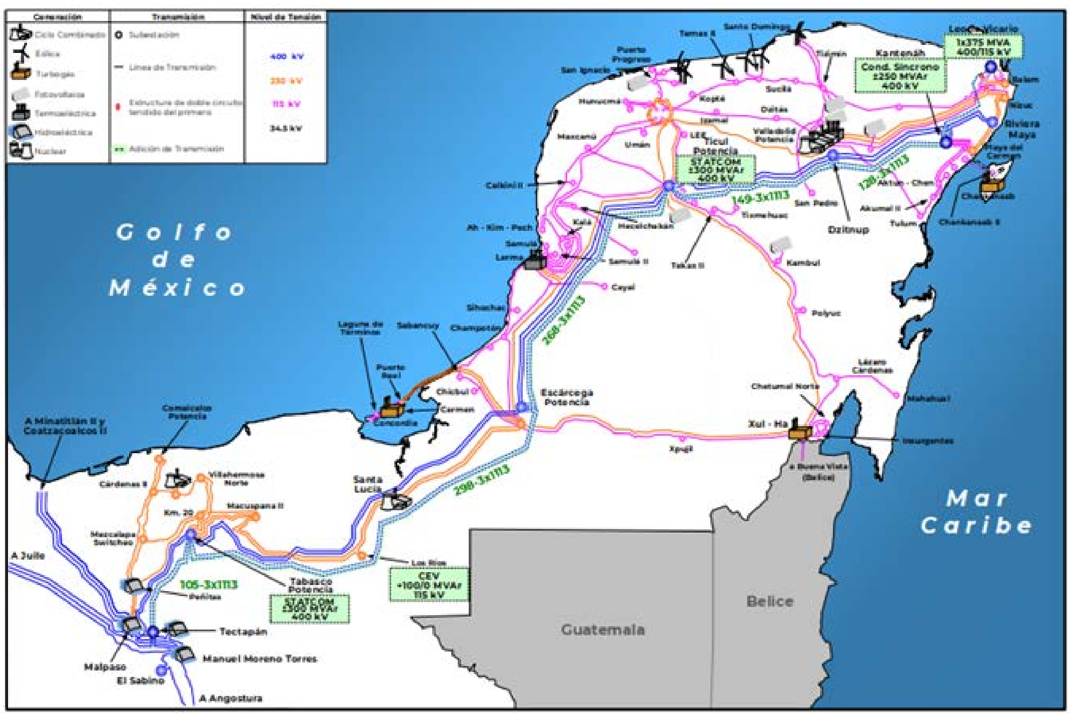


Figure 8-4: AC 400 kV Option



Either one of these options will increase the transfer limit Oriental Peninsular from 1,200 MW to approximately 2,300 MW or 1,100 MW net increase

- Option 1 HVDC limit: 2,302 MW
- Option 2 400 kV limit: 2,326 MW

This expansion is planned by 2025, but it is likely to be delayed and we are modeling it to be in service by 2030.

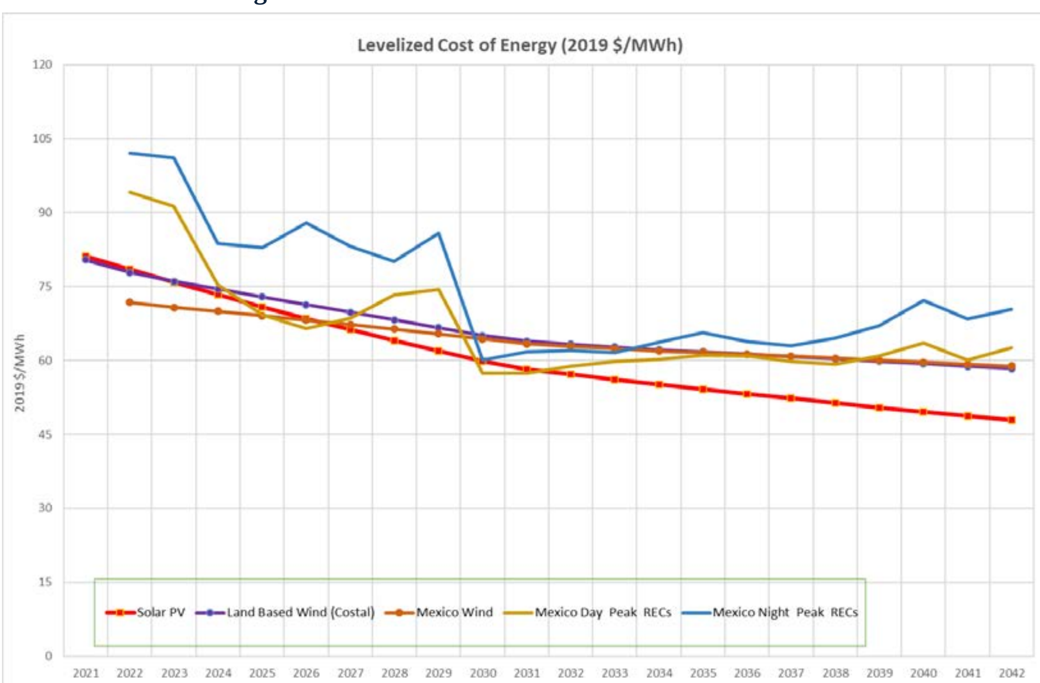
8.1.5 Impact of increased interconnection on prices.

Based on the transmission limitations above our models indicate that supply limitations at the peak are likely and cost will remain higher until the interconnection to Oriental is expanded.

When we add to the market costs, the cost of the RECs to make it comparable with installing renewable generation, we observe that (see figure below) when the transmission is expanded (2030) the Mexican market cost with RECs can be more economic than wind and solar, making it attractive. In this figure the blue trace is the prices during the night peak that can be to be compared with wind generation costs that is also available in this timeframe, and the copper trace are daytime prices that can be compared with solar.

Before 2030, and in particular 2025 to 2028, there are periods of low daytime energy prices, and this opens the opportunity to supply some of the daytime renewable energy from Mexico delaying the entry of solar to 2028 as Belize moves to the 75% by 2030.

Figure 8-5: Peninsular Prices VS Renewable LCOE.



8.1.6 Mexican Generation Imports (Vientos del Caribe)

As mentioned earlier for a project located in Mexico to provide firm capacity and energy directly to BEL there would have to be a direct interconnecting line. This limits the availability of candidate projects, but fortunately the Chetumal region just north of the border with Belize is rich in wind generation potential and a project located there can interconnect via a short line to BEL.

This is the case of the Vientos de Caribe project that was assessed in this study as a representative of this type of projects and offered as a candidate for the capacity expansion plan. The most important differences that makes this option attractive over the long term, versus building in Belize itself is that the Mexican project can be large as it can supply part of its generation to Mexico and segregate a few turbines to interconnect with Belize. Also, the cost of capital could be lower as the developer can supply either Mexico (if there are issues in Belize) or Belize if there are issues in Mexico.

The Vientos del Caribe project is expected to have 200 MW of wind generation and is currently developed a few miles north of the Belize border with Mexico. This project will interconnect to Xul-Ha.

There is the possibility of expanding the project to 250 to 260 MW and sell the additional power to BEL via a dedicated short line (approximately 5 miles). This line would start at the project and end just south of the border where it would connect to a simple switching substation where it would tie with the exiting 115 kV line Xul-Ha – Chan –Chen. Moreover, the line from the border to Xul-Ha has a position for a second circuit available that could be used to string the line from the project.

At this moment, the details of the project are unknown but based on Siemens models for the Mexican Peninsular Region we are currently modeling the project with the following assumptions.

- Mexico Regional Multiplier = 1
- Cost of Debt 7.2%, Cost of Equity 13.9%, Debt / Equity 60%/40% and 20 years economic life, a Mexico Capital Cost Recovery Factor (CCR) = 9.8% real / 11.5% nominal was determined
- Capital costs; large wind projects > 100 MW in 2019$ = 1,522 /kW
- O&M $ 43.8 /kW-year
- Added transmission cost of US$ 4.3 million for the independent line to Belize and switching substation.
- Wind Profile: Peninsular wind which results in a capacity factor of 30% and it is similar profile to Belize Coastal Wind.

8.1.7 Expansion of the interconnection with Mexico

A sensitivity case was assessed where the interconnection with Mexico was expanded doubling the transmission capacity.

A new 115 kV line Xul-Ha – Chan-Chen – Camalote (or Belmopan) was assessed with the route shown in the figure below.

This line was modeled in our capacity expansion plan as providing sightly over 200 MW of interconnection capacity (212 MW) and required the expansion of the Xul-Ha 230/115 kV transformer capacity (one new transformer).

The estimated cost of this expansion using BEL planning level unit costs for the 115 kV system in Belize, which are lower than the US costs[15] and our internal costs for 230 kV and 115 kV for the Mexican component, resulted in a total expected cost of 55 million as detailed in Table 8-1.

These transmission costs were considered when assessing the convenience of the expanding the interconnection with Mexico and as shown later in this report, it made this option the least preferred.

[15] The Belize unit costs were about 40% of our estimate for breakers and 91% for the lines. The transformer costs provided per MVA, while not used where much higher and probably included some additional component as the breakers.

Figure 8-6: Possible Interconnection Expansion with Mexico

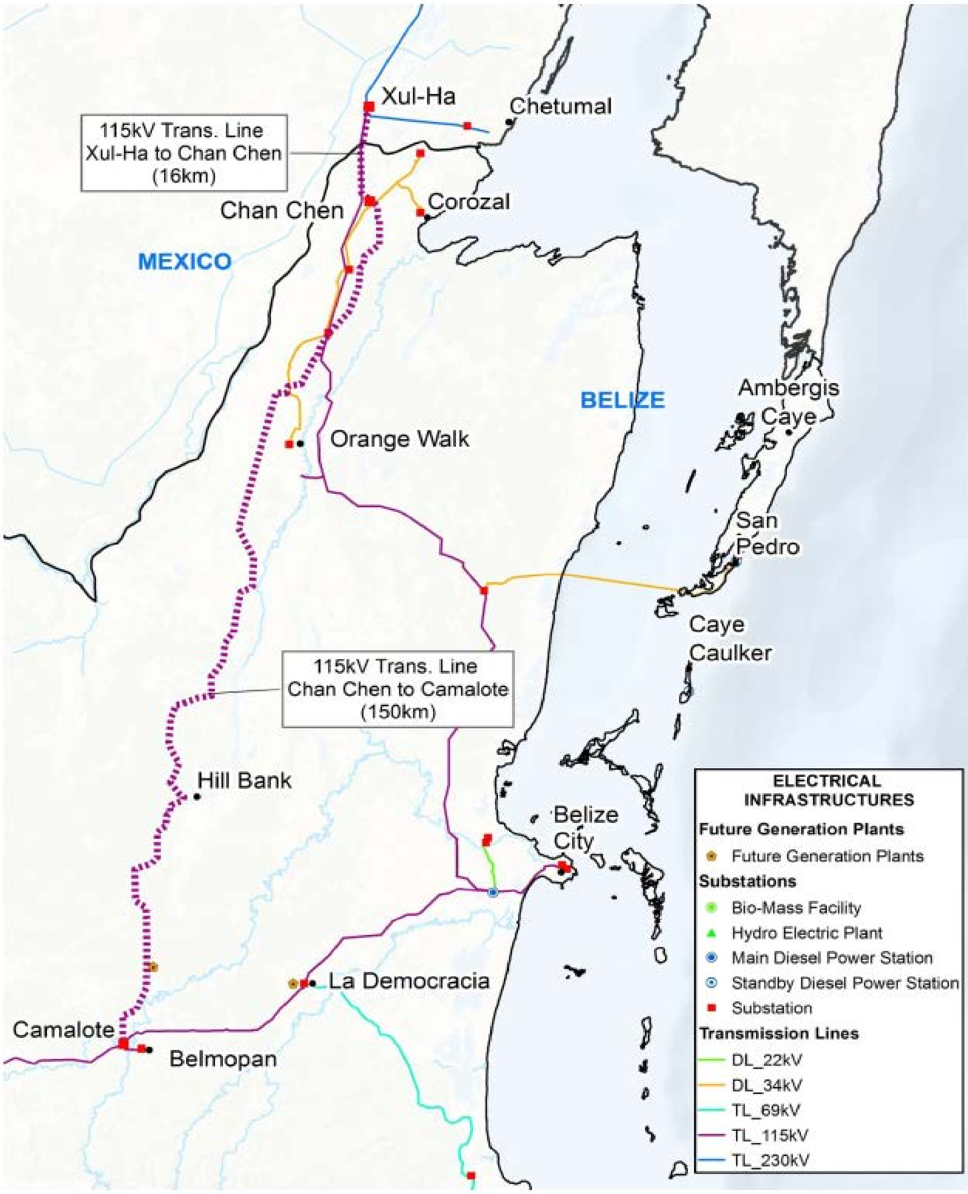


Table 8-1: Estimated Capital Costs of the new interconnection

	unit / MVA /miles	Unit Cost	Total
Xul-Ha			
230 kV Positions	1	$2,400,000	$2,400,000
230/115 kV transformer	100	$8,460	$845,977
115 kV positions	2	$1,306,425	$2,612,850
Total Xul-Ha			**$5,858,828**
Line Xul-Ha Chan-Chen	10.0	$345,000	$3,450,000
Chan-Chen			
115 kV Positions	2	$526,415	$1,052,831
disconnect switch / switcher	1	$66,575	$66,575
Total Chan-Chen			**$1,119,406**
Line Chan-Chen - Camalote	94	$345,000	$32,430,000
Camalote			
115 kV Positions	1	$526,415	$526,415
disconnect switch / switcher	1	$66,575	$66,575
Total Camalote			**$592,991**
Base Total			**$43,451,224**
Contingency / Financing			*28%*
Total Cost			**$55,400,000**

8.2 Guatemala

Guatemala is another opportunity for interconnection for Belize and there exists two candidate points for interconnection

- An interconnection via Melchor de Mencos: This interconnection is facilitated by a new 230 kV line Peten – ITSA – Ixpanpajul – Melchor de Mencos (33 + 80 km). Melchor de Mancos is approximately 3 km from the 115 kV line Vaca to San Ignacio, where a 230/115 kV stepdown could be located.

- An interconnection via Modesto Mendez 230 kV: There is a new 230 kV line Yalchacti – Modesto Mendez (125km) to reinforce this area and Modesto Mendez is approximately 48 km from Punta Gorda. This interconnection would be limited by 69 kV unless the path is upgraded to La Democracia.

-

Both interconnections appear to be feasible geographically. However, there are technical challenges that need to be addressed including the potential inadvertent flows and stability issues by having a parallel path from Mexico to Guatemala via Belize and unto the rest of the Central America. From an economic perspective there is also uncertainty as the costs must be balanced by the economics of the energy and capacity exchanges with Guatemala. Currently there is no information available to answer these questions and we understand that an NDA is being negotiated with the between the GoB and the Guatemalan government.

9. Portfolio Development

As indicated earlier in this report two strategies were proposed for the identification of the Preferred Portfolio: The Base Strategy and the Belize Centric Strategy. In this section we present the procedures and results for the identification of these the two best portfolios under each strategy that then will be subject to sensitivities and scenarios for the identification of the Preferred Portfolio.

9.1 Reference Strategy

The reference strategy uses the international purchases (Mexico) as a central element of the expansion and the results are presented next.

9.1.1 Initial Expansion

This is initial long-term capacity expansion plan that emerged directly from the Aurora LTCE process considering all the Reference Conditions with respect of demand, fuel costs, cost of renewable, etc. as well as maintaining the existing contract limit with Mexico for market purchases of 55 MW line and no availability for Mexico RECs.

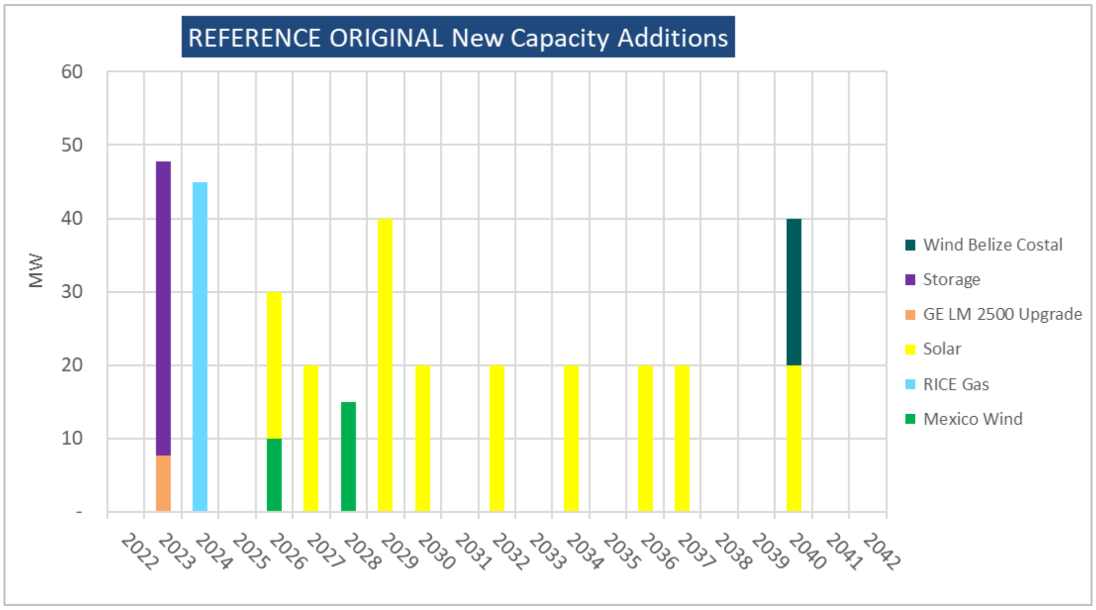
Capacity Expansion

The capacity expansion selected is shown in the figure below, note that it included the upgrade and conversion of the LM2500 unit in 2023. All portfolios consistently selected this upgrade as its need for near term capacity made it an optimal resource option in the short term.

Along with this upgrade, the initial plan included 40 MW of battery storage to meet capacity requirements and energy shifting and 45 MW gas fired reciprocating internal combustion engine (RICE) capacity in 2024. The battery option was also selected under all portfolio formulation and the RICE was also present but with reduced amounts in some cases.

The drive to meet a 75% RPS by 2030 (and sustain after 2030) encouraged the selection of 200 MW solar resources through 2040, 25 MW of Vientos de Caribe project in Mexico as well as a Belize Coastal wind selected in the later part of the forecast.

Figure 9-1: Capacity Expansion Incremental Buildout: Reference Strategy Initial Expansion

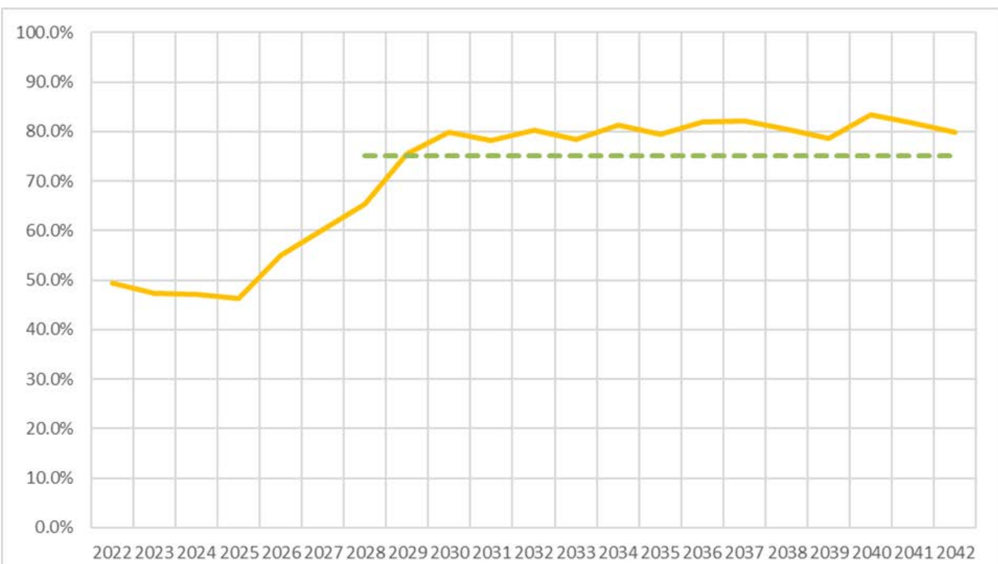


Source: Siemens PTI

RPS Compliance and Reserves

With this initial buildout, renewable penetration meets the 75% requirement and remains slightly over it (~80%) beginning in 2030 (Figure 9-2. The RPS targets were a large driver of the expansion plans

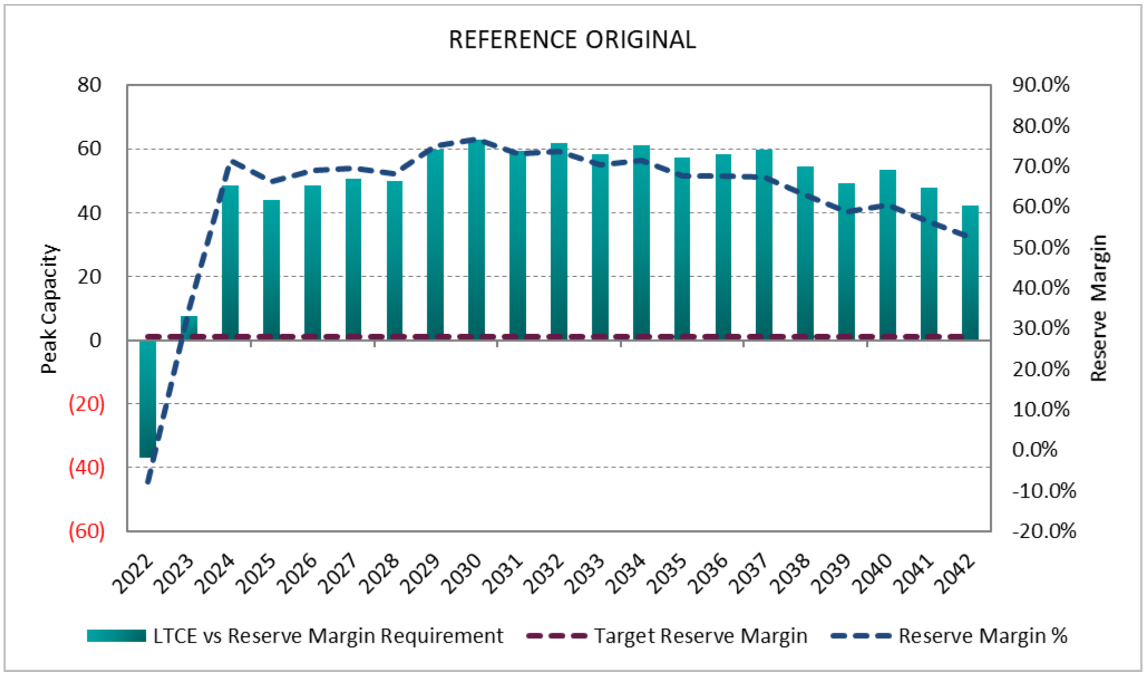
Figure 9-2: Renewable Energy Levels: Reference Strategy Initial Expansion



Source: Siemens PTI

The portfolio also addresses the existing reliability concern associated with insufficient in country reserves with the conversion of the LM 2500 and the storage in 2023, bringing the in-country reserves over the 29% estimated minimum requirement, as shown below. We also note that for 2024 onwards, the economic additions also bring the reserves well above the minimum requirement, which indicates that reserves were not a driver of further expansions, but the RPS as indicated above.

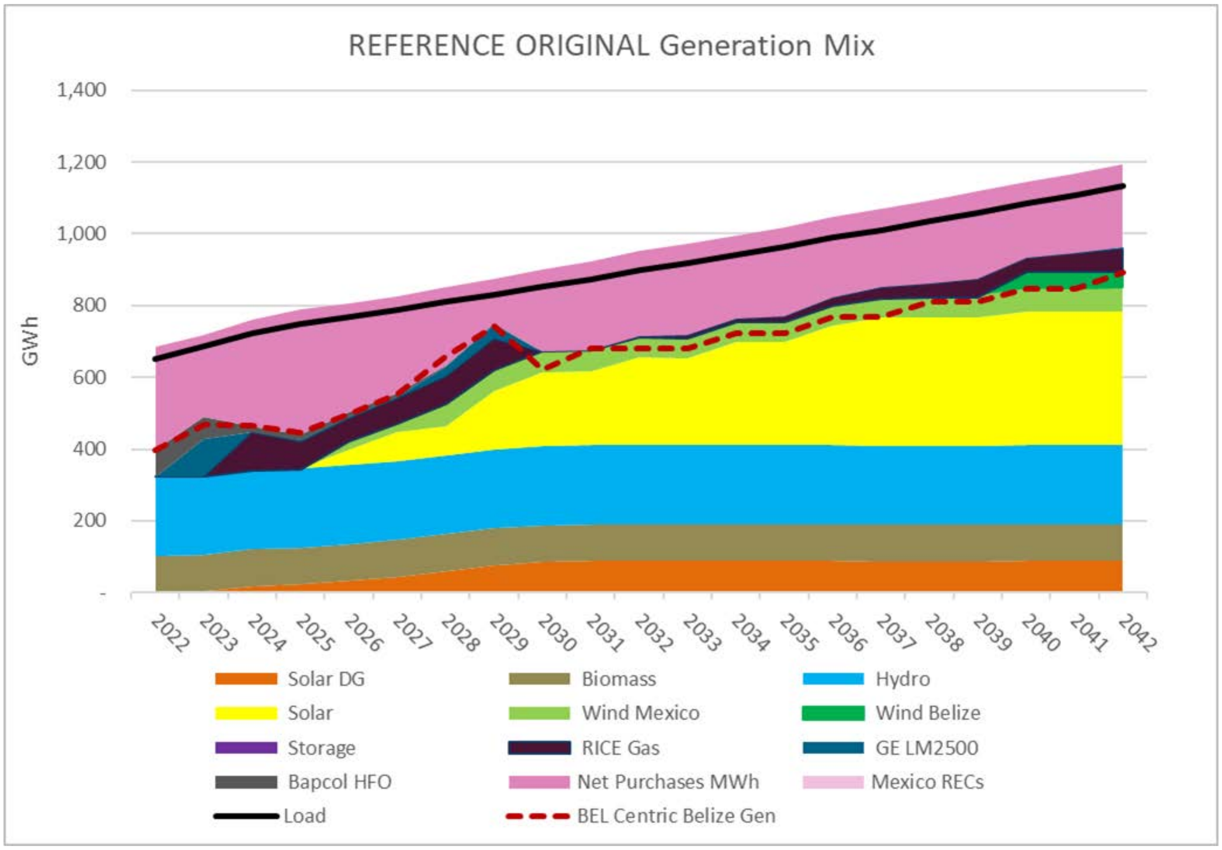
Figure 9-3: Reference Strategy Initial Expansion Reserves by year



Energy Supply

Base load generation needs are consistently met with biomass and hydroelectric generation along with market purchases from Mexico. The GE LM2500 and Rice units that are added early in the study period support load needs and offset higher costs in certain hours from Mexico prior to 2030 but then the dispatch of these units goes to near zero in 2030 due to reduced Mexican power prices when the expansion of the interconnection Peninsular – Oriental is assumed to come online, but then starts increasing again with the load, as the 55 MW contract becomes a limiting factor. This is shown in Figure 9-2. below, where we also note that starting in 2025, incremental base load needs are largely met with renewables. In this figure we show as well, as a reference, a dotted red line shows the internal Belize generation for the recommended portfolio under the same reference conditions. Note the preferred portfolio has lower in country generation after 2030.

Figure 9-4: Belize Generation Mix: Reference Strategy Initial Expansion

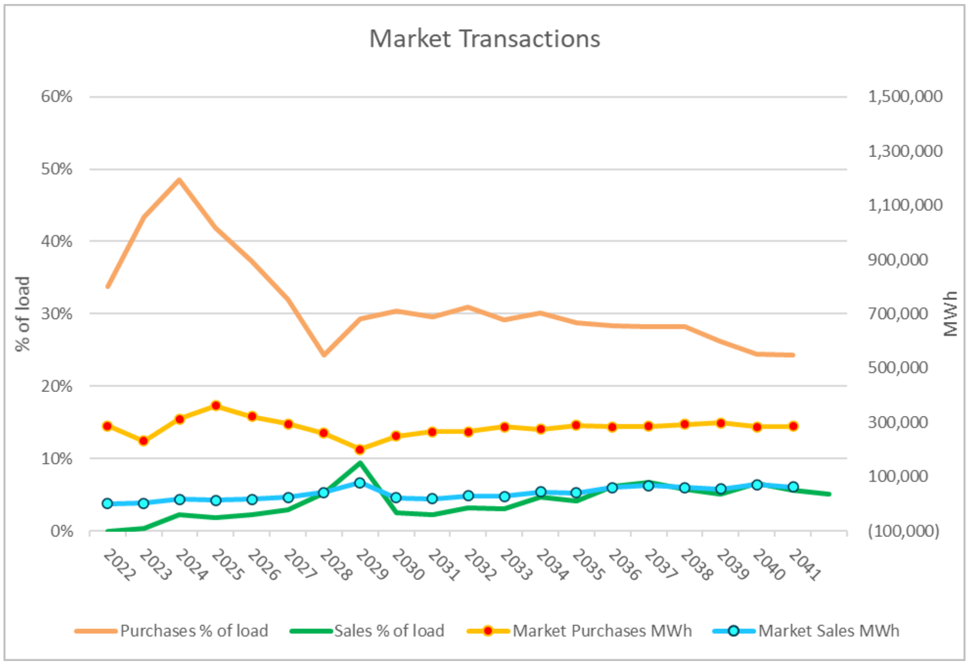


Source: Siemens PTI

As can be seen in Figure 9-5, in this Portfolio, market purchases decline after 2024 with new renewable capacity additions, including Vientos del Caribe until 2030, after which they increase with the drop in Mexican prices and remain largely constant in MWh over the longer term. The market purchases are close to the maximum contractual values for an increasing amount of time (see Figure 9-6)

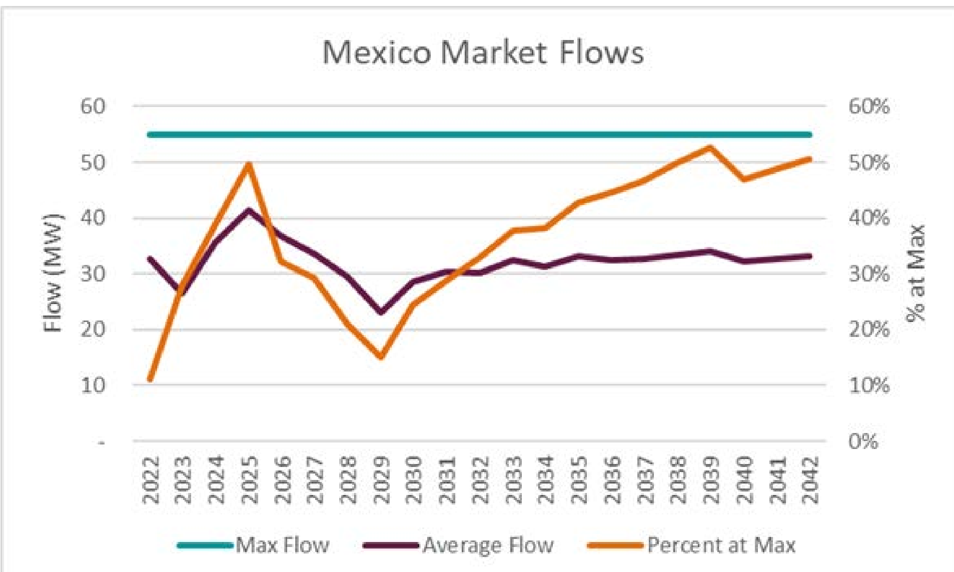
Market sales are minimal starting in 2023 (mostly below 5%) and are opportunistic based on prices.

Figure 9-5: Market Transactions: Reference Strategy Initial Expansion



Source: Siemens PTI

Figure 9-6: Mexico Market Purchases: Reference Strategy Initial Expansion



Source: Siemens PTI

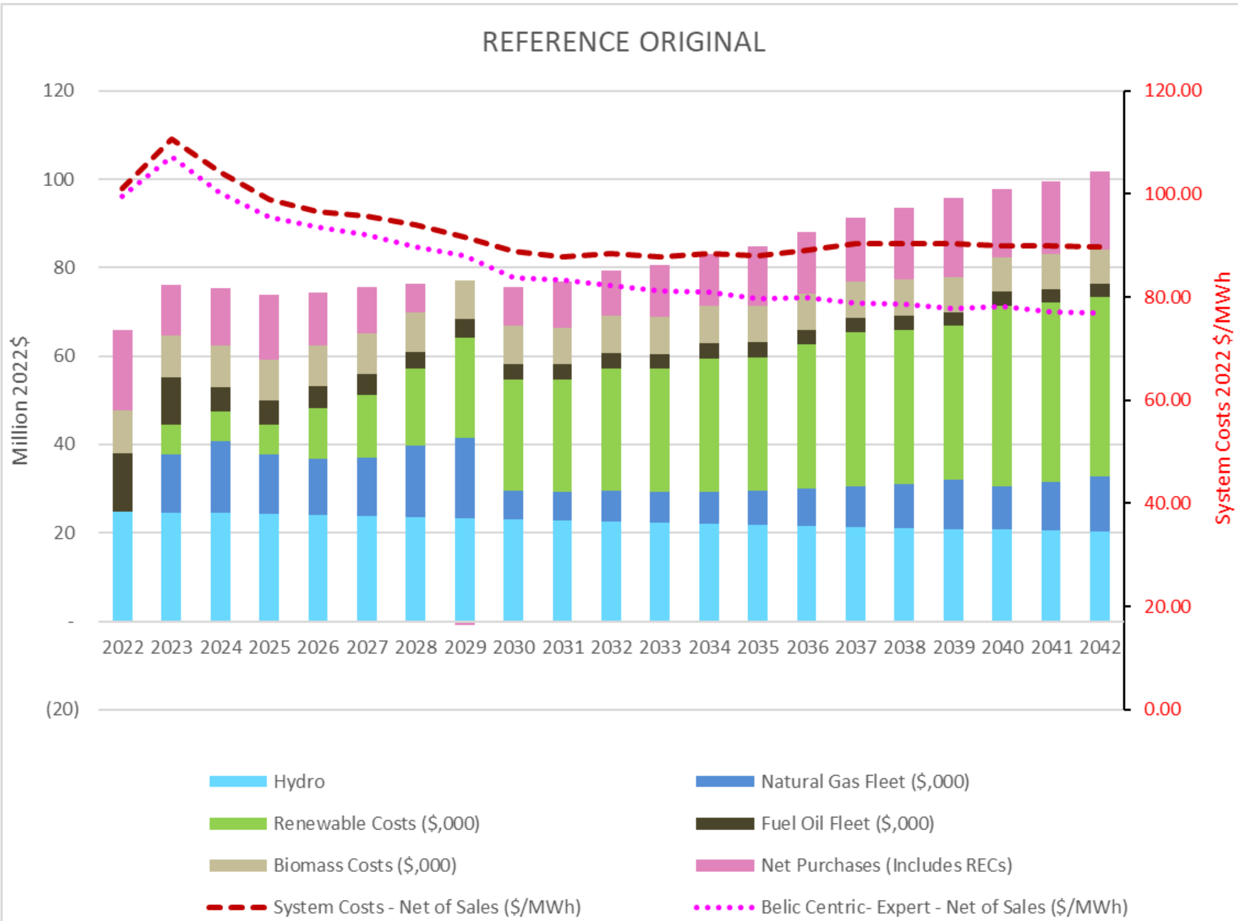
Portfolio Costs

Figure 9-6 shows the Portfolio cost components and the total cost in $/MWh across the planning period. We note that there is an initial increase in 2023 with the new battery storage and upgrade to the LM 2500 unit, which is necessary to address the current reliability issue when losing the connection with Mexico. From 2023 onwards to 2030 the Portfolio costs drop with the lowering the imports from Mexico, offset by gas and renewable generation.

From 2030 to the end of the planning period the cost remains largely flat in $/MWh with an upward trend largely due to increases in the dispatch of natural gas RICE units.

Finally in this figure we show the cost for the Preferred Portfolio, and we note that there are consistently higher, and the difference increases over time due to limits in the Mexican purchases.

Figure 9-7: Cost by Year Reference Strategy Initial Expansion



Total portfolio NPV of Revenue Requirements (NPVRR) is estimated to be US $939 million ($2022) at a real discount rate of 6%, as shown in the table below.

The largest component of the costs is the fixed cost portion at $717 million and the effective cost is US $93.86/MWh, calculated as the ratio of the present value of the revenue requirements over the present value of the energy.

The Net Mexican Market costs (market purchases less sales revenues) represent 15.2% or the costs (NPV) and 29.4% of the load (energy). Market sales to Mexico occur largely when prices are higher in that country

This portfolio is about 7% more expensive than the recommended portfolio; the Belize Centric Expert Design, which will be presented later in this report.

Table 9-1: Belize Portfolio Cost by Component: Reference Strategy Initial Expansion

NPV $000 (2022$)	Reference Case
Variable	79,492
Fixed	716,941
Purchases	174,242
Total Costs before sales	970,675
Sales	31,394
Total after sales	**939,282**
Total Load (MWh)	10,007,705
Mkt + RECS Purchases (MWh)	3,322,188
Energy Sales (MWh)	378,995
Total Costs $/MWh	93.86
Purchase Costs $/MWh	52.45
Sales Price $/MWh	82.83
Delta to Reference	0.0%
Delta to cheapest	7.3%
%Variable	8.5%
% Fixed	76.3%
Market Purchases % Tot. Cost	18.6%
Market Sales % Tot. Cost	3.3%
Net Market % Tot. Cost	15.2%
Market Purchases % load	33.2%
Market Sales % load	3.8%
Net Market % load	29.4%

Conclusions and Observations.

After reviewing the initial expansion plan, it was clear that the 55 MW link from Mexico was a limiting factor within the portfolio. This same portfolio was then run with a larger market limit and the market flows are modeled constrained only by the transmission limits and not contractually imposed limits (106 MW instead of 55 MW) and presented next.

9.1.2 Reference Strategy with Increased Market Limit

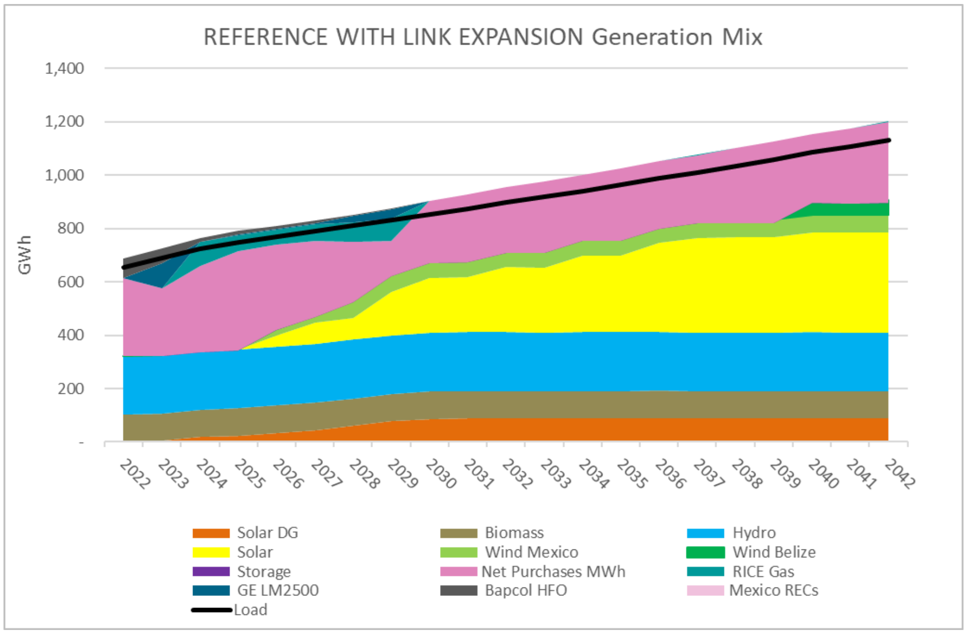
The existing contract was found to be limiting particularly after 2030, when the transmission to Peninsular was assumed to be expanded. This expansion is likely to occur as the Peninsular region is a high growth high economic development area of Mexico and pressures are likely to mount to prevent this region to collapse.

Belize can benefit from this by expanding the contract. Note that we are aware that in the past CFE has indicated the need to increase the transformation capacity at Xul-Ha. However in our opinion this should be revisited because a) generation injection is expected at Xul-Ha which will reverse the flows on the transformers and b) there is no obligation for CFE to honor the higher limit if overloads occur in real time and a Remedial Action Scheme can be put in place that in case that a contingency occurs that would overload the transformation at Xul-Ha, then either BEL generation (i.e. the LM2500) increases to reduce the flows or load is temporarily shed until generation is increased. Finally, even in the unlikely case that investments need to be made, as shown below the benefits far outweigh the investments in adding one transformer to Xul-Ha.

Energy Supply

With the increased market flow limit, the GE LM2500 and RICE units support dispatch pre-2030 but are no longer needed as heavily to support the later years.

Figure 9-8: Belize Generation Mix: Reference Strategy Initial Expansion with Mexico Link Expansion



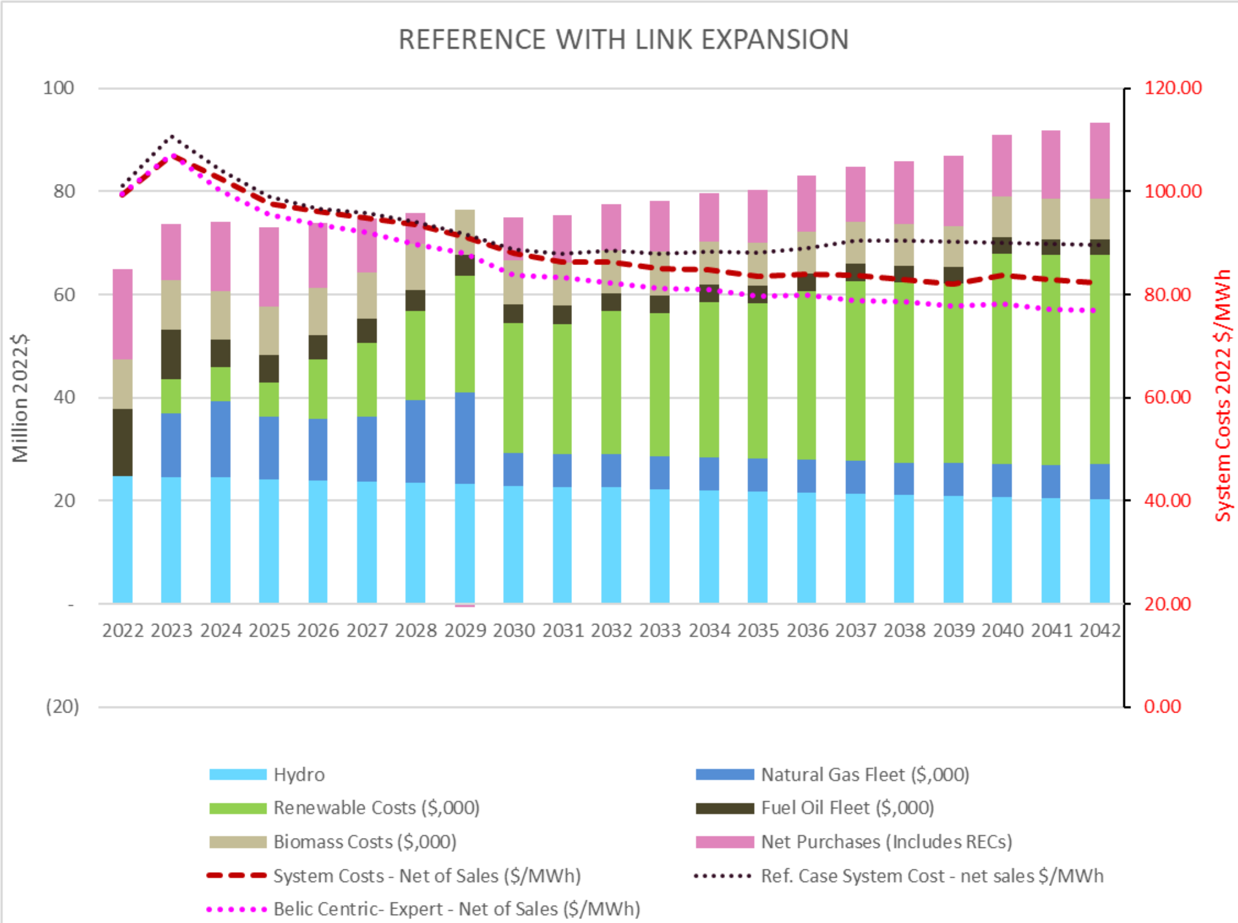
Source: Siemens PTI

Portfolio Costs

Along with increased market purchases, a reduction in costs were observed as the transmission interconnection was increased. Flows increased by 16% average by the end of the forecast.

The figure below shows the overall costs and compares the average costs in $/MWh with the previous case (doted black line) where we note the important gains after 2030

Figure 9-9: Belize Portfolio Cost: Reference Strategy Initial Expansion with Mexico Link Expansion



Source: Siemens PTI

As shown in the table below the total portfolio NPV of Revenue Requirements is reduced to US $907 million (3.3% drop) or $ 31million, which would clearly cover any investments in Xul-Ha that should be under US$ 4.5 million to add a new transformer.

The effective costs drop to US$ 90.73/MWh.

Net Mexican purchases drop as a percentage % or the costs (NPV) but increase to 31.9% of the load (energy). More purchases occur at lower prices.

More sales to Mexico also occur largely when prices are high.

Table 9-2: Belize Portfolio Cost by Component: Reference Strategy Initial Expansion with increased Market Purchases

NPV $000 (2022$)	Reference Case	Reference with Increased Market Limit
Variable	79,492	62,081
Fixed	716,941	716,941
Purchases	174,242	162,187
Total Costs before sales	970,675	941,208
Market Sales	31,394	33,259
Total after sales	**939,282**	**907,949**
Total Load (MWh)	10,007,705	10,007,705
Mkt + RECS Purchases (MWh)	3,322,188	3,617,295
Energy Sales (MWh)	378,995	421,536
Total Costs $/MWh	93.86	90.73
Purchase Costs $/MWh	52.45	44.84
Sales Price $/MWh	82.83	78.90
Delta to Reference	0.0%	-3.3%
Delta to cheapest	7.3%	3.7%
%Variable	8.5%	6.8%
% Fixed	76.3%	79.0%
Market Purchases % Tot. Cost	18.6%	17.9%
Market Sales % Tot. Cost	3.3%	3.7%
Net Market % Tot. Cost	15.2%	14.2%
Market Purchases % load	33.2%	36.1%
Market Sales % load	3.8%	4.2%
Net Market % load	29.4%	31.9%

9.2 Reference Strategy with Mexico REC Purchases

Another expansion plan was created which assumes that Mexico market energy purchases could come from renewable and include REC credits to meet Belize RPS requirements. This scenario also assumes that market purchases are also considered to be expanded beyond the 55 MW limit and Mexico flows are limited by transmission only.

Capacity Expansion

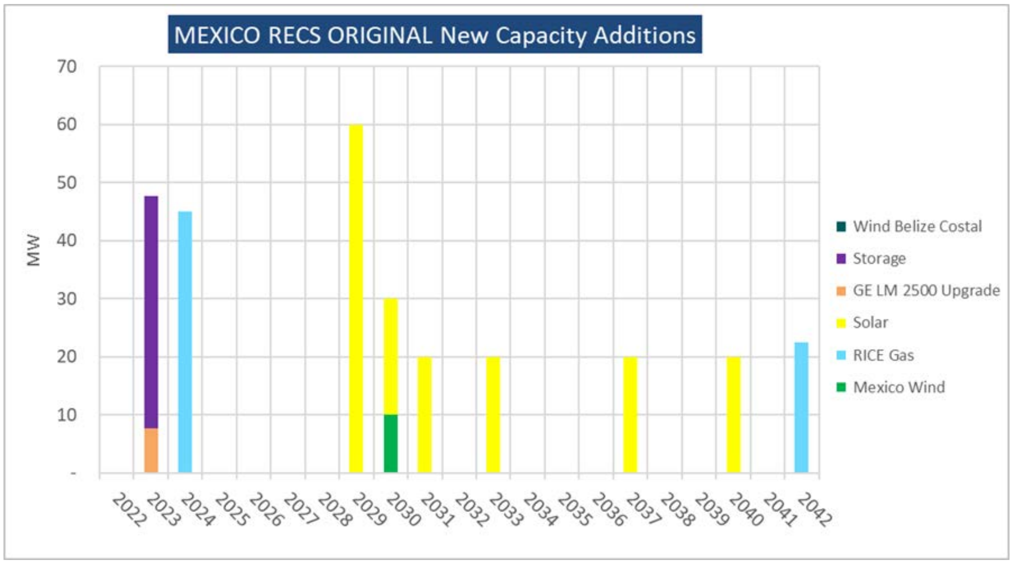
The resulting long-term capacity expansion plan selected a similar near-term buildout as the initial reference strategy buildout which includes the conversion of the LM2500, 40 MW battery and 45 MW RICE. There was no installation if renewables until 2029 when 60 MW of solar was added and overall, less renewables added as the Mexico RECs continue to be the preferred method of meeting the RPS requirements.

There are reduced amounts of renewable in this case.

- 170 MW (160 Solar, 10 Wind) total in this case (RECs) Vs.
- 245 MW (200 Solar, 45 Wind) total in reference

A RICE unit is added long term to meet reserves.

Figure 9-10: Capacity Expansion Incremental Buildout: Reference Strategy with Mexico RECs

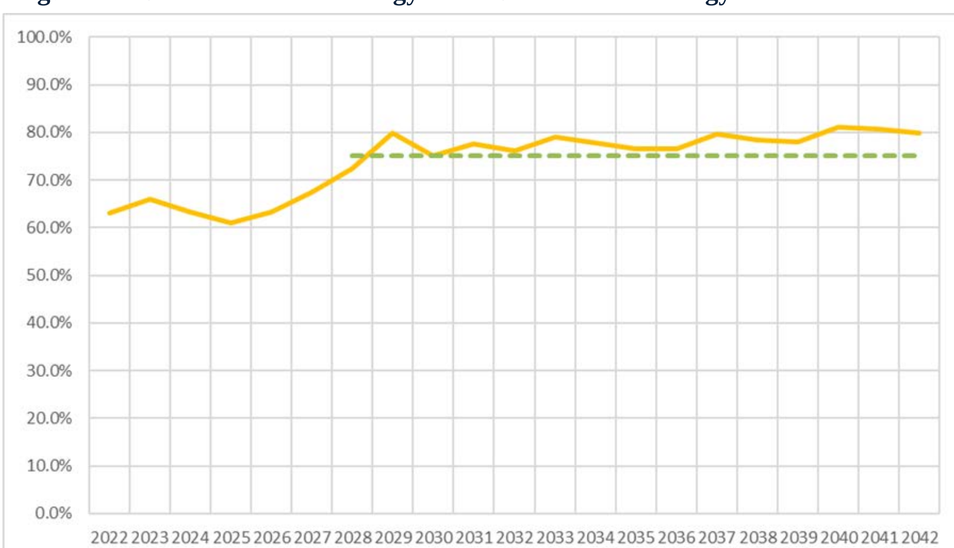


Source: Siemens PTI

RPS Compliance

This portfolio meets the RPS requirements in a similar fashion as to keeping relatively stable above 75% after 2030.

Figure 9-11: Renewable Energy Levels: Reference Strategy with Mexico RECs

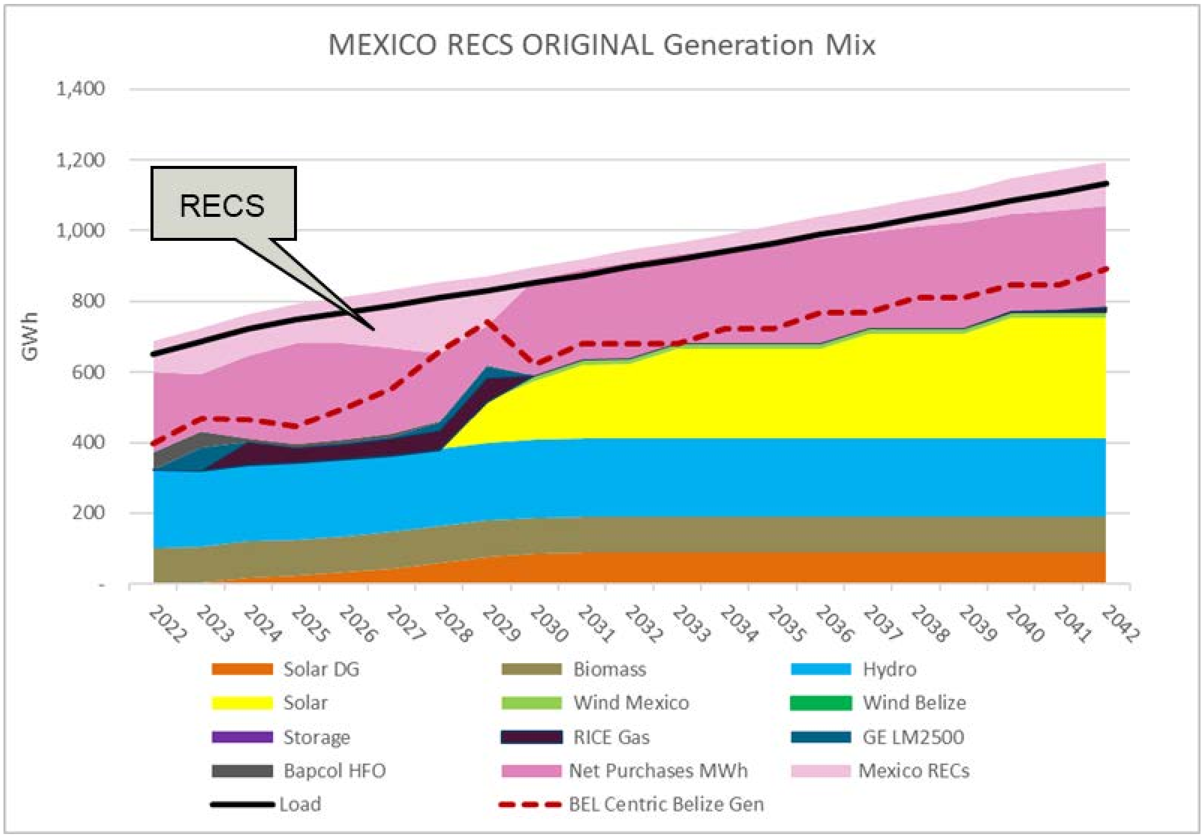


Source: Siemens PTI

Energy Supply

With the increased market limits and the RECs, the GE LM2500 and RICE units dispatch until 2030 and very limited thereafter. These units provide useful reserves and protection against market volatility. The internal generation is much lower than in the preferred portfolio highlighting the reliance of this Portfolio in Mexico.

Figure 9-12: Belize Generation Mix: Reference Strategy with Mexico RECs



Source: Siemens PTI

9.3 Reference Strategy Expert Design Buildout

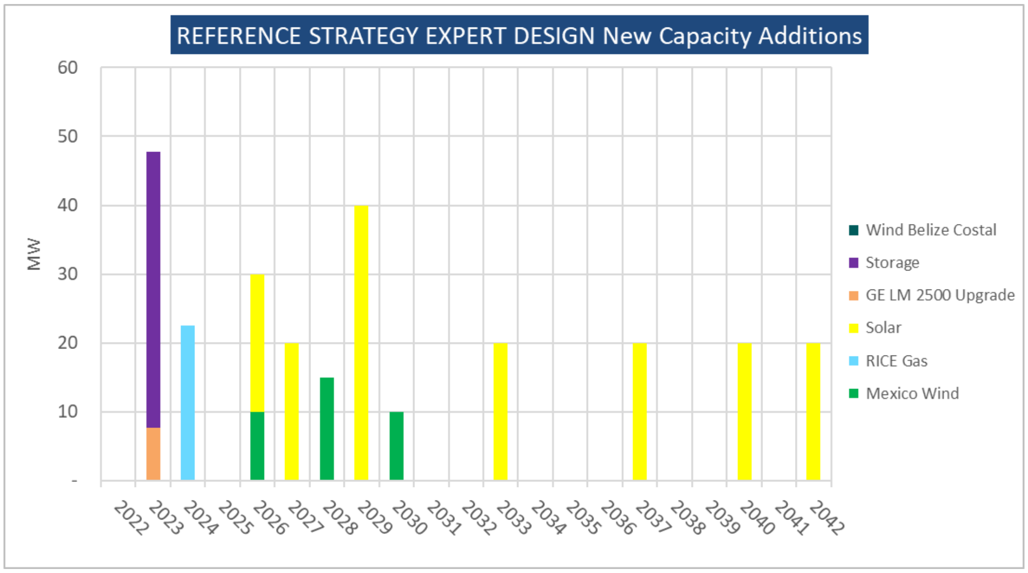
Capacity Expansion

Using information gathered from the prior cases, the Initial Build Out with increased market purchases and the RECs allow designing a better portfolio by combining the best features of both. The following improvements were implemented:

- The initial capacity expansion plan to 2030 was maintained as in the Reference Case, given that the largest savings with the RECs occur after 2030.
- REC's purchases are limited to after 2030, which gives time for the Mexican Market to mature (or Belize to continue with the Reference Plan).
- Mexican Market Purchases limited by transmission (106 MW).
- Only one RICE is installed in 2024 (22.5 MW) instead of two, to reduce the dependence on imported fuels. The RICE by 2043 is also eliminated.

- One 20 MW solar was replaced for wind (Mexico) complementing the initial installation and reducing dependence on solar PV.

Figure 9-13: Capacity Expansion Plan Reference Strategy Expert Design



Source: Siemens PTI

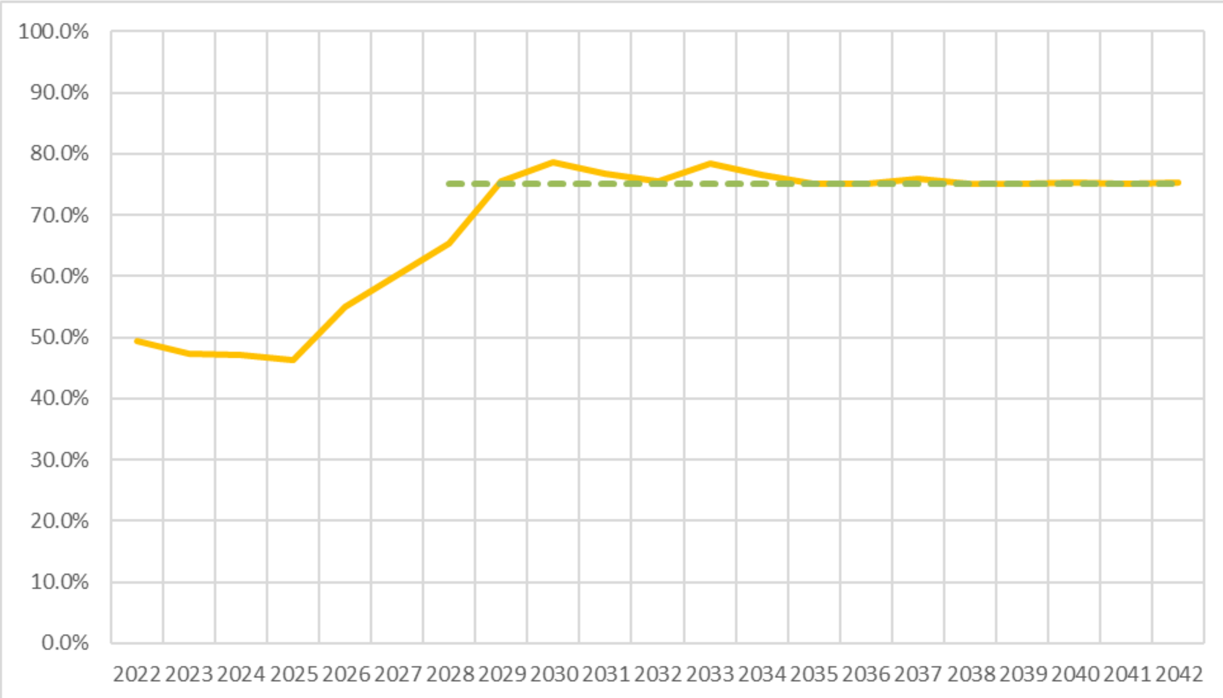
The portfolio compares as per below

- 195 MW (160 Solar, 35 Wind) total in Reference Expert design
- 170 MW (160 Solar, 10 Wind) total in RECs
- 245 MW (200 Solar, 45 Wind) total in Reference

RPS Compliance and Reserves

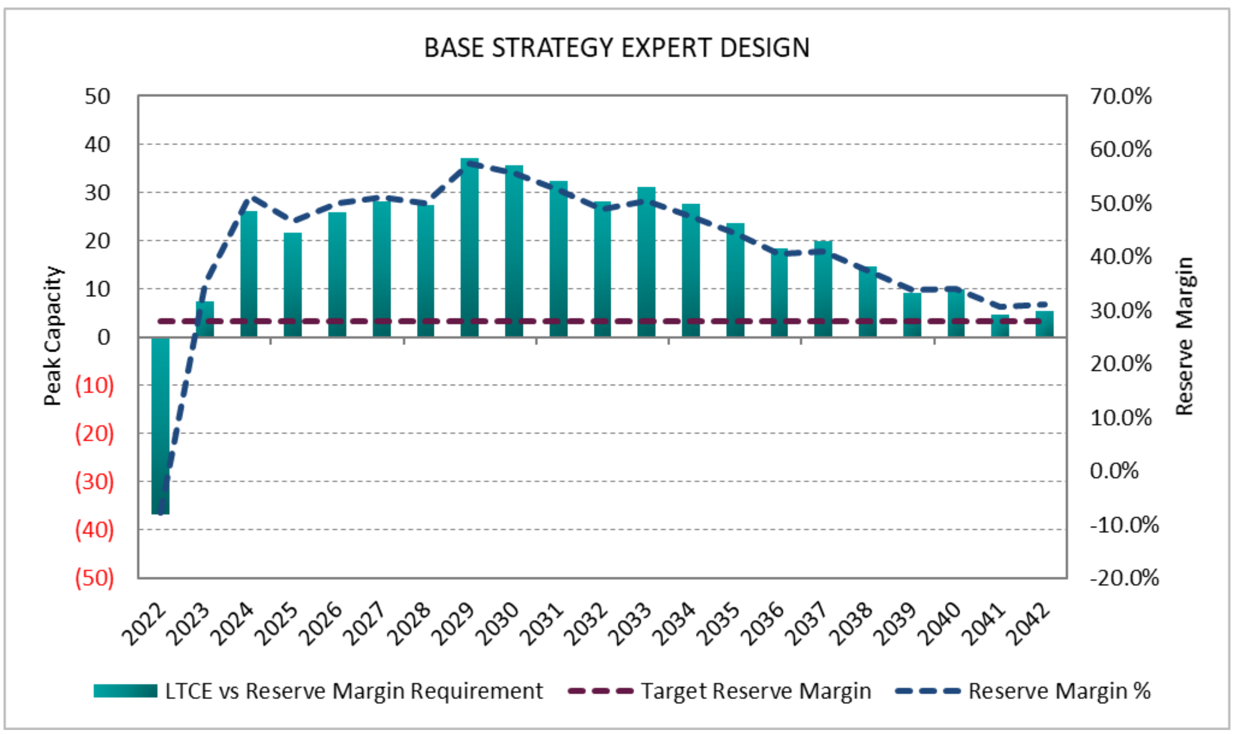
The plan gets to 75.5% by 2029 remains largely on the 75% target after 2030 not deviating significantly. The combination of the adjusted expansion plan and REC purchases are used to meet the targets.

Figure 9-14: Renewable Energy Levels: Reference Strategy Expert Design



As before, the initial investment recovers the reserves above the minimum limit and there are met thereafter to the end of the planning period. The second RICE is not necessary.

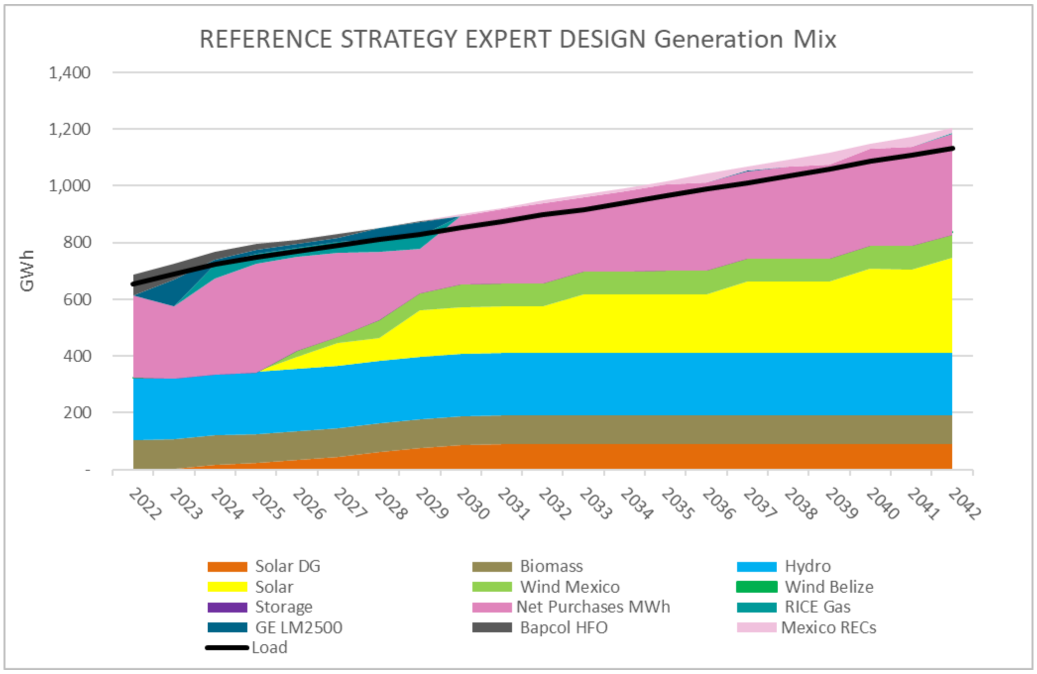
Figure 9-15: Reference Strategy Expert Design Reserves by year



Energy Supply

With this updated mix of resources as well as the Mexico RECs purchases available beginning in 2030, REC purchases are minimized to when needed to sustain the RPS requirements after 2030.

Figure 9-16: Belize Generation Mix: Reference Strategy Expert Design



Source: Siemens PTI

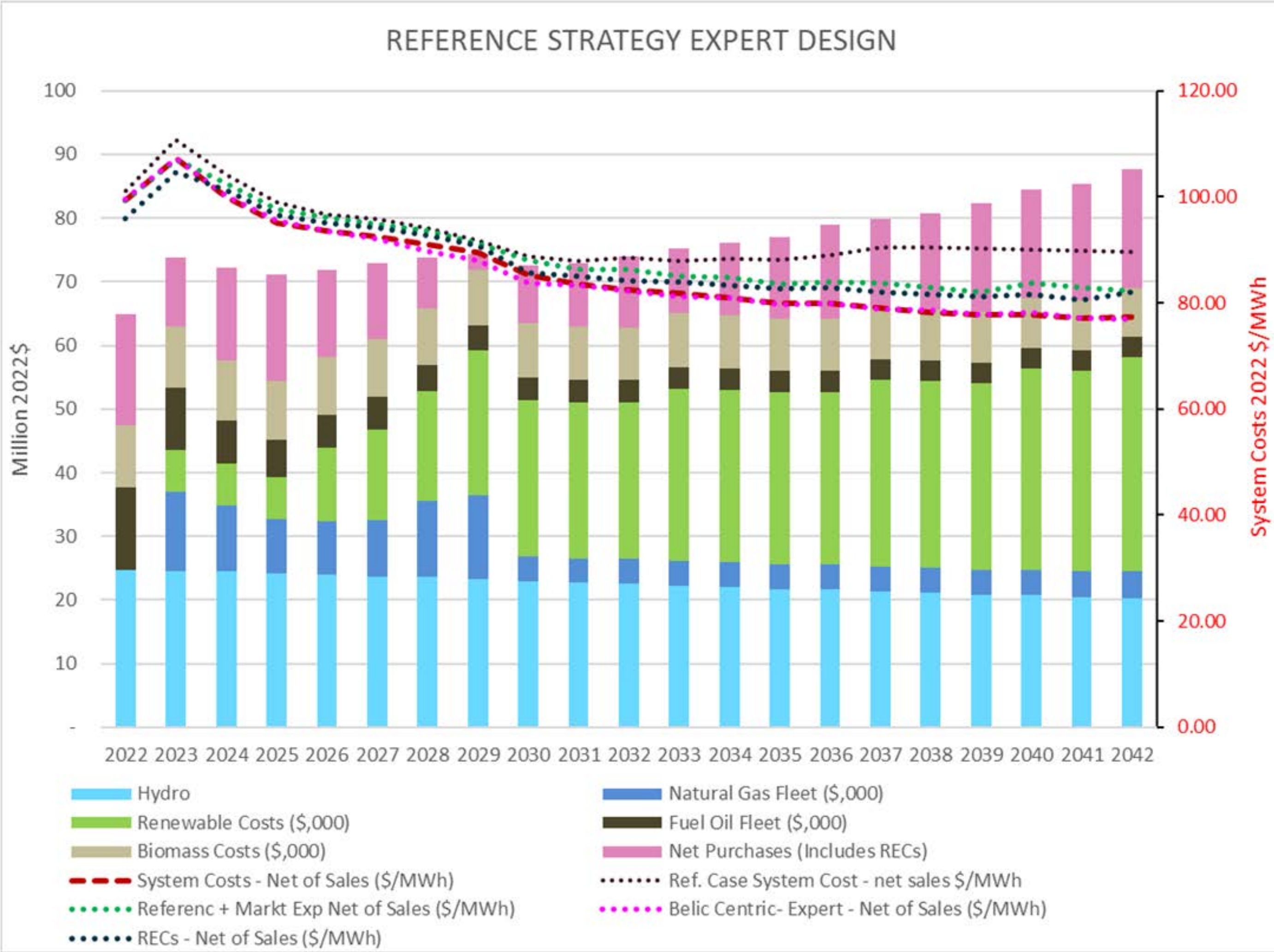
Portfolio Costs

The costs in $/MWh are lower than the reference case and the situation where the market purchase limit is expanded limited only by the transmission limit as can be appreciated below; compare dotted lines with the dashed line representing this portfolio. We also note that this portfolio costs $/MWh is very close to the preferred portfolio.

As before there is still an important increase in the purchases to Mexico after 2030 given by the combination of expanded regular market purchases and the use of the RECs.

The combination of in country expansion pre-2030 and then more reliance on Mexico post 2030 results in the reduced costs and this Portfolio gives time to see the developments in Mexico and pivot, as necessary.

Figure 9-17: Portfolio Cost: Reference Strategy Expert Design



Source: Siemens PTI

Total portfolio Net Present Value of revenue requirements is reduced overall in the Reference Strategy Expert Design as compared to all previous portfolios described so far.

Total portfolio NPV of Revenue Requirements is reduced to US $878 million (6.5% drop with respect of reference) or 62 million and the effective costs drops to US$88.0/MWh.

Net Mexican purchases are 17.1 % or the costs (NPV) and 34.5% of the energy higher than the Reference Case. Sales to Mexico continue being small

Table 9-3: Portfolio Cost Components: Reference Strategy Expert Design vs Others

NPV $000 (2022$)	Reference Case	Reference with Increased Market Limit	Scenario MX REC Energy Purchases	Reference Expert Design
Variable	79,492	62,081	47,577	57,677
Fixed	716,941	716,941	656,334	670,178
Purchases	174,242	162,187	208,084	168,537
Total Costs before sales	970,675	941,208	911,996	896,393
Market Sales	31,394	33,259	18,400	18,497
Total after sales	**939,282**	**907,949**	**893,596**	**877,896**
Total Load (MWh)	10,007,705	10,007,705	10,007,705	10,007,705
Mkt + RECS Purchases (MWh)	3,322,188	3,617,295	4,377,800	3,651,218
Energy Sales (MWh)	378,995	421,536	350,718	196,758
Total Costs $/MWh	93.86	90.73	89.29	87.72
Purchase Costs $/MWh	52.45	44.84	47.53	45.05
Sales Price $/MWh	82.83	78.90	52.46	94.01
Delta to Reference	0.0%	-3.3%	-4.9%	-6.5%
Delta to cheapest	7.3%	3.7%	2.1%	0.3%
%Variable	8.5%	6.8%	5.3%	6.6%
% Fixed	76.3%	79.0%	73.4%	76.3%
Market Purchases % Tot. Cost	18.6%	17.9%	23.3%	19.2%
Market Sales % Tot. Cost	3.3%	3.7%	2.1%	2.1%
Net Market % Tot. Cost	15.2%	14.2%	21.2%	17.1%
Market Purchases % load	33.2%	36.1%	43.7%	36.5%
Market Sales % load	3.8%	4.2%	3.5%	2.0%
Net Market % load	29.4%	31.9%	40.2%	34.5%

9.4 Belize Centric Strategy

For the formulation of the Belize Centric Strategy capacity expansion plan, Aurora was given assumptions that would promote in country generation. Specifically

a) Belize new resources are assumed to have lower capital charge rates as compared to the reference conditions (1% reduction on the CCR factor), reflecting in country support for renewable energy.

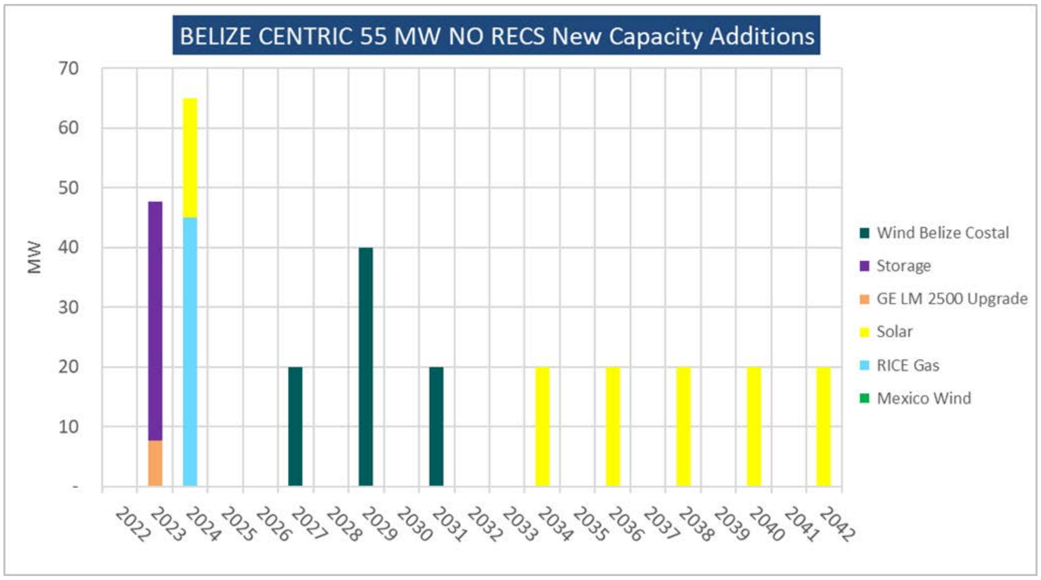
b) Higher Mexico prices due to the assumption that the 2030 expansion between Peninsular – Oriental will no longer occur.

Capacity Expansion

The initial long term capacity expansion plan that was selected in the Belize Centric strategy favored Belize Coastal wind over the Vientos de Caribe, which was favored in the reference strategy.

The expansion plan chooses wind in the near future over solar which differs from the reference strategy. This is largely driven by the fact that the plan was created using higher Mexican prices that promotes wind resources that have higher production during the high night peak prices in Mexico. Similar to the reference strategy, this portfolio also selected the upgrade of the LM2500 unit as well as 40 MW storage and 45 MW RICE capacity in 2024.

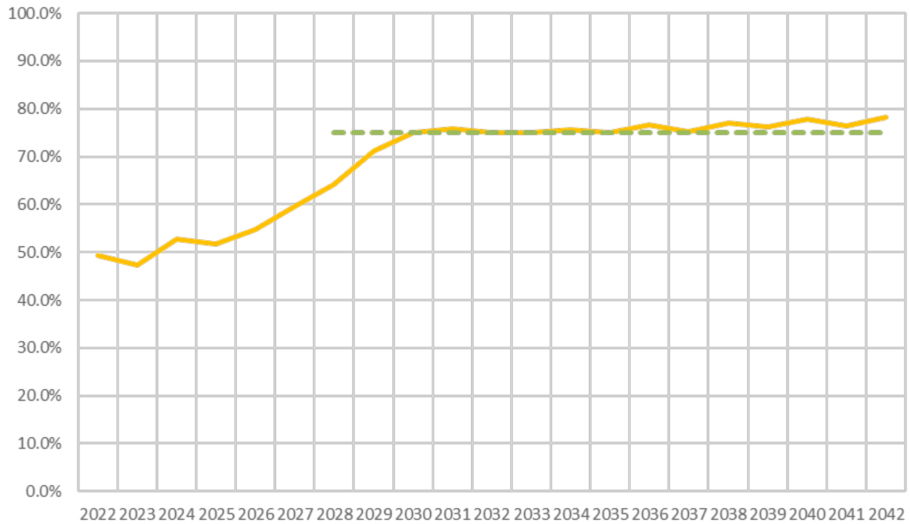
Figure 9-18: Capacity Expansion Plan: Belize Centric Strategy Original Plan



RPS Compliance and Reserves

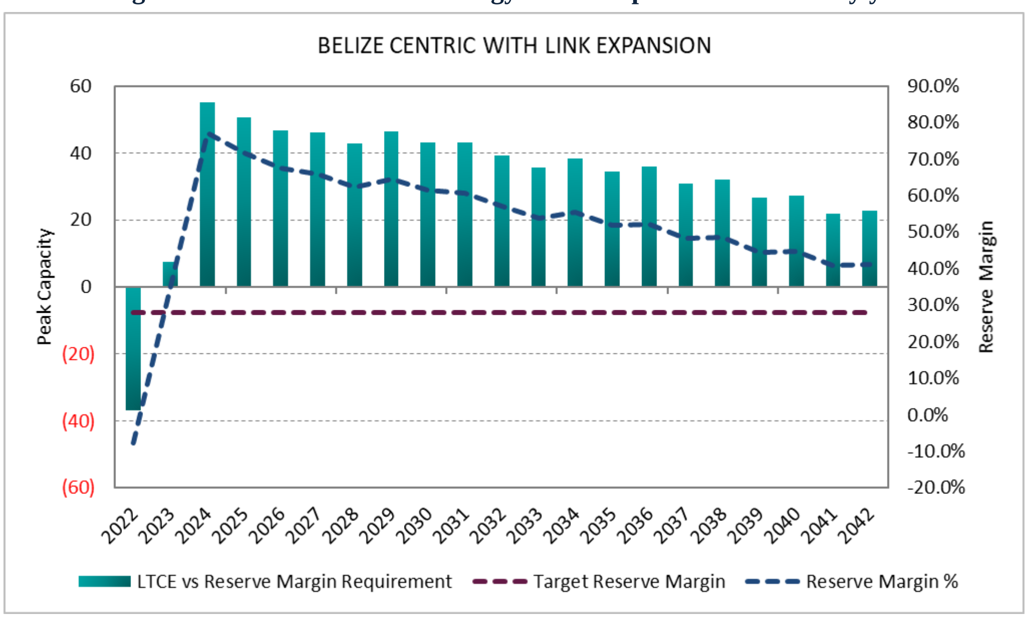
Like the reference portfolio, the plan gets the necessary RPS requirements of slightly over 75% by 2030 and remaining consistent thereafter as well as meeting reserves throughout the entire planning period.

Figure 9-19: Renewable Energy Levels: Belize Centric Strategy Original Plan Evaluation



As with the Reference Strategy, the portfolio addresses the existing reliability concern associated with insufficient in country reserves with the conversion of the LM 2500 and the storage in 2023, bringing the in-country reserves over the 29% estimated minimum requirement. From 2024 onwards, the economic additions also bring the reserves above the minimum requirement but to a lesser extent than the Reference Strategy as wind has lower capacity credit than solar.

Figure 9-20: Reference Strategy Initial Expansion Reserves by year

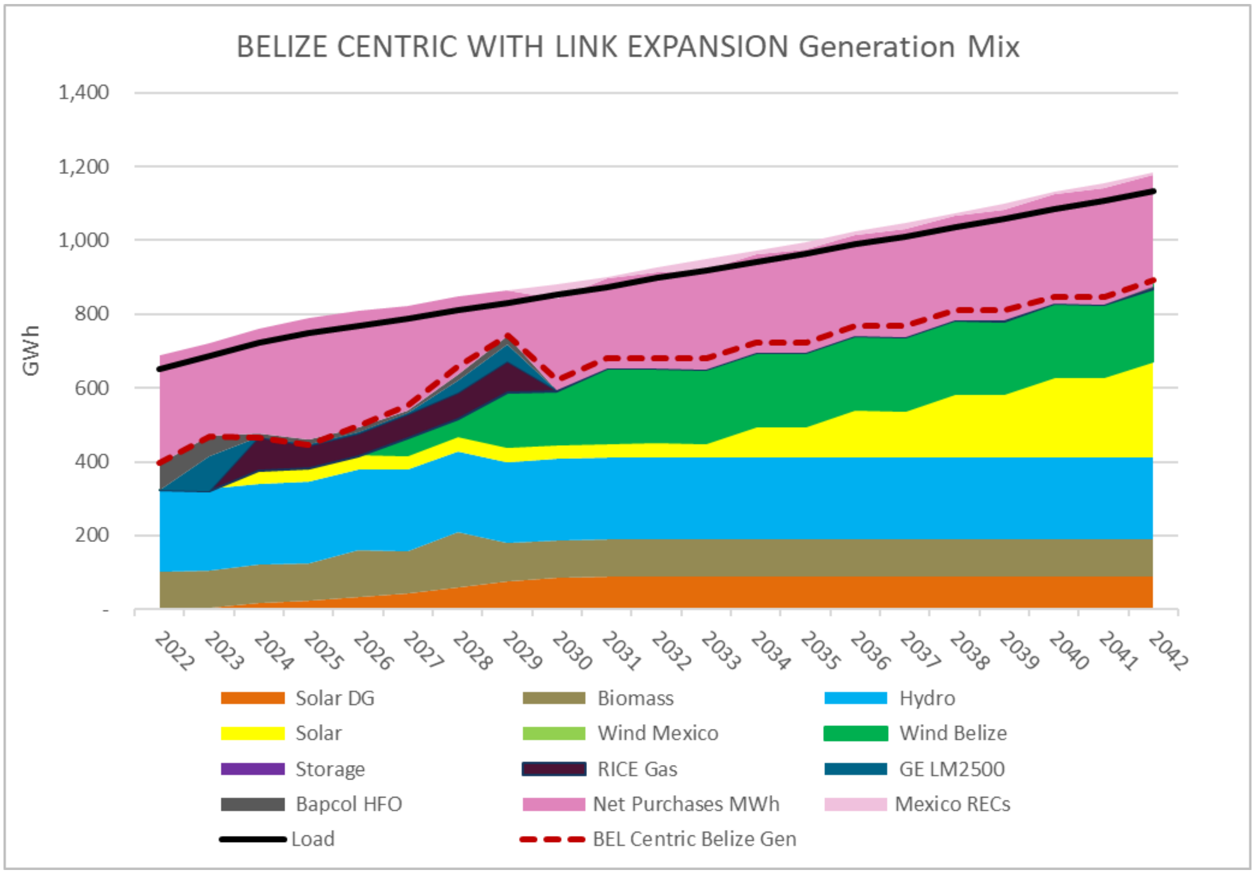


Energy Supply

Although the Belize Centric portfolio was developed in response to a set of assumptions on cost of capital and Mexican Market, its performance is evaluated under Reference Conditions for comparison with the Reference Strategy. Additionally, as it was identified that increasing the market purchase availability (limited only by transmission and not by contractual MW) was advantageous, this strategy was run with this added flexibility.

Under these evaluation conditions, the use of the GE LM2500 and RICE units to support load is very similar to the reference portfolio, consisting of some use pre-2030 and little to no use afterwards. As seen in figure below, a large amount of solar is displaced by wind in the Belize centric portfolio as compared to the reference strategy portfolios.

Figure 9-21: Belize Generation Mix: Belize Centric Strategy Original with Mexican Market Expansion

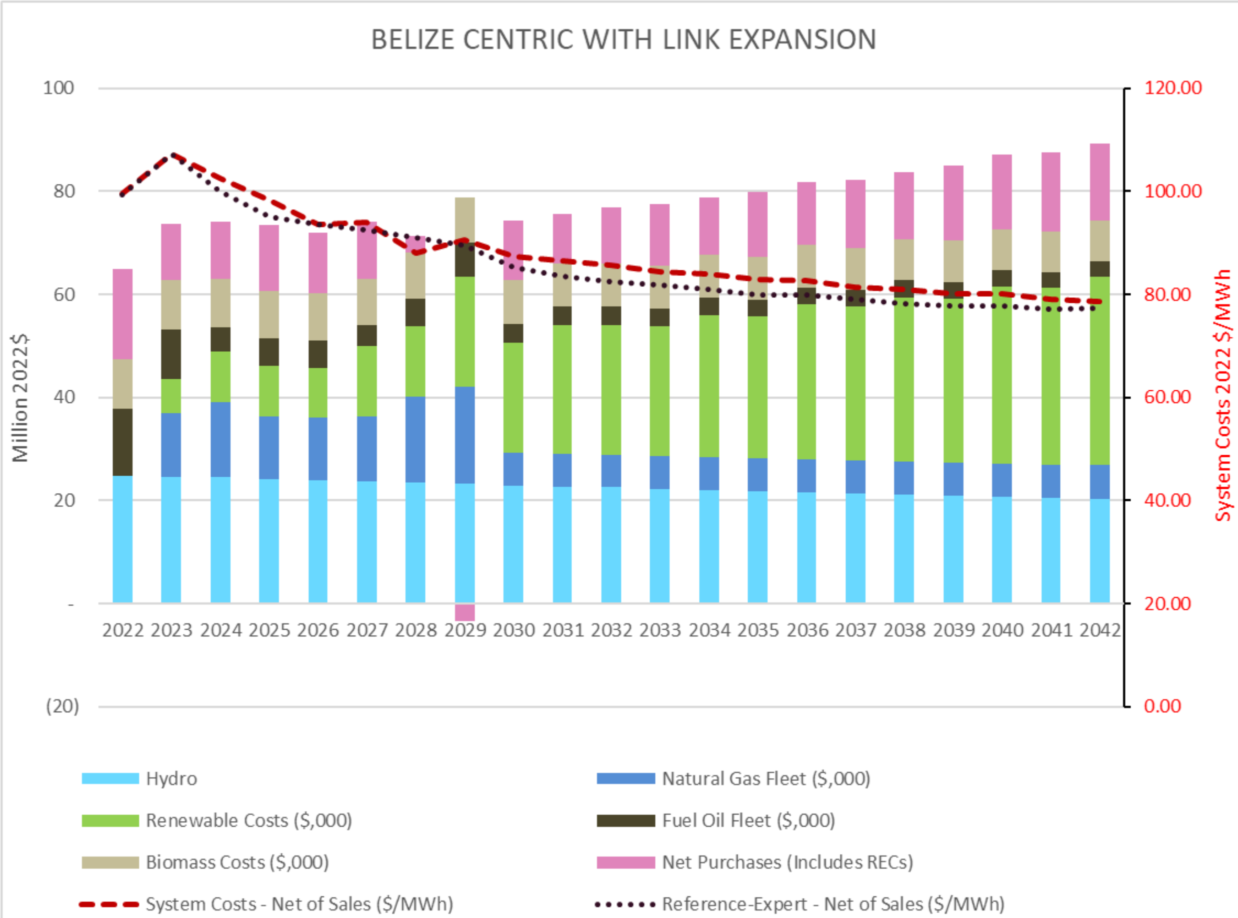


Portfolio Costs

Similar to the reference strategy, total portfolio costs on a $/MWh basis increase in 2023 with the implementation of new battery storage and the upgrade of the LM2500 unit to address the reserve issue. Also similar to the reference, portfolio costs then drop post 2023 as there is less reliance on imports from Mexico which are being offset by gas and renewable generation.

From 2030 the cost continues to decline with the Mexico imports and renewable generation but are higher than the Base Strategy Expert Design. Investigation into this showed that wind generation with its higher capital cost did not compete well with solar when the cost of Mexico become attractive.

Figure 9-22: Portfolio Cost: Belize Centric Strategy Original with Mexican Market Expansion



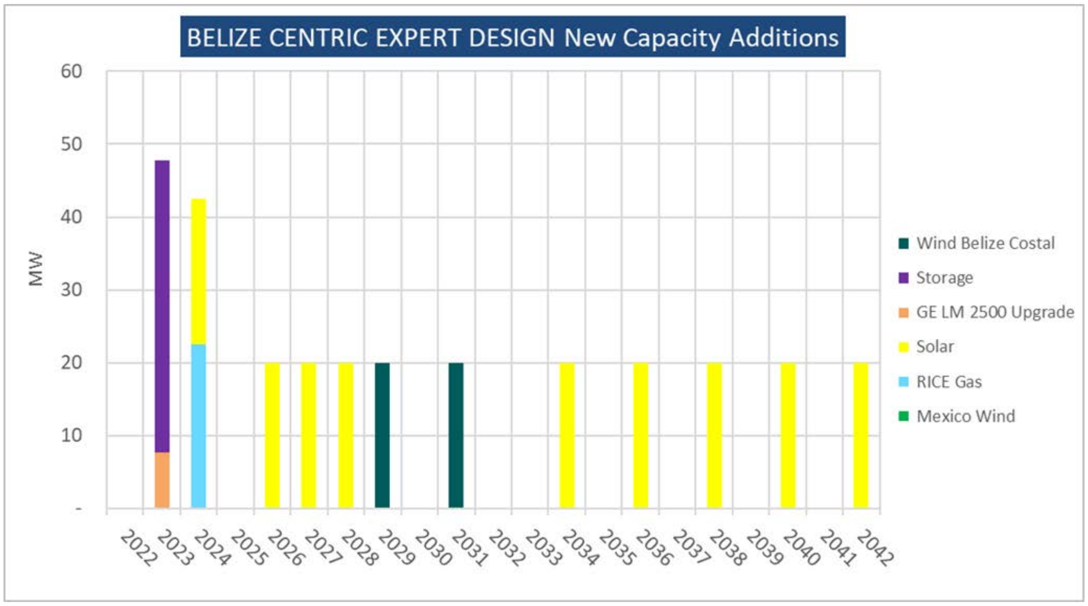
1.5 Belize Centric Expert Design Portfolio

The Belize Centric portfolio as originally designed had too much dependence on wind generation (80 MW), which are more difficult to site than solar, as well as 2 RICE units. To address this, some improvements were implemented to the Belize Centric portfolio which included the following:

- 20 MW of wind generation in 2027 and in 2029 were replaced by 20 MW of solar in 2026, 2027 and 2028. This is based on the expectation that the costs in Mexico will decline in the Peninsular region as transmission is added to prevent its economic hardship.
- Only one RICE is installed in 2024 (22.5 MW) instead of two, to reduce the dependence on imported fuels.
- Wind is maintaned after 2030 in similar levels as the Reference strategy

These adjustments resulted in the expansion plan known as Belize Centric Expert Design which is featured below.

Figure 9-23: Capacity Expansion Plan: Belize Centric Strategy Expert Design



The main difference between the Reference Expert and the Belize Centric Expert is the use of Belize wind in the second and in a smaller amount in the initial years (20 MW vs 35 MW) by 2030, compensated by 20 MW more wind post 2030 in Belize Centric Expert and 20 MW more of solar. Below we proved a comparison of the total renewable.

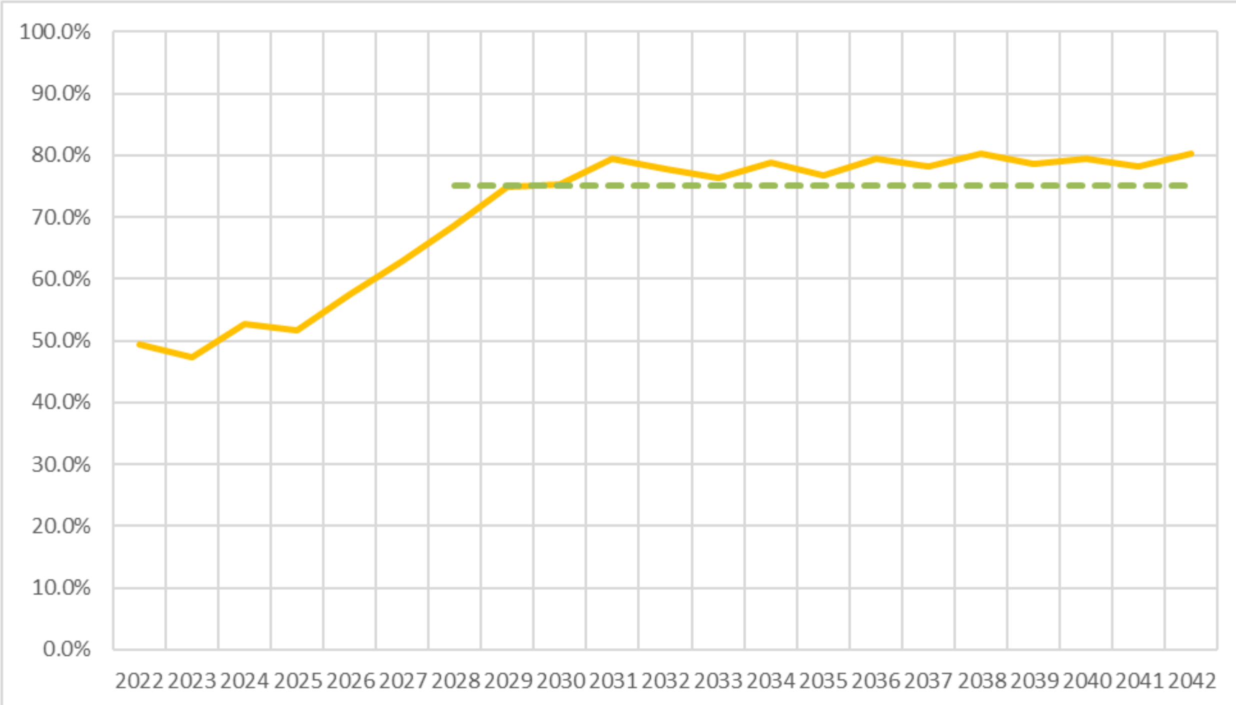
- 220 MW (180 Solar, 40 Wind) total in Belize Centric Expert
- 195 MW (160 Solar, 35 Wind) total in Reference Expert design
- 200 MW (120 Solar, 80 Wind) total in Belize Centric
- 245 MW (200 Solar, 45 Wind) total in Reference

RPS Compliance and Reserves

The plan gets to 75% by 2029 remains largely on the 75% target after 2030 reaching 80% by 2042

The combination of the adjusted expansion plan is enough to meet the targets.

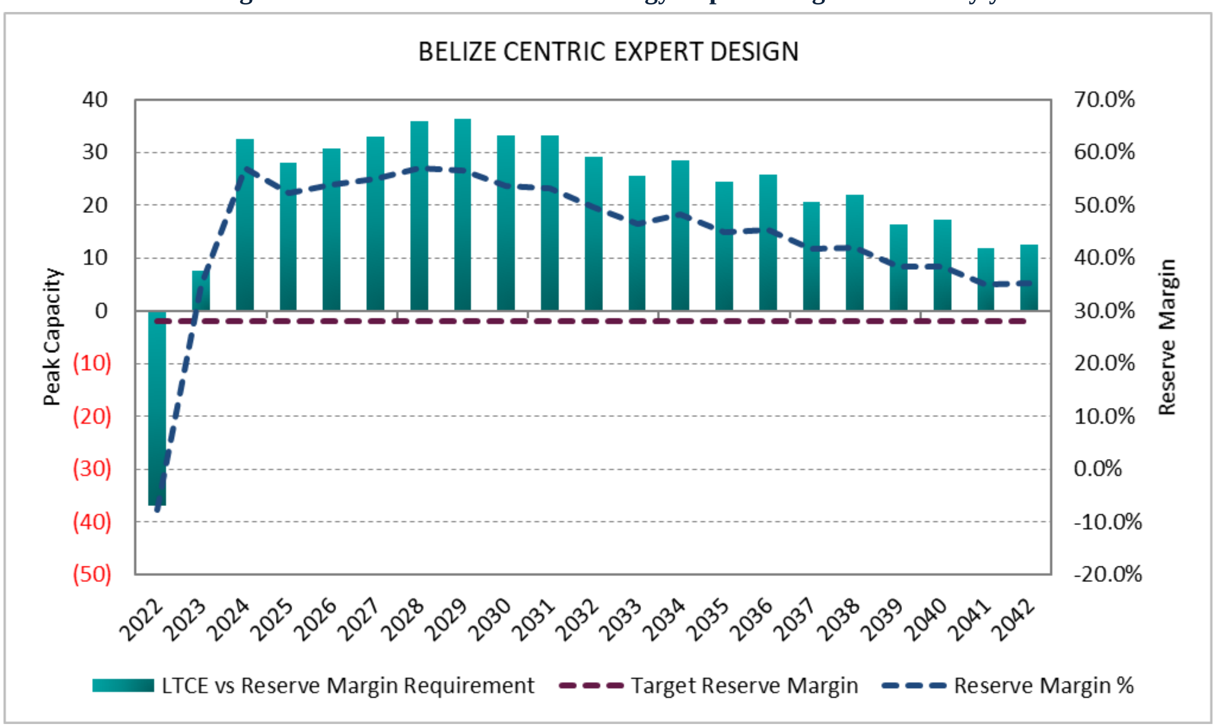
Figure 9-24: Renewable Energy Levels: Belize Centric Strategy Expert Design



Source: Siemens PTI

The portfolio addresses the existing reliability concern associated with insufficient in country reserves and maintains the reserves above the minimum requirement for the entire planning period.

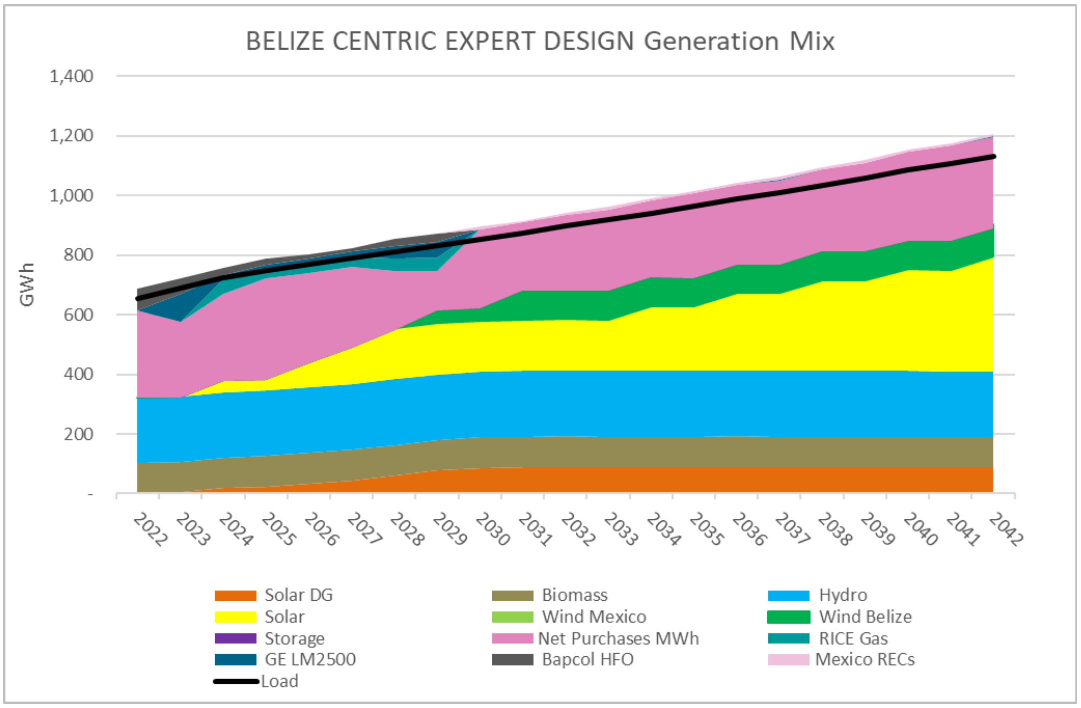
Figure 9-25: Belize Centric Strategy Expert Design Reserves by year



Energy Supply

The generation profile of the expert design portfolio is similar to that of the initial Belize Centric with some replacement of wind with solar energy. Also, the Belize Centric has more in country generation overall and by 2042 75% of the energy is produced in country vs 70% in the Reference. Also 80% of the load is supplied from renewable versus 75% in the Reference Strategy as show earlier. This is the Preferred Portfolio as shown later in this document.

Figure 9-26: Belize Generation Mix: Belize Centric Strategy Expert Design



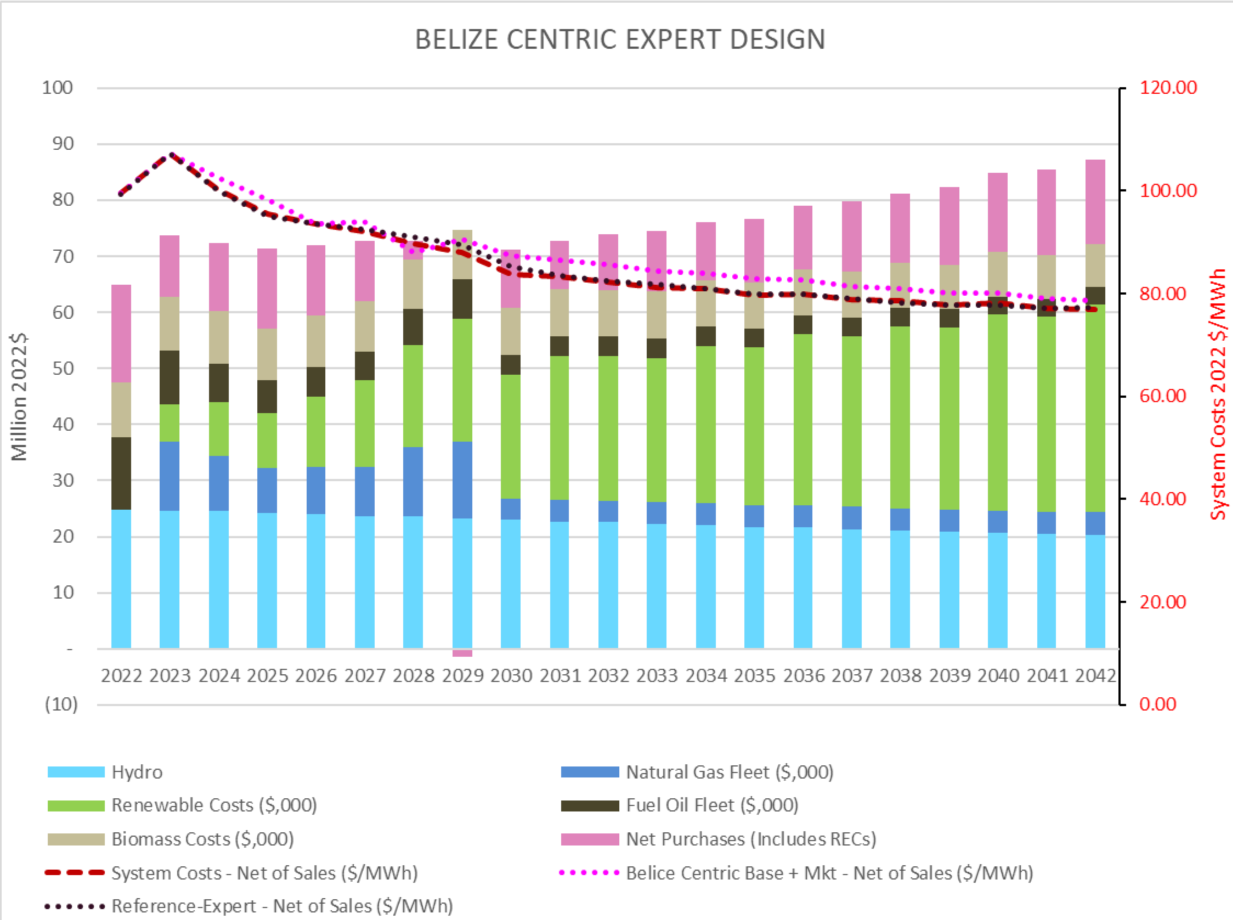
Portfolio Costs

The Expert Design by introducing solar in place of a majority wind Portfolio, achieves better cost performance than the Initial Belize Centric Portfolio, after 2030 when the Mexican Market prices drop.

This is expected as solar by itself has better LCOE than wind and absent high night peak prices, it can be a better option than wind.

The cost trajectory in $/MWh is very similar to the Reference Strategy – Expert Design, i.e., under Reference Conditions they behave similarly.

Figure 9-27: Belize Portfolio Cost Components: Belize Centric Strategy Expert Design



The Belize Centric Expert Design portfolio are lower than the Belize Centric initial portfolio and is competitive with the Reference Strategy Expert Design portfolio.

The Belize Centric Expert Design Portfolio has a total cost of to US $875millions (6.8% drop with respect of reference) and very similar (0.3% difference) with the Reference Strategy Expert Portfolio costs (877 million).

The Belize Centric has lower market purchase costs but higher fixed costs and slightly higher variable costs. The effective costs drop to US$87.46/MWh.

Net Mexican purchases are 14.8% of the costs (NPV) and 31.6% of the energy, lower to the Reference, as expected.

Figure 9-28: Portfolio Cost: Reference Strategy Expert Design vs. Belize Centric Expert Design

NPV $000 (2022$)	Reference Expert Design	Belize Centric Expert Design
Variable	57,677	61,160
Fixed	670,178	684,182
Purchases	168,537	159,460
Total Costs before sales	896,393	904,803
Market Sales	18,497	29,502
Total after sales	**877,896**	**875,301**
Total Load (MWh)	10,007,705	10,007,705
Mkt + RECS Purchases (MWh)	3,651,218	3,509,257
Energy Sales (MWh)	196,758	346,392
Total Costs $/MWh	87.72	87.46
Purchase Costs $/MWh	45.05	44.91
Sales Price $/MWh	94.01	85.17
Delta to Reference	-6.5%	-6.8%
Delta to cheapest	0.3%	0.0%
%Variable	6.6%	7.0%
% Fixed	76.3%	78.2%
Market Purchases % Tot. Cost	19.2%	18.2%
Market Sales % Tot. Cost	2.1%	3.4%
Net Market % Tot. Cost	17.1%	14.8%
Market Purchases % load	36.5%	35.1%
Market Sales % load	2.0%	3.5%
Net Market % load	34.5%	31.6%

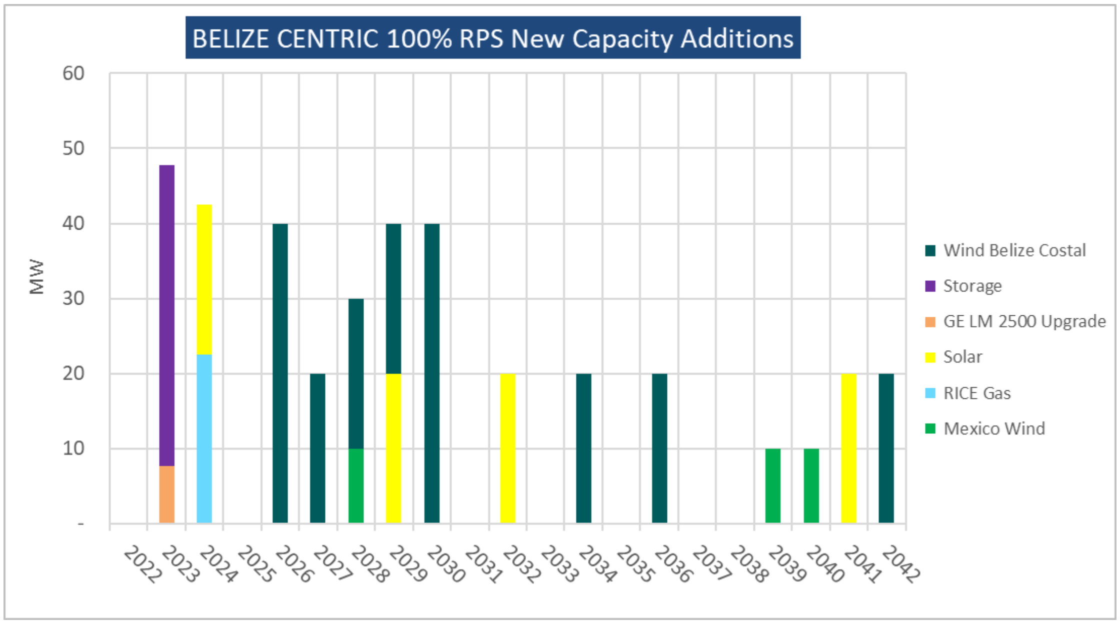
9.5 100% Renewable by 2030

Another capacity expansion plan was created in order to assess what it would take in order to achieve 100% renewable energy by 2030.

Capacity Expansion

This plan gives preference to wind generation as this provides a more uniform supply across the 24 hours of the day along with the fact that purchases from Mexico need to be largely phased out after 2030, as Mexico RECs were not considered in this assessment.

Figure 9-29: Expansion Plan: Belize Centric Strategy with 100% RPS Requirements

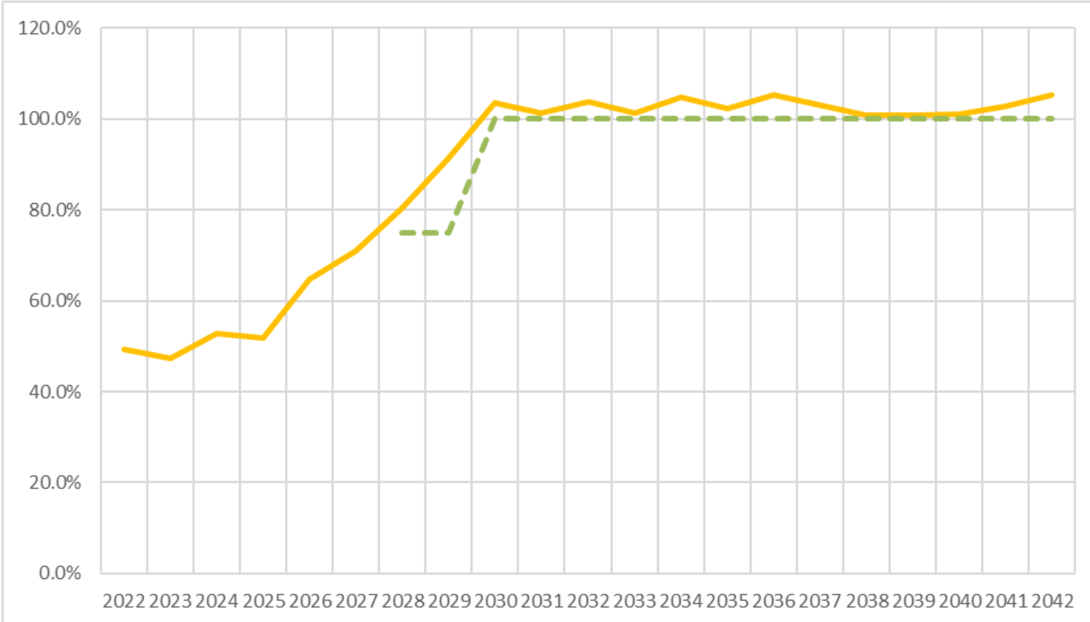


This portfolio installed 150 MW of wind resources (inclusive of 10 MW of Vientos del Caribe wind project) and 40 MW solar by 2030 and overall, 230 MW wind with 80 MW solar throughout the entire period. This further confirms the assessment that wind generation is a good hedge against high Mexico prices or other conditions that may limit the energy that can be purchased from Mexico. Note that this plan also installs a RICE gas unit for reserves.

RPS Compliance and Reserves

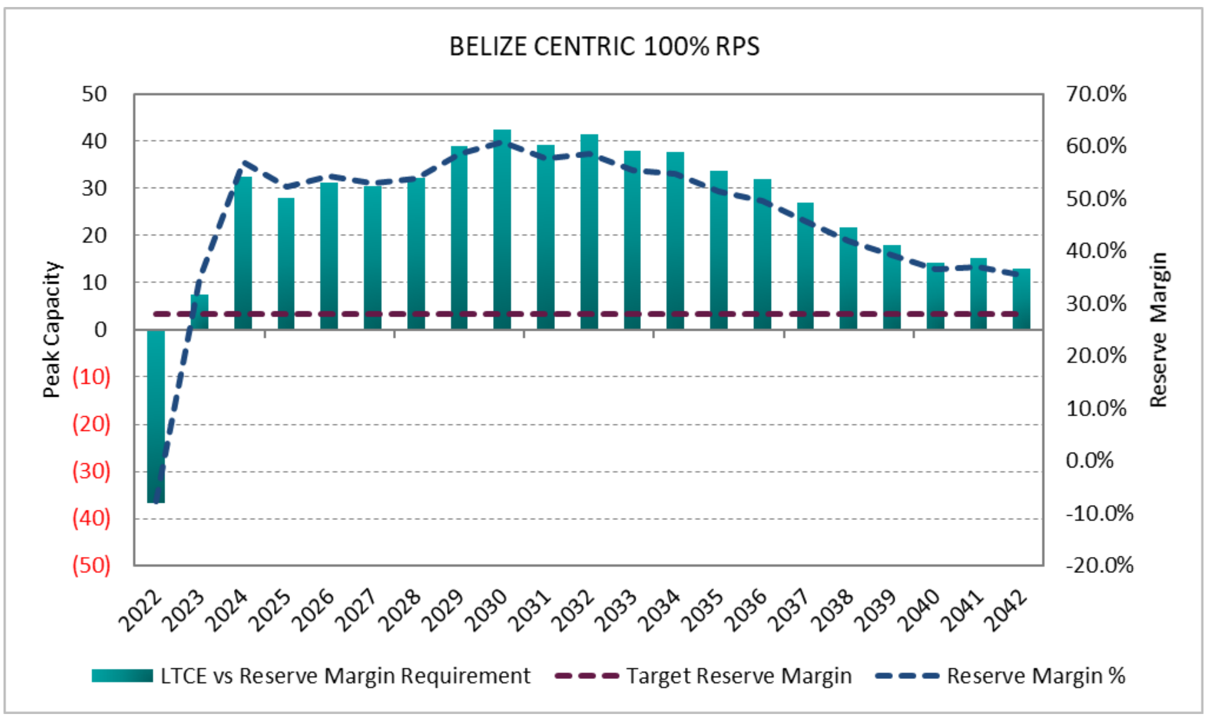
This plan successfully achieves 100% renewable energy by 2030 and keeps that consistently throughout the study period. The renewable targets are the main driver of the expansion plan.

Figure 9-30: Renewable Energy Requirements: Belize Centric Strategy with 100% RPS Requirements



The reserves have a profile very similar to all prior cases, with the initial increase in 2023.

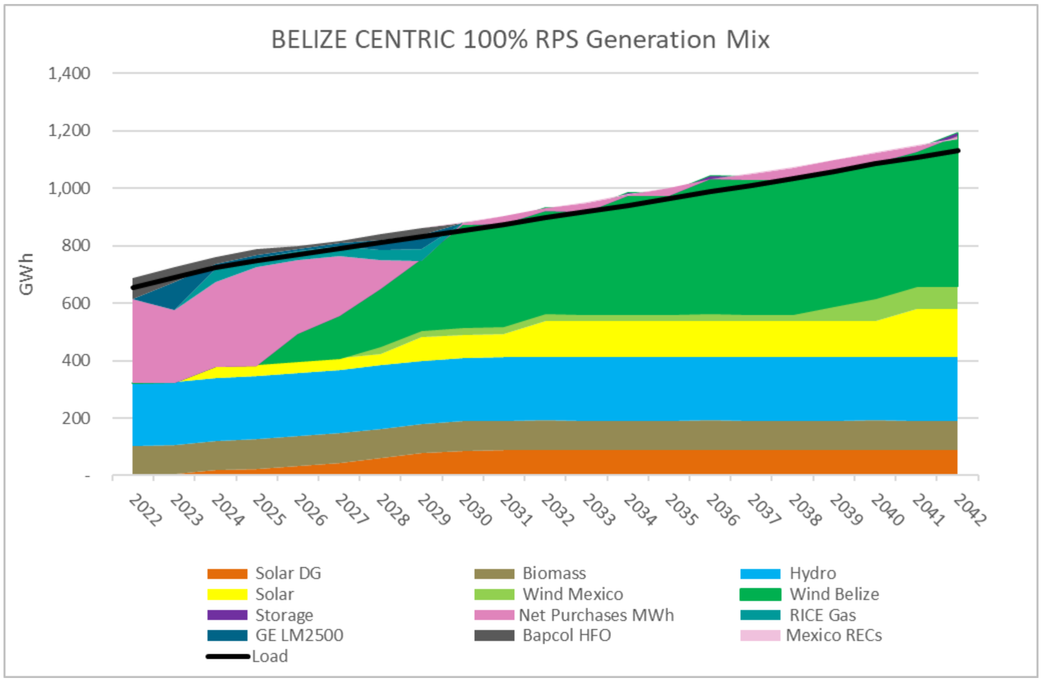
Figure 9-31: Belize Centric Strategy with 100% RPS Reserves by year



Energy Supply

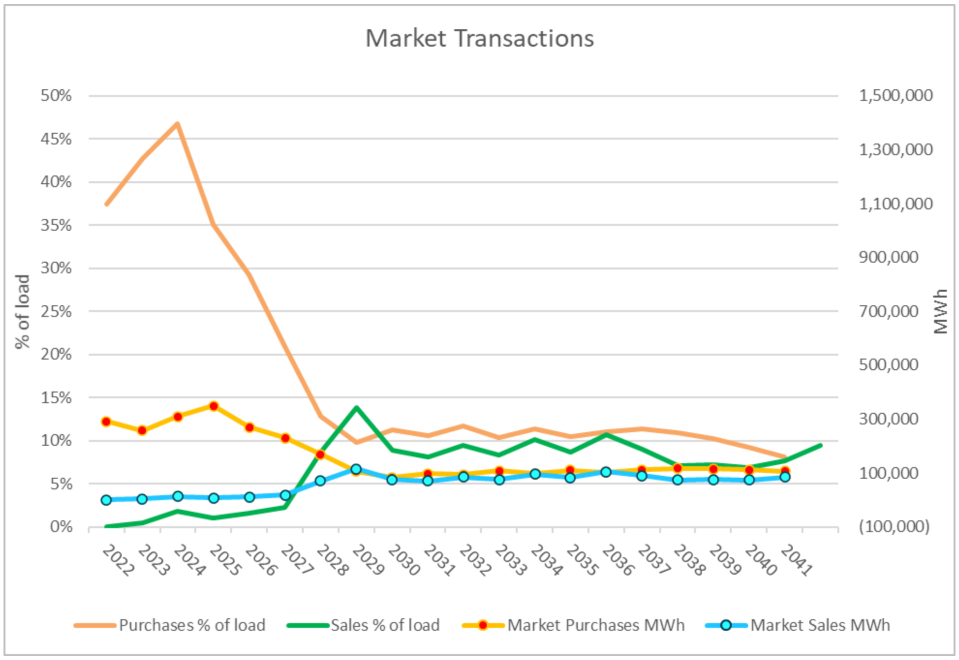
For the generation mix associated with this portfolio, wind becomes the leading source of energy to support Belize load, followed by hydro. Mexico purchases are phased out by 2029 and the sales are in line with purchases following that year.

Figure 9-32: Belize Generation Mix: Belize Centric Strategy with 100% RPS Requirements



One of the largest differences in the 100% RPS portfolio is its independence from Mexico purchases as compared to all other portfolios. Market transactions between Mexico drop significantly in the first 6 years, dropping to only 10% market purchases by 2028 as compared to the 20-30% purchases in other portfolios.

Figure 9-33: Belize Market Transactions: Belize Centric Strategy with 100% RPS Requirements

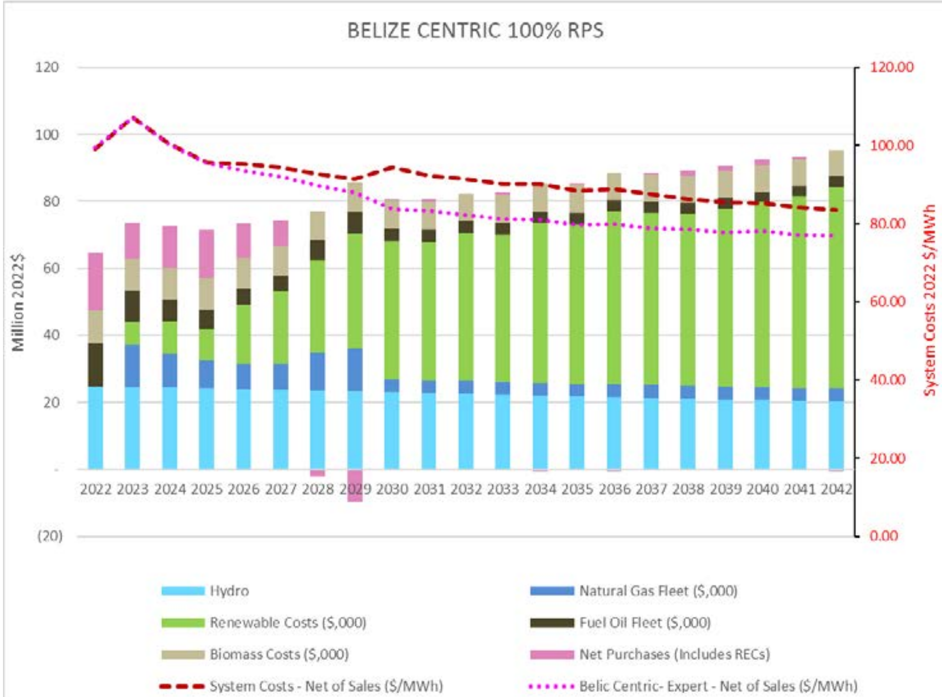


Portfolio Costs

From a portfolio cost perspective, the 100% RPS Portfolio comes out to be roughly 6% higher than the expert design portfolios, largely due to its fixed cost portions and slightly offset by lower market purchases and increased market sales with Mexico.

We note below that from 2030 onwards when the cost in Mexico drops due to the expansion of the interconnection Oriental – Peninsular, the cost separate, and the 100% renewable becomes more expensive ~ US$8.0/MWh (0.8 US Cents / kWh).

Figure 9-34: Belize Portfolio Costs: Belize Centric Strategy with 100% RPS Requirements



As shown in the table below, the Total portfolio NPV of Revenue Requirements is US $927 million and about 5.9 % more expensive than the Belize Centric Expert Portfolio. The Net Mexican purchases represent 6% of the costs (NPV) and 15.2 % of the load (energy).

Table 9-1: Portfolio Cost Comparison

NPV $000 (2022$)	Reference Expert Design	Belize Centric Expert Design	Belize Centric 100% by 2030
Variable	57,677	61,160	56,660
Fixed	670,178	684,182	814,749
Purchases	168,537	159,460	98,944
Total Costs before sales	896,393	904,803	970,352
Sales	18,497	29,502	43,136
Total after sales	**877,896**	**875,301**	**927,216**
Total Load (MWh)	10,007,705	10,007,705	10,007,705
Mkt + RECS Purchases (MWh)	3,651,218	3,509,257	2,148,036
Energy Sales (MWh)	196,758	346,392	623,775
Total Costs $/MWh	87.72	87.46	92.65
Purchase Costs $/MWh	45.05	44.91	45.73
Sales Price $/MWh	94.01	85.17	68.99
Delta to Reference	-6.5%	-6.8%	-1.3%
Delta to cheapest	0.3%	0.0%	5.9%
%Variable	6.6%	7.0%	6.1%
% Fixed	76.3%	78.2%	87.9%
Market Purchases % Tot. Cost	19.2%	18.2%	10.7%
Market Sales % Tot. Cost	2.1%	3.4%	4.7%
Net Market % Tot. Cost	17.1%	14.8%	6.0%
Market Purchases % load	36.5%	35.1%	21.5%
Market Sales % load	2.0%	3.5%	6.2%
Net Market % load	34.5%	31.6%	15.2%

Conclusions and Observations.

Belize can achieve 100% renewable by 2030 but this will result in a capacity expansion plan that is more expensive than the proposed plan and will forfeit the opportunities to benefit from the lower costs in the Mexican market after 2030.

9.6 Expanded Transmission Portfolio

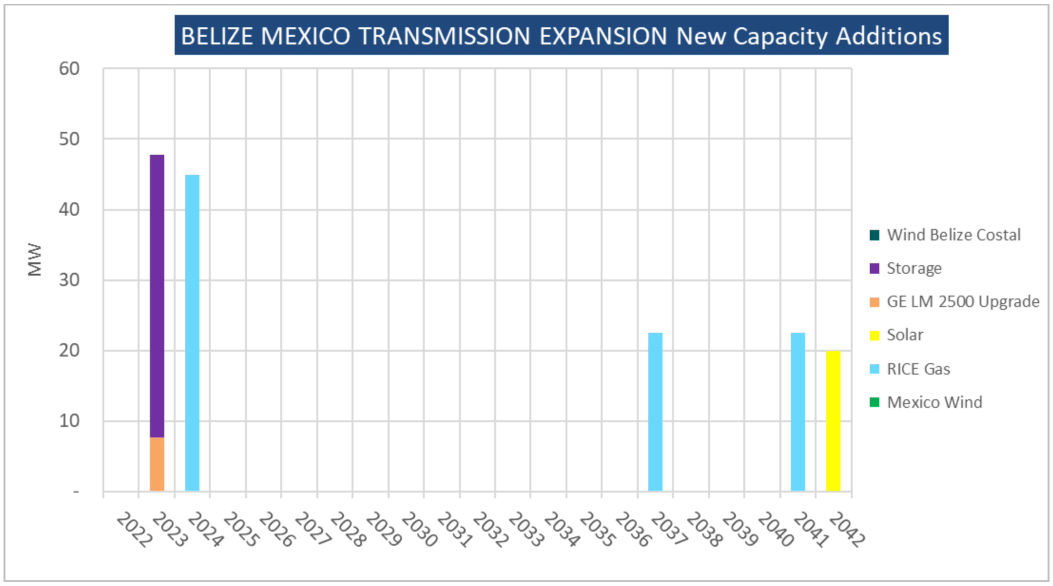
This portfolio that was created to assess the benefits of expanding the interconnection with Mexico. The new interconnection was assumed to be in service by 2027 along with the assumption that there was also much more access to purchase Mexico RECs in order to meet the Belize RPS requirements in 2030 and beyond.

Capacity Expansion

The capacity expansion portfolio that resulted from this scenario resulted in similar near-term additions such as the LM2500 expansion, battery storage and the addition of RICE gas units by 2024.

No renewable energy was selected until 2042 as the RPS requirements were met purely through Mexico REC purchases.

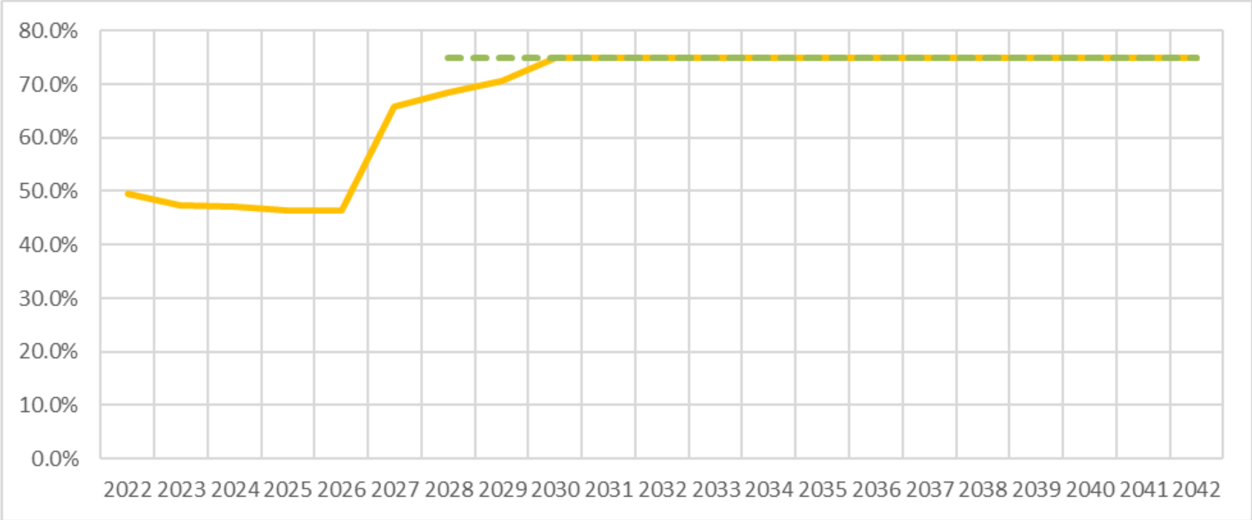
Figure 9-35: Expansion Plan: Mexico Transmission Expansion Plan



RPS Compliance and Reserves

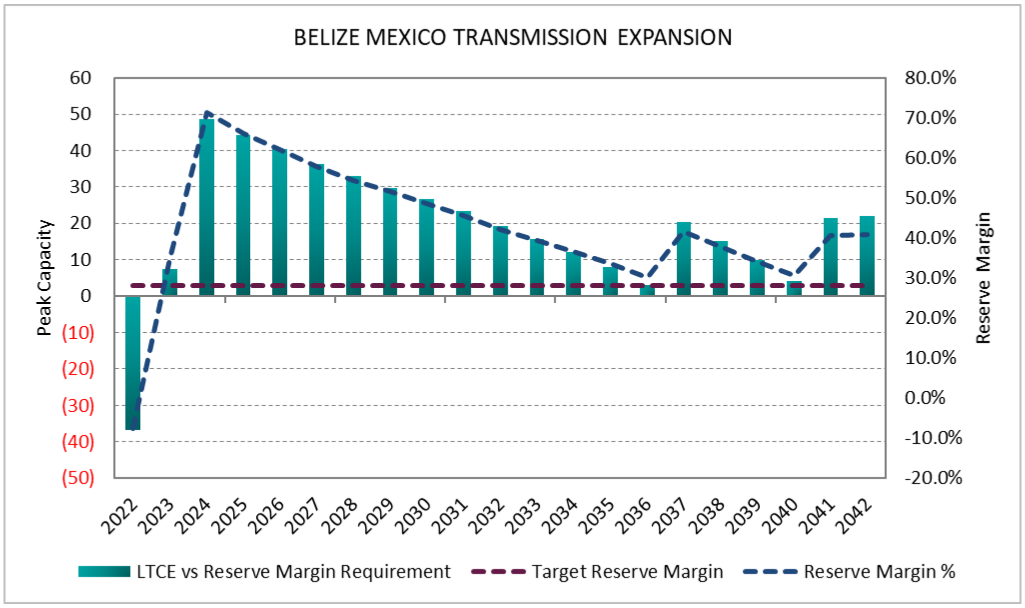
The plan met the RPS to the exact 75% and stayed there.

Figure 9-36: Renewable Energy Levels: Expanded Transmission



Also, we see below that all generation additions were needed in order to meet necessary reserves.

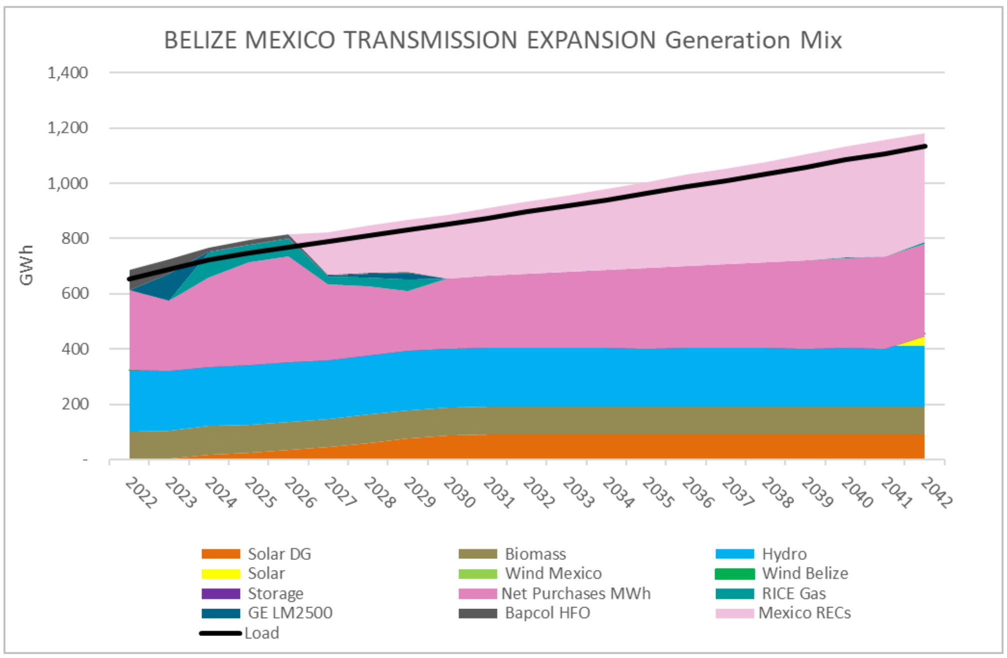
Figure 9-37: Belize Reserve Margin: Mexico Transmission Expansion Plan



Energy Supply

This scenario resulted in high reliance on Mexico purchases to meet overall load as well as RPS requirements.

Figure 9-38: Belize Generation Mix: Mexico Transmission Expansion Plan



Portfolio Cost

Despite its flexibility for market purchases, this portfolio came out slightly more expensive than both of the Expert Design portfolios (Reference strategy and Belize Centric strategy) even before the transmission costs are added. Total portfolio NPV with the increased capability to import from Mexico has a total cost of $880 million vary similar to the Belize Centric cost ($875 million), but once we added the cost of the new interconnection ($55 million), became significantly more expensive $934 million as shown below.

Table 9-4: Belize Portfolio Cost by Component: Increased transmission

NPV $000 (2022$)	Belize Centric Expert Design	Expanded Imports from Mex (second line)
Variable	61,160	52,846
Fixed	684,182	611,335
Purchases	159,460	280,530
Total Costs before sales	904,803	944,712
Market Sales	29,502	10,458
Total after sales	**875,301**	**934,254**
Total Load (MWh)	10,007,705	10,007,705
Mkt + RECS Purchases (MWh)	3,509,257	2,148,036
Energy Sales (MWh)	346,392	623,775
Total Costs $/MWh	87.46	93.35
Purchase Costs $/MWh	44.91	48.60
Sales Price $/MWh	85.17	48.14
Delta to Reference	-6.8%	-0.5%
Delta to cheapest	0.0%	6.7%
%Variable	7.0%	5.7%
% Fixed	78.2%	65.4%
Market Purchases % Tot. Cost	18.2%	30.0%
Market Sales % Tot. Cost	3.4%	1.1%
Net Market % Tot. Cost	14.8%	28.9%
Market Purchases % load	35.1%	21.5%
Market Sales % load	3.5%	6.2%
Net Market % load	31.6%	15.2%

9.7 Portfolio Summary

Based on the studies conducted both the Reference and the Belize Centric strategies has its merits and result in portfolios with similar costs once the initial output from Aurora is further enhanced. There can be important gains by increasing the ability to import energy from the Mexican Market beyond the 55 MW contractual limit with Calificados.

The Belize Centric Expert Design Portfolio and the Reference Strategy Expert Design Portfolio were recommended to be kept and further analyzed with sensitivities for the identification of the preferred portfolio.

From a transmission point of view, both strategies with the same levels of dispatchable generation thermal and storage, have very similar behavior and it should be the sensitivities and scenarios factor to be used for the selection of the preferred portfolio

Figure 9-39: Belize Portfolio Cost Components: All Candidate Portfolios

NPV $000 (2022$)	Reference Case	Reference with Increased Market Limit	Scenario MX REC Energy Purchases	Reference Expert Design	Belize Centric Base	Belize Centric Expert Design	Belize Centric 100% by 2030	Expanded Imports from Mex (second line)
Variable	79,492	62,081	47,577	57,677	65,336	61,160	56,660	52,846
Fixed	716,941	716,941	656,334	670,178	698,781	684,182	814,749	611,335
Purchases	174,242	162,187	208,084	168,537	158,592	159,460	98,944	280,530
Total Costs before sales	970,675	941,208	911,996	896,393	922,710	904,803	970,352	944,712
Market Sales	31,394	33,259	18,400	18,497	27,882	29,502	43,136	10,458
Total after sales	**939,282**	**907,949**	**893,596**	**877,896**	**894,828**	**875,301**	**927,216**	**934,254**
Total Load (MWh)	10,007,705	10,007,705	10,007,705	10,007,705	10,007,705	10,007,705	10,007,705	10,007,705
Mkt + RECS Purchases (MWh)	3,322,188	3,617,295	4,377,800	3,651,218	3,441,747	3,509,257	2,148,036	2,148,036
Energy Sales (MWh)	378,995	421,536	350,718	196,758	252,660	346,392	623,775	623,775
Total Costs $/MWh	93.86	90.73	89.29	87.72	89.41	87.46	92.65	93.35
Purchase Costs $/MWh	52.45	44.84	47.53	45.05	45.02	44.91	45.73	48.60
Sales Price $/MWh	82.83	78.90	52.46	94.01	110.35	85.17	68.99	48.14
Delta to Reference	0.0%	-3.3%	-4.9%	-6.5%	-4.7%	-6.8%	-1.3%	-0.5%
Delta to cheapest	7.3%	3.7%	2.1%	0.3%	2.2%	0.0%	5.9%	6.7%
%Variable	8.5%	6.8%	5.3%	6.6%	7.3%	7.0%	6.1%	5.7%
% Fixed	76.3%	79.0%	73.4%	76.3%	78.1%	78.2%	87.9%	65.4%
Market Purchases % Tot. Cost	18.6%	17.9%	23.3%	19.2%	17.7%	18.2%	10.7%	30.0%
Market Sales % Tot. Cost	3.3%	3.7%	2.1%	2.1%	3.1%	3.4%	4.7%	1.1%
Net Market % Tot. Cost	15.2%	14.2%	21.2%	17.1%	14.6%	14.8%	6.0%	28.9%
Market Purchases % load	33.2%	36.1%	43.7%	36.5%	34.4%	35.1%	21.5%	21.5%
Market Sales % load	3.8%	4.2%	3.5%	2.0%	2.5%	3.5%	6.2%	6.2%
Net Market % load	29.4%	31.9%	40.2%	34.5%	31.9%	31.6%	15.2%	15.2%

10. Scenarios and Sensitivities

A variety of sensitivities and scenarios were performed on the selected portfolios to analyze how each would perform under specific sets of circumstances. This included 3 sensitivities and 6 additional scenarios.

10.1 Sensitivities

The sensitivities analyzed included the following:

- Low Hydro
- Low Demand Forecast
- High Demand Forecast

10.1.1 Low Hydro Sensitivity

In the “Low Hydro” sensitivity, the hydroelectric energy produced by Belize hydro resources is expected to be only at the 20th percentile of generation using historical data, as compared to the reference scenarios whereas the expected generation is calculated with the 50th percentile.

In both the Reference Strategy Expert Design portfolio and the Belize Centric Expert Design portfolio, the main impact on the portfolios is the decreased hydro generation within the portfolio resulted in an increase in Mexico REC purchases in order to meet the RPS requirements of 75% renewable generation by 2030.

Figure 10-1: Belize Generation Mix – Reference Low Hydro

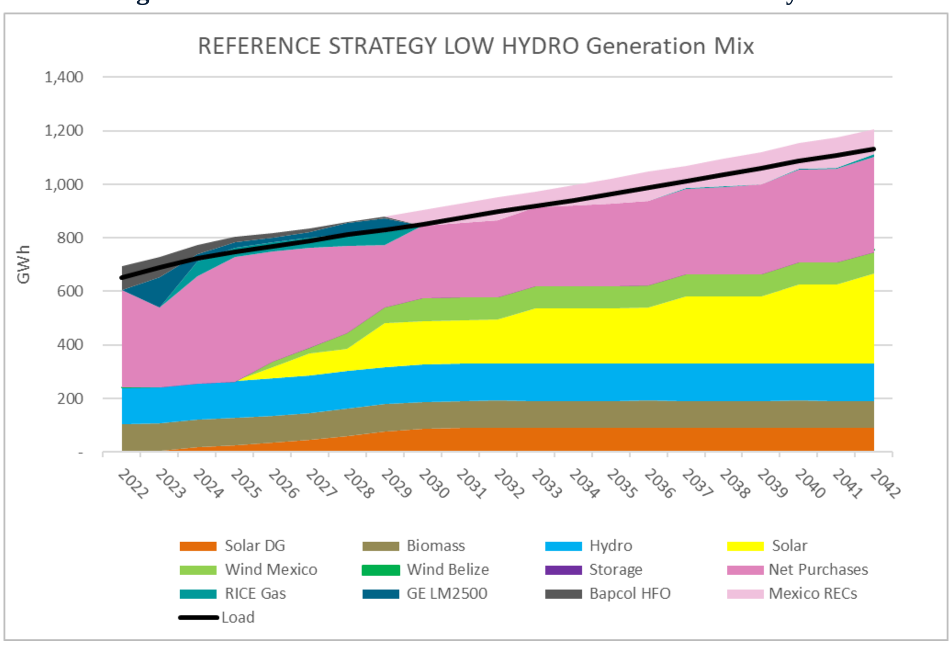
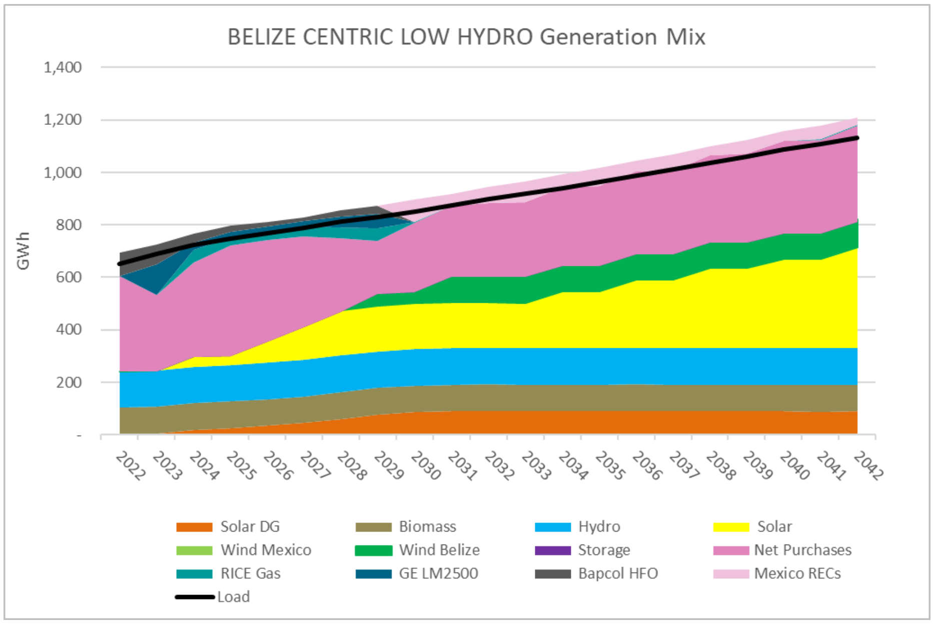


Figure 10-2: Belize Generation Mix: Belize Centric Strategy



On a portfolio cost basis, there is larger impact on the Reference Strategy portfolio over the Belize Centric. The Belize Centric with higher renewable in country is better able to manage this condition and (the regret of selecting the Ref. Strategy) increases to US$ 4.8 million from $ 2.6 million under reference conditions, as detailed below.

Figure 10-3: Portfolio Cost Comparison

NPV $000	Reference Expert Design Reference Conditions	Belize Centric Expert Design Reference Conditions	Reference Expert Low Hydro	Belize Centric Expert Low Hydro
Variable	57,677	62,888	68,978	71,597
Fixed	670,178	684,182	670,178	684,182
Purchases	168,537	157,732	221,242	209,624
Total Costs before sales	896,393	904,803	960,399	965,402
Market Sales	18,497	29,502	13,351	23,122
Total after sales	877,896	875,301	947,048	942,280
Regret	2,596	-	4,768	-
Total Load (MWh)	10,007,705	10,007,705	10,007,705	10,007,705
Energy Purchases (MWh)	3,651,218	3,509,257	4,113,673	4,077,113
Energy Sales (MWh)	196,758	346,392	151,587	279,044
Total Costs $/MWh	88	87	95	94
Purchase Costs $/MWh	46	45	54	51
Sales Price $/MWh	94	85	88	83

10.1.2 Low Demand Forecast Sensitivity

As discussed previously in the "Energy Demand Forecasts" section, a low demand sensitivity was created by adjusting 2 key independent variables in the load forecast, which include the population forecast and the GDP variables lower range outlooks. More information regarding these forecasts can be found in the Demand Forecast section of this report. This sensitivity also included a lower EV outlook as well.

As opposed to the low hydro sensitivity, the low demand forecast resulted in less reliance on Mexico REC purchases to meet the necessary RPS requirements. This sensitivity also resulted in less overall purchases from Mexico as well as increased sales to Mexico.

Figure 10-4: Low Demand Sensitivity Generation Mix – Reference Portfolio

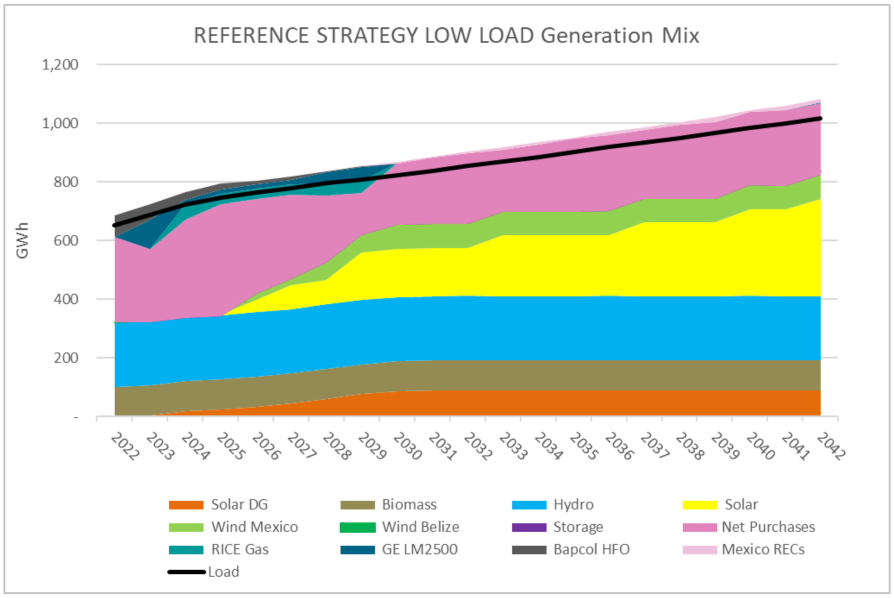
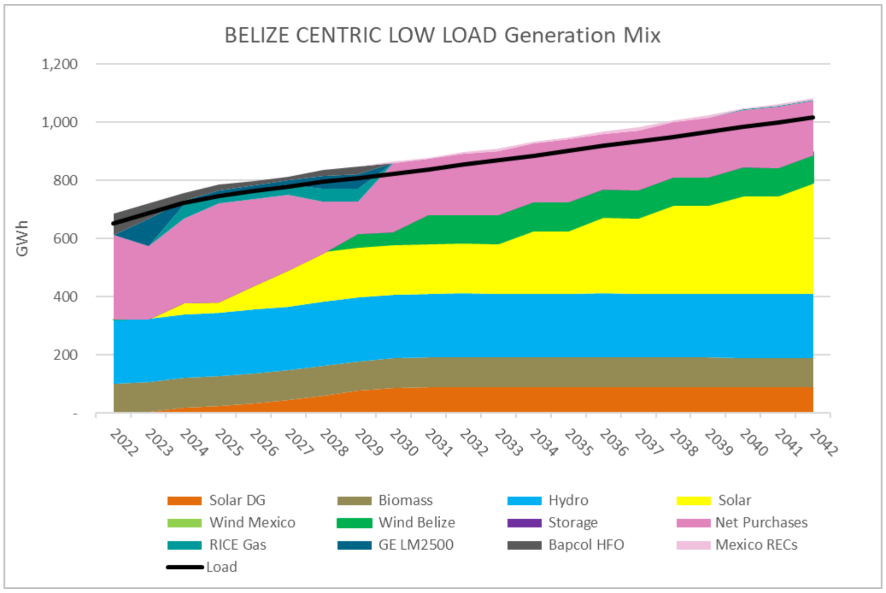


Figure 10-5: Low Demand Sensitivity Generation Mix – Belize Centric Portfolio



The RPS targets are met and exceeded in this sensitivity. As seen below, the Reference Strategy portfolio stays constant around 80% and the Belize Centric portfolio reaches nearly 90% by 2042.

Figure 10-6: Low Load Sensitivity Renewable Energy Levels – Reference Portfolio

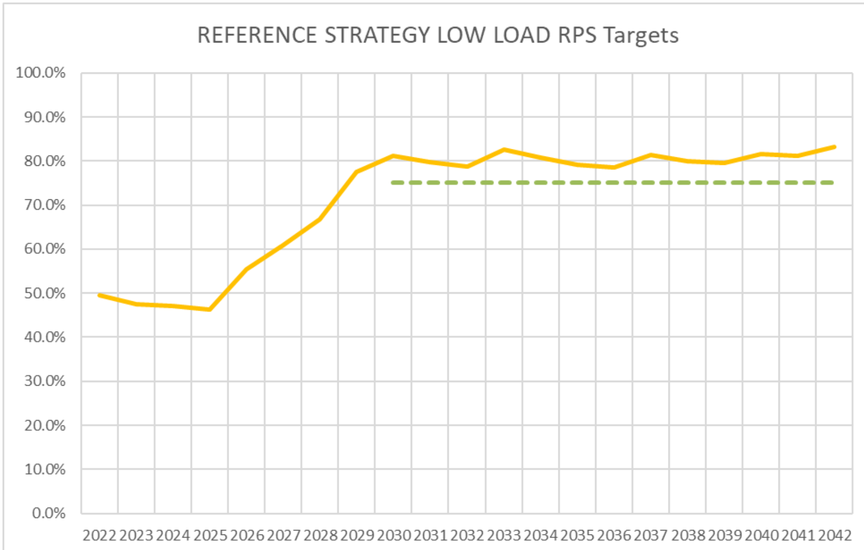
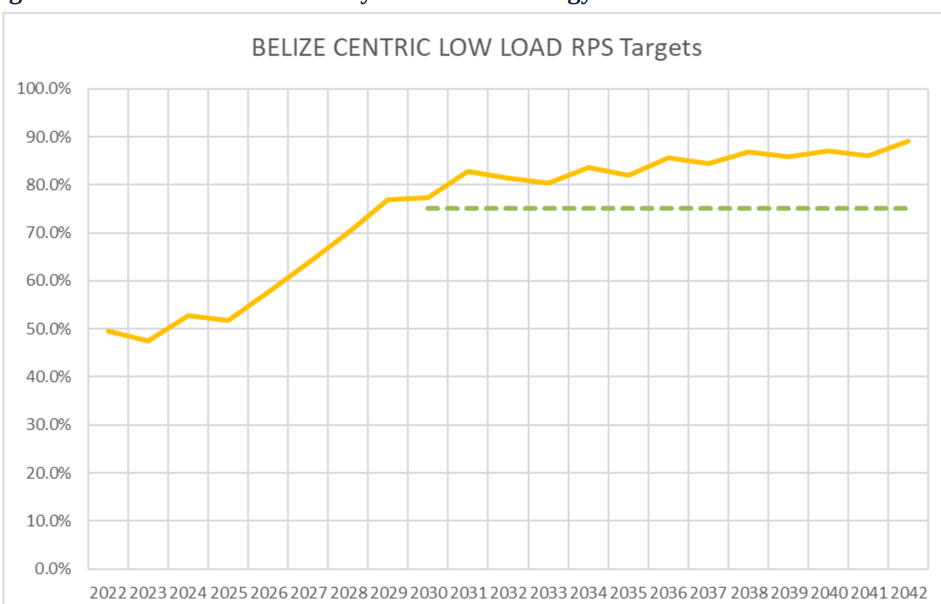


Figure 10-7: Low Load Sensitivity Renewable Energy Levels – Belize Centric Portfolio



As expected, on a cost basis, the total portfolio costs decrease in the low load sensitivity due to the decreased energy purchases and increased energy sales. The Reference Strategy with lower in country generation was expected to manage better the low load condition, but the Belize Centric portfolio continue being the optimal portfolio from a cost perspective, but the level of regret of the Reference Strategy portfolio decreased when compared with Reference Conditions.

Table 10-1: Low Load Sensitivities Cost Comparison

NPV $000	Reference Expert Design Reference Conditions	Belize Centric Expert Design Reference Conditions	Reference Expert Low Load	Belize Centric Expert Low Load
Variable	57,677	62,888	57,260	60,890
Fixed	670,178	684,182	670,178	684,182
Purchases	168,537	157,732	151,244	144,219
Total Costs before sales	896,393	904,803	878,683	889,291
Market Sales	18,497	29,502	21,141	33,382
Total after sales	877,896	875,301	857,542	855,909
Regret	2,596	-	1,633	-
Total Load (MWh)	10,007,705	10,007,705	9,615,842	9,615,842
Energy Purchases (MWh)	3,651,218	3,509,257	3,349,314	3,195,125
Energy Sales (MWh)	196,758	346,392	254,562	428,327
Total Costs $/MWh	88	87	89	89
Purchase Costs $/MWh	46	45	45	45
Sales Price $/MWh	94	85	83	78

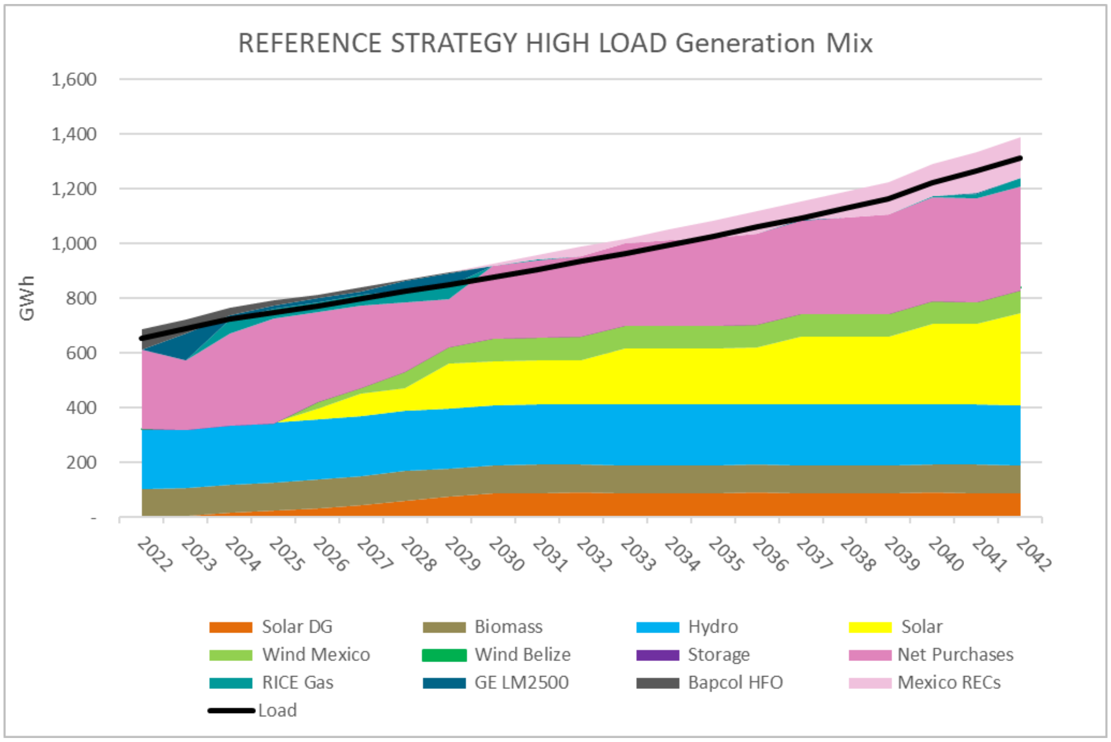
10.1.3 High Demand Sensitivity

As with the low demand sensitivity, a high demand sensitivity was also created using high range outlooks for population growth and GDP variables. Along with a general increase in baseline demand assumptions, a high EV forecast was also incorporated into the high demand sensitivity.

Within the high demand sensitivity, there is an additional demand for not only meeting load requirements, but also in order to meet the 75% RPS requirement based on the increased load values. This results in a higher need to purchase Mexico RECs within both portfolios in the sensitivity.

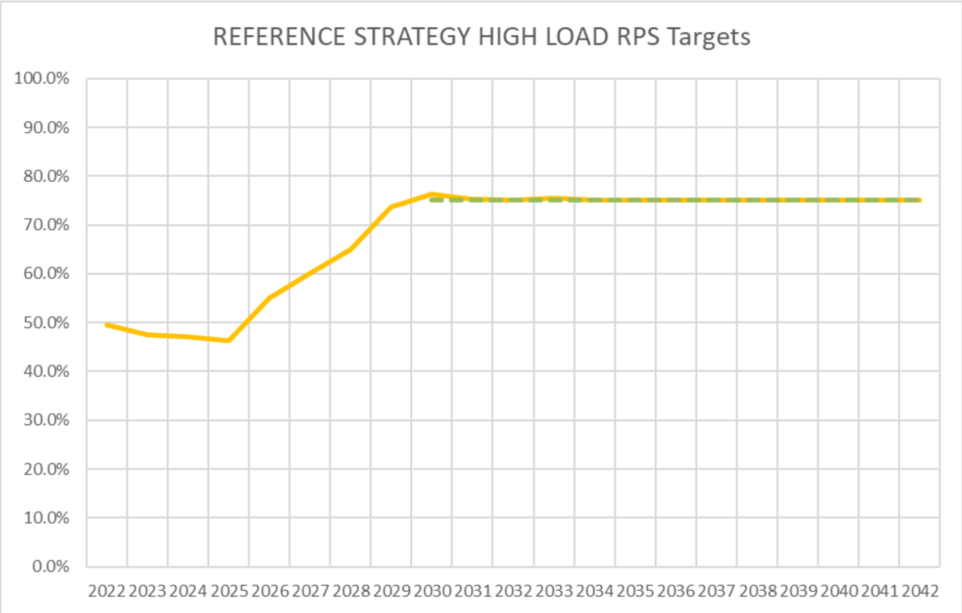
The generation mix remains relatively similar to other sensitivities, but with a significant difference in the Mexico RECs portion.

Figure 10-8: High Load Sensitivity Generation Mix – Reference Portfolio



As seen in the graph below, each MWh of Mexico REC purchases are necessary to meet the new 75% target based on a higher demand forecast.

Figure 10-9: High Load Sensitivity Renewable Energy Levels – Reference Portfolio



Similar patterns persist in the Belize Centric portfolio that require increased market purchases, specifically RECs in order to meet the necessary load and RPS requirements.

This sensitivity does have a larger impact on overall portfolio cost in the reference portfolio, as it relies on Mexico purchases more than the Belize Centric portfolio, which has more wind generation in critical hours and has more renewable in country. The overall regret on the Reference portfolio increases over 200% in the high load sensitivity when compared with the reference conditions.

Table 10-2: High Load Sensitivities Cost Comparison

NPV $000	Reference Expert Design Reference Conditions	Belize Centric Expert Design Reference Conditions	Reference Expert High Load	Belize Centric Expert High Load
Variable	57,677	62,888	59,438	61,586
Fixed	670,178	684,182	670,178	684,182
Purchases	168,537	157,732	193,975	182,026
Total Costs before sales	896,393	904,803	923,591	927,794
Market Sales	18,497	29,502	15,723	26,058
Total after sales	877,896	875,301	907,868	901,735
Regret	2,596	-	6,132	-
Total Load (MWh)	10,007,705	10,007,705	10,455,001	10,455,001
Energy Purchases (MWh)	3,651,218	3,509,257	3,773,519	3,761,069
Energy Sales (MWh)	196,758	346,392	148,489	282,221
Total Costs $/MWh	88	87	87	86
Purchase Costs $/MWh	46	45	51	48
Sales Price $/MWh	94	85	106	92

10.2 Scenarios

The Reference Strategy Expert Design and Belize Centric Expert Design Portfolios also went through a multitude of various scenarios as well. These scenarios combined various sensitivities together. A total of 6 additional scenarios were analyzed. These scenarios included the following:

- High International Pricing
- Low Capital and Low International Pricing
- High Technology
- High Regulation
- Low Regulation
- Climate Crisis
- Low Hydro – High Demand

10.2.1 High International Pricing Scenario

In the High International Pricing scenario, the underlying assumptions included a high price of capital along with high fuel pricing and overall higher international purchase pricing due to a combination of high fuel prices in Mexico as well as the assumed line expansion in 2030 between Peninsular-Oriental is no longer applied. The high capital costs were calculated using ratios for low capital based on NREL scenarios.

The loss of the 2030 Peninsular-Oriental line expansion has a large direct effect on overall Peninsular prices and the decision for Belize to purchase energy at certain hours. The high cost of imported energy results in direct increases from Belize dispatchable energy from the RICE additions and LM2500 unit in each portfolio until purchases (RECS included) are necessary for load supply and reliability.

Figure 10-10: High International Energy Generation Mix – Reference Portfolio

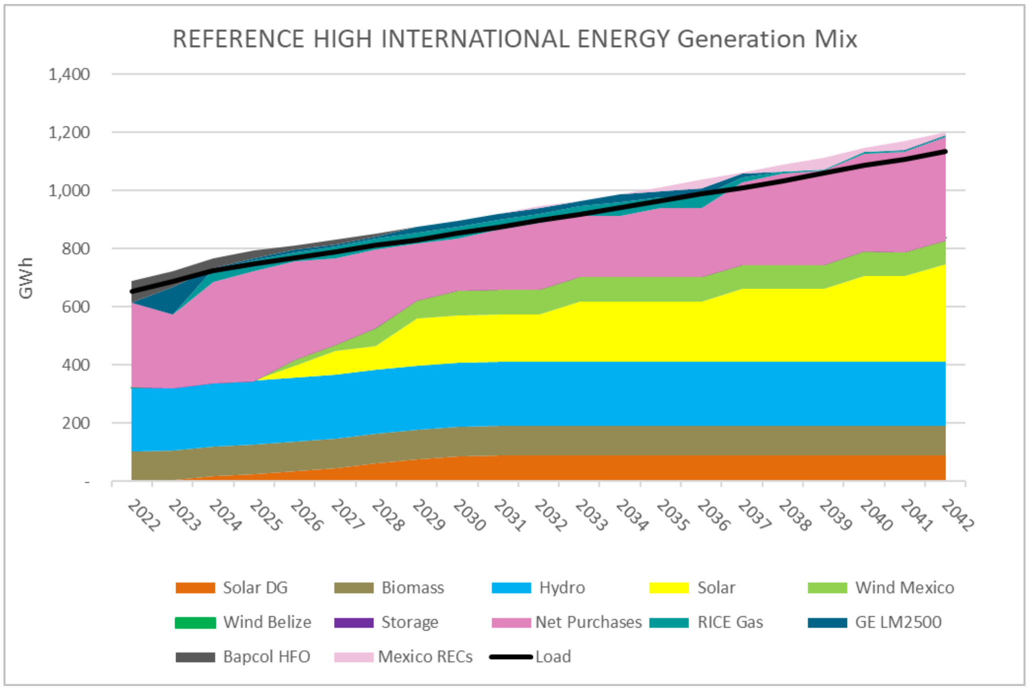
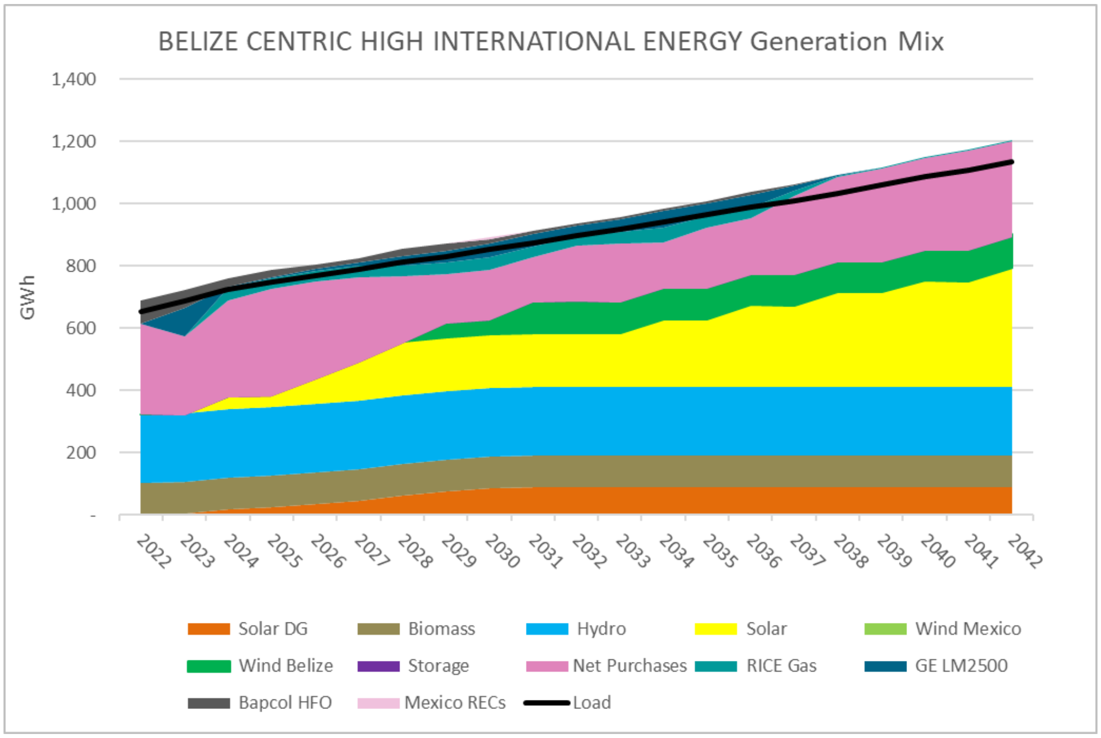


Figure 10-11: High International Energy Generation Mix – Belize Centric Portfolio



In this case the Belize Centric strategy manages better the increase in fuel prices and Mexico Prices, with a small impact on the increase in capital cost that more adversely affect this portfolio. The regret of selecting the Reference Strategy increases to US$ 6.9 million.

Table 10-3: High International Pricing Scenario Cost Comparison

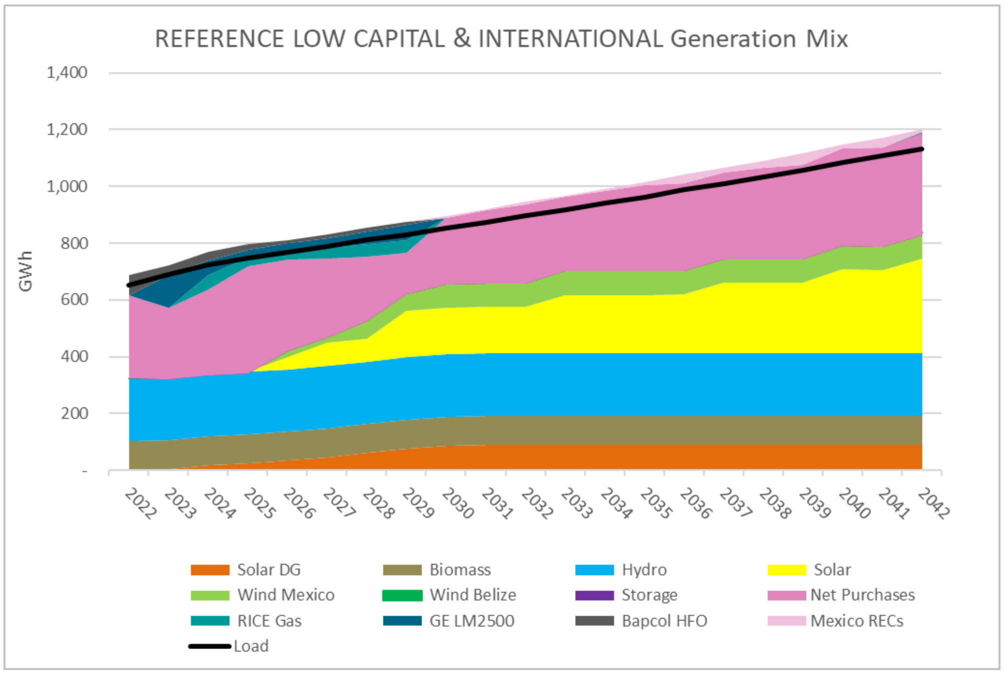
NPV $000	Reference Expert Design Reference Conditions	Belize Centric Expert Design Reference Conditions	Reference Expert High Int Cost	Belize Centric High Int Cost
Variable	57,677	62,888	81,223	99,718
Fixed	670,178	684,182	709,372	720,191
Purchases	168,537	157,732	206,629	202,668
Total Costs before sales	896,393	904,803	997,223	1,022,577
Market Sales	18,497	29,502	26,296	58,564
Total after sales	877,896	875,301	970,927	964,013
Regret	2,596	-	6,914	-
Total Load (MWh)	10,007,705	10,007,705	10,007,705	10,007,705
Energy Purchases (MWh)	3,651,218	3,509,257	3,077,224	2,968,021
Energy Sales (MWh)	196,758	346,392	317,331	699,324
Total Costs $/MWh	88	87	97	95
Purchase Costs $/MWh	46	45	58	57
Sales Price $/MWh	94	85	95	90

10.2.2 Low Capital and Low International Prices Scenario

In the Low Capital and Low International Prices scenario, the underlying assumptions included a low price of capital, low Belize fuel prices and low international purchase prices driven by low fuel prices in Mexico. The low capital costs were calculated using ratios for low capital based on NREL scenarios.

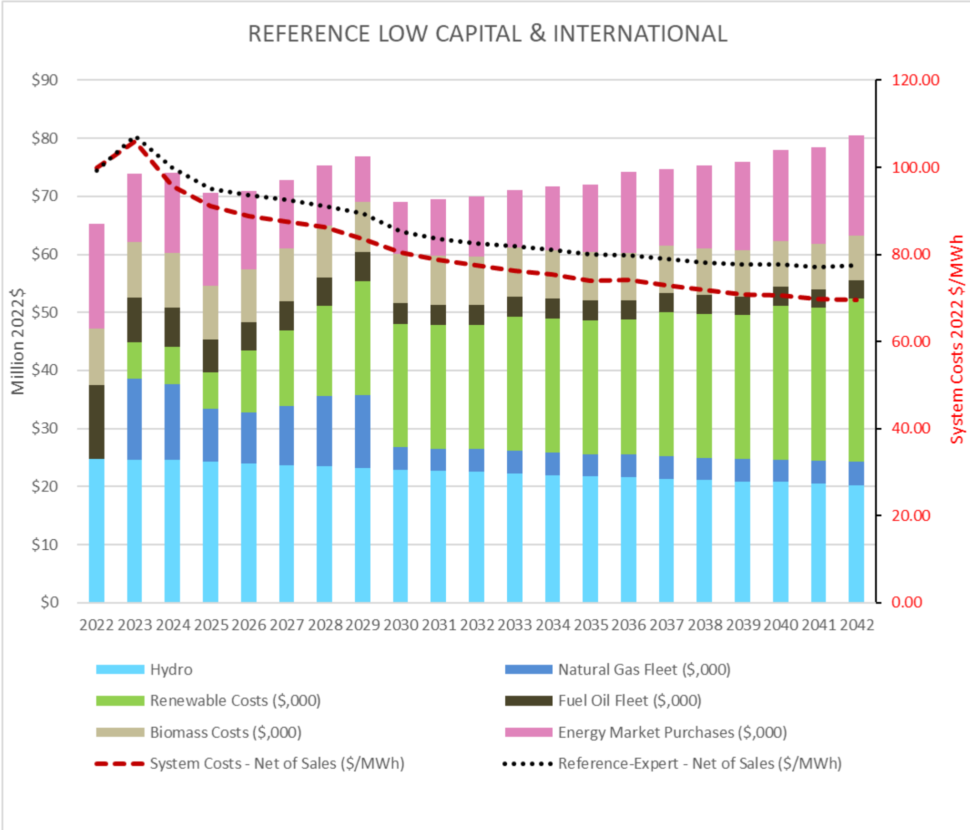
The generation mix within this scenario is very similar to that of the original portfolios, with the low cost of fuel not resulting in a large increase of fuel specific generation and a similar amount of Mexico purchases, despite the low costs. These similarities are largely due to the amount of renewable generation within the portfolio and the unchanged load forecast makes the dispatch order to cover Belize load extremely similar to the base conditions.

Figure 10-12: Low Capital and International Pricing Generation Mix – Reference Portfolio



The low capital and international purchase prices do have a significant impact on the overall portfolio costs however, with the decreased price of purchases, lower capital for renewable builds and lower fuel costs resulting in a much lower overall system cost. For the Reference Expert Design portfolio, the NPVRR comes out almost 6% lower than under base conditions.

Figure 10-13: Low Capital and International Pricing Cost Components – Reference Portfolio



The Belize Centric portfolio has similar traits in which the generation mix does not vary extensively in the low capital and low international scenario but does not have as large of a payoff as the reference case as it relies slightly less than the Reference portfolio on Mexico purchases, therefore saving less money when there are low purchase price opportunities, also not gaining as much revenue for the small amount of sales that are usually beneficial in the Belize Centric portfolio.

Figure 10-14: Low Capital and International Pricing Generation Mix – Belize Centric Portfolio

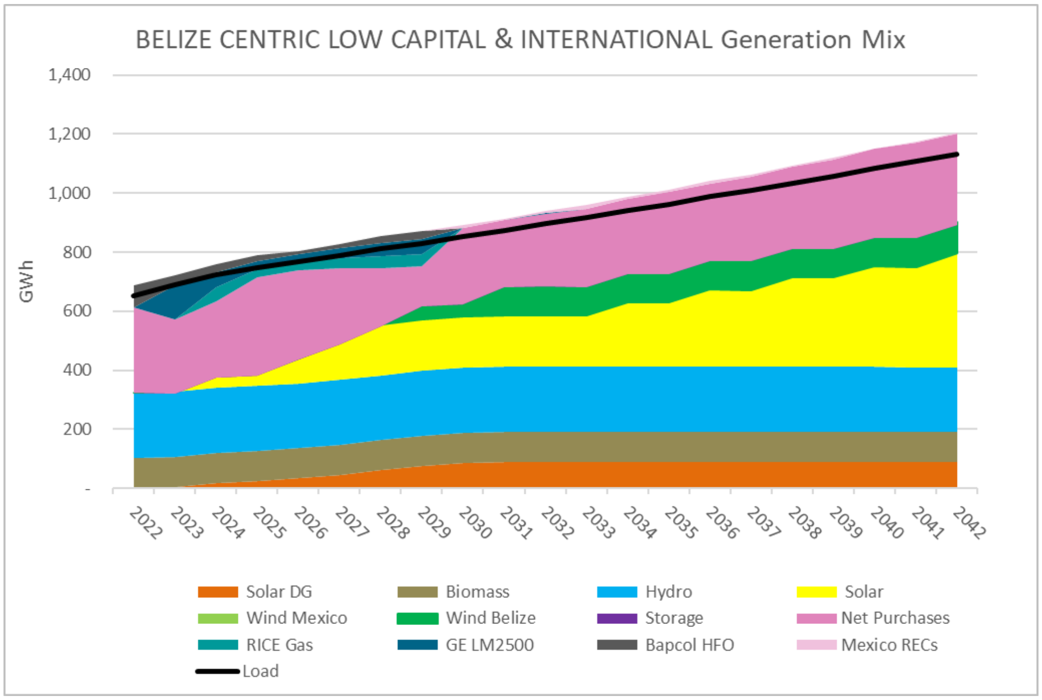
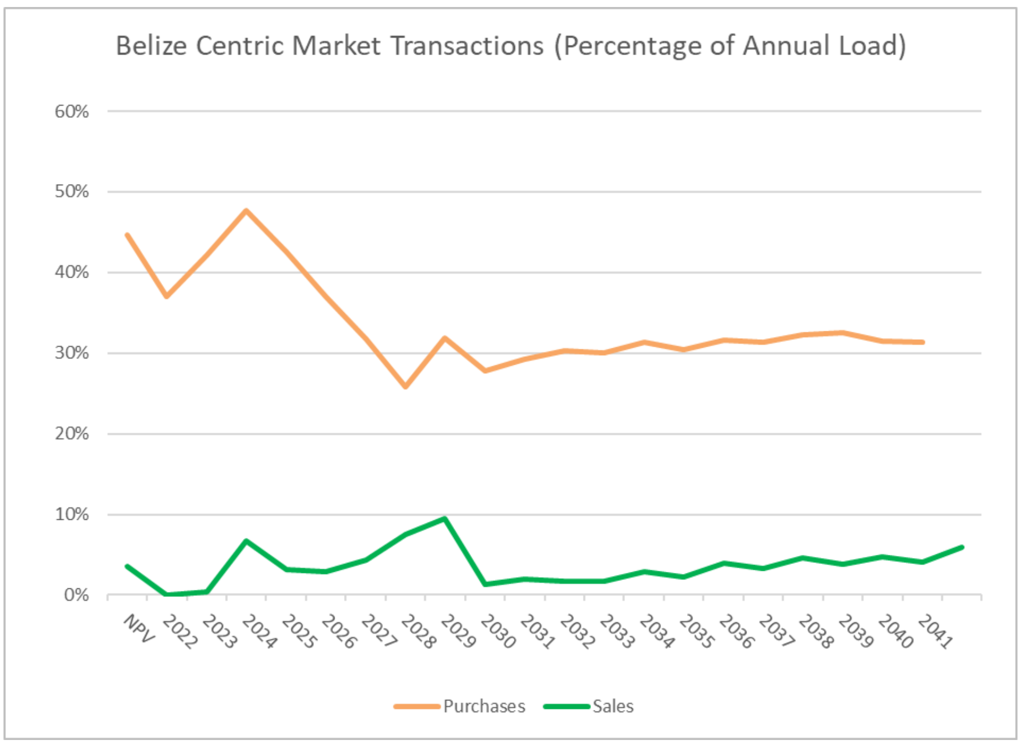


Figure 10-15: Low Capital and International Pricing Market Transactions – Belize Centric Portfolio



The portfolio costs do benefit from low capital, fuel cost and Mexico purchase prices as compared to the base scenario.

This is the only scenario where Belize Centric has regret US$ 0.9 million as shown below. This regret is much lower than any of the cases, so the plan is still "Min Regret" although it is not NO Regret.

Table 10-4: Low Capital and International Pricing Cost Comparison

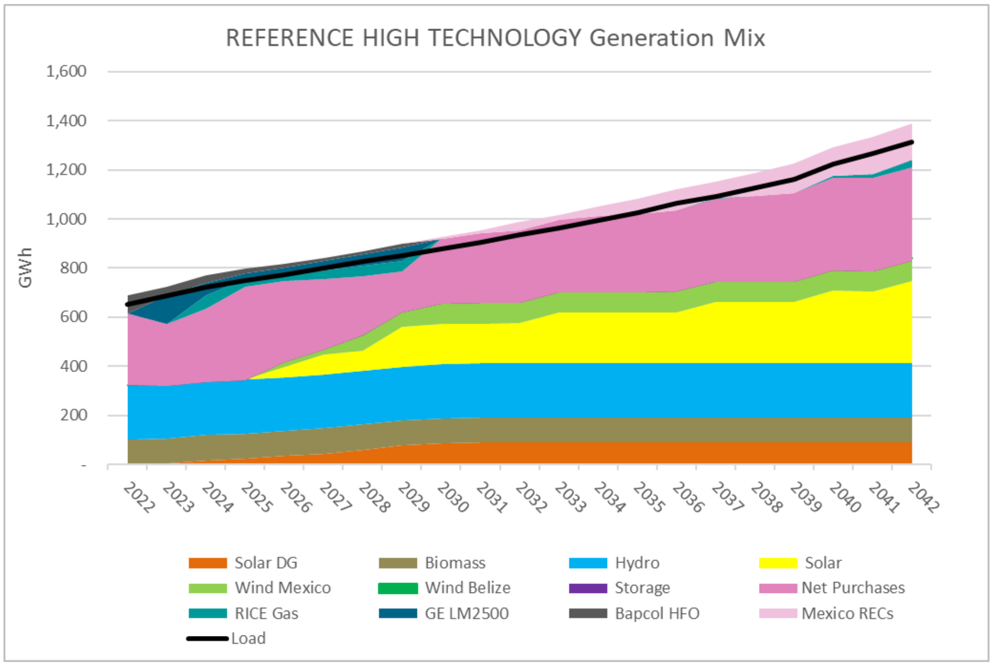
NPV $000	Reference Expert Design Reference Conditions	Belize Centric Expert Design Reference Conditions	Reference Expert Low Capital & International Energy	Belize Centric Low Capital & International Energy
Variable	57,677	62,888	61,866	62,122
Fixed	670,178	684,182	641,851	656,620
Purchases	168,537	157,732	150,381	143,166
Total Costs before sales	896,393	904,803	854,098	861,907
Market Sales	18,497	29,502	24,781	31,722
Total after sales	877,896	875,301	829,317	830,186
Regret	2,596	-	-	869
Total Load (MWh)	10,007,705	10,007,705	10,007,705	10,007,705
Energy Purchases (MWh)	3,651,218	3,509,257	3,612,414	3,469,225
Energy Sales (MWh)	196,758	346,392	235,298	357,832
Total Costs $/MWh	88	87	83	86
Purchase Costs $/MWh	46	45	42	41
Sales Price $/MWh	94	85	105	89

10.2.3 High Technology Scenario

In the high technology scenario, the underlying assumptions include high demand projection in Belize, driven by higher economic growth and electrification along with lower renewable and storage costs which results in low fuel price projections, driven by decreased demand for fuels.

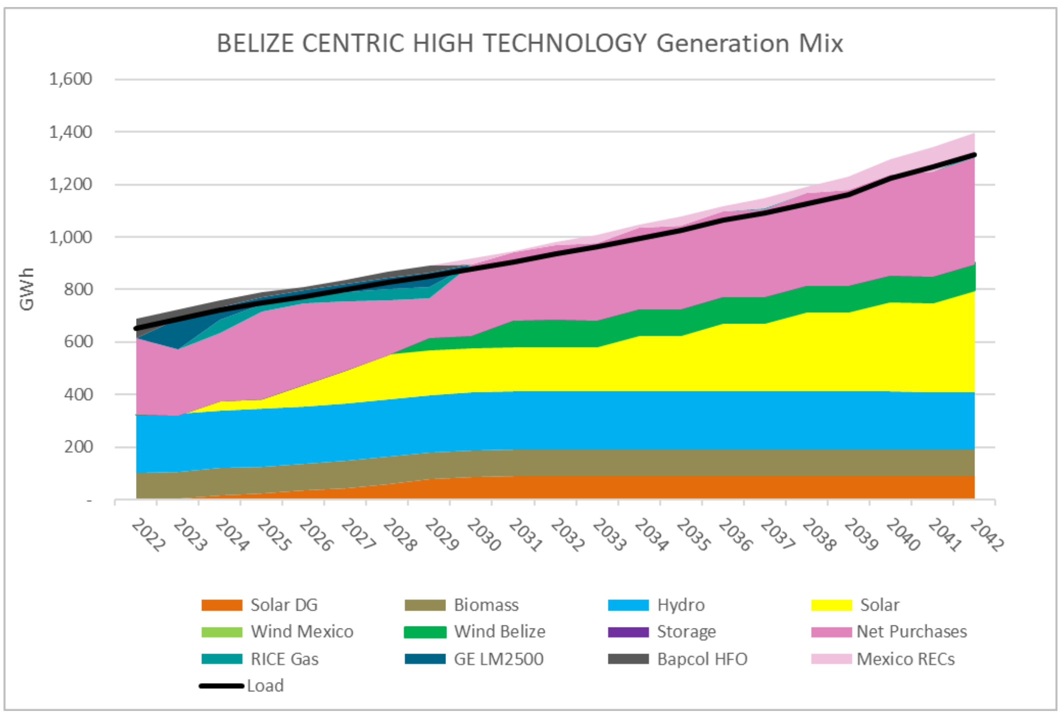
The generation mix changes in this scenario involve increased Mexico REC purchases in order to support load growth and the necessary RPS requirements for both the Reference and Belize Centric portfolios.

Figure 10-16: High Technology Generation Mix – Reference Portfolio



Within the reference portfolio, the low fuel projections also make it more economically feasible for some late year RICE gas generation in order to help support demand in hours that are usually higher priced due to renewable volatility.

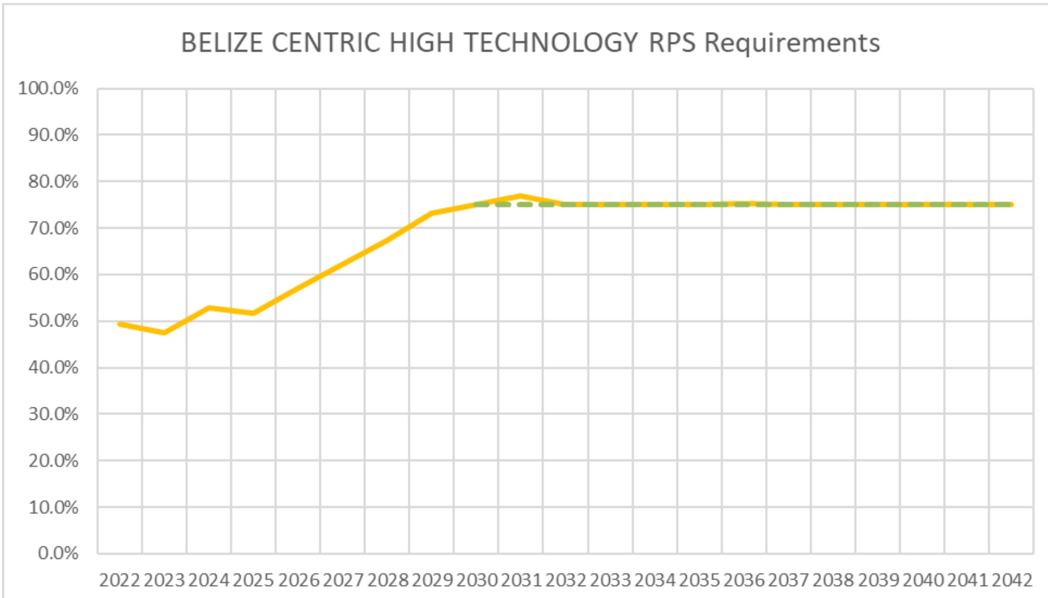
Figure 10-17: High Technology Generation Mix – Belize Centric Portfolio



The Belize centric portfolio does not require further support from the RICE unit as it has slightly more wind available in those hours as compared to the reference portfolio.

The RPS requirements for both portfolios are met through the purchase of Mexico RECs as the high load increased the necessary energy to maintain the 75% goal.

Figure 10-18: High Technology Renewable Energy Levels – Belize Centric Portfolio



On a portfolio cost basis, the Reference portfolio was the best performer under these circumstances and the regret of the Reference Strategy increased slightly as shown below.

Table 10-5: High Technology Cost Comparison

NPV $000	Reference Expert Design Reference Conditions	Belize Centric Expert Design Reference Conditions	Reference Expert High Tech	Belize Centric High Tch
Variable	57,677	62,888	63,194	62,487
Fixed	670,178	684,182	641,851	656,620
Purchases	168,537	157,732	173,697	162,931
Total Costs before sales	896,393	904,803	878,742	882,037
Market Sales	18,497	29,502	22,661	28,925
Total after sales	877,896	875,301	856,081	853,112
Regret	2,596	-	2,968	-
Total Load (MWh)	10,007,705	10,007,705	10,455,001	10,455,001
Energy Purchases (MWh)	3,651,218	3,509,257	3,748,751	3,722,552
Energy Sales (MWh)	196,758	346,392	193,197	296,815
Total Costs $/MWh	88	87	82	84
Purchase Costs $/MWh	46	45	46	44
Sales Price $/MWh	94	85	117	97

10.2.4 High Regulation Scenario

In the high regulation scenario, the underlying assumptions include low demand projection along with high cost of fuel driven by high regulation of fuels as well as carbon penalties are applied to Belize and Mexico.

In the high regulation scenario, generation mix is similar to that of others, with slightly less reliance on Mexico purchases due to the decreased demand.

Figure 10-19: High Regulation Generation Mix – Reference Portfolio

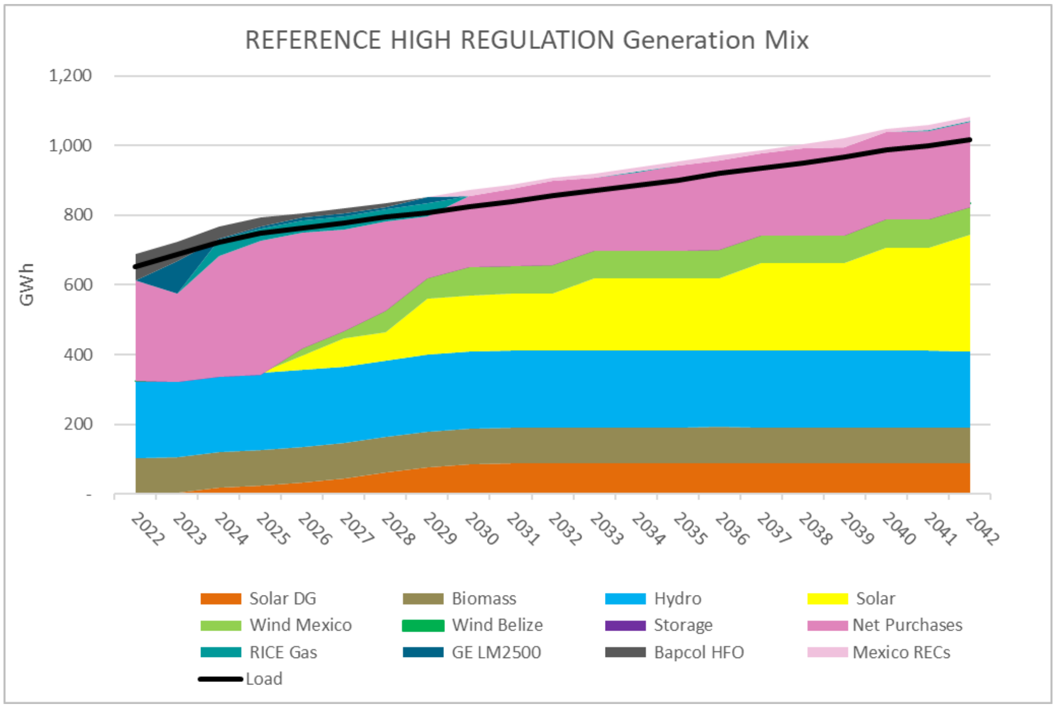
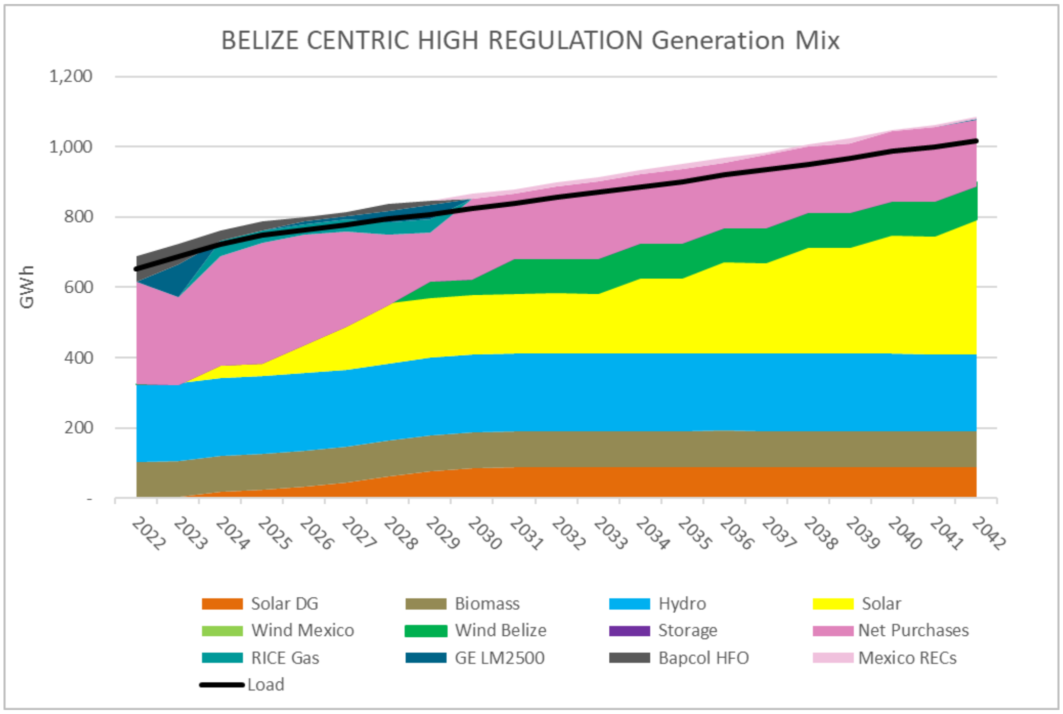
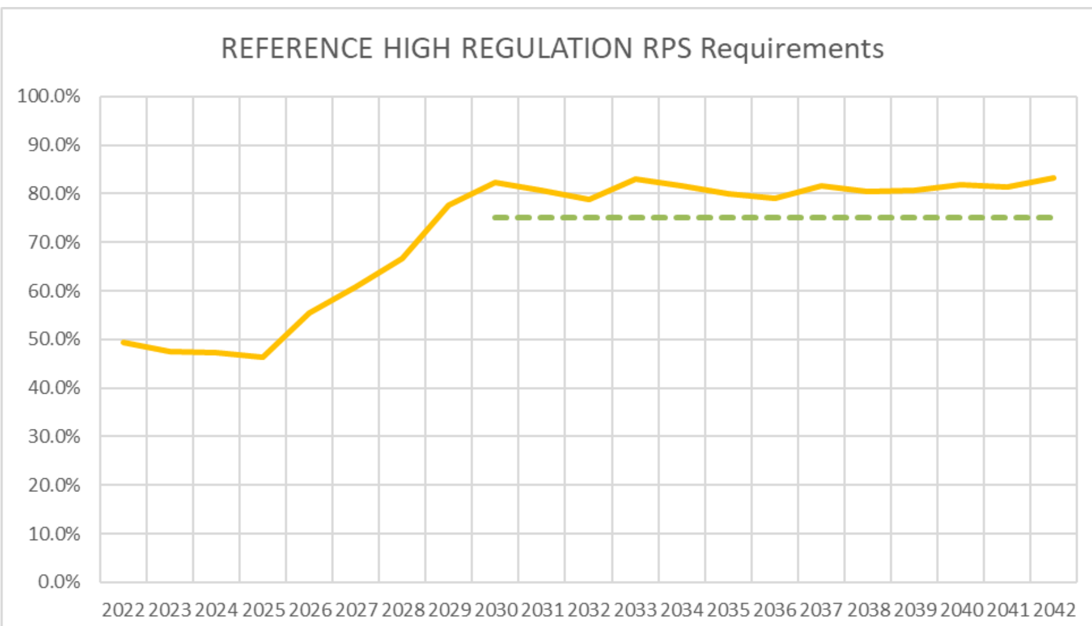


Figure 10-20: High Regulation Generation Mix – Belize Centric Portfolio



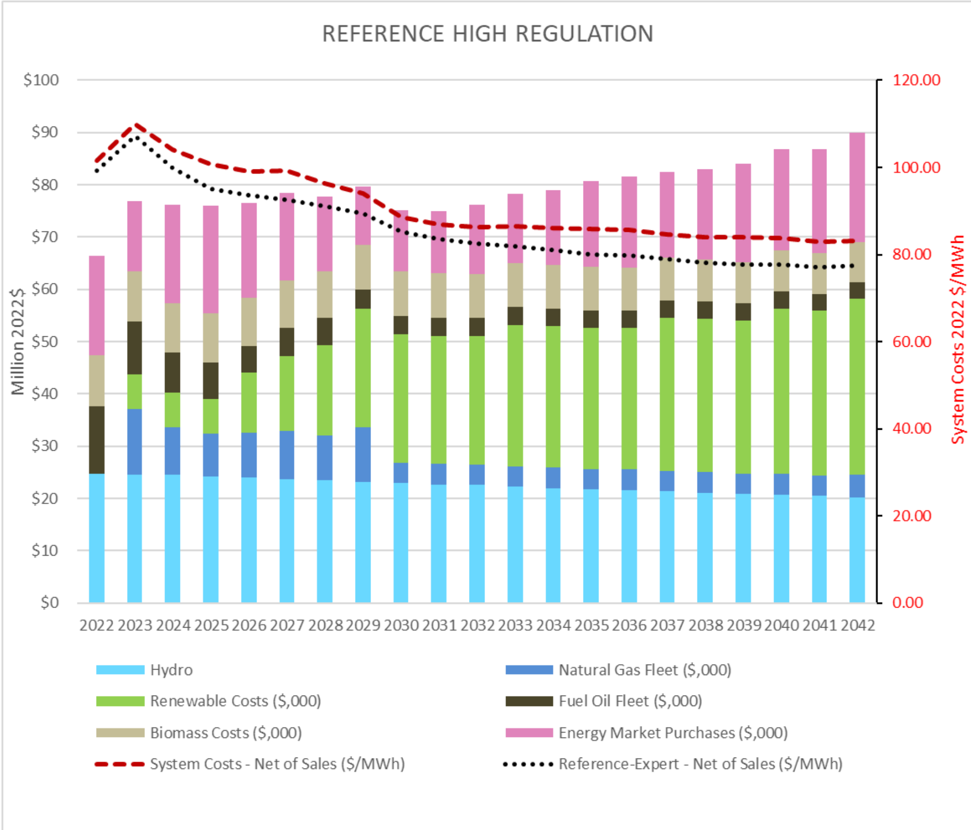
All RPS requirements are exceeded due to the lower demand assumptions.

Figure 10-21: High Regulation Renewable Energy Levels – Reference Portfolio



Despite the decreased demand and market purchases, the costs of each portfolio come out higher than their base scenario counterparts due to the increased capital, fuel costs and CO2 penalties imposed in a high regulation future.

Figure 10-22: High Regulation Cost Components – Reference Portfolio



The excess energy in the Belize centric scenario during high demand hours due to its abundance of solar and wind generation pays off with market sales as compared to the reference strategy portfolio. These hours of market sales make higher revenues due to the increased price of energy with the various regulations and price increase assumptions included in the high regulation scenario. A larger regret is seen for the reference strategy portfolio under this scenario, as shown below.

Table 10-6: High Regulation Cost Comparison

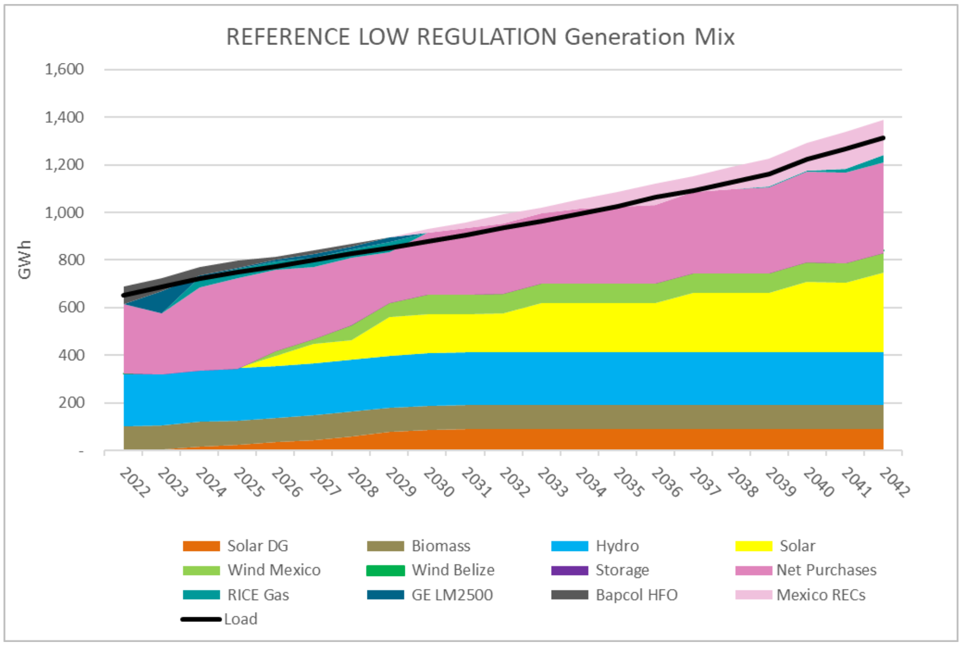
NPV $000	Reference Expert Design Reference Conditions	Belize Centric Expert Design Reference Conditions	Reference Expert High Regulation	Belize Centric High Regulation
Variable	57,677	62,888	55,656	58,644
Fixed	670,178	684,182	670,178	684,182
Purchases	168,537	157,732	190,374	181,826
Total Costs before sales	896,393	904,803	916,208	924,652
Market Sales	18,497	29,502	24,569	39,531
Total after sales	877,896	875,301	891,639	885,121
Regret	2,596	-	6,518	-
Total Load (MWh)	10,007,705	10,007,705	9,615,842	9,615,842
Energy Purchases (MWh)	3,651,218	3,509,257	3,395,498	3,249,360
Energy Sales (MWh)	196,758	346,392	258,660	427,085
Total Costs $/MWh	88	87	93	92
Purchase Costs $/MWh	46	45	56	56
Sales Price $/MWh	94	85	95	93

10.2.5 Low Regulation Scenario

In the low regulation scenario, the underlying assumptions include high demand projection as well as high cost of fuels driven by high demand.

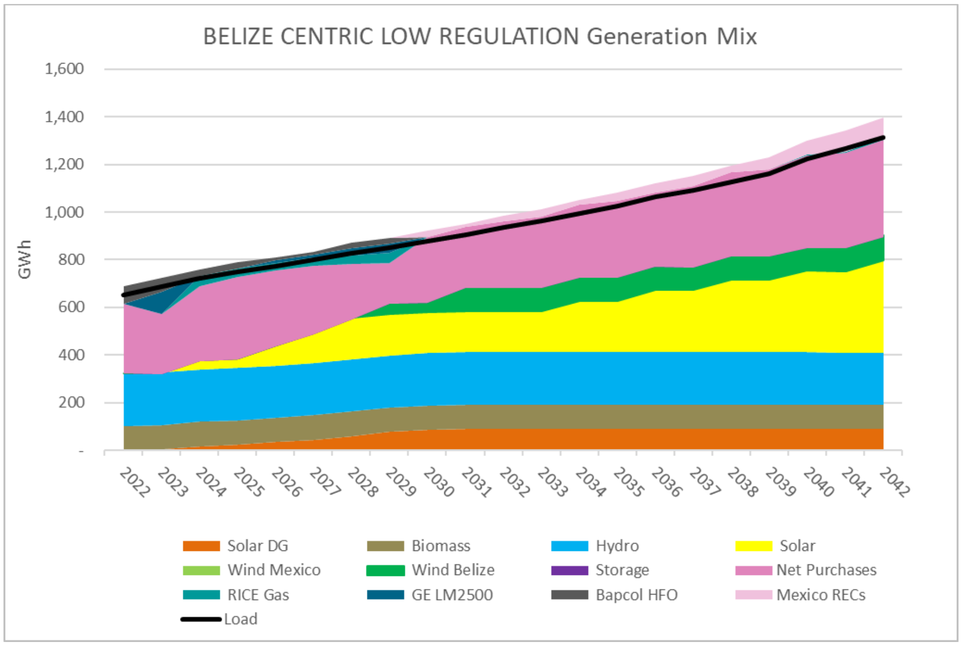
In a low regulation scenario, both the reference portfolio and the Belize Centric portfolio rely on increased Mexico purchases and Mexico REC purchases to meet demand and RPS requirements.

Figure 10-23: Low Regulation Generation Mix – Reference Portfolio



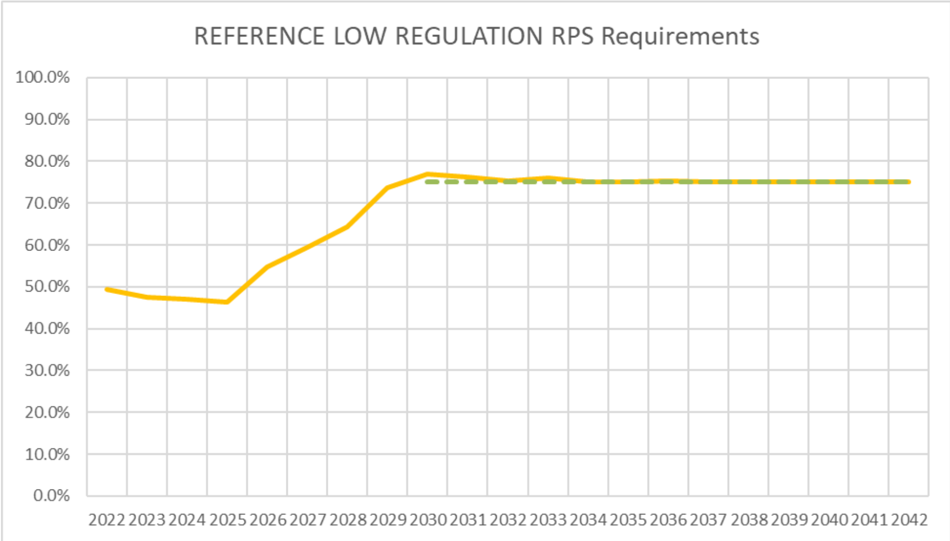
A similar generation mix effect is had on the Belize Centric portfolio as well with slightly higher Mexico and Mexico REC purchases.

Figure 10-24: Low Regulation Generation Mix – Belize Centric Portfolio



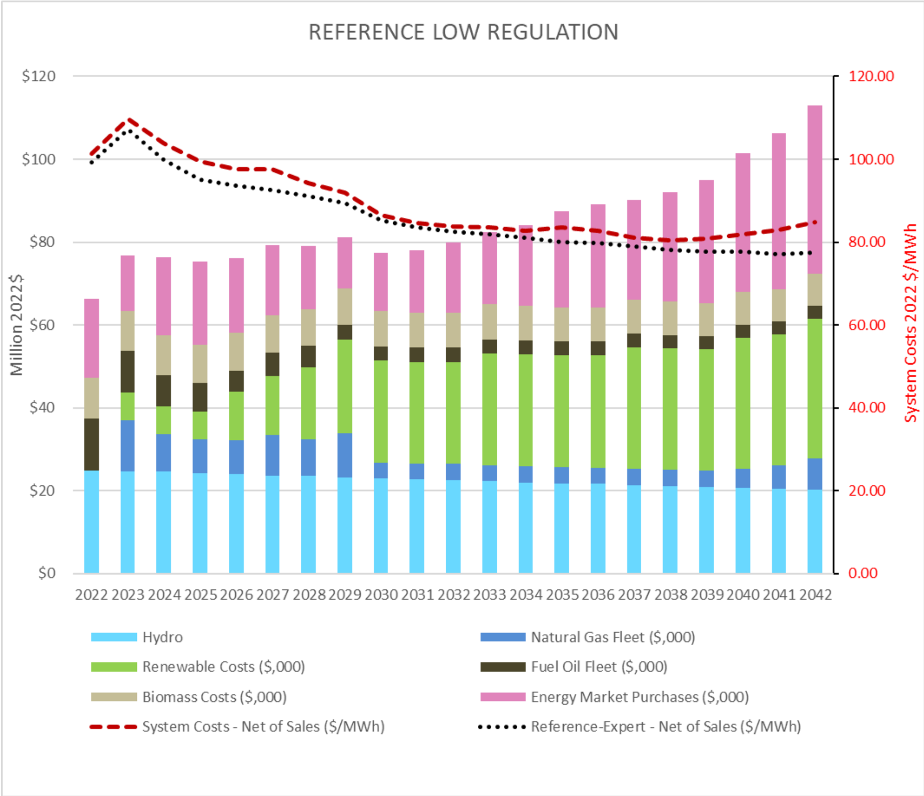
All RPS requirements are met with the necessary help from Mexico REC purchases to meet and sustain a 75% renewable generation portfolio.

Figure 10-25: Renewable Energy Levels – Reference Portfolio



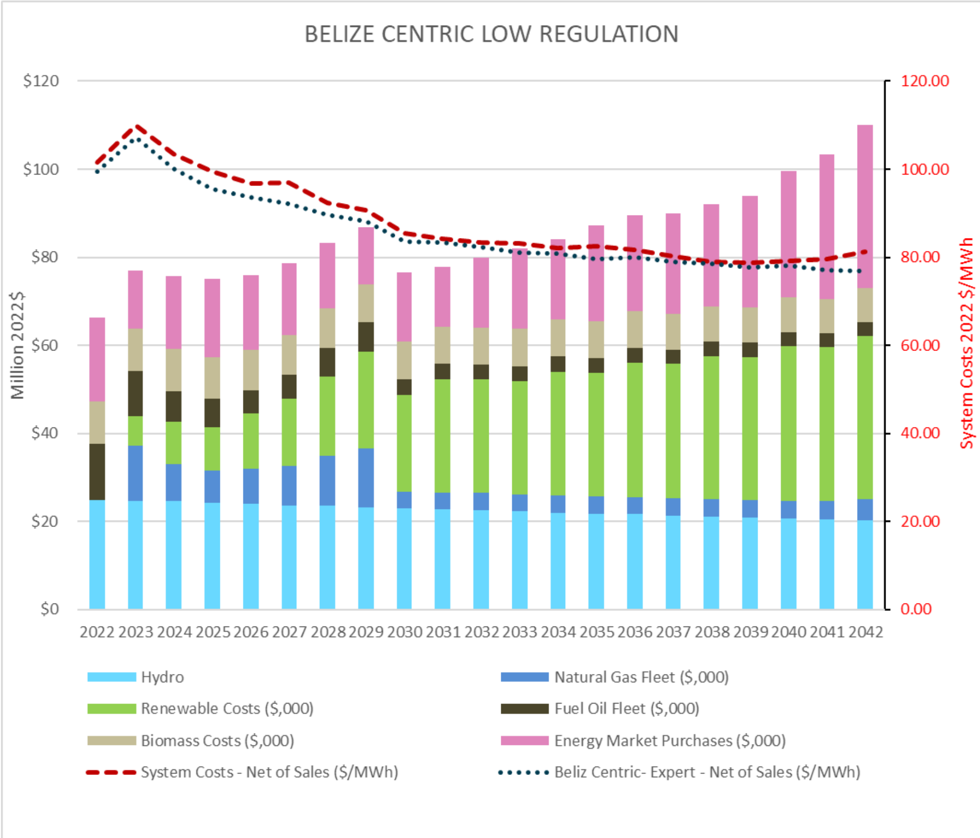
Unfortunately, the cost of the increased market and REC purchases are higher due to the increased fuel costs and impact the portfolio cost negatively for both the Reference and Belize Centric, but it has a greater impact on the Reference portfolio.

Figure 10-26: Low Regulation Cost Components – Reference Portfolio



The Belize Centric portfolio also had increased costs, but not quite as high in comparison to its base strategy counterpart.

Figure 10-27: Low Regulation Cost Components – Belize Centric Portfolio



This results in a higher regret for the Reference portfolio of about $10.3 million.

Table 10-7: Low Regulation Scenario Cost Comparison

NPV $000	Reference Expert Design Reference Conditions	Belize Centric Expert Design Reference Conditions	Reference Expert Low Regulation	Belize Centric Low Regulation
Variable	57,677	62,888	57,703	60,023
Fixed	670,178	684,182	670,178	684,182
Purchases	168,537	157,732	233,489	218,903
Total Costs before sales	896,393	904,803	961,370	963,107
Market Sales	18,497	29,502	15,288	27,387
Total after sales	877,896	875,301	946,081	935,721
Regret	2,596	-	10,361	-
Total Load (MWh)	10,007,705	10,007,705	10,455,001	10,455,001
Energy Purchases (MWh)	3,651,218	3,509,257	3,826,000	3,794,394
Energy Sales (MWh)	196,758	346,392	139,491	268,536
Total Costs $/MWh	88	87	90	89
Purchase Costs $/MWh	46	45	61	58
Sales Price $/MWh	94	85	110	102

10.2.6 Climate Crisis Scenario

In the climate crisis scenario, the underlying assumptions include low demand projected along with low renewable and storage capital costs, high cost of fuels, CO2 penalties for Belize and Mexico and a low hydro production projection.

In the climate crisis scenario, despite having lower demand and therefore having lower RPS requirements to fulfill, the decreased hydro generation causes a shortage of renewable generation and increases the need to purchase additional Mexico RECs. General market purchases increase by about 5% on average as compared the base scenario as a percentage of annual load. This effect is seen in both the Reference Strategy portfolio and the Belize Centric portfolio but is more prevalent in the Reference portfolio.

Figure 10-28: Climate Crisis Scenario Generation Mix – Reference Portfolio

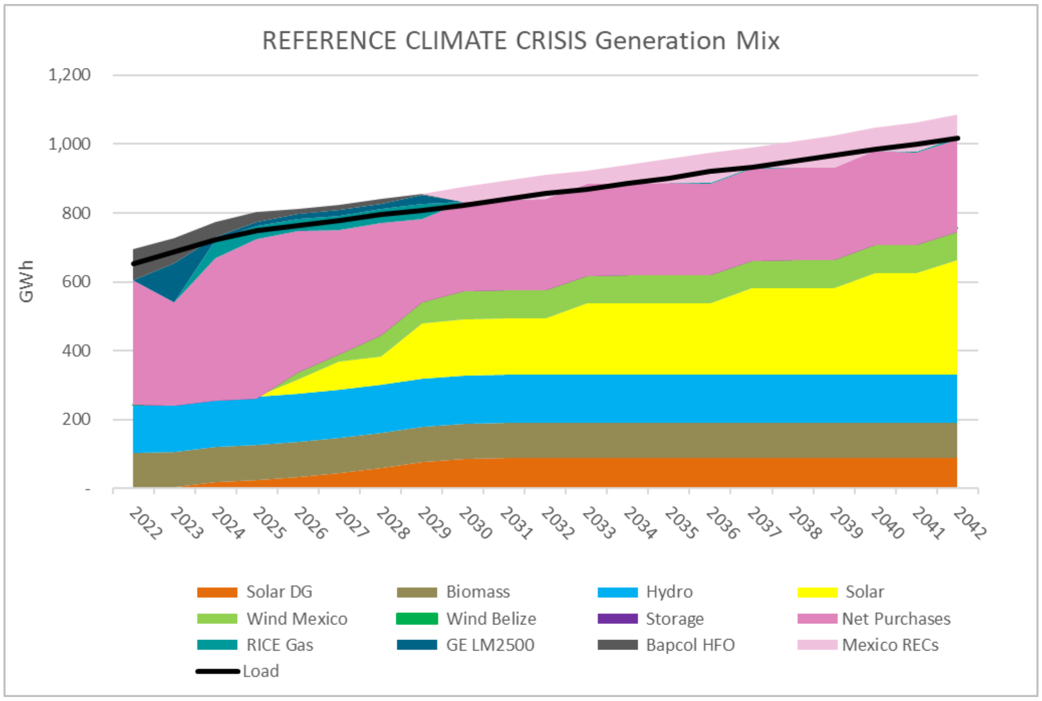
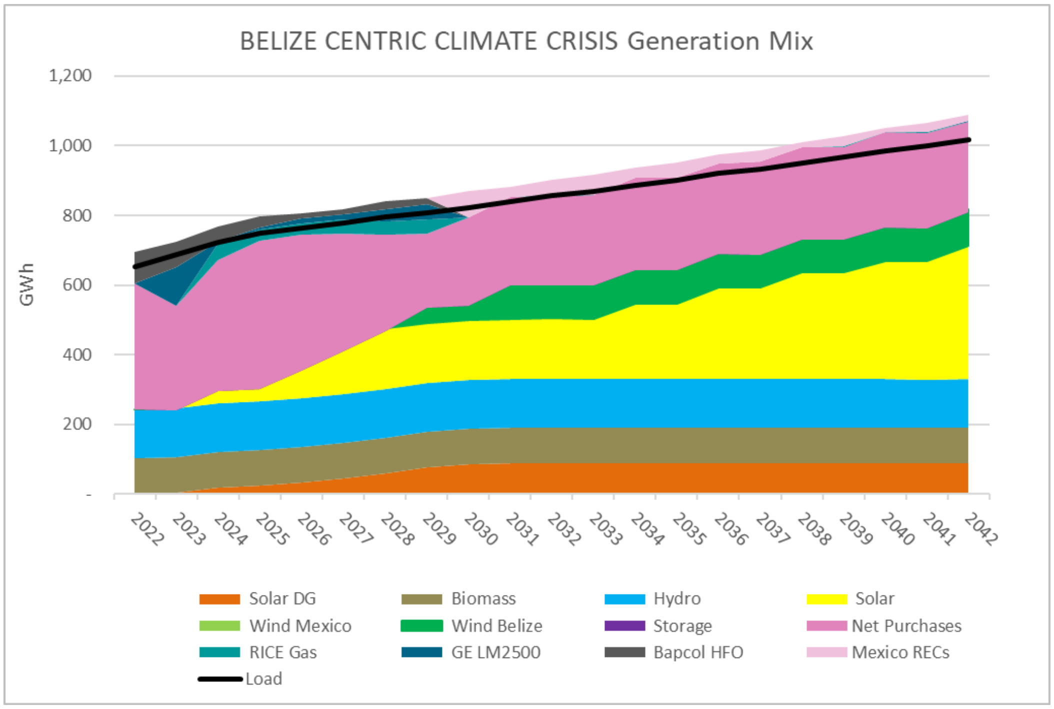
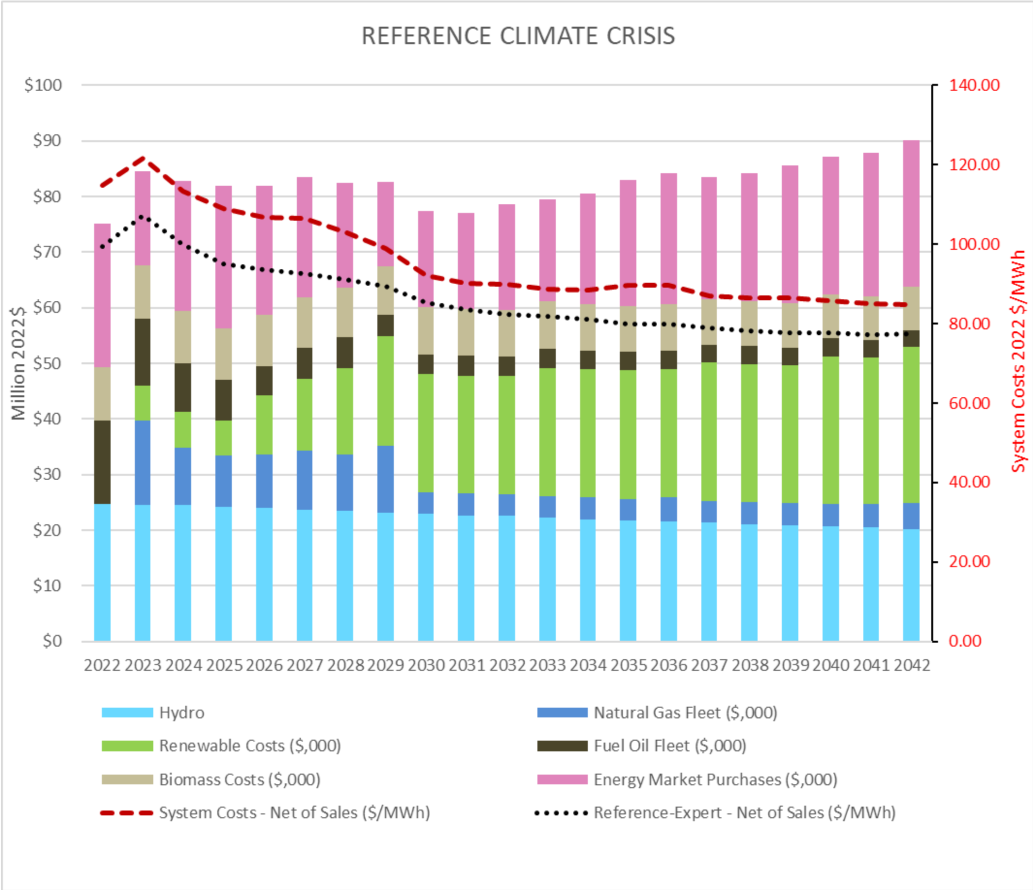


Figure 10-29: Climate Crisis Scenario Generation Mix – Belize Centric Portfolio



Despite decrease load projection and lower capital cost, increased purchases along with increased purchase prices due to increased fuel prices and CO2 penalties result in increased overall portfolio costs for both portfolios. A clear portfolio cost increase is seen beginning in 2022 due to the decreased hydro production needing to be replaced by market purchases.

Figure 10-30: Climate Crisis Scenario Cost Components – Reference Portfolio



Lower demand benefits the Reference Strategy; however, this is not enough to overcome the inherent better performance of the Belize Centric, the effect of lower capital costs and effect of higher fuel cost.

The regret of selecting the Base Strategy increases US$ 8.4 million as shown below.

Table 10-8: Climate Crisis Scenario Cost Comparison

NPV $000	Reference Expert Design Reference Conditions	Belize Centric Expert Design Reference Conditions	Reference Expert Climate Crisis	Belize Centric Climate Crisis
Variable	57,677	62,888	69,432	71,221
Fixed	670,178	684,182	641,851	656,620
Purchases	168,537	157,732	252,046	240,465
Total Costs before sales	896,393	904,803	963,329	968,306
Market Sales	18,497	29,502	17,224	30,633
Total after sales	877,896	875,301	946,104	937,673
Regret	2,596	-	8,432	-
Total Load (MWh)	10,007,705	10,007,705	9,615,842	9,615,842
Energy Purchases (MWh)	3,651,218	3,509,257	3,931,744	3,911,243
Energy Sales (MWh)	196,758	346,392	199,554	344,516
Total Costs $/MWh	88	87	98	100
Purchase Costs $/MWh	46	45	64	61
Sales Price $/MWh	94	85	86	89

10.2.7 Low Hydro and High Demand

This last scenario combines two of the sensitivities of low hydro due to climate change and high demand due to better economics in Belize.

In the Reference Strategy and the Belize Centric strategy the low hydro combined with high demand results in higher Mexico purchases and thermal dispatch even in the long term.

Figure 10-31: Low Hydro and High Demand– Reference Portfolio

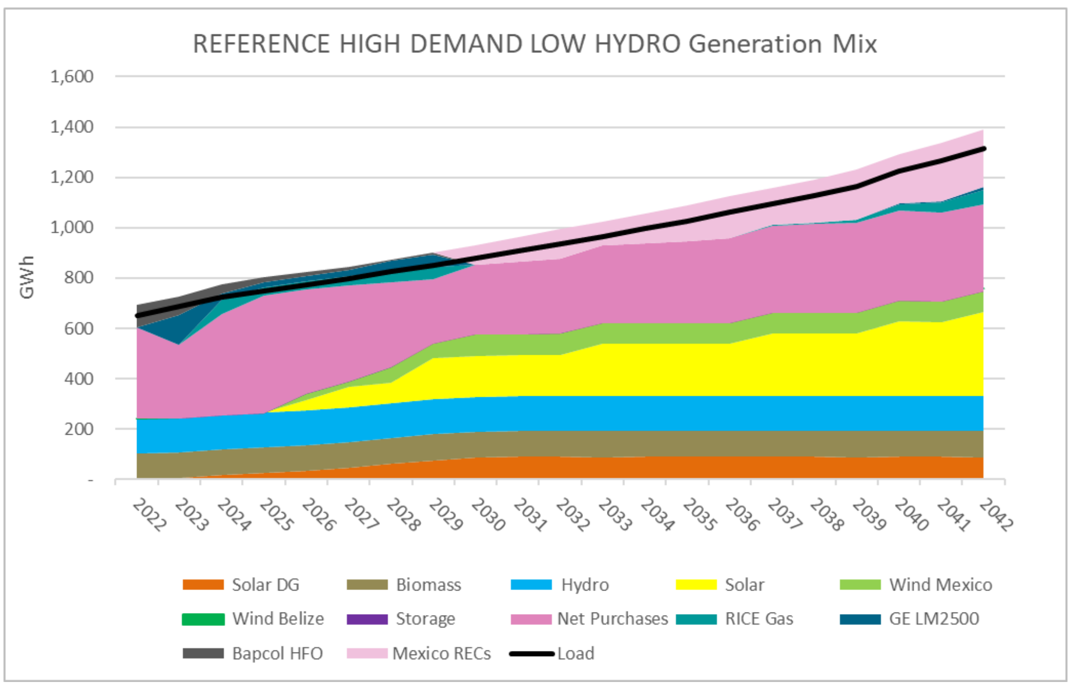
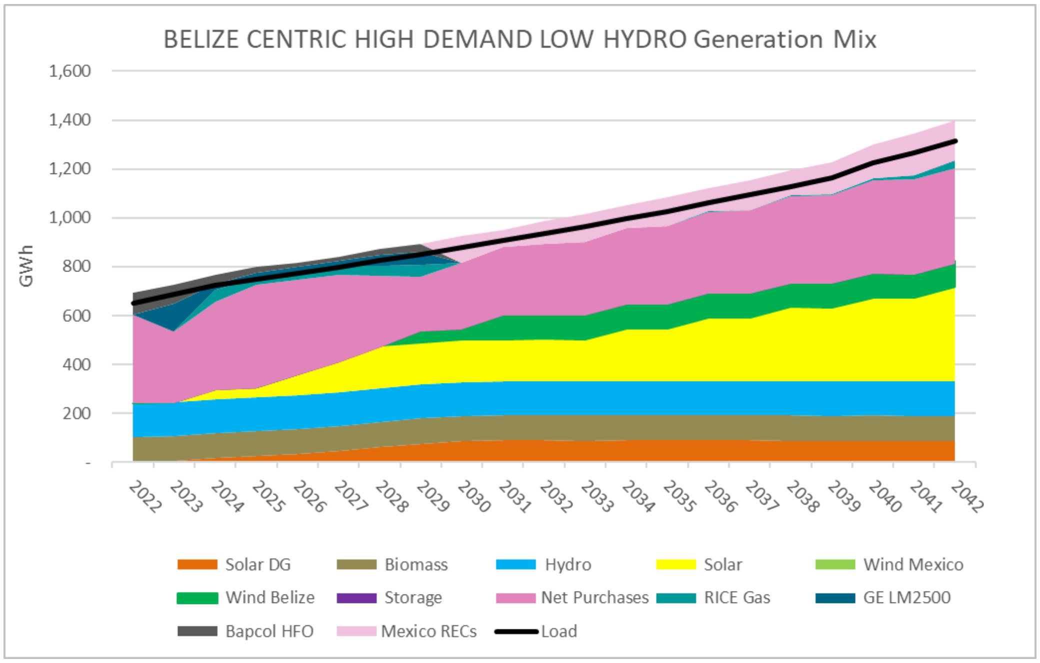


Figure 10-32: Low Hydro and High Demand – Belize Centric Portfolio



The Belize Centric with higher renewable in country is much better able to manage this condition and the regret of selecting the Reference Strategy increases further to US$ 7.6 million.

Table 10-9: Low Hydro and High Demand Cost Comparison

NPV 2022 $000	Reference Expert Design Reference Conditions	Belize Centric Expert Design Reference Conditions	Reference Expert High Demand Low Hydro	Belize Centric High Demand Low Hydro
Variable	57,677	62,888	73,766	73,300
Fixed	670,178	684,182	670,178	684,182
Purchases	168,537	157,732	250,992	238,883
Total Costs before sales	896,393	904,803	994,936	996,364
Market Sales	18,497	29,502	11,644	20,691
Total after sales	877,896	875,301	983,292	975,673
Regret	2,596	-	7,619	-
Total Load (MWh)	10,007,705	10,007,705	10,455,001	10,455,001
Energy Purchases (MWh)	3,651,218	3,509,257	3,826,000	3,794,394
Energy Sales (MWh)	196,758	346,392	139,491	268,536
Total Costs $/MWh	88	87	94	93
Purchase Costs $/MWh	46	45	60	57
Sales Price $/MWh	94	85	98	90

10.3 Scenarios and Sensitivities Observations and Conclusions

Based on the results presented it can be concluded that the Belize Centric Strategy minimizes the regret and should be considered as the forerunner for becoming the Preferred Portfolio.

11. Balanced Scorecard

A scorecard was developed comparing the performance of each portfolio against the objectives and metrics defined in the initial steps of the IRP Planning Process. The score card also compares the performance of each portfolio under the set of Scenarios and Sensitivities presented in this report.

The balanced scorecard allows us to assess the tradeoffs between portfolios (i.e., least cost, and environmental stewardship) and will enable the team to determine the best performing portfolio. Weights are used to produce a final score of the portfolios.

A regret analysis was included in the score card as well. The regret is defined as the difference between a Portfolio outcome under a given scenario or sensitivity and the outcome of the best performing Portfolio for that scenario or sensitivity. The best performing Portfolio under most scenarios / sensitivities, i.e., the Belize Centric, is likely the Preferred Portfolio, but as other objectives are important this is assessed via the scorecard below.

Additionally in this step, depending on the outcomes hedging strategies can be identified to address a particularly adverse outcome, example delaying construction until there is clarity on the load growth or prices / development on an external market.

Regret can be applied to any metric and can result in adjustments to the Preferred Portfolio for better performance.

Table 11-1 shows the objectives and metrics for the Reference Expert Design Portfolio and the Belize Centric Expert Design Portfolio. The high and low load as well as the low hydro sensitivity are also included under each category of the objectives and metrics.

The Belize Centric Expert Design Portfolio has lowest NPV of cost by $2.6 million compared to the Refence Expert Design Portfolio. The NPV of energy market purchases is also lower and the capital investment requirements through 2030. In terms of sustainability, it has larger emissions reductions compared to the Reference Expert Design Portfolio and meets the 75% renewable mandate by 2030.

In terms of energy security, both portfolios rely about one third of their total generation from solar power in the long-term (post 2030) with the Belize Centric having a bit more dependency than the Reference Expert Design. Prior to 2030, both portfolios rely on Hydro with about one third of the total generation.

When both portfolios are tested for varied long-term energy demand conditions and low hydro conditions, the Belize Expert Design also performs better in terms of costs (lower NPV of costs), lower market exposure to Mexico imports and slightly lower fuel costs[16]. CO2 emissions reductions are larger for the Belize Centric Expert Portfolio, given the reduced dependency on Mexico imports which given the expectations for future generation mix in the Yucatan Peninsula, have a higher

[16] Capital Investment requirements are the same across all the sensitivities and scenarios as the expansion plans were not modified but only tested under different conditions.

emissions content compared to Belize's internal generation mix (Peninsula is expected to have more dependency on fossil fuel).

Table 11-2 shows the comparison of the performance of each Portfolio for all the Scenarios simulated. The Belize Centric Expert Portfolio has lower NPV of costs under the Climate Crisis, High International Energy costs, High Regulation, High Technology and Low Regulation conditions. However, the portfolio has higher NPV of costs under Low Capital and International Energy costs. The Belize Centric also has higher fuel costs under the High International Energy costs scenario, High Regulation and Low Regulation cases. In other words, the Belize Centric could potentially have a higher commodity price risk. The Belize Centric also has a lower reliance on market purchase costs from Mexico.

The Belize Centric has larger emissions reductions under most scenarios except under High International Energy costs and Low Regulation Scenarios[17].

[17] The High International Energy Costs scenarios are under review by the Siemens Team. Results for this Scenario could change.

Table 11-1: Reference and Belize Centric Score Card with Sensitivities

Categories	Objectives	IRP Metric	Reference Expert Design Reference Conditions	Belize Centric Expert Design Reference Conditions	Reference Expert Low Hydro	Belize Centric Expert Low Hydro	Reference Expert High Load	Belize Centric Expert High Load	Reference Expert Low Load	Belize Centric Expert Low Load
Least Cost/Least Risk	Least Cost	NPV of the Revenue Requirements ($Millions)	$878	$875	$947	$942	$908	$902	$858	$856
	Rate Stability	"Regret" - evaluates for each Portfolio its worst outcome (measured by the NPVRR) on an adverse Scenario	$2.6	$0.0	$4.8	$0.0	$6.1	$0.0	$1.6	$0.0
	Energy Security	Largest Technology Generation Share 2030+	32%	34%	32%	35%	29%	32%	32%	34%
	Market Exposure	NPV Energy Market Purchases ($Millions)	$169	$158	$221	$210	$194	$182	$151	$144
	Fuel Dependency	NPV of Imported fuels cost ($Millions)	$35	$35	$41	$40	$37	$36	$35	$35
	Intensity of Construction	Capital Investment Requirements ($Millions) (2022-2030)	$212	$195	$212	$195	$212	$195	$212	$195
Sustainability	Reduce CO_2 Footprint	CO_2 Emissions Reductions by 2042	-50%	-58%	-47%	-48%	-35%	-40%	-65%	-74%
	Renewable Generation	Renewable Penetration by 2030	78.5%	75.4%	75.0%	75.0%	76.3%	75.0%	81.1%	77.4%
Reliability *	Manage Largest Contingency (N-1)	Firm Generation to offset largest Unit trip								
		Energy Not Served	None	None	None	None	None	None	None	None

Table 11-2: Reference and Belize Centric Score Card with Scenarios

Categories	Objectives	IRP Metric	Reference Expert Climate Crisis	Belize Centric Climate Crisis	Reference Expert High Int Cost	Belize Centric High Int Cost	Reference Expert High Regulation	Belize Centric High Regulation	Reference Expert High Tech	Belize Centric High Tech	Reference Expert Low Capital & International Energy	Belize Centric Low Capital & International Energy	Reference Expert Low Regulation	Belize Centric Low Regulation
Least Cost/Least Risk	Least Cost	NPV of the Revenue Requirements ($Millions)	$946	$938	$971	$964	$892	$885	$856	$853	$829	$830	$946	$936
	Rate Stability	"Regret" - evaluates for each Portfolio its worst outcome (measured by the NPVRR) on an adverse Scenario	$8.4	$0.0	$6.9	$0.0	$6.5	$0.0	$3.0	$0.0	$0.0	$0.9	$10.4	$0.0
	Energy Security	Largest Technology Generation Share 2030+	33%	37%	27%	29%	32%	34%	29%	32%	32%	34%	29%	32%
	Market Exposure	NPV Energy Market Purchases ($Millions)	$252	$240	$208	$197	$190	$182	$174	$163	$150	$143	$233	$219
	Fuel Dependency	NPV of Imported fuels cost ($Millions)	$36	$35	$51	$62	$30	$32	$41	$39	$40	$39	$33	$33
	Intensity of Construction	Capital Investment Requirements ($Millions) (2022-2030)	$212	$195	$212	$195	$212	$195	$212	$195	$212	$195	$212	$195
Sustainability	Reduce CO_2 Footprint	CO_2 Emissions Reductions by 2042	-63%	-65%	-51%	-58%	-67%	-74%	-48%	-43%	-50%	-58%	-48%	-43%
	Renewable Generation	Renewable Penetration by 2030	76.0%	76.0%	91.5%	93.7%	82.3%	78.3%	76.0%	75.0%	78.7%	75.4%	77.0%	75.2%
Reliability *	Manage Largest Contingency (N-1)	Firm Generation to offset largest Unit trip												
		Energy Not Served	None	None	None	None	None	None	None	None	None	None	None	None

12.Capital Investment Costs

Siemens evaluated the expected capital costs investments under the Reference Expert Design and the Belize Expert Design portfolios. The capital costs estimates were developed according to the assumptions presented in Section 7 of this report.

Each of the scenarios and sensitivities evaluated were assessed under the same generation expansion plans for the Reference and Belize Centric portfolios. In other words, the capacity additions do not vary across scenarios or sensitivities for each case and the capital costs only vary if the assumption of the scenario considers higher or lower unit costs than Reference Conditions.

The Reference Strategy Expert Design has expected capital investment costs of US$230 million for the period of 2022-2030 (Table 12-1) and $312.7 million for the entire planning period (Table 12-2). These costs are comprised of US$ 50.6 million for the Vientos del Caribe Mexico wind project, US$25.4 million for the 23 MW of RICE gas in 2024, US$50.2 million in Battery Storage investments and US$183.6 million for solar for the first 8 years (2022 to 2030) rising to US$183.6 million for the entire planning period. In addition, the planned upgrade of the GE LM 2500 unit will cost around US $2.6 million. All these costs are assumed to be in 2022$ dollars.

The Belize Expert Design Portfolio has total expected capital investment costs of US$212.2 million for the 2022 to 2033 period, US$18 million below the Reference Expert Design Portfolio (see Table 12-1). Under this portfolio, there are higher investment costs for solar (US$4.1 million higher), in addition to in-country wind resources on the coast for $29 million in 2022-2030. Both combined are offset by the avoided cost of the Mexico wind project of $50 million (based on assumed PPA costs under current market conditions). This portfolio has the same capital investments costs for RICE natural gas, battery storage and the GE LM 2500-unit upgrade, which were unchanged between the two portfolios.

When the entire planning period is considered (Table 12-2), this Portfolio Capital costs are US$342.9 million, US$ 30 million higher than the Reference Strategy. The main reason for this difference is the larger investment in renewable generation happening post 2030 in this Portfolio; 100 MW of solar plus 20 wind generation versus 80 MW of solar in the Reference, that results in solar costs that are US$ 25 million higher and when added to the wind cost $56 million we have a total cost of $ 81 million that does not fully compensate the cost of the Mexico Wind; $50 million. This higher long-term investment on the Belize Centric is central in its ability to manage issues with higher cost in the Mexican market.

Table 12-1: Capital Investment Costs Reference and Belize Centric Expert Portfolios for the period 2022 to 2030

	Reference Strategy Expert Design		Belize Centric Expert Design	
	Capacity MW	Capital Costs (2022US$ Millions)	Capacity MW	Capital Costs (2022US$ Millions)
Mexico Wind	35	$50.6	0	$0.0
RICE Natural Gas	23	$25.4	23	$25.4
Solar PV	160	$183.6	180	$208.3
GE LM 2500 Upgrade	8	$11.5	8	$11.5
Battery Storage	40	$50.2	40	$50.2
Wind Belize Costal	0	$0.0	40	$56.1
Total	**265**	**$321.3**	**290**	**$351.5**

Table 12-2: Capital Investment Costs Reference and Belize Centric Expert Portfolios for the period 2022 to 2042

	Reference Strategy Expert Design		Belize Centric Expert Design	
	Capacity MW	Capital Costs (2022US$ Millions)	Capacity MW	Capital Costs (2022US$ Millions)
Mexico Wind	35	$50.6	0	$0.0
RICE Natural Gas	23	$25.4	23	$25.4
Solar PV	80	$100.9	80	$105.0
GE LM 2500 Upgrade	8	$11.5	8	$11.5
Battery Storage	40	$50.2	40	$50.2
Wind Belize Costal	0	$0.0	20	$28.6
Total	**185**	**$238.6**	**170**	**$220.8**

The figures below present the investments by year for each of the Portfolios presented above.

Figure 12-1: Reference Strategy Expert Design CapEx by Year

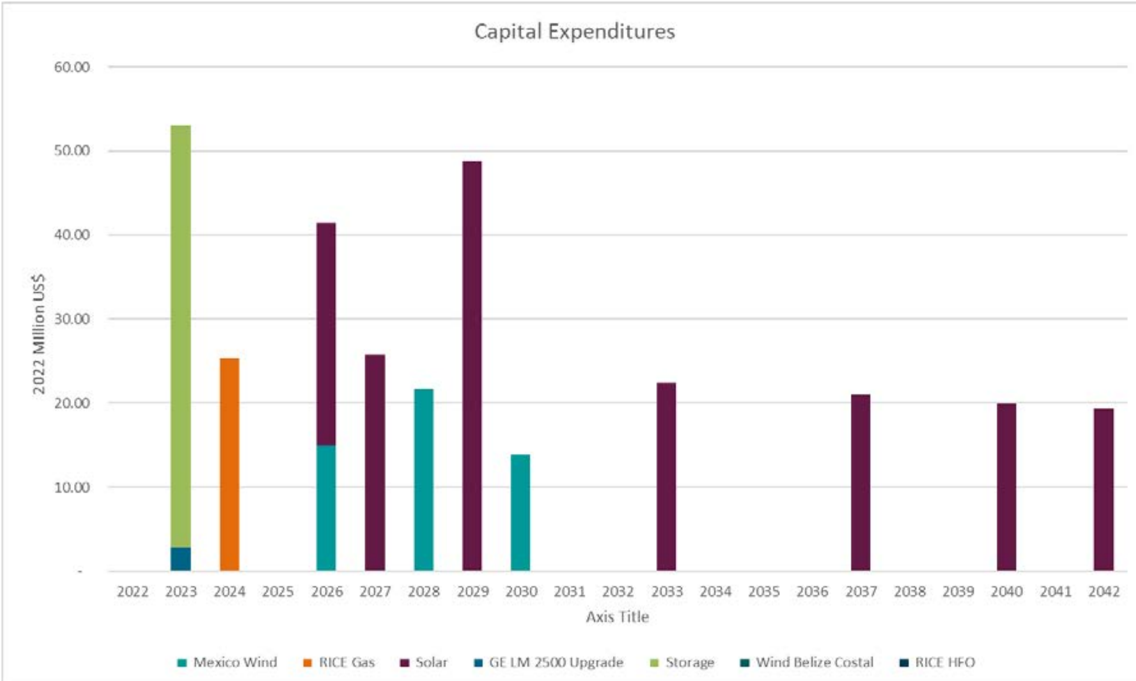
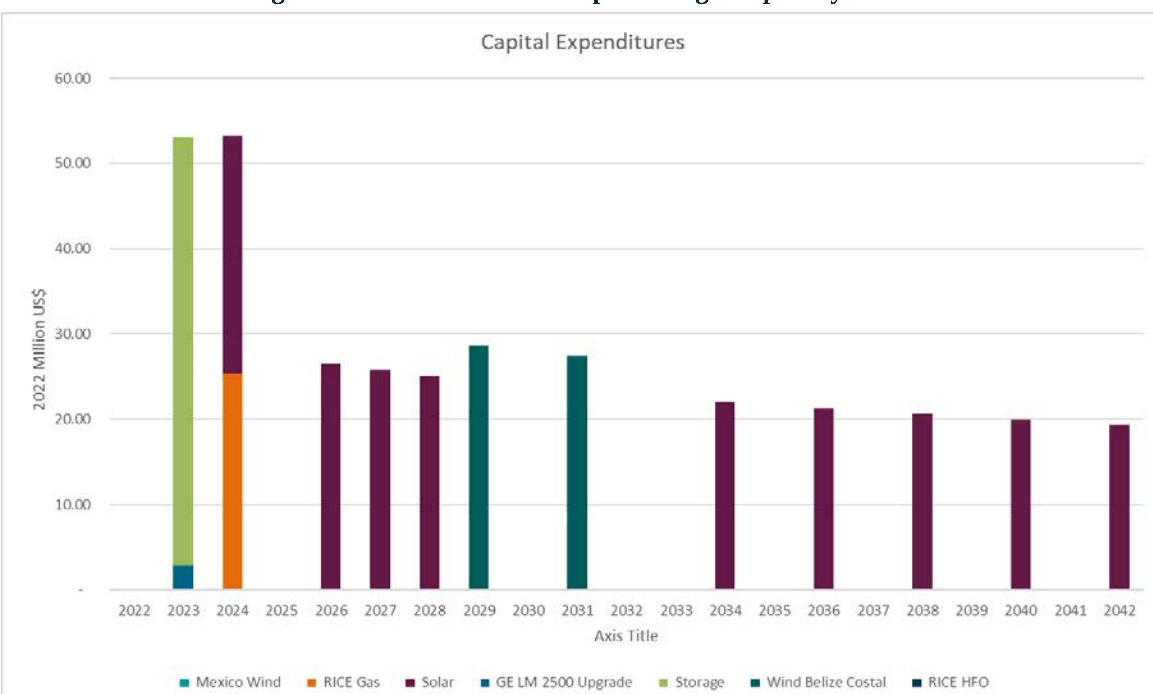


Figure 12-2: Belize Centric Expert Design CapEx by Year



13. Preferred Portfolio Selection and Action Plan.

13.1 Preferred Portfolio.

The comparative results for both the Reference Expert Design and the Belize Centric Expert Design Portfolio shows that the Preferred Portfolio should be the Belize Centric Expert Design with an NPV of revenue requirements of $875 million (2022 US$), reduced market exposure from Mexico imports, less regret to adverse conditions and larger emissions reductions, while meeting the 75% by 2030 renewable generation mandate and setting Belize on a Path to 100% renewable by 2050 (80% renewable vs. 75% in the Reference Strategy). It should be noted that while the Portfolio results in a reduction in costs in real terms, there is a slight increase when observed in nominal terms because of the effect of inflation.

Figure 13-1: Preferred Portfolio Capacity Expansion Plan

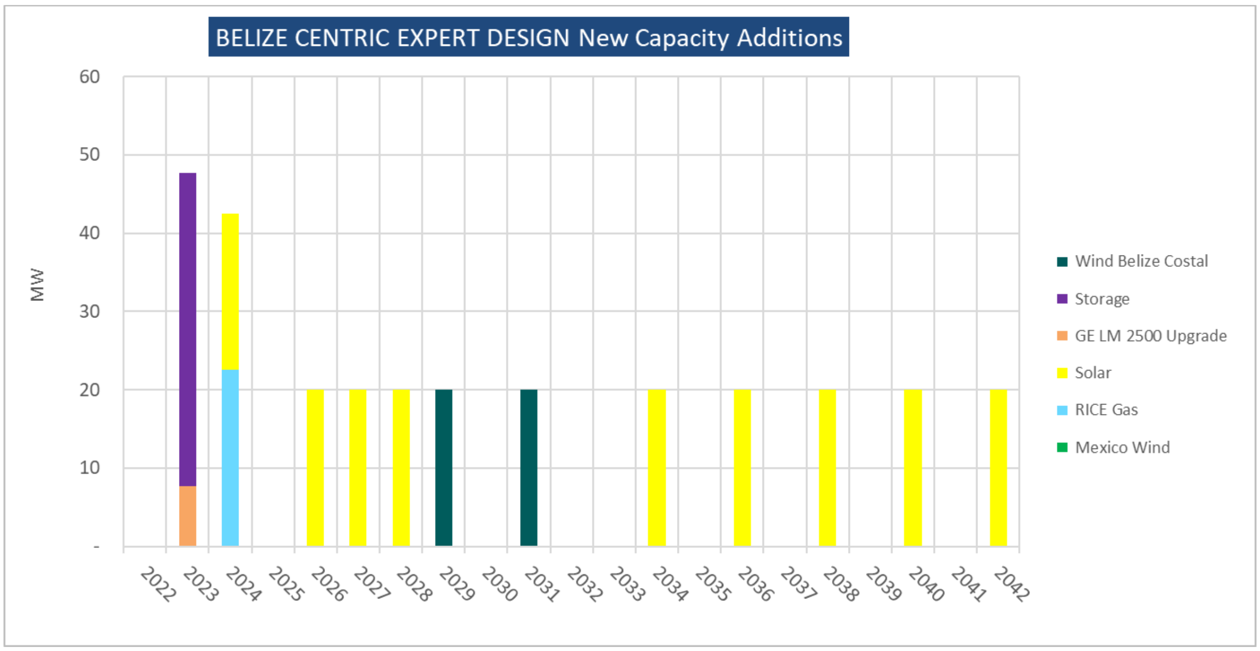


Figure 13-2: Preferred Portfolio (Belize Centric) Cumulative Capacity Additions

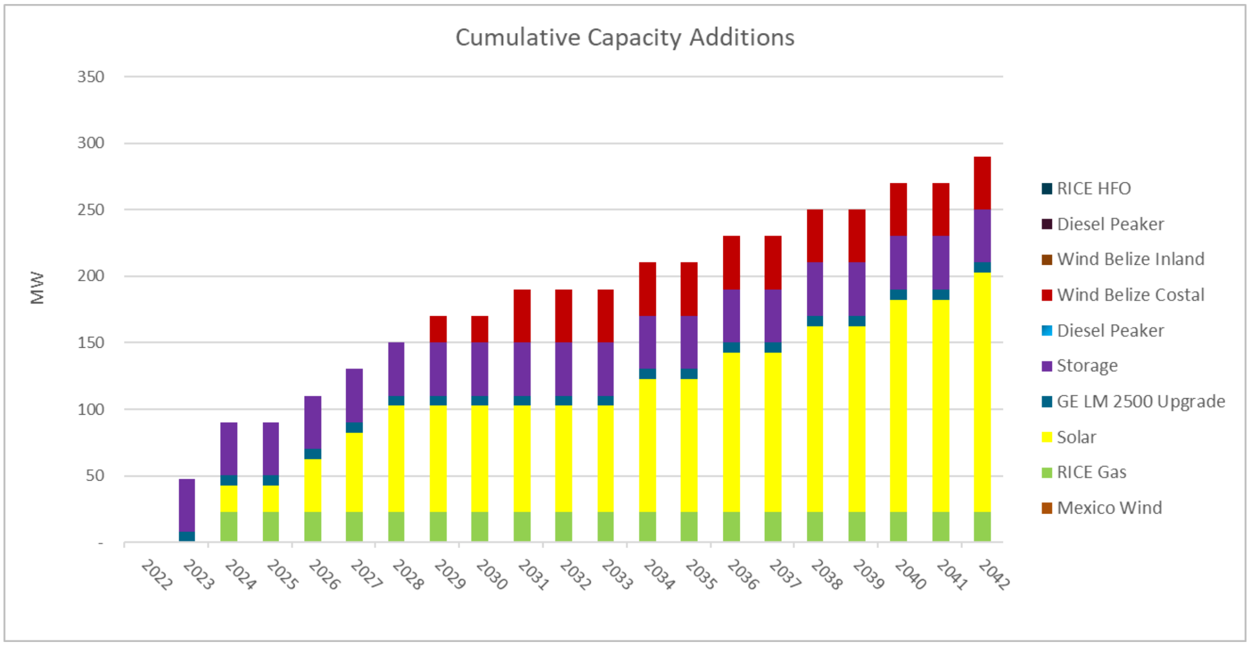


Figure 13-3: Preferred Portfolio (Belize Centric) Cumulative System Cost by Year (2022$)

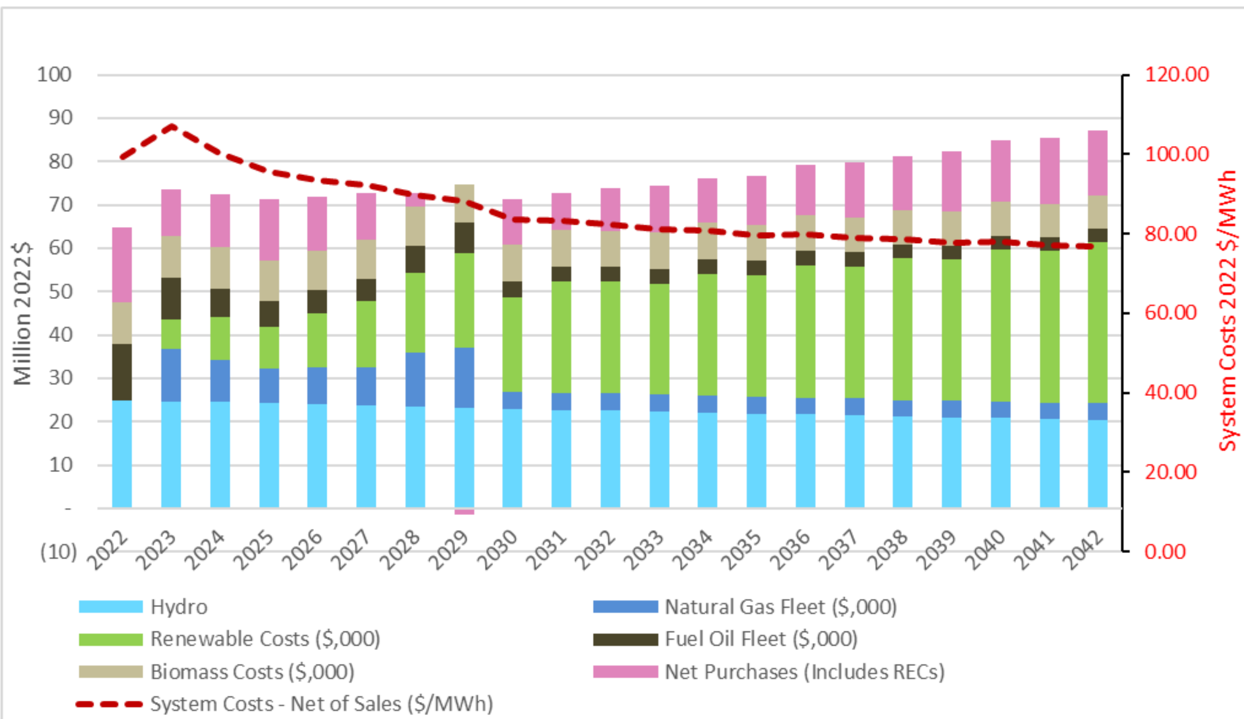
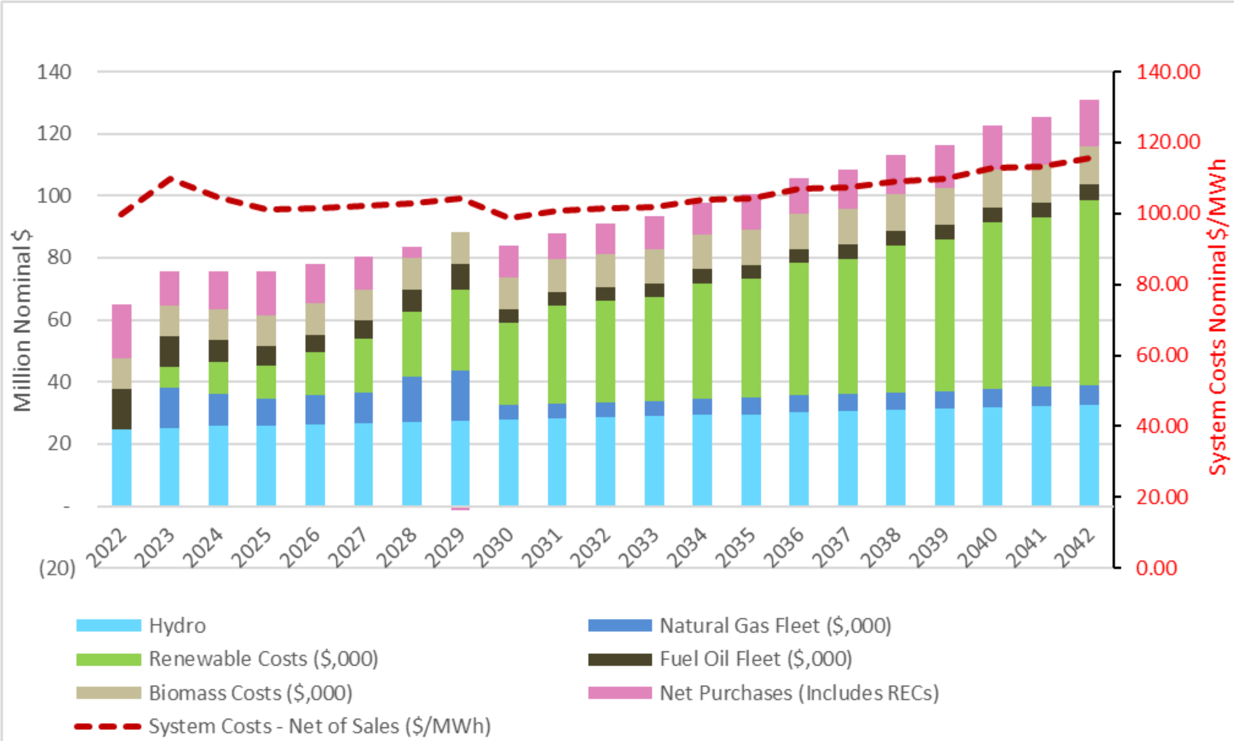


Figure 13-4: Preferred Portfolio (Belize Centric) Cumulative System Cost by Year (Nominal $)



13.2 Action Plan.

13.2.1 Thermal Generation and Storage.

The thermal generation and storage additions are common to the Belize Centric and the Reference Strategy and hence are a robust solution. Table 13-1 presents an overview of these investments, including the in-service year, the expected capital costs, relationship to the Reference Strategy, when an RFP should be issued and who should develop the project. We provided further details below.

With respect of the LM2500 upgrade, BEL should continue with the repowering targeting an in-service date of no later than end 2023 for the fuel conversion and capacity increase. The unit must be given the possibility to operate in a synchronous condenser mode using a clutch, as shown in the Transmission Section of this report. GE has this technology for the LM6000 and is testing its performance on the LM2500. The conversion to Synchronous condenser is not required until when there is heavy penetration of renewable energy (see section 14.10), so it can be delayed and should be in service by 2028 or sooner.

The storage as detailed in the Section 14 of this report, has important transmission support functions, its location is critical and should be developed by BEL, as the owner and of the transmission assets and responsible for its operation. BEL should issue an RFP for the procurement of this storage to qualified suppliers to engineer procure and construct these assets for BEL and under BEL supervision. The RFP should be issued as soon as possible (2022) targeting an in-service date of late 2023, start of 2024.

For the RICE, this should be owned and operated by a third party, with whom BEL should enter into a PPA for the life of the plant. Based on the general requirements indicated in this document with respect of capacity, fuel, maximum heat-rate and location, BEL should issue an RFP early 2023 targeting an in-service date of early 2024.

Table 13-1: Belize Thermal and Storage Investments – Preferred Portfolio

Belize Preferred Portfolio Investments by Year						
In Service Year	Technology	MW	CapEx (2022$ Millions)	Common To Reference Strategy	RFP Issue date	Developer / Owner
2023	LM2500 Upgrade	7.74	2.87	Yes	On Going	BEL
2023	Storage	40	50.21	Yes	ASAP	BEL
2024	RICE	22.5	25.39	Yes	2023	Private

13.2.2 Solar PV.

Table 13-2 presents an overview of the solar PV investments, including the in-service year, the expected capital costs, relationship to the Reference Strategy, when an RFP should be issued and who should develop the project. Solar PV should be developed by a third party with whom BEL should enter into a long term PPA for the life of the project. The first RFP should be issued in 2023 (or sooner given the state of the industry) targeting an in-service date of 2024 for the first 20 MW. This is to be followed by 20 MW RFPs in 2025, 2026 and 2027 for a total of 80 MW in service by 2028. On the Base Strategy the first 20 MW enter a bit later in 2026 which is compensated by 20 MW more in-service in 2028. Thus, if there are delays in procuring the first 20 MW due to supply issues, this would be okay provided that by 2028 the entire first tranche of 80 MW to be in service.

Note that in general we are allowing two years from the time the RFP is issued to the time when the project comes online. This historically has been acceptable, with even shorter timelines (18 months after RFP), however the current supply chain issues affecting the industry have introduced much longer delays.

The notes to Table 13-2 provide additional details, including the possibility of delaying the last 20 MW block beyond 2042.

Table 13-2: Solar PV Investments – Preferred Portfolio

Belize Preferred Portfolio Investments by Year						
In Service Year	Technology	MW	CapEx (2022$ Millions)	In Reference Strategy	RFP Issue date	Developer / Owner
2024	Solar	20	$27.84	Delayed to 2028	2023 (1)	Private
2026	Solar	20	$26.42	Yes	2024	Private
2027	Solar	20	$25.73	Yes	2025	Private
2028	Solar	20	$25.06	Yes but 40 MW	2026 (2)	Private
2034	Solar	20	$22.01	Yes but 2033	2032 (3)	Private
2036	Solar	20	$21.31	Yes but 2037	2034 (4)	Private
2038	Solar	20	$20.63	NO	2036 (4)	Private
2040	Solar	20	$19.97	Yes	2038 (4)	Private
2042	Solar	20	$19.35	Yes	2040 (4)	Private

(4) Issue as soon as possible given the state of the renewable industry
(5) Could include more than 20 MW to achieve a total of 80 MW by 2028
(6) The 2034 project can be advanced to 2033, thus the RFP could be issued in 2031
(5) Consider reviewing the state of the Mexican Market and delay further (beyond 2042) the last 20 MW block and align with the Base Strategy.

Table 13-3 presents the same details as above for wind turbine generation. On the Belize Centric Strategy, the wind generation enters later in the plan by 2029 and 2031 as compared with the Base Strategy, which includes the Mexico Wind starting in 2026. BEL should consider issuing an RFP as early as 2023 that should be open to wind generation located in Mexico as well as generation in country and award to the Mexico Wind if after the delivery costs are added (new transmission line) the price is competitive with the local wind.

Table 13-3: Wind Turbine Generation Investments – Preferred Portfolio

Belize Preferred Portfolio Investments by Year						
In Service Year	Technology	MW	CapEx (2022$ Millions)	In Reference Strategy	RFP Issue date	Developer / Owner
2029	Belize Wind	20	$28.63	Earlier Mx Wind 25MW by 2028	2027 (1)	Private
2031	Belize Wind	20	$27.46	Earlier Mx Wind 10 MW in 2029	2029 (1)	Private

(2) Consider issuing the RFP earlier and open to Mexican wind for increased competition

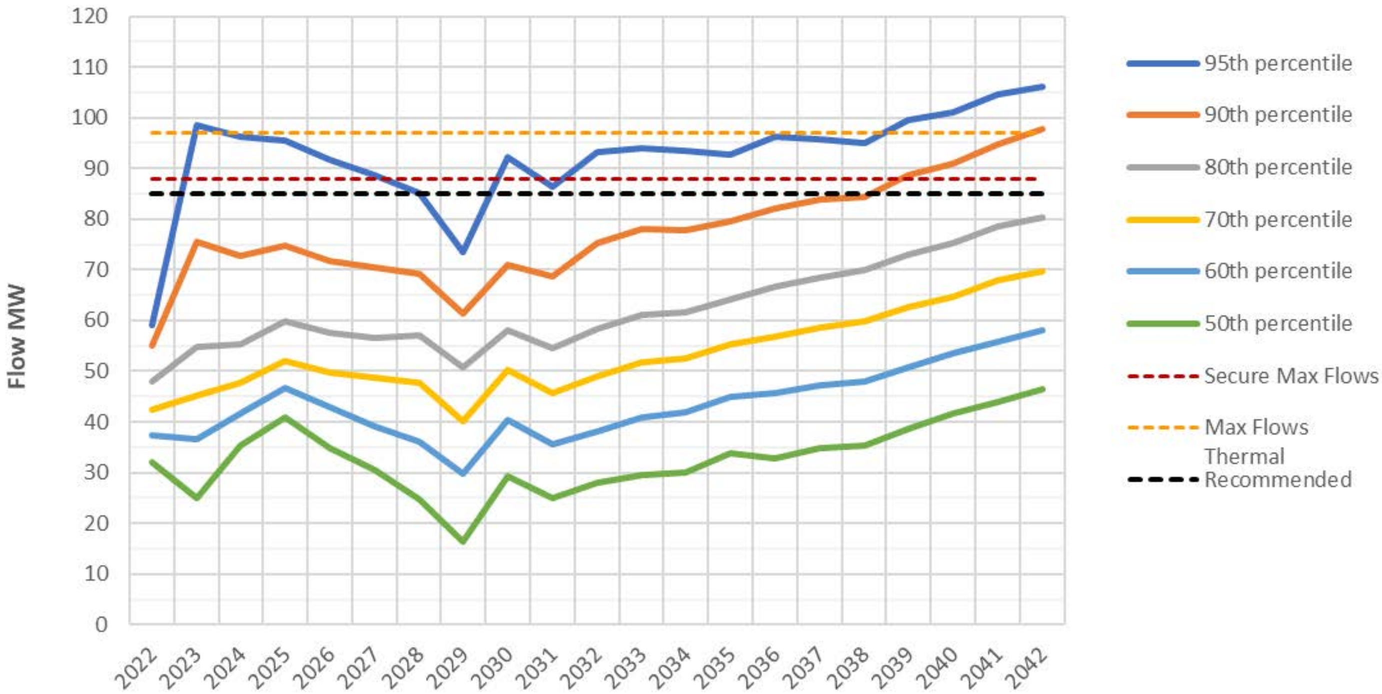
13.2.1 Negotiation of Expanded Contracts with Mexico.

As shown in this report it is recommended that BEL expands the limit of the contract with CFE Calificados beyond the current limit of 55 MW. To assess what should be a target level for the increase we looked at the hourly flows under the Belize Centric Strategy across the planning horizon and determined the various percentile levels.

As can be observed below, the 90th percentile is expected to be above the 55 MW limit for the entire planning period. It is expected to reach 75 MW by 2023 but decline until 2029 due to the transmission limitations to Peninsular and the entry of renewable generation in Belize. From 2030 onwards is expected to increase once the transmission limitations are resolved and reach the 80 MW level by

2035, 85 MW by 2038 and keep increasing. We also added to this figure the maximum flows from Mexico that resulted in a secure system (88 MW) and the theoretical maximum before thermal constraints become severe (97 MW), but would possibly triger a collapse if the interconnection with Mexico Opens.

Figure 13-5: Belize Centric Market Flows to BEL Percentiles



To further assess this, we examined the average hourly flows per season and month for selected years. As can be observed below by 2038 the average flows exceed the 85 MW value only by a few hours in the morning during "winter" (Dec – Feb). September is the month with maximum flows followed by January and February.

We also looked at 2030 were we noted a similar situation the 85 MW value was exceed for a few hours in the morning, being the "winter" (Dec – Feb) the period with maximum flows and December was the month with maximum.

Finally, by 2025, the patters are quite different as Solar PV is not yet the leading supplier, but we still see that the 85 MW level is reached in the first part of the day for a few hours.

Based on the above it is recommended that BEL uses a value between 80 and 85 MW as the target for negotiations with Calificados.

Figure 13-6

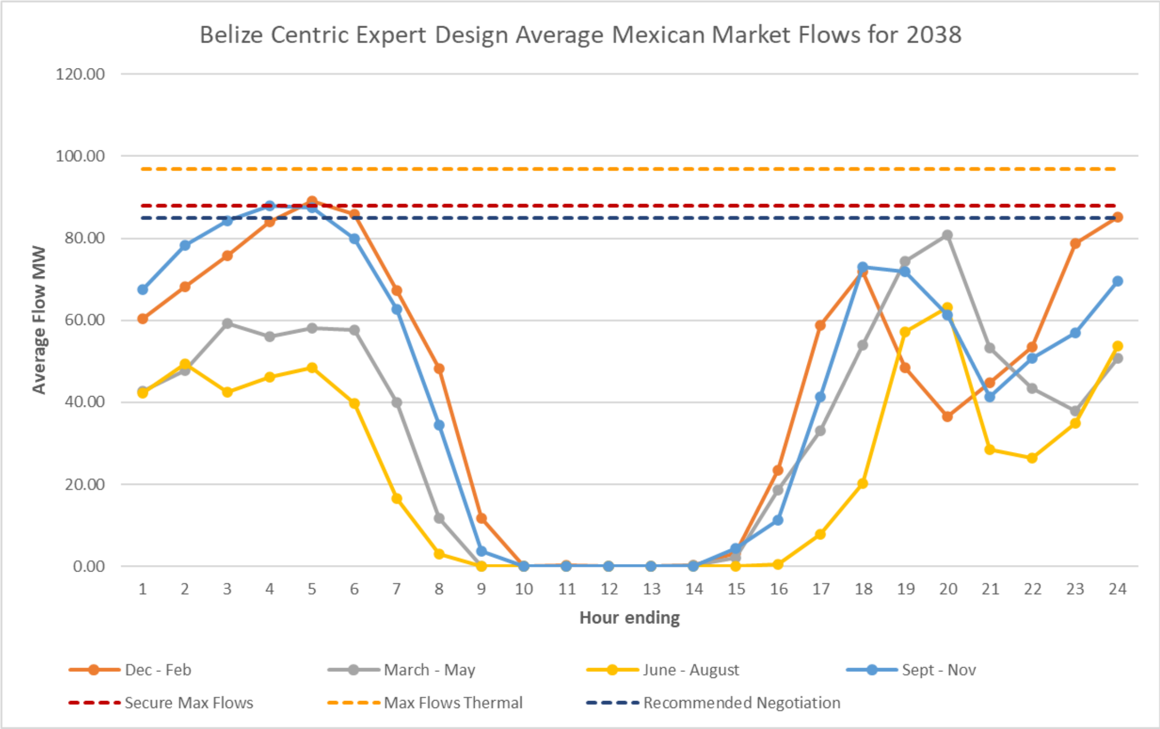


Figure 13-7

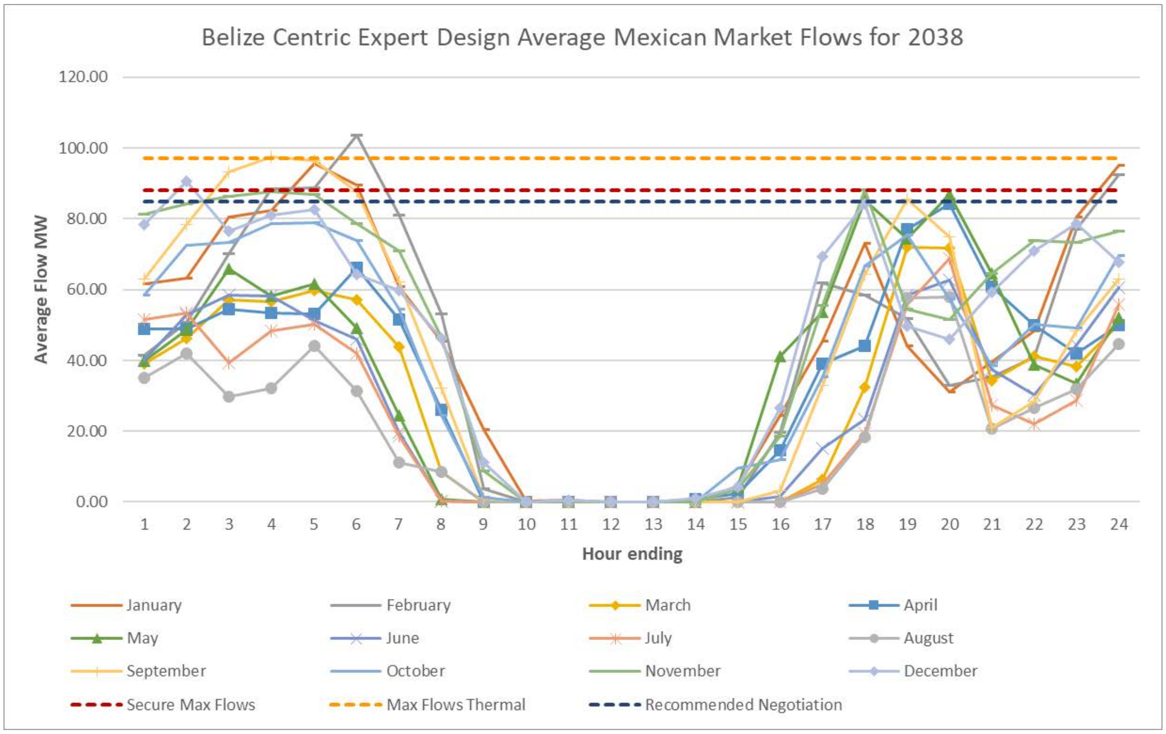


Figure 13-8

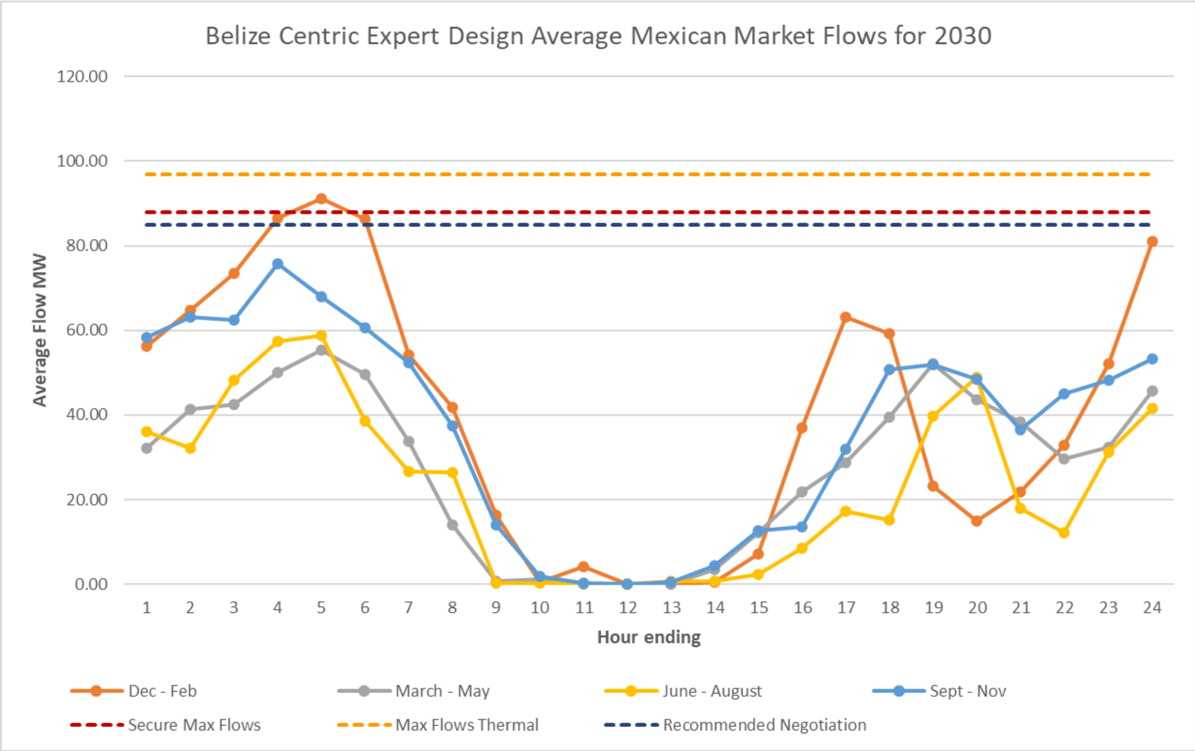


Figure 13-9

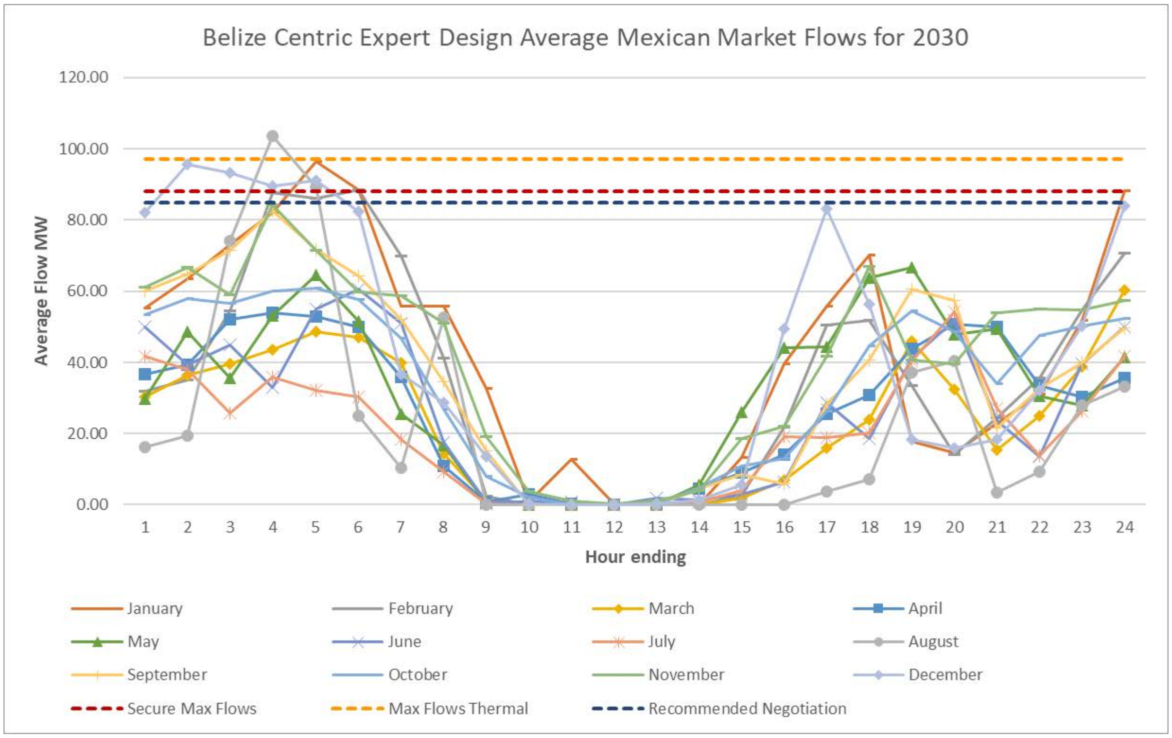


Figure 13-10

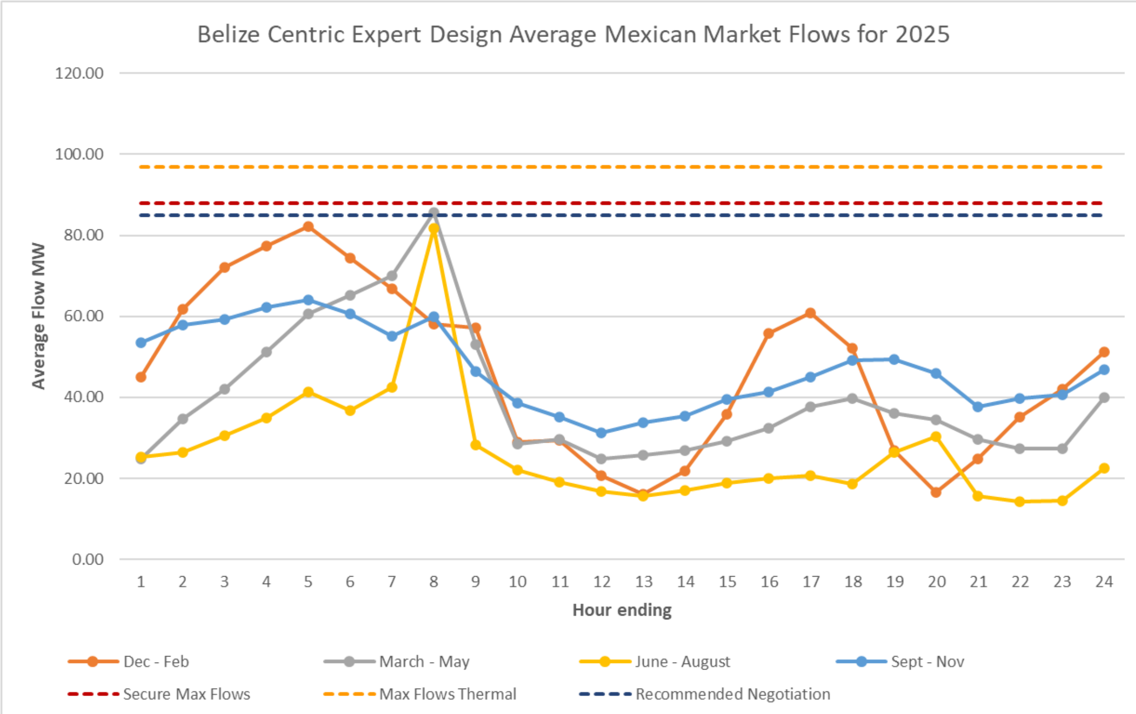
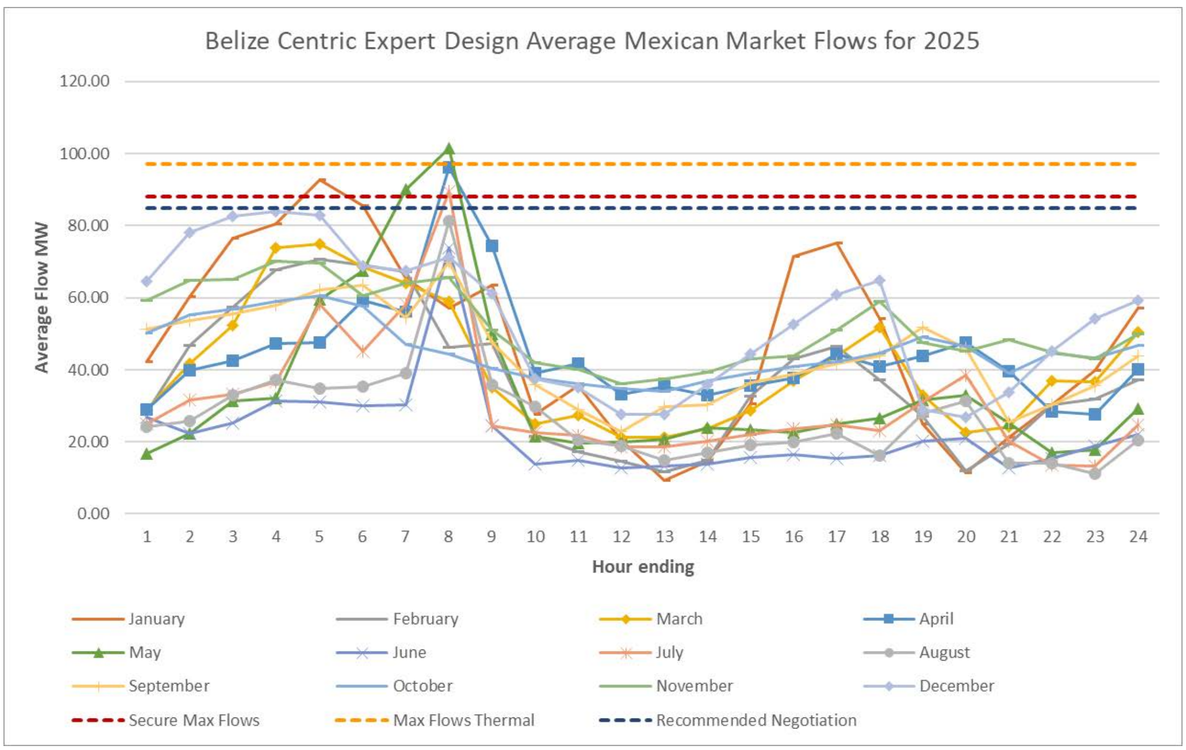


Figure 13-11



14.Transmission System Assessment

14.1 Introduction

BEL transmission system being largely made up of single transmission lines interconnecting substations, without the possibility of an alternative path in what is called a radial system, is particularly vulnerable, as a single outage (called N-1) results in the interruption of flow to important sections of the system and results in load being interrupted (shed). As the system becomes larger supplying greater loads as presented earlier in this report, this situation becomes unsustainable particularly considering the effects that severe weather has on the availability of the overhead transmission lines.

The classical approach to address this is to build new transmission lines, ideally following a different path than the reinforced lines, creating a backup supply in what is called a loop service. However, BEL has a unique opportunity to leapfrog the industry and move its design to one that leverages the use of non-wires-alternatives to provide reliability and resiliency.

In this approach, as shown below, we used the resources identified in the capacity expansion plan to provide local support to the load and reduce the dependence on imported power via transmission during emergencies.

There are few instances where new facilities are recommended for a) addressing construction issues with the existing transmission and at the same time allowing better integration of the new generation (e.g., Dangriga 115 kV), b) short new lines are proposed for reliability of supply (e.g., Belmopan 115 kV) or c) new lines and substations will prove a second supply to the load congested areas and included undergrounding to increase resiliency (Belize City). Additionally, there are multiple expansions to the transformation capacity at the substations to supply the increased load and recommendations are being made to improve the configuration so that a failure on one line does not unduly affect more than the interconnecting substations (e.g., BAPCOL tap).

As will be observed, the recommendations made in this report result in a highly reliable system that supports the development of Belize and the associated expected high load growth, the electrification of transportation and the interconnection of the new renewable resources.

14.2 Study Process

The process followed for the assessment of BEL system started from modeling the system as it currently exists (2021 conditions) to obtain a baseline from which to compare the improvements to be achieved by recommended plan. Next, we modeled the horizon 2042 conditions, including the projected load growth and new resources identified by the capacity expansion plan and determined the preferred location of the new resources and needed transmission additions to reliably supply the projected load and interconnect the generation. With this horizon system as an objective where we would like to evolve the system, we determined the latest in-service dates for the new recommended facilities and their priority.

The process followed of evaluating first the horizon year and then defining the in-service dates for investments is known as the Jump Forward and Stage Back and it avoids the pitfalls of not selecting right-sized investments for the long term that frequently happens when sequential planning is done.

14.3 Study Assumptions and Planning Criteria

14.3.1 Study Assumptions

Given the high expected penetration of photovoltaic (PV) generation identified in the capacity expansion plan, the study was carried out for daytime and nighttime conditions with the following assumptions:

- Hydro generation was assumed to be able to provide support during the night peak. This is expected to be the case even under low hydro conditions which would affect the energy availability but to a lesser extent the capability of the units to dispatch for short periods of time close to their peak capacity. On daytime the hydro was modeled at minimum output (only one unit on at Mollejon and Chalillo power plants).

- BELCOGEN is assumed to be available to supply the peak night load, as its historical dispatch indicates that it was able to provide some level of capacity throughout the year, with the exception of October, and given its location on the north of the system its dispatch stresses transmission to get its production to the load. It was modeled out of service during daytime.

- SANTANDER was conservatively assumed to be offline for both night and day conditions as historically it had zero output from October to December.

- Wind generation was modeled at 80% of its installed capacity for both day and night conditions.

- Solar generation and distributed generation (DG) were modeled at 80% of installed capacity during daytime and at zero during nighttime.

- Storage was modeled as a dispatchable resources and initially modeled charging at maximum capacity (10 MW) during daytime and discharging at 5 MW in the evenings. But this dispatch can be changed given the contingencies.

- The thermal generation, i.e., BAPCOL, the Mile 8 LM 2500 and the new RICE units were modeled online and dispatched at their minimum for the night on a case that is called the "Maximum Security Case" or the Secure Case, where the imports from Mexico are at 60 MW (contractual ceiling expanded) and offline during daytime and even in this case there are exports to Mexico (17 MW). Another case called the" Max Economy" or Economic Case modeled these units also offline at night and increased the imports to approximately 78 MW from the Mexican Market. It also assumes that the contractual ceiling is expanded.

- The load was modeled for peak conditions (2042 for the horizon) but taking into consideration the load profiles to account for the differences between day and night peak. This was also done for the Electric Vehicles charging load, whose profile was considered and reflected the highest contribution to the night peak.

14.3.2 Planning Criteria

The planning criteria establishes the minimum criteria that the electric system must meet and provides a uniform framework for selecting the short-, medium- and long-term investments in the network to move the existing system to the desired end state.

Reliability

This is a central criterion, and we are of the opinion that BEL can and must move to a reliable system significantly improving the metrics of supply and in particularly the SAIFI and SAIDI. As discussed under the objectives section of this report, BEL has been steadily improving its transmission and subtransmission SAIDI and SAIFI and achieved values of 8.35 hours/yr. SAIDI and 6.99 times/yr. SAIFI, which results in 14.5 hours SAIDI and 11.3 times SAIFI when distribution is added. These values while in line with other developing countries can and should be improved significantly.

With this in mind, the system should be planned so that load interruptions under single contingency conditions are minimized as indicated below.

- All transmission substations must have breakers at the incoming lines, preventing that a fault on a single line trips the entire substation and all must have firm transformer capability, this means that the loss of a single transformer should not result in the need to shed load and the remaining transformers should sustain the load without loss of life (i.e., loading at their emergency ratings). The only exception are smaller transformers at the subtransmission to distribution level.

- The loss of a single transmission line resulting in islanding of sections of the system should not result in loss of significant amounts of load (e.g., no loss greater than 10 MW or 5% of the load) and local resources should be able to carry the load and provide time for repairs to be made or in the worst case organizing a rotating outage schedule.

Performance / quality of supply

The system must meet the following standards:

- Voltage must be within ± 5% of nominal (0.95 / 1,05 pu) under system intact conditions and within ± 10% of nominal (0.90 / 1.10 pu) under contingency conditions.
- All facilities must be under 100% of their normal rating under system intact conditions and under the emergency rating (when available) under contingency.
- The voltage must recover above 75% nominal within 2 seconds
- System to recover to a frequency in the band 59.4 Hz and 60.6 Hz at the end of the transient.
- Maximum over- frequency of 61.8 Hz and not be exceeded during the transients.
- Frequency to drop below 61.5 Hz within 60 seconds (after governor response)
- Frequency not to drop under 57.0 Hz.
- Frequency to recover above 57.8 Hz within 30 seconds (after governor response)
- Frequency to recover above 58.2 Hz within 300 seconds (after governor response)

Extreme events and Resiliency

The system to be designed such that no credible contingency (e.g., an N-2) event results in system collapse and are managed by underfrequency / undervoltage load shedding.

In addition, the system should be developed such that the load likely to be interrupted during the outage of longer transmission lines and whose restoration may take several weeks to perform after a major event, is minimized. This consideration favors the distribution of generation resources across the system and avoid the concentration of large power plants.

14.4 2021 Case Creation and Analysis

14.4.1 Case Creation of 2021

BEL provided a network model in PSS®E which is a result of a prior study, their internal network model in ETAP, a single line diagram of the BEL transmission (November 2021), transmission system maps in Google Earth and auxiliary files with inventory for generation, transformers, generation profiles of each unit/plant and SCADA measurement for 2021 by feeder/substation.

Using the provided data and after several cross checks between the sources and clarifications with BEL engineers, a BEL transmission network model in PSS®E was created to reflect latest topology and status of the system. Siemens PSS®E power system analysis software was selected as a tool for conducting transmission analysis because of its capabilities for contingency (N-1) analysis with remedial actions (RAS) and stability analysis.

A 2021 peak load case was modeled in PSS®E. This case reflected the peak load conditions for 09/16/2021 3:00 pm with a peak load of 95.8 MW as shown in Table 14-1. Only for Corozal F5, Corozal F6 and Mullin River demands are assumed based on the consumption values as SCADA system is not available at these locations.

Table 14-1: Demand by substation at system peak

Substation	System Peak Load Time	Load at Time of System Peak P [MW]	Q [MVAr]
Belize	16.09.2021 15:00	18.44	2.81
Ladyville	16.09.2021 15:00	9.34	2.54
Westlake	16.09.2021 15:00	7.15	1.62
Belmopan	16.09.2021 15:00	11.72	1.46
San Ignacio	16.09.2021 15:00	8.53	1.22
Dangriga	16.09.2021 15:00	5.80	0.77
San Pedro	16.09.2021 15:00	9.63	1.55
Orange Walk	16.09.2021 15:00	9.51	2.41
Corozal	16.09.2021 15:00	6.48	0.84
Independence	16.09.2021 15:00	7.06	1.39
Punta Gorda	16.09.2021 15:00	2.03	0.26
Mullin Rivers	16.09.2021 15:00	0.11	0.02
	Total Load	**95.80**	**16.88**
	Transmission Losses	**6.20**	
	Total Generation	**102.00**	**12.5**
	Loses %	**6.1%**	

The generation dispatch shown in Table 14-2 was modeled which is reflective of stressed transmission conditions for assessing performance with high imports from Mexico (CFE). As can be observed the technical losses are 6.2% which is relatively high compared with other systems but expected for BEL given its radial (single line) nature of its system.

Table 14-2: The most stressful dispatch for 2021 case of BEL transmission system

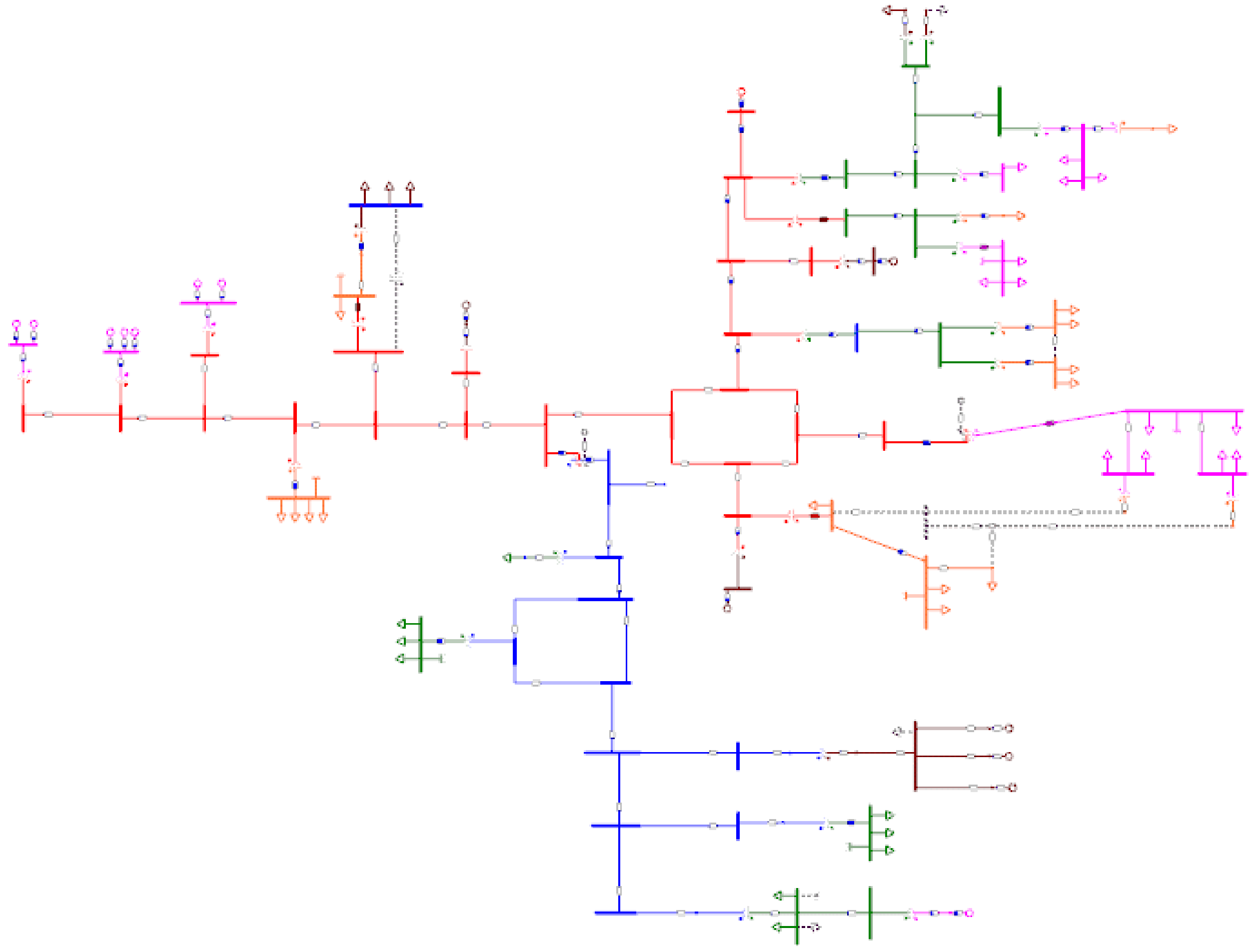
Plant	PGen (MW)	PMax (MW)	QGen (MVAr)	QMax (MVAr)	QMin (MVAr)
CFE	60.0	100.00	-2.92	100.00	-100.00
Chalillo	3.02	7.00	-1.55	4.02	-4.02
Mollejon	8.98	25.20	1.41	10.98	-10.98
Vaca	5.09	19.00	1.90	9.96	-9.96
Hydro Maya	1.64	3.40	-0.13	2.62	-2.62
Bapcol	3.60	22.50	-2.71	8.76	-8.76
Belcogen	11.25	12.50	6.06	7.75	-7.75
GT- LM2500[18]	4.00	19.00	7.57	14.90	-14.90
Santander	4.40	8.00	2.78	2.78	-2.78
Total Generation	**102.0**				
Total Load	**95.8**				
Transmission Losses	**6.2**				

[18] According to our conversations with GE this version of the LM2500 can be operated continuously at a very low values, e.g., 1 MW. The value modeled 4 MW (21% of Pmax) is achievable. The unit is online basically to provide spinning reserves.

An overview of the BEL transmission network is shown in Figure 14-1 and the 2021 model in Figure 14-1

Figure 14-1: An overview of the BEL transmission network

Figure 14-2: BEL 2021transmission network model in PSS®E



14.4.2 Analysis of the existing BEL System

The existing (2021) BEL transmission system was analyzed under both normal and emergency conditions to identify its performance and any voltage or overloading violations.

Base Case overloading violations were found on three transformers no voltage violation along the system. The overloaded transformers and the solutions assessed later in this report to address these issues are listed in Table 14-3.

Table 14-3: Overloading violations for 2021 Peak Condition

Monitored Element	Contingency	Base Flow	Rate A	%	Rate B	%	Note
2644 115-BUENAVST115.00 2695 34.5_BVA-OWK34.500 2	BASE CASE	10,69	7,5	143,83	10	106,9%	Chan Chen investment needed. Transformer is above emergency limit
2596 115_BELMOPAN115.00 2612 22-BELMOPAN 22.000 1	BASE CASE	12,12	10	121,57	13	93,2%	Overload below emergency rate. by the Belmopan new project
2322 115-WST-LDV 115.00 2323 22-WST-LDV 22.000 1	BASE CASE	17,26	15	115,23	20	86,3%	Overload below emergency rate. Address by the Belize II - Ladyville project

Under single contingency (N-1) conditions significant load shed is expected as shown in Table 14-4 given the radial (single line) nature of the system. The load shed indicates is the minimum required to maintain the balance between generation and consumption after the creation of the electrical island and the redispatch of the generation to its maximum. The solutions shown in Table 14-4 are those studied later in this report required to address the load shed issue.

Table 14-4: Overloading violations under normal condition of 2021 case

Contingency (Facility Opened)	Total Shed MW	Note
BUS 402 [34.5-CZLTAP 34.500] TO BUS 2646 [34.5-SPDRCZL34.500] CKT 1	5.14	Address by Chan Chen Project
BUS 402 [34.5-CZLTAP 34.500] TO BUS 2647 [34.5-COROZAL34.500] CKT 3	4.12	Address by Chan Chen Project
BUS 402 [34.5-CZLTAP 34.500] TO BUS 2678 [34.5-CZLFZON34.500] CKT 2	1.02	Address by Chan Chen Project
BUS 502 [22-LDV-F1 22.000] TO BUS 2324 [22-LADYVILLE22.000] CKT @1	3.18	Partially addressed by transfer load to Palloti
BUS 2322 [115-WST-LDV 115.00] TO BUS 2323 [22-WST-LDV 22.000] CKT 1	16.49	To be addressed by the Belize II substation Project
BUS 2323 [22-WST-LDV 22.000] TO BUS 2324 [22-LADYVILLE22.000] CKT 2	9.34	To be addressed by the Belize II substation Project
BUS 2403 [69-MULRIVER 69.000] TO BUS 2561 [24.9-MULRIVE24.900] CKT 1	0.11	Accept load shed
BUS 2406 [69-BALTAP 69.000] TO BUS 2407 [69-SAVANNAH 69.000] CKT 1	5.72	To be partially addressed by the RICE and Battery at Independence
BUS 2407 [69-SAVANNAH 69.000] TO BUS 2466 [69-INDEPNDNC69.000] CKT 1	7.06	To be partially addressed by the RICE and Battery at Independence
BUS 2466 [69-INDEPNDNC69.000] TO BUS 2467 [69-INDPNC_TX69.000] CKT @1	7.06	To be partially addressed by the RICE and Battery at Independence

Contingency (Facility Opened)	Total Shed MW	Note
BUS 2467 [69-INDPNC_TX69.000] TO BUS 2468 [24.9-INDPDNC24.900] CKT 1	7.06	To be partially addressed by the RICE and Battery at Independence
BUS 2535 [69-DANGRG-3 69.000] TO BUS 2545 [24.9-DANGRG 23.000] CKT 1	5.8	To be addressed by the new 115 kV line between La Democracia and Dangriga
BUS 2564 [115-CAMALOTE115.00] TO BUS 2596 [115_BELMOPAN115.00] CKT 2	11.72	To be addressed by second circuits between Camalote to Belmopan and reconfiguration of both substations.
BUS 2565 [115-SANIGNC 115.00] TO BUS 2566 [22_SI 22.000] CKT 1	8.53	To be addressed by new transformers at San Ignacio
BUS 2596 [115_BELMOPAN115.00] TO BUS 2612 [22-BELMOPAN 22.000] CKT 1	11.72	To be addressed by second transformers at Belmopan
BUS 2611 [22-BELMPN_TX22.000] TO BUS 2612 [22-BELMOPAN 22.000] CKT @1	6.33	To be addressed by second transformers at Belmopan
BUS 2642 [115-MASKALL 115.00] TO BUS 2727 [34.5-MASKALL34.500] CKT 1	9.63	To be addressed by new 69 kV line to San Pedro and battery
BUS 2644 [115-BUENAVST115.00] TO BUS 2645 [34.5-BVA-CZL34.500] CKT 1	6.48	Address by Chan Chen Project
BUS 2644 [115-BUENAVST115.00] TO BUS 2695 [34.5_BVA-OWK34.500] CKT 2	9.51	To be addressed by Chan Chen Project. and battery and PV at Orange Walk
BUS 2645 [34.5-BVA-CZL34.500] TO BUS 2646 [34.5-SPDRCZL34.500] CKT 1	6.48	Address by Chan Chen Project
BUS 2695 [34.5_BVA-OWK34.500] TO BUS 2705 [34.5-OWK 34.500] CKT 1	9.51	To be addressed by Chan Chen Project. and battery and PV at Orange Walk
BUS 2705 [34.5-OWK 34.500] TO BUS 2710 [22-OWK 22.000] CKT 2	2.41	To be addressed by new transformers at Orange Walk
BUS 2727 [34.5-MASKALL34.500] TO BUS 2738 [34.5-SANPDRO34.500] CKT 1	9.63	To be addressed by new 69 kV line to San Pedro and battery
BUS 2738 [34.5-SANPDRO34.500] TO BUS 2740 [22-SANPDR-1 22.000] CKT 1	5.67	To be addressed by new 69 kV line to San Pedro and battery
BUS 2738 [34.5-SANPDRO34.500] TO BUS 2742 [22-SANPDR-2 22.000] CKT 2	3.96	To be addressed by new 69 kV line to San Pedro and battery
BUS 2775 [115-WEST-E 115.00] TO BUS 2785 [115-BELIZE 115.00] CKT 3	18.44	To be addressed by the Belize II substation Project

14.5 Considerations for the 2042 Horizon Case Creation

14.5.1 Committed Projects

The 2042 model was developed starting from the 2021 model and adding to it the already committed projects:

a. Second submarine cable at 69 kV Maskall to San Pedro and continuation of connection to Caye Caulker at 34.5 kV. This project is also analyzed in this report and its convenience and necessity confirmed. Additionally, as will be shown later a 10 MW battery at San Pedro is recommended.

b. Transmission committed projects at or near Chan-Chen substation.

   i. New 115/34.5 kV substation at Chan-Chen

ii. New 115/34.5 kV substation at Belcogen and expansion to ring bus.
iii. New 115 kV line from Chan-Chen- Tap to Xul-Ha substation.
iv. New 34.5kV line from Belcogen to Orange Walk Substation 4.25 miles
v. New 34.5kV sub-transmission line 8.1 Miles Chan-Chen to Belcogen.

14.5.2 Generation Resources

The generation resources identified by both capacity expansion strategies were allocated considering for solar and wind generation the areas of the country where the underlying resource was adequate, i.e., the coastal region for wind, the north of the country for solar and for new thermal generation closeness to the ports for the delivery of the containerized LNG. Within these parameters the solar generation was placed in areas where there would be land available for its development and if possible close to load centers as was the case of Ladyville and Orange Walk. Other plants were located at places where there are already ongoing developments as is the case of Maskall and Chan Chen or central to the system as West and La Democracia substation.

Wind generation was modeled at the proposed Vientos del Caribe project for the Base Strategy that includes it and just south of the border at Corozal and at San Pedro for the Belize Centric Strategy.

For the new thermal a compromise solution was proposed, the plant selected by the capacity expansion plan was a 3x7.5 MW RICE units. Initially, we considered placing these units as a single plant at one location in Dangriga and have the LNG containers delivered from Independence. However, the Independence load is highly exposed and dependent on a long 69 kV line. Thus, the plant was split in 2x7.5 MW to be installed at Dangriga and 1x7.5 MW to be installed at Independence. The units are recommended to be installed by the same developer and controlled from a central location, possibly at Dangriga.

The tables below show the proposed location by generation expansion strategy.

Table 14-5: Generation Location for Base Strategy

RICE Gas

Total MW	In Service year	POI (Location)	Note
22.50	2024	Dangriga	Build 115 kV line to Dangriga

Solar PV

Total MW	In Service year	POI (Location)
20.00	2026	Ladyville (Includes Belize Solar)
20.00	2027	Maskall (Includes BAPCOL 8 MW)
20.00	2029	Orange Walk
20.00	2033	West
20.00	2029	Chan-Chen (Includes BAPCOL 7 MW)
20.00	2037	West
20.00	2040	La Democracia
20.00	2042	La Democracia

Storage

Total MW	In Service year	POI (Location)	Note
10.00	2023	San Pedro	Model 5 MW at night -10 day
10.00	2023	Ladyville	Model 5 MW at night -10 day
10.00	2023	Ladyville	Model 5 MW at night -10 day
10.00	2023	Independence	Model 5 MW at night -10 day
10.00	2023	Orange Walk	Model 5 MW at night -10 day

Wind Turbine Generation

Total MW	In Service year	POI (Location)	Note
10.00	2026	South of Xul-Ha	Model @ 80% Pmax day or night
15.00	2028	South of Xul-Ha	Model @ 80% Pmax day or night
10.00	2030	South of Xul-Ha	Model @ 80% Pmax day or night

Table 14-6: Generation Location for Belize Centric Strategy

Rice Gas

Total MW	In Service year	POI (Location)	Note
22.50	2024	Dangriga	Build 115 kV line to Dangriga

Solar

Total MW	In Service year	POI (Location)	Note
20.00	2024	Orange Walk	Model @ 80% Pmax during peak daytime
20.00	2026	Ladyville (Includes Belize Solar)	Model @ 80% Pmax during peak daytime
20.00	2034	La Democracia	Model @ 80% Pmax during peak daytime
20.00	2036	West	Model @ 80% Pmax during peak daytime
20.00	2038	La Democracia	Model @ 80% Pmax during peak daytime
20.00	2040	La Democracia	Model @ 80% Pmax during peak daytime
20.00	2042	West	Model @ 80% Pmax during peak daytime

Storage

Total MW	In Service year	POI (Location)	Note
10.00	2023	San Pedro	Model 5 MW at night -10 day
10.00	2023	Ladyville	Model 5 MW at night -10 day
10.00	2023	Independence	Model 5 MW at night -10 day
10.00	2023	Orange Walk	Model 5 MW at night -10 day

Wind Belize Coastal

Total MW	In Service year	POI (Location)	Note
20.00	2029	San Pedro	Model @ 80% Pmax day or night
20.00	2031	Corozal	Model @ 80% Pmax day or night

14.5.3 Load Model

The horizon 2042 system model was created by scaling the loads to represent the expected 2042 conditions as well as the Distributed Generation and the EV loads. The table below shows the load by substation (including EV) for day peak and night peak conditions. We note that as expected BEL will become night peaking due to the EV charging loads and the total customer load served during the day is significantly reduced due to the distributed generation.

Table 14-7: Total Load and Distributed Generation by substation Load for Base Strategy

	Day Peak		Night Peak	
Substation Load	**MW**	**MVAr**	**MW**	**MVAr**
Belize I	19.5	3.1	17.9	3.1
Belize II	10.7	2.5	10.7	2.6
Ladyville	13.8	3.8	15.2	4.2
Belmopan	17.9	2.3	18.5	2.8
San Ignacio	13.7	2.1	16	2.7
San Pedro	20.5	3.5	22.4	4.2
Caye Caulker	3.3	0.5	3.2	0.5
Orange Walk	14.5	3.7	17.7	4.6
Corozal	8.1	1.1	10.7	1.7
Dangriga	10.1	1.4	11.6	1.8
Independence	13.7	2.8	15.1	3.2
Punta Gorda	3.4	0.5	4.2	0.7
Mullin Rivers	0.1	0	0.1	0
Total Load MW/MVAr	**149.3**	**27.2**	**163.3**	**32.2**
Distributed Generation	**MW**	**MVAr**	**MW**	**MVAr**
Belize I	9.5	0.0	0.0	0.0
Belize II	5.2	0.0	0.0	0.0
Ladyville	6.8	0.0	0.0	0.0
Belmopan	4.1	0.0	0.0	0.0
San Ignacio	3.3	0.0	0.0	0.0
San Pedro	6.2	0.0	0.0	0.0
Caye Caulker		0.0	0.0	0.0
Orange Walk	4.2	0.0	0.0	0.0
Corozal	2.5	0.0	0.0	0.0
Dangriga	2.6	0.0	0.0	0.0
Independence	3.4	0.0	0.0	0.0
Punta Gorda	0.9	0.0	0.0	0.0
Mullin Rivers	0.0	0.0	0.0	0.0
Total DG MW/MVAr	**48.6**	**0.0**	**0.0**	**0.0**
Net Load Served	**100.7**	**27.2**	**163.3**	**32.2**

14.5.4 Generation Dispatch

One dispatch was modeled for daytime conditions minimizing the thermal generation in country and results in an export to Mexico of 17 MW and two dispatches for nighttime conditions as indicated earlier. The Max Security or Secure Case maintain in country thermal generation and import from Mexico approximately 60 MW with an expansion of the contractual limit and the Max Economy that turn off the thermal units and increases the import from Mexico to 69.5 MW.

The tables below show the dispatch of the units in service[19] for the Base Strategy which is the most demanding from a transmission point of view and was used for the assessment of performance. The Belize Centric strategy requires the same investments in transmission, which are largely driven by load growth and the available dispatchable resources (RICE and Battery energy storage) which are the same as for the Base Strategy.

As shown later the Max Economy while minimizes the cost of generation represents a risk for the system, it is not recommended and is provided as a reference.

Table 14-8: Generation Day Peak Dispatch Base Strategy

Generator	Type	PGen (MW)	QGen (MVAr)	PMax (MW)
Vientos del Caribe 1	Wind	12.0	-0.3	15.0
Vientos del Caribe 2	Wind	8.0	-0.2	10.0
Vientos del Caribe 3	Wind	8.0	-0.2	10.0
Ladyville Battery	Storage	-10.0	1.2	10.0
Ladyville PV	Solar	16.0	0.4	20.0
West PV 1	Solar	16.0	-6.6	20.0
West PV 2	Solar	16.0	-6.6	20.0
La Democracia PV 1	Solar	16.0	2.2	20.0
La Democracia PV 2	Solar	16.0	-2.2	20.0
Hydro Maya	Hydro	1.3	1.9	2.5
Independence Battery	Storage	-10.0	4.8	10.0
Chalillo	Hydro	1.8	2.0	3.5
Mollejon	Hydro	4.2	-2.0	8.4
Maskall PV	Solar	16.0	-1.6	20.0
Mexico (CFE)	Mexico	-17.0	4.5	100.0
Chan Chen PV	Solar	16.0	-6.6	20.0
Orange Walk PV	Solar	16.0	2.2	20.0
San Pedro Battery	Storage	-10.0	4.8	10.0
Orange Walk Battery	Storage	-10.0	1.2	10.0
Total Utility Generation MW/MVAr		**106.3**	**-1.1**	
Total Load Served		**100.7**	**27.2**	
Total Losses MW		**5.6**		
Total Losses %		**5.3%**		

Table 14-9: Generation Night Peak Max Security Dispatch Base Strategy

Generator	Type	PGen (MW)	QGen (MVAr)	PMax (MW)
Vientos del Caribe 1	Wind	12.0	0.7	15.0
Vientos del Caribe 2	Wind	8.0	0.5	10.0
Vientos del Caribe 3	Wind	8.0	0.5	10.0
LM 2500 Gas Turbine[20]	Gas	6.2	1.3	30.9
Ladyville Battery	Storage	5.0	4.1	10.0
Hydro Maya	Hydro	2.3	0.3	2.5
Independence Battery	Storage	5.0	1.7	10.0
Independence RICE 1/3	Gas	1.2	1.6	7.5
BAPCOL 1	Thermal	1.2	0.2	7.5
BAPCOL 2	Thermal	1.2	0.2	7.5
BAPCOL 3	Thermal	1.2	0.2	7.5
Dangriga RICE 2/3-1	Gas	1.2	0.4	7.5
Dangriga RICE 2/3-2	Gas	1.2	0.4	7.5
Chalillo 1	Hydro	3.2	0.1	3.5
Chalillo 2	Hydro	3.2	0.1	3.5
Mollejon 1	Hydro	7.6	0.0	8.4
Mollejon 2	Hydro	7.6	0.0	8.4
Mollejon 3	Hydro	7.6	0.0	8.4
Vaca 1	Hydro	8.6	0.7	9.5
Vaca 2	Hydro	8.6	0.7	9.5
Mexico (CFE)	Mexico	60.1	-3.5	100.0
Belcogen	Biomass	3.1	1.7	12.5
San Pedro Battery	Storage	5.0	4.8	10.0
Orange Walk Battery	Storage	5.0	4.1	10.0
Total Utility Generation MW/MVAr		**172.9**	**20.9**	
Total Load Served		**163.3**	**32.2**	
Total Losses MW		**9.6**		
Total Losses %		**5.6%**		

[19] Units not dispatched as for example Vaca on the day peak are not shown in the table.
[20] According to our conversations with GE this version of the LM2500 can be operated continuously at a very low values, e.g., 1 MW. The value modeled 6.2 MW (20% of Pmax) is achievable. The unit is online basically to provide spinning reserves.

Table 14-10: Generation Night Peak Max Economy Dispatch Base Strategy

Generator	Type	PGen (MW)	QGen (MVAr)	PMax (MW)
Vientos del Caribe 1	Wind	12.0	1.8	15.0
Vientos del Caribe 2	Wind	8.0	1.2	10.0
Vientos del Caribe 3	Wind	8.0	1.2	10.0
Ladyville Battery	Storage	6.0	3.2	10.0
Hydro Maya	Hydro	2.3	1.3	2.5
Independence Battery	Storage	6.0	4.7	10.0
Chalillo 1	Hydro	3.5	1.1	3.5
Chalillo 2	Hydro	3.5	1.1	3.5
Mollejon 1	Hydro	8.4	1.1	8.4
Mollejon 2	Hydro	8.4	-0.16	8.4
Mollejon 3	Hydro	8.4	-0.16	8.4
Vaca 1	Hydro	9.5	2.3	9.5
Vaca 2	Hydro	9.5	2.3	9.5
Mexico (CFE)	Mexico	69.5	4.0	100.0
San Pedro Battery	Storage	6.0	4.8	10.0
Orange Walk Battery	Storage	6.0	4.8	10.0
Total Utility Generation MW/MVAr		**174.9**	**30.7**	
Total Load Served		**163.3**	**32.2**	
Total Losses MW		**11.6**		
Total Loses %		**6.6%**		

14.5.5 System Model

System reinforcements were added to the model as it was being developed to address identified issues and this is discussed in detail in the section below.

The following figures shows a single-line diagram as an overview of the BEL transmission network for year 2042, modelled on PSS®E. The diagram is pseudo-geographic. This is, for example, Xul-HA substation is in the top (north), Belize on the right (east), Punta Gorda in the bottom-left (south), San Ignacio in the left (west), and so on. In the diagram, the proposed reinforcements were added to the 2021 case, and these reinforcements and the new generation projects are shown inside rectangles with dashed lines. The reinforcements are justified in the following sections in a by-substation-analysis manner.

The diagrams are fully detailed and can be zoomed in and show that there are no base case overloads, otherwise they would be highlighted in the diagrams with thicker red lines.

Figure 14-7 shows a heatmap with voltage as the criteria and we observe there that for all cases analyzed the voltages were withing acceptable values for base case conditions.

Figure 14-3: An overview of the BEL transmission network in PSS®E for 2042

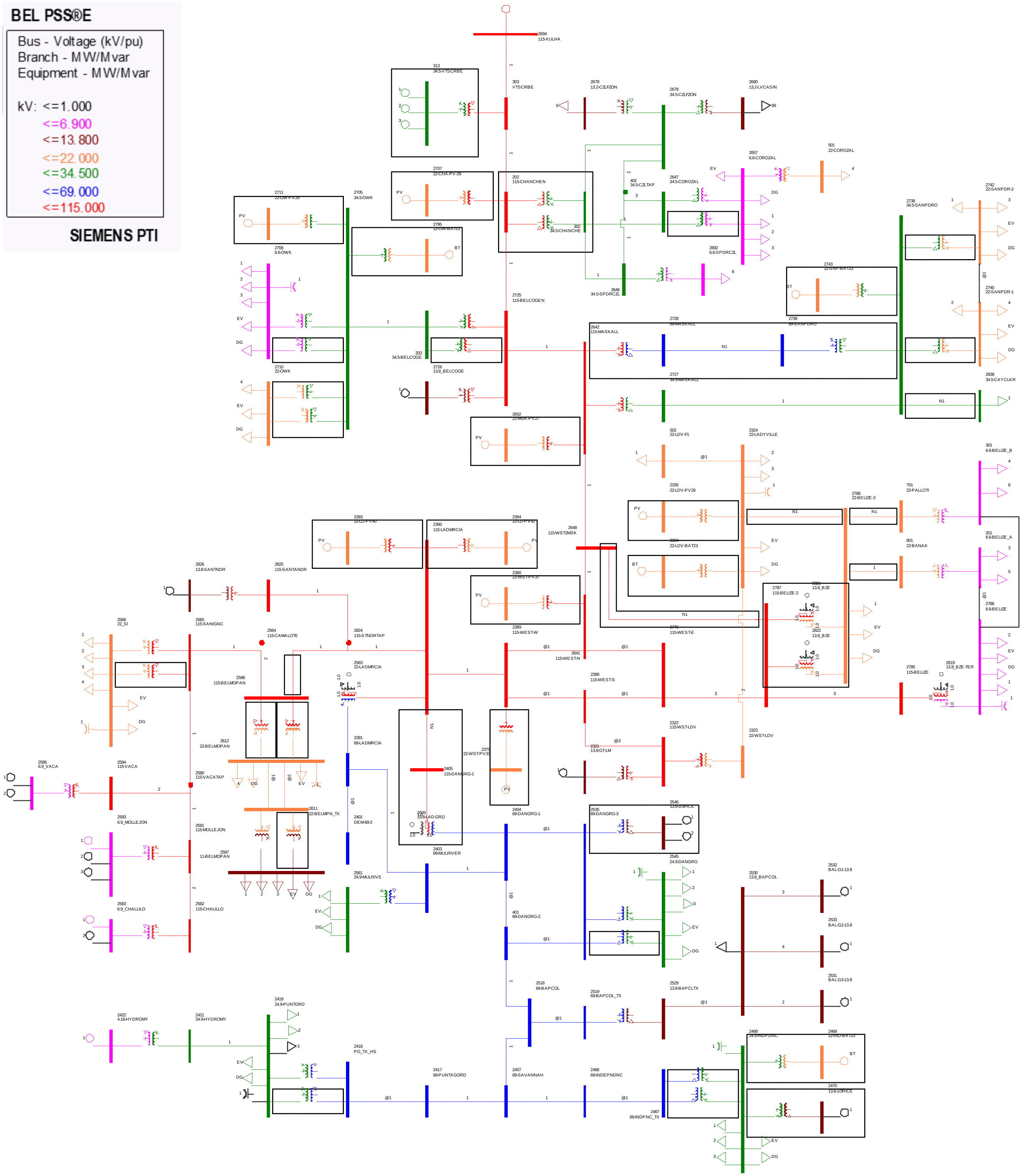


Figure 14-4: Power Flow results for Day Peak, base case for 2042

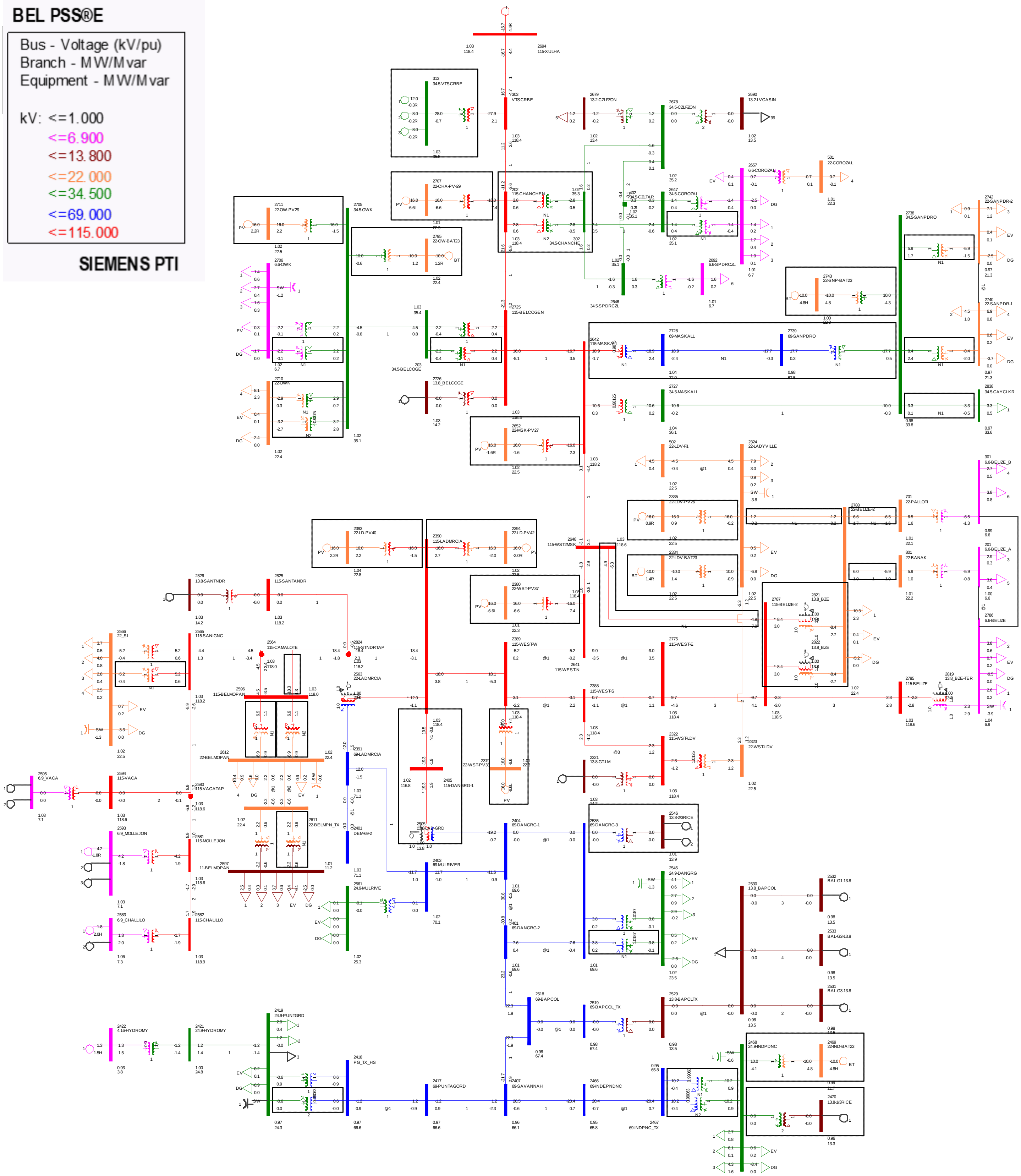


Figure 14-5: Power Flow results for Night Peak, Maximum Security, base case for 2042

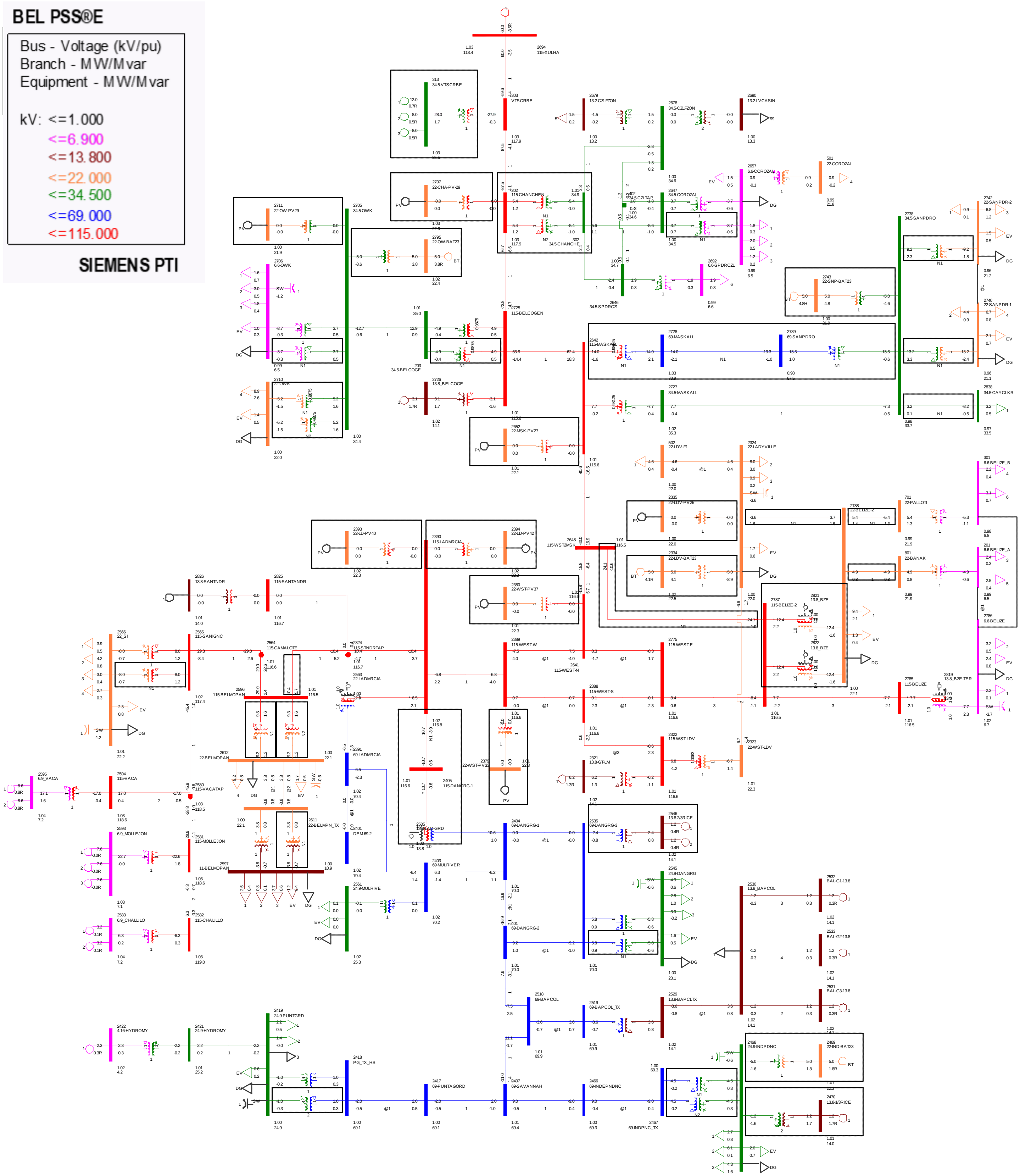


Figure 14-6: Power Flow results for Night Peak, Maximum Economy, base case for 2042

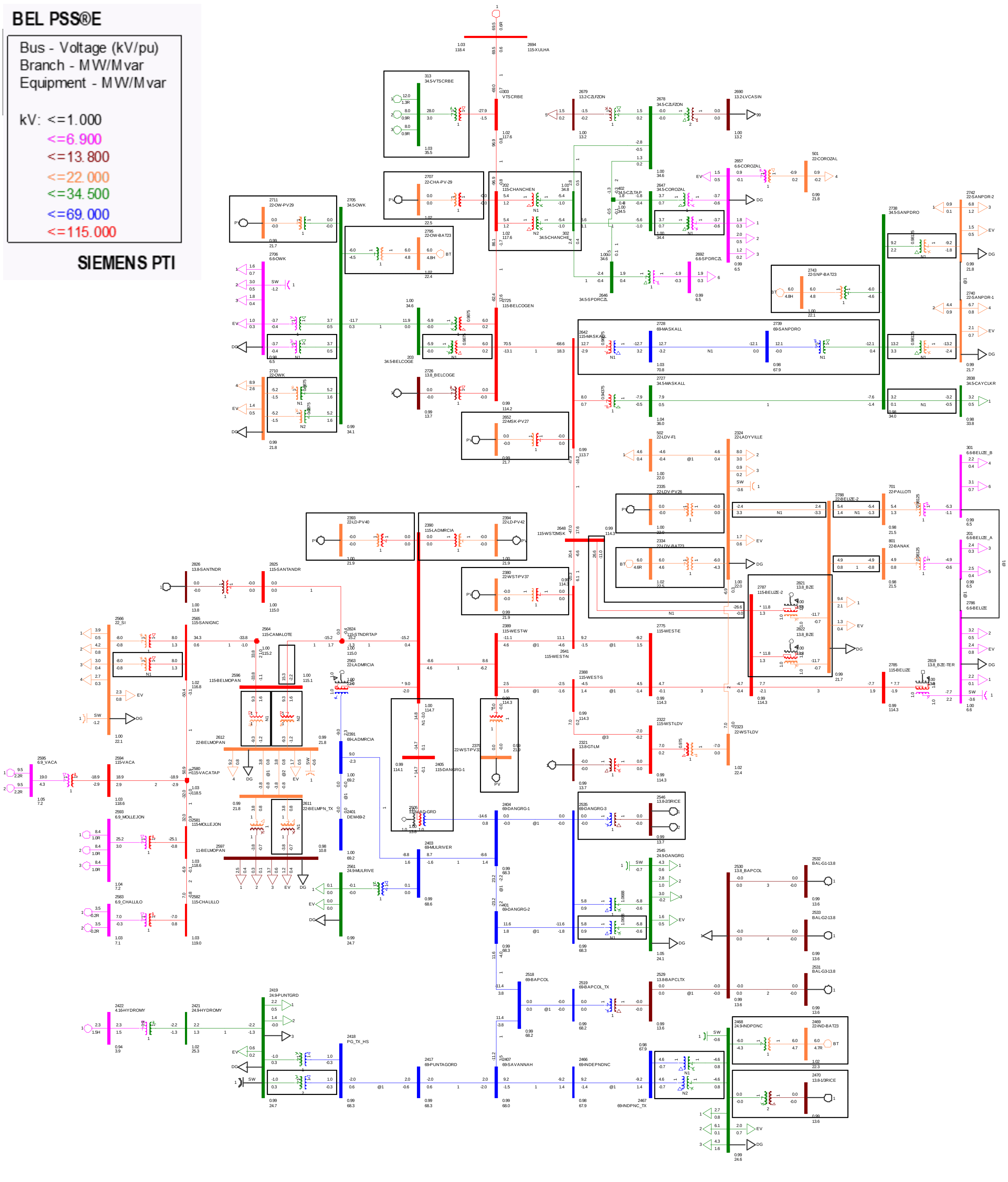
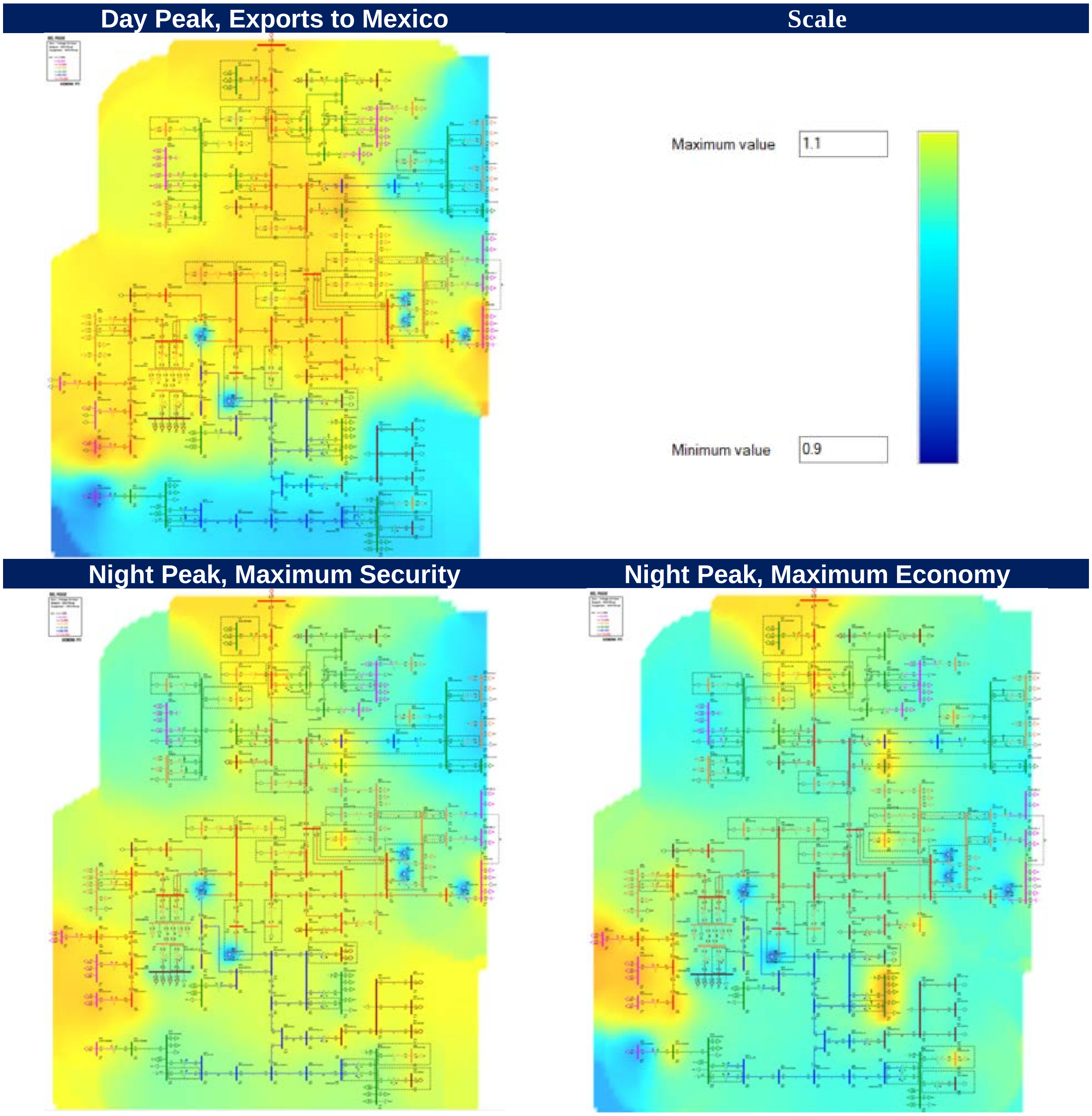


Figure 14-7: Power Flow results for per-unit Voltage profile, base case for 2042



14.6 Analysis of BEL System under Horizon conditions and identification of in-service dates of investments.

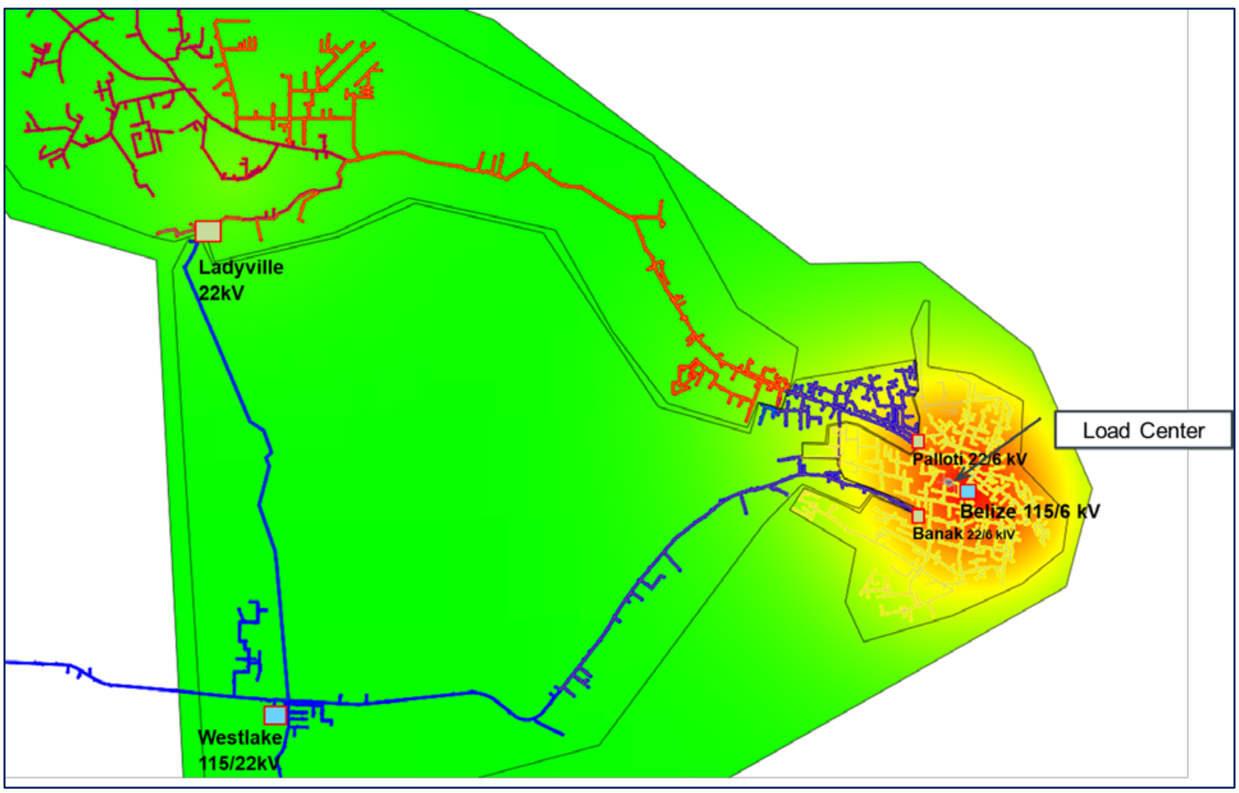
14.6.1 Belize Metropolitan District.

Diagnostic.

Belize City and the surrounding metropolitan area are supplied by three main substations Belize City 115/6.6 kV, Westlake 115/22 kV and Ladyville 22 kV. There are also two 22/6.6 kV substations Banak and Palloti with 10/14 MVA that allows transferring 6.6 kV load to the 22 kV system supplied from Westlake and potentially partially supply Ladyville load in case of tripping the single 22 kV line from Westlake.

The figure below shows an overview of the region indicating the location of the substations above, the area covered and a heatmap of the load density. Here we observe that the center of load is currently located very close to the Belize City, but there is a 22 kV area northwest of the city that is supplied from a rural feeder from Westlake, and we understand that most of the growth in Belize City is happening at this voltage level, with minimal or no growth at 6.6 kV.

Figure 14-8: Belize City Metropolitan District



Belize City 115 kV/6.6 kV supplies six 6.6 kV feeders (BZE-F01 to F-06) with a total coincident peak load of approximately 18.4 MW (2021) and if the growth in the city were to be supplied by this substation our load projection for the region indicates that by 2025 there would be a peak load of 20.2 MVA that would exceed the normal capacity of the single existing transformer (20 MVA).

Another issue with this substation is that beyond there being a single 115/6.6 kV transformer there is a single supply at 115 kV from Westlake the outage of either one would result in the need to shed load at Belize if this were to happen during peak load conditions as the existing 115/22 kV transformer at Westlake is also heavily loaded as discussed below and the only alternative for partial support would be the 15 MVA mobile substation and the long 22 kV feeders. This situation is in violation of the planning criteria presented above.

As mentioned above the115/22 kV transformer at Westlake is also projected to be heavily loaded by the 22 kV load directly supplied from this substation 7.2 MW (WST-F1) and Ladyville load 9.6 MW (LDV F01 to F03) for a total of 16.8 MW that exceeds the normal capacity of this transformer 15 MVA forcing it to operate under the emergency rating ONAF-1 (20 MVA). The loss of this transformer under peak load conditions will likely result in load shed unless the mobile substation is used as there is no real possibility of alternate supply from Belize City Substation. Additionally, the loss of either 22 kV circuit above may result in load shed and in particular the line to Ladyville as discussed later in this document.

This situation is projected to become worse given the expected load growth in the area.

Belize City Solution.

Several solutions were investigated for the area including adding 20 MW of storage at Belize City substation together with a second 115/6.6 kV transformer or more likely a 115/22 kV transformer and a 22/6.6 kV transformer to allow transferring of load during emergencies. But even in this case the loss of the single 115 kV line to Westlake would result in load shed unless the line is repaired before the batteries are depleted, which is a risky situation as there would be no practical way to recharge the battery.

Given the above a second 115 kV line to Belize City was considered initially coming from Westlake and this second supply should be underground. However, we understand firstly that the expansion of Westlake is problematic and secondly, as most of the growth is expected to happen at 22 kV, the location of the existing Belize City substation is not ideal.

Belize II substation

BEL identified a location for a new substation along Chetumal St. near the intersection with Holy Emanuel Street that would be well located to supply the 22 kV load and can be readily connected to the 115 kV line from Westlake to Belize City sub (see Figure 14-12 and Figure 14-13). This new substation called Belize II in this report is proposed to take the 22 kV load at Belize City currently supplied from Westlake and most of the load growth in Belize City, which could include the conversion of sections of 6.6 kV feeders to 22 kV. In our analysis we considered that the load in the existing Belize City sub (called Belize I) will only have vegetative load growth on the existing customers (approximately 0.1% per year) or 2% growth for the planning period plus the new EV charging load. There is no load directly supplied from Westlake and the 115/22 kV transformer is limited to supplying Ladyville.

Based on the above we projected for the Belize II a total peak load of 18.9 MW for day peak by 2042 (including 0.7 MW of EV charging load) and 18.2 MW for the night peak including 2.4 MW of EV charging load (see table below and Figure 14-9).

Table 14-11: 2042 Projected load at Belize II

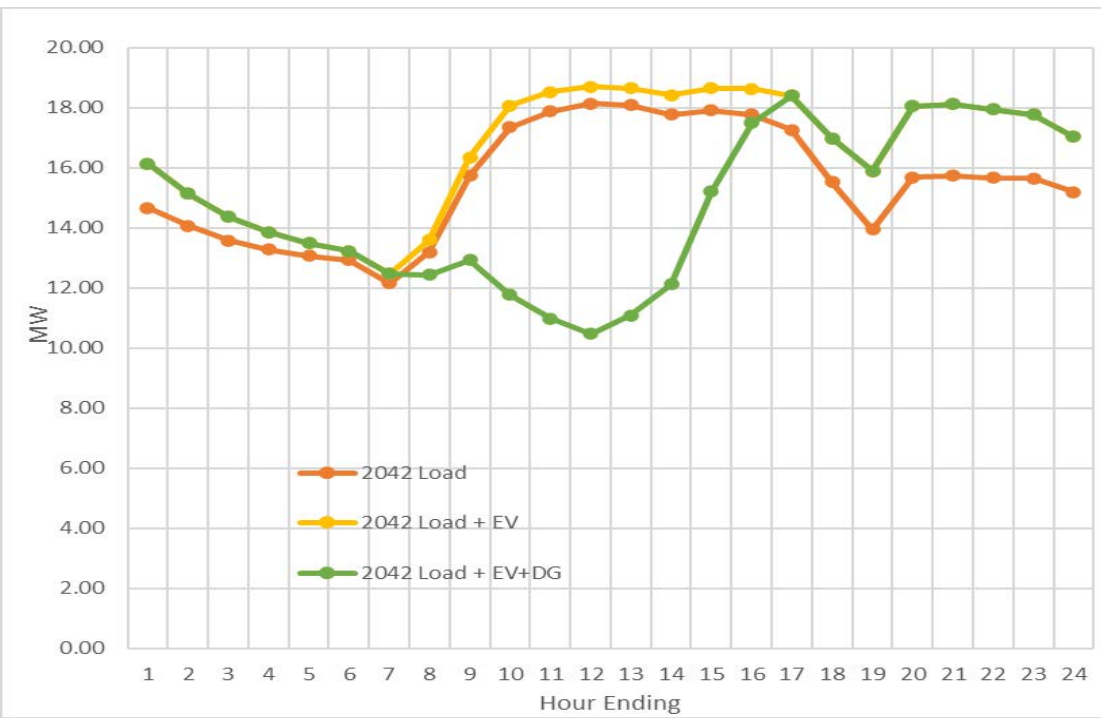
	Base Load	EV	Total
Day Peak	18.13	0.72	18.86
Night Peak	15.74	2.39	18.12

In agreement to the planning criteria, two new 115/22 kV transformers are recommended with the ratings shown in Table 14-12 below. The ONAF rating is the minimum recommended but if higher would be acceptable. These transformers should also have on load tap changers with a range of ± 10% and 32 steps. As shown in the table by 2042 the outage of one transformer will result in 84% loading of the remaining transformer, thus the substation has firm capacity.

Table 14-12: Recommended Transformers for Belize II

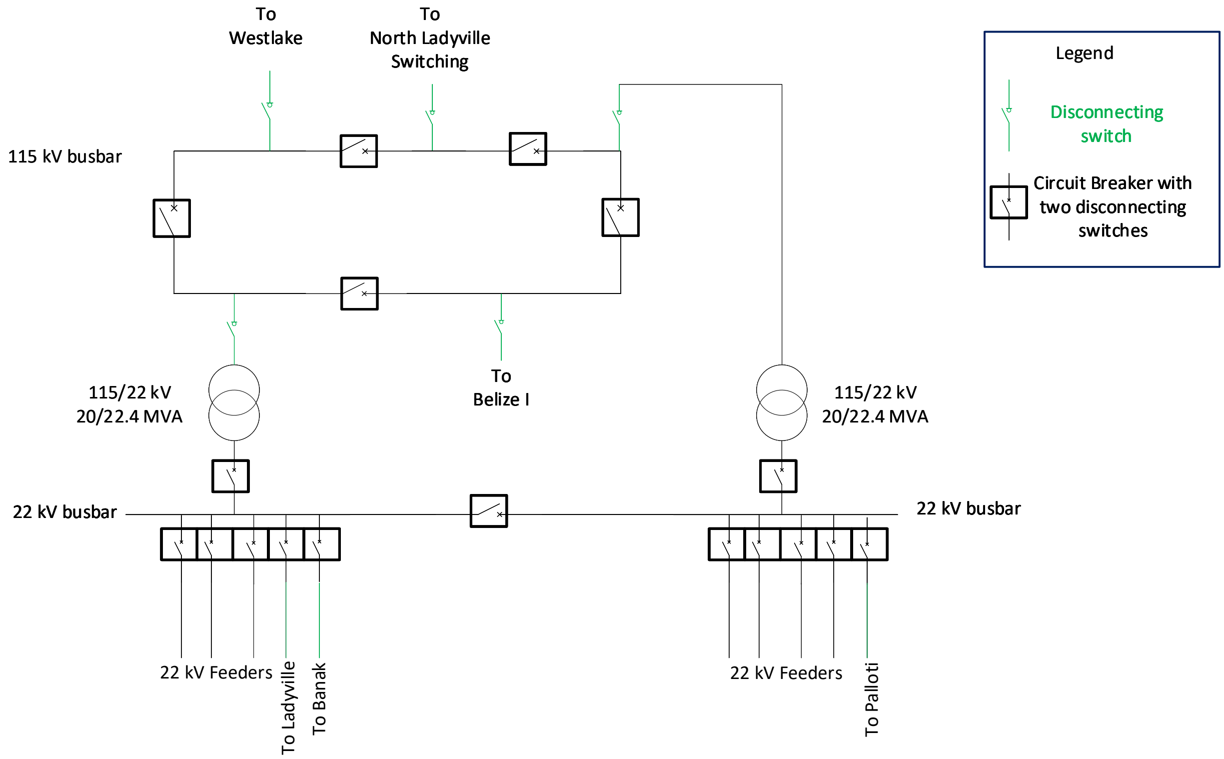
			Rating MVA		2042 loadings	
In Service Year	Voltage	Units	Normal (ONAN)	Emergency (ONAF)	N-0	N-1
2025	115/22kV	2	20	22.4	47%	84%

Figure 14-9: Belize II Peak Load Day 2042



The substation should have a ring bus configuration at 115 kV with at least five positions; two for the transformers, one for the line from Westlake, one for the line to Belize I and one for a new 115 kV supply to be discussed below. At 22 kV, 7 breakers are allocated to the transmission function, two for the transformers, one for the bus tie and three for the 22 kV lines (express feeders) to Palloti and Banak as well as the Ladyville tie as discussed later in this report. The figure below shows simplified an overview of this substation (only main equipment shown).

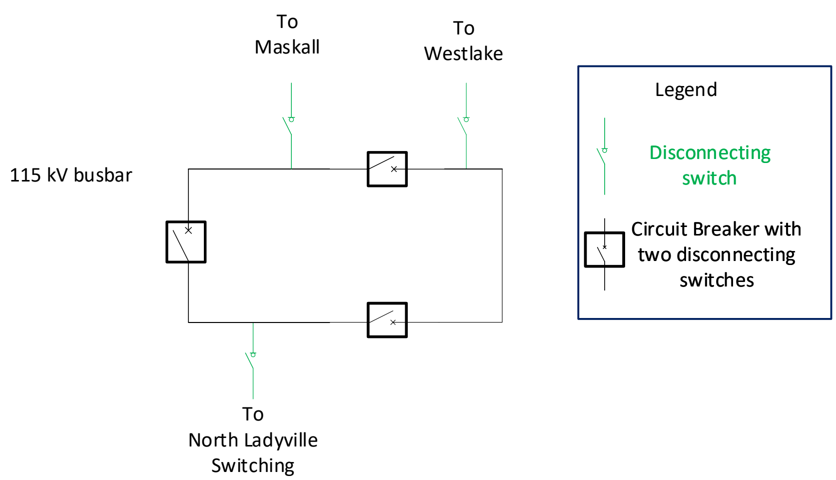
Figure 14-10: Belize II 115/22 kV Simplified One-Line Diagram



Second 115 kV line and North Ladyville Switching substation

A second 115 kV line to the new Belize II is proposed starting from a new switching station located on the line from Maskall to Westlake at approximately 10 miles from Westlake (23.7 miles from Maskall). This new switching substation, called North Ladyville Switching in this report, should have a ring bus configuration with 3 exits, one for the line from Maskall, one for the line to Westlake and one for the new line to Belize II and its simplified one-line diagram is shown in the figure below.

Figure 14-11: North Ladyville 115 kV Simplified One-Line Diagram



The new line to Belize II is proposed to start overhead for about 6 miles up to a point near the crossing of the North Hwy with International Airport Rd. where it is to transition to a cable for another 6 miles for resiliency considerations. This is shown in Figure 14-12.

Belize I Substation backup

Finally, to provide backup to Belize I (the existing substation) that will continue to have a single transformer and a single incoming line, two lines (express feeders) at 22 kV lines are proposed connecting Belize II to Banak and Palloti substations. Figure 14-13 shows the location of Belize II, the two 22 kV lines to Banak and Palloti (green) as well as details on the opening of the 115 kV line from Westlake to Belize I (red) and the line from the new switching substation (fuchsia).

The line to Banak could use the existing 22 kV feeder and for Palloti we are assuming a new 2.5 miles feeder will need to be build.

These investments should be in place by or before 2025, when the existing transformer at Belize I could start overloading or sooner given the concerns with the reliability of supply to Belize.

Figure 14-12: Supply of Belize II substation

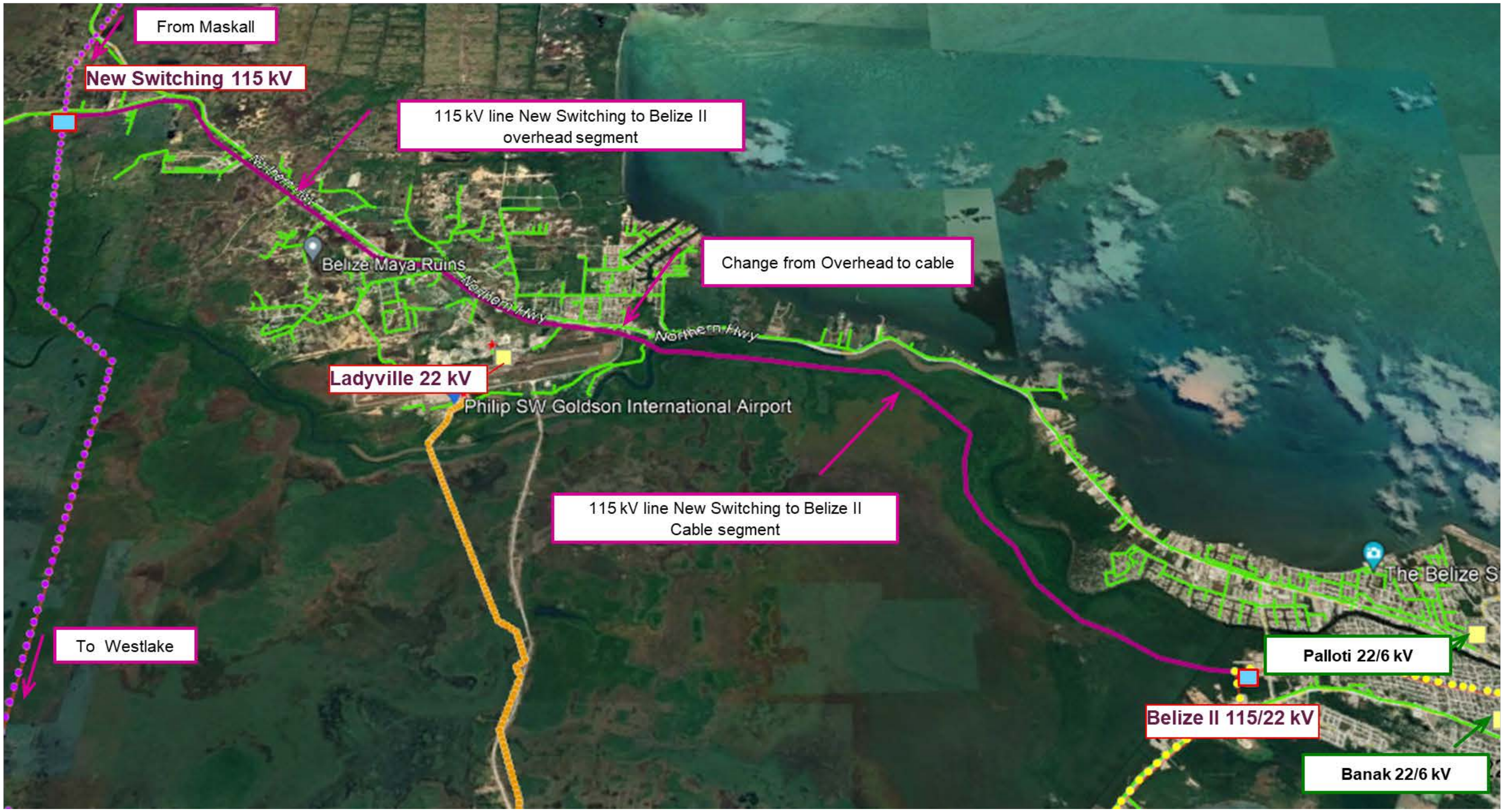


Figure 14-13: Belize II location and interconnecting facilities

Ladyville Solution.

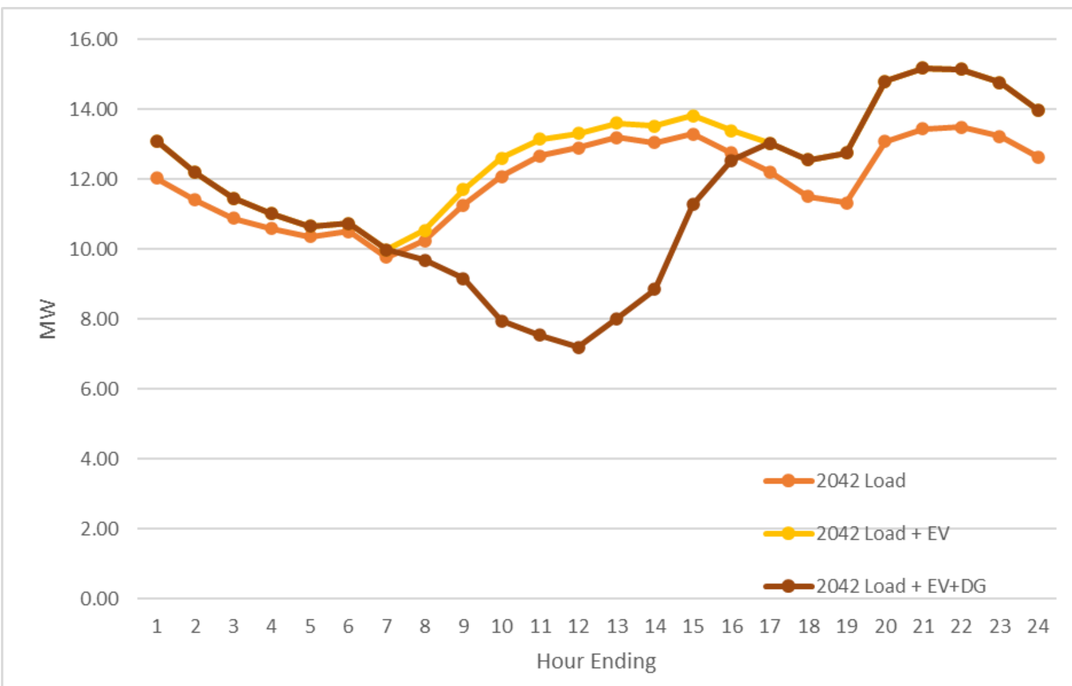
Ladyville is supplied under normal conditions from a 22 kV line from Westlake rated at 16 MVA and for its outage backup can be provided via a connection between the West F1 and LDV F1 and approximately 5.5 MW can be restored. A large client Bowen & Bowen cannot be supplied. There are plans to increase the maximum load that could be served but this would still fall short of being able to supply the large client.

Ladyville is a high growth area, and our projections indicate that the load should be at least as shown below.

Table 14-13: 2042 Projected load at Ladyville

	Base Load	EV	Total
Day Peak	13.30	0.53	13.83
Night Peak	13.50	1.74	15.23

Figure 14-14: Ladyville Peak Load Day 2042



D

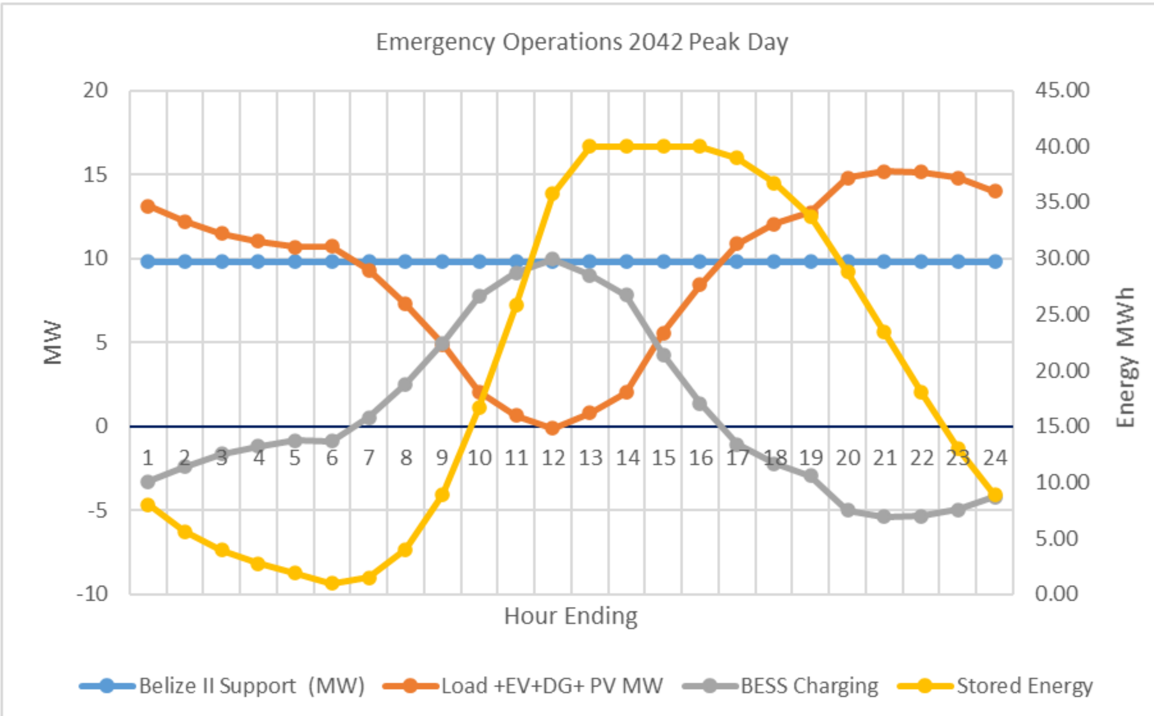
To address this situation a new 5 miles 22 kV line from Belize II to Ladyville is proposed, which will provide the main means of backup. This line should be rated at 16 MVA, similar to the existing line to Ladyville - Westlake.

Additionally, to increase the resiliency of the Ladyville and in general the Belize District Load, one of the PV projects (20 MW) and one of the battery energy storages identified by the capacity expansion plan is proposed to be installed in the area and interconnecting to Ladyville 22 kV. These facilities should be installed in accordance with the capacity expansion plan, 2023 the batteries and

2026 at the latest the PV. However, as the PV and the Batteries could be co-located and be part of the same project the facilities could be in service as early as end of 2023.

With these facilities in place the need for additional support from Belize II for the loss of the line to Westlake can be as low as 10 MW as shown in the figure below that shows that during daytime the battery could be charged maintaining the flow at 10 MW and at night the battery would discharge maintaining the flow at 10 MW. Note that the energy stored recovers to the same value at the beginning of the day including 15% roundtrip losses.

Figure 14-15: Ladyville Emergency Operations with 10 MW support from Belize II

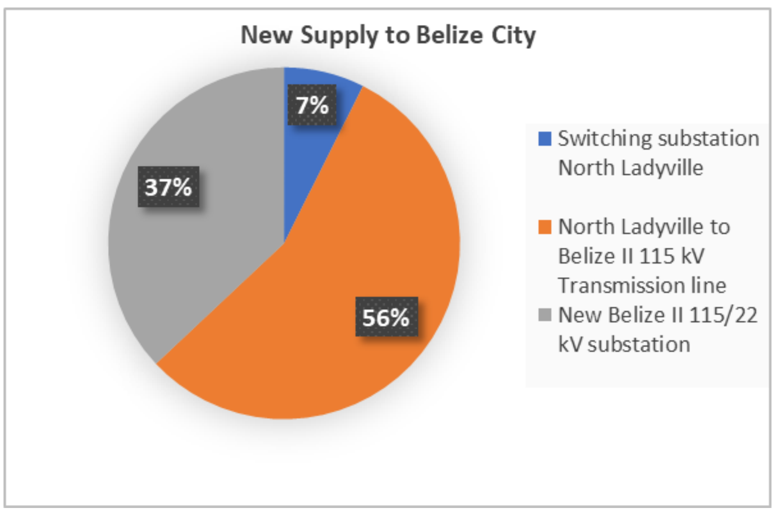


Capital Costs

As shown in Table 14-14 below the total capital expenditures on the transmission system to enhance the supply to the Belize district adds to US$ 19.2 million, where the new transmission line is the largest component representing 56% of the costs. This line however is an important asset for resiliency, and it will allow in the future to develop a new 115/22 kV substation at Ladyville if the load growth in that area demands it as could well be the case given the potential for development. To reiterate the investments are for reliability as under single contingency the Belize District load may be severely curtailed.

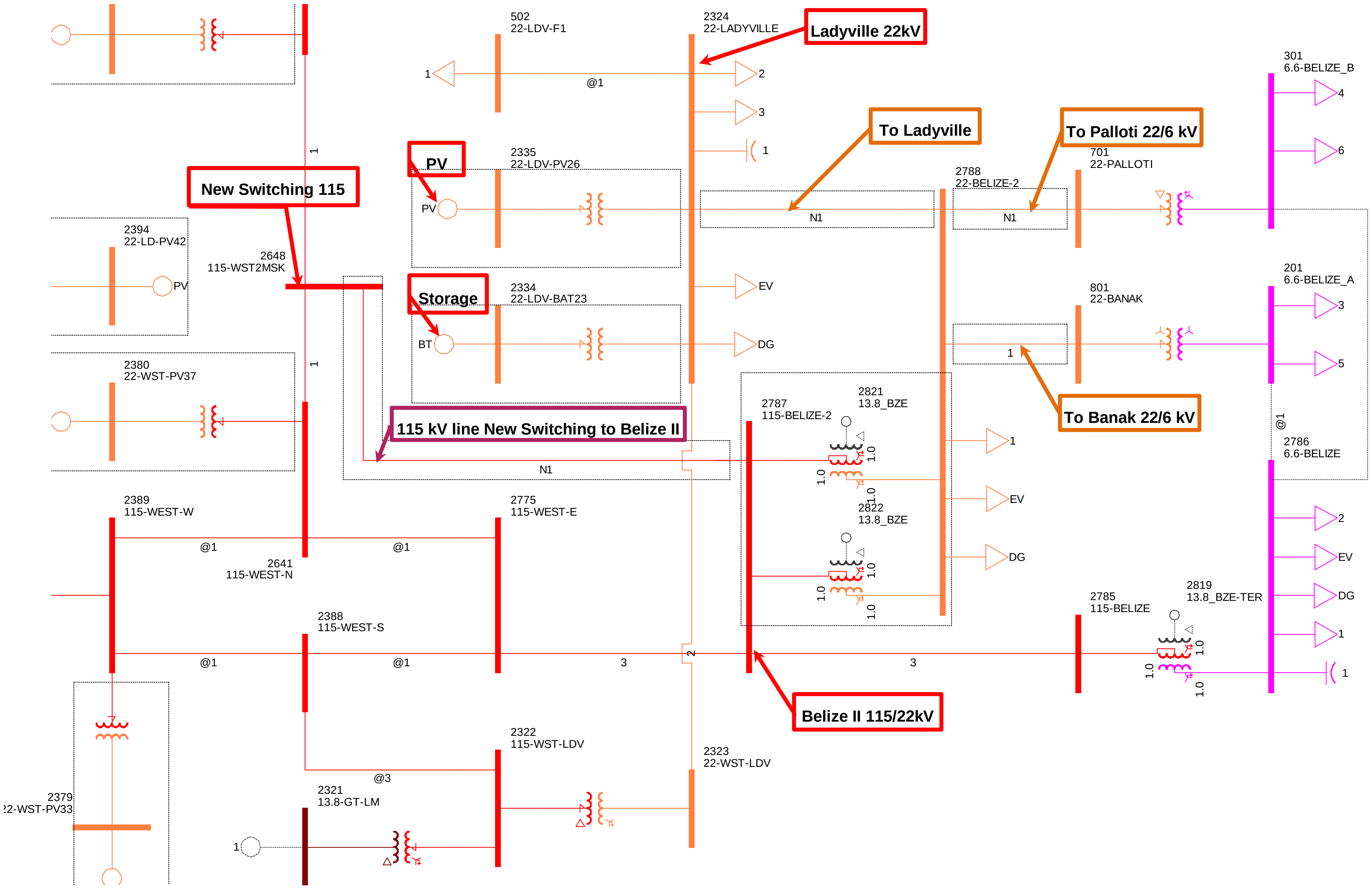
Table 14-14: New Supply to Belize City and Ladyville (2022US$)

Investment	Number	Length (miles) or MVA (normal) or layout	N-1 / heavy loading recommended year	ONAF Overload Required year	Unit Cost $/Mile (lines/cables) $/MVA Transformers $/unit (breakers)	Cost
Switching substation North Ladyville						
Breakers 115 KV	3	Ring bus	2025		$473,599	$1,420,797
Subtotal						$1,420,797
North Ladyville to Belize II 115 kV Transmission line						
115 kV Overhead section	1	6	2025		$345,000	$2,070,000
115 kV Underground section	1	6	2025		$1,380,000	$8,280,000
Subtotal						$10,350,000
New Belize II 115/22 kV substation						
115/22 kV Transformer	2	20	2025		$32,957	$1,318,299
Breakers 115 KV	5	Ring bus	2025		$473,599	$2,367,995
Breakers 22 KV	6	Single bus	2025		$283,228	$1,982,598
22 kV Overhead line to LDV	1	5	2025		$190,535	$952,677
22 kV Overhead line to Palloti	1	2.5	2025		$190,535	$476,338
Subtotal						$7,097,907
Total			2025			**$19,178,387**



Finally, Figure 14-16 below shows an overview of the system in supplying the Belize City Metropolitan District, including the new recommended facilities. We observe that Westlake now supplies no load and that Palloti and Banak are modeled normally supplying part of load formerly served by Belize I resulting in a more uniform loading of the transformers at Belize I and Belize II.

Figure 14-16: Belize Metropolitan District System Overview 2042 Night Peak



14.6.2 San Pedro Supply

Diagnostic.

San Pedro is an important tourist area of Belize, and it is currently supplied by a single 34.5 kV cable with a rating of 19.7 MVA (considering a load factor of 75%) and this rating drops to 17.3 MVA considering a load factor 100%, as could occur during the future emergency conditions. The cable is supplied by a single transformer at Maskall with a rating of 15 MVA normal 25 MVA emergency (ONAF).

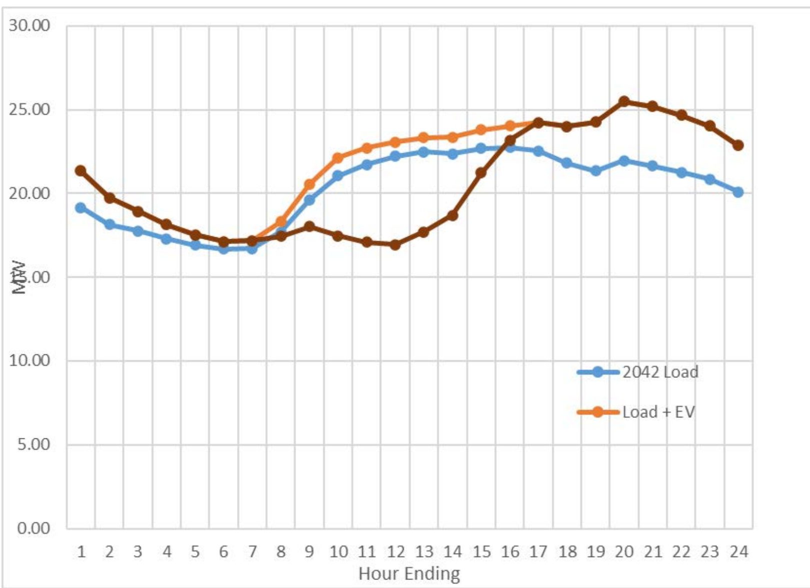
San Pedro is expected to reach by 2042 a peak load of 23.8 MW (including 1.1 MW of EV charging load) for the day peak and 25.5 MW for the night peak including 3.58 MW of EV charging load (see table below).

Table 14-15: 2042 Projected load San Pedro 34.5 kV

	Base Load	EV	Total
Day Peak	22.69	1.08	23.78
Night Peak	21.96	3.58	25.54

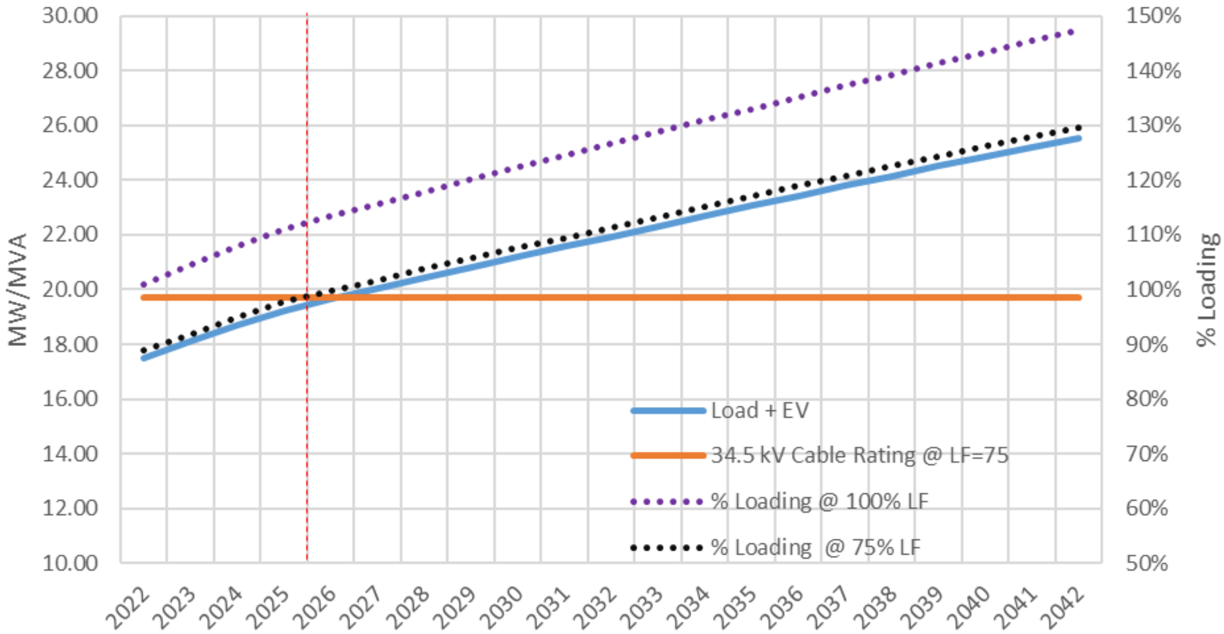
In addition to the above about 3.2 MW of load from Cay Caulker will be connected to San Pedro via a new 34.5 kV cable.

Figure 14-17: San Pedro Peak Load Day 2042



As shown in the figure below by 2026 the 75% LF capacity of the cable will be exceeded. Thus, the San Pedro supply is unreliable and will become worse as the load grows and needs to be addressed.

Figure 14-18: San Pedro 34.5 kV Load + Kay Caulker and Cable Loadings



San Pedro Supply Solution.

The long-term solution for San Pedro is a new 69 kV cable to be supplied from Maskall 115 kV, closest 115 kV substation to the Caye and parallel to the existing one.

This cable was modeled as a 23 miles line (11 miles overhead and 12 miles submarine cable) with a normal and emergency capacity of 30 MVA and supplied by 115/69 kV transformer at Maskall with 30 MVA rating and ending on a 69/34.5 kV transformer at San Pedro also with a rating of 30 MVA. It is not necessary to have a higher emergency rating for the transformers.

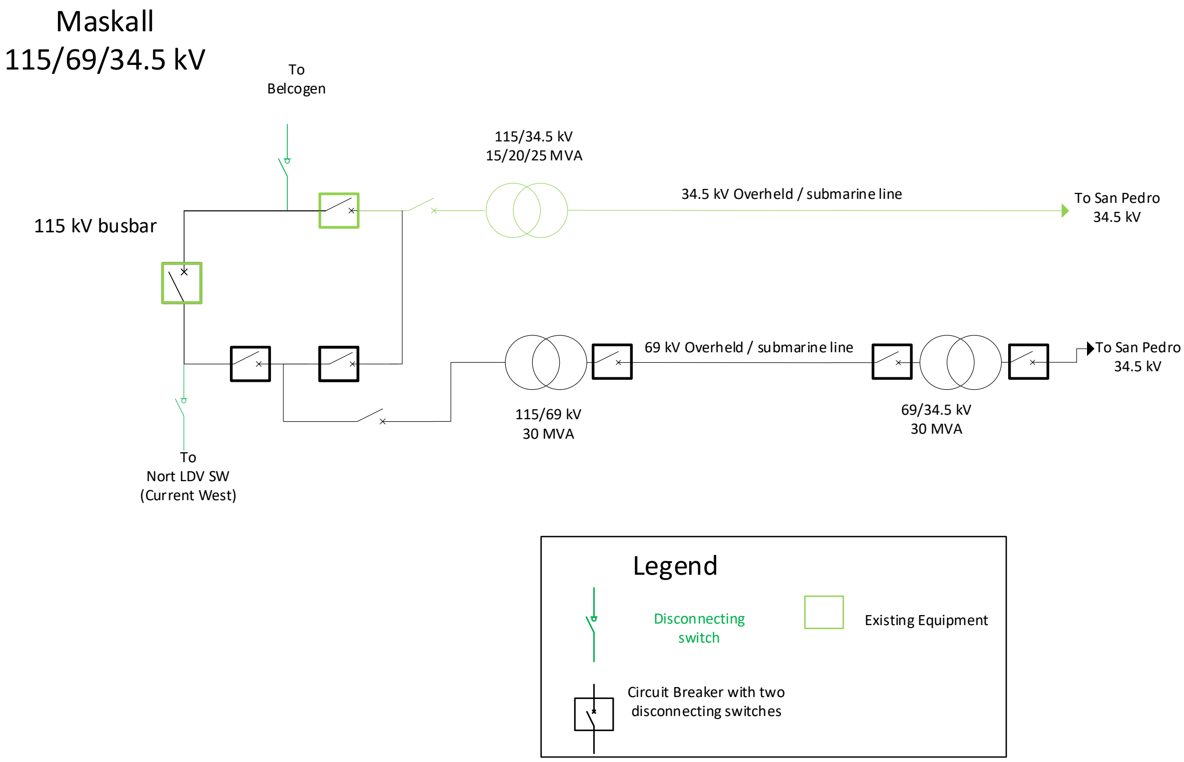
The table below shows the ratings for the new and existing equipment. As before the transformers are recommended to have on load tap changers ± 10% and 32 steps. This equipment should be in service as soon as possible and a 2025 date was included as a reference.

Table 14-16: San Pedro Supply Facilities.

					Rating	
Investment Year	Voltage	From	To	Type	Normal	Emergency.
Existing	34.5	Maskall	San Pedro	Cable	17.3	17.3
Existing	115/34.5	Maskall		Tr	15	25
2025 sooner for N-1	69 kV System	Maskall	San Pedro	Cable	30	30
	115 kV/69	Maskall		Tr	30	30
	69/ 34.5 kV	San Pedro		Tr	30	30

In addition to the above Maskall needs to be upgraded to ring bus with two new 115 kV breakers, and the cable protected with two 69 kV breakers and one 34.5 kV breakers as detailed in the simplified one-line diagram below.

Figure 14-19: San Pedro Supply Simplified One-Line Diagram



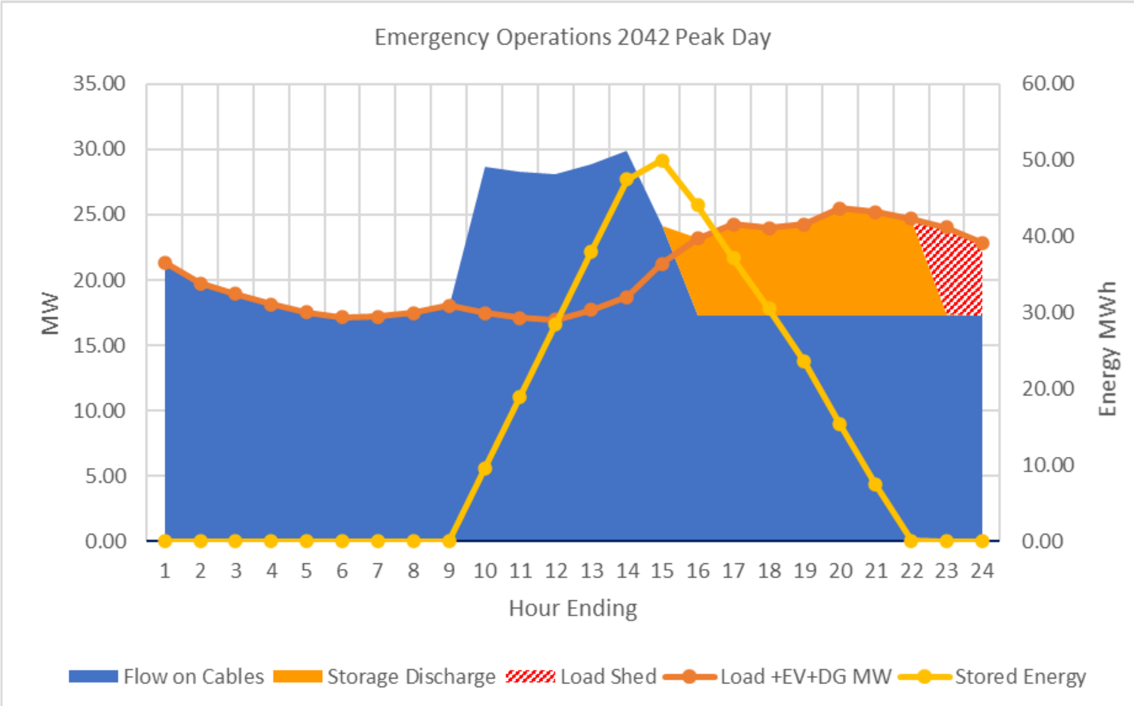
Battery storage

The cable although immediately necessary for contingency conditions, it will take a few years to develop hence a battery storage would be a faster palliative providing some level of support in case of the loss of the existing cable. This battery can also support the use of temporary power effectively allowing for “peak shaving”.

On the long term the existing 34.5 kV cable alone would not be able to supply the entire load for the loss of the 69 kV cable and the battery storage will continue to be useful to prevent load shed. Thus, one of the battery storage facilities identified by the capacity expansion (10 MW) is recommended to be installed by 2023 here. The storage capacity was assumed to be 5 hours in the calculations below.

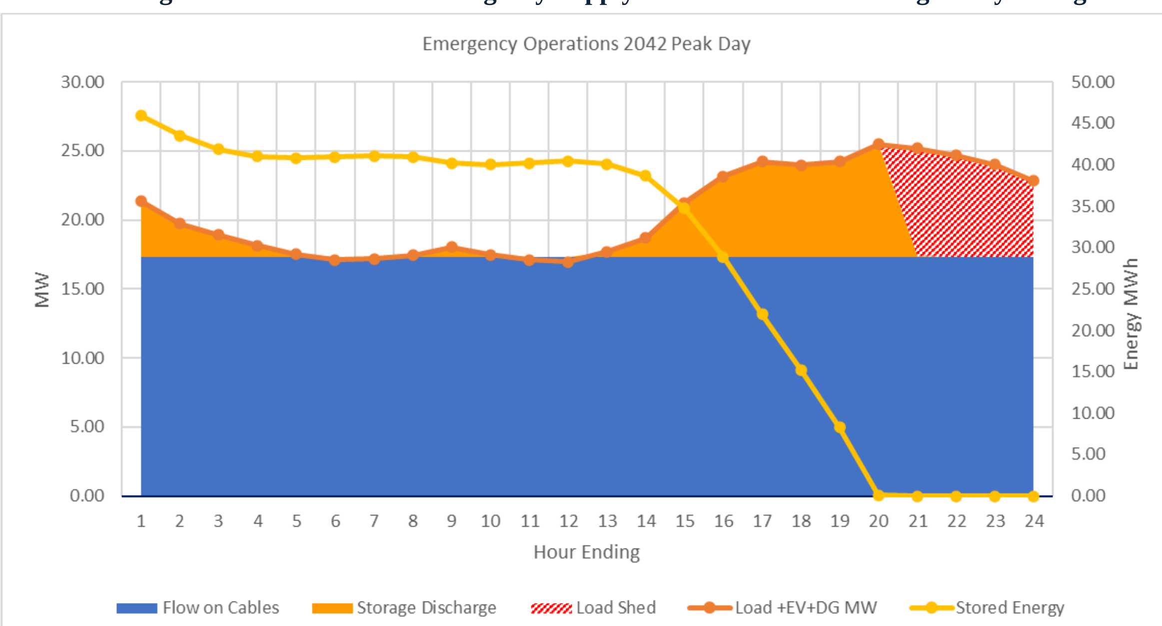
Depending on the time and the state of charge of the battery the time to repairs before load shed and the amount of load shed varies. The first case below shows a situation when the event happens on the peak load day, shortly after storage has reached its max. We see in the figure below that the storage plus the 34.5 kV cable can supply the load for up tp7 hours, after which some load shed is necessary.

Figure 14-20: San Pedro Emergency Supply fault at Hr. 15



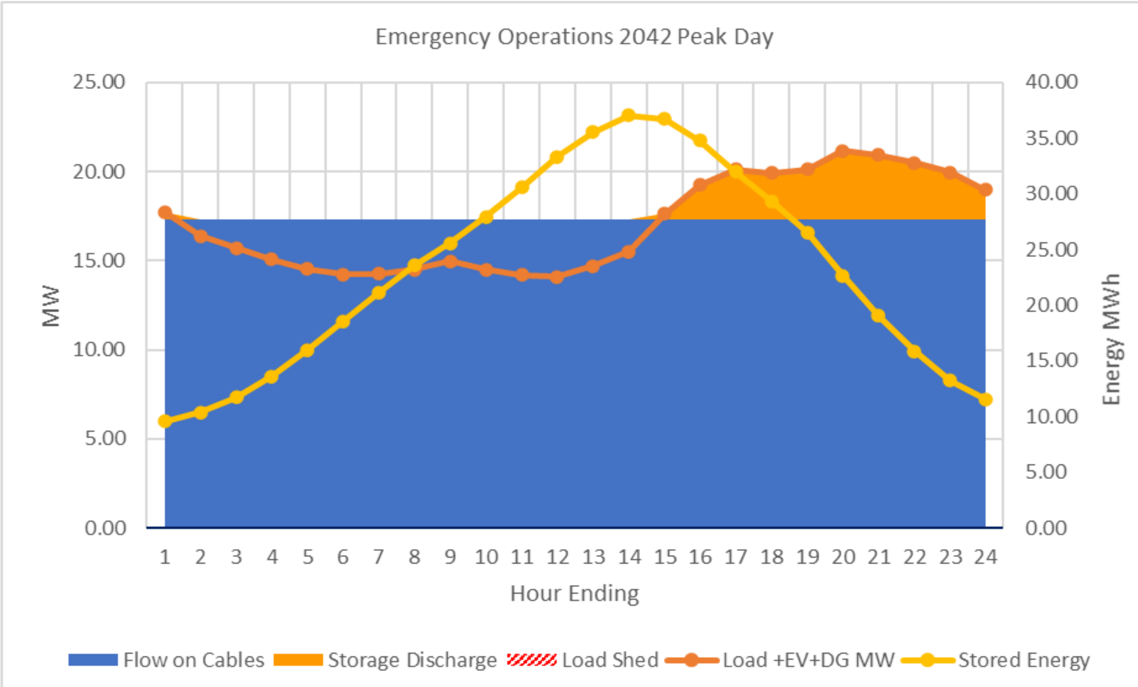
Another situation could be that in preparation for an event BEL's operators keep the battery fully charged (e.g., storm is coming) and the events happen. The figure shows worst case (24 hours of need). Twenty hours of support is provided, and four hours of load shed would happen in this case.

Figure 14-21: San Pedro Emergency Supply fault at Hr. 1 with Storage Fully Charged



Finally, the cases above assume a peak load case (2042), but if the load is lower no load shed would be necessary. The figure shows a situation with the load is 83% of the peak load and we see that the storage plus the cable can supply the load for multiple days; the stored energy is never depleted.

Figure 14-22: San Pedro Emergency Supply 85% of peak load days

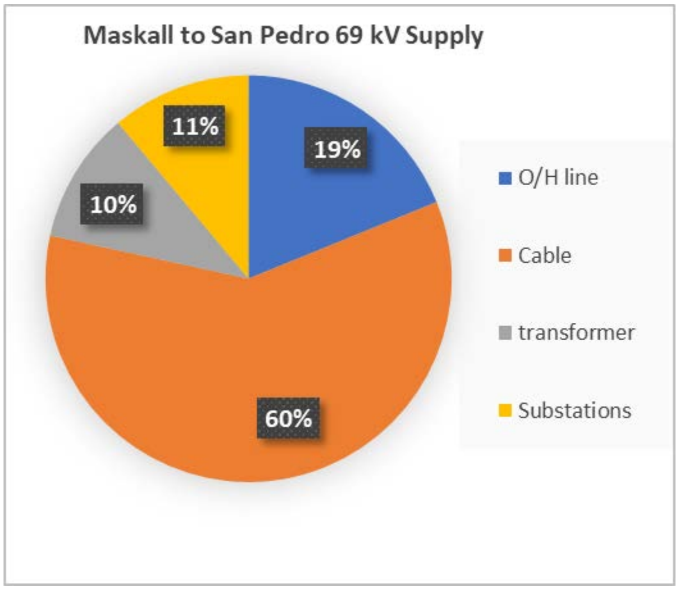


Capital Costs

As shown in Table 14-17 below the total capital expenditures on the transmission system to enhance the supply to San Pedro adds to US$ 18.4 million, where the new submarine is the largest component representing 60% of the costs.

Table 14-17: San Pedro 69 kV Supply (2022 US$)

Investment	Number	Length (miles) or MVA (normal) or layout	N-1 / heavy loading recommended year	ONAF Overload Required year	Unit Cost $/Mile (lines/cables) $/MVA Transformers $/unit (breakers)	Cost
69 kV Overhead line	1	10		2025	$345,000	$3,450,000
69 kV Submarine cable	1	12.9		2025	$844,786	$10,897,744
115/69 kV Transformer	1	30		2025	$32,957	$988,724
69/34.5 kV Transformer	1	30		2025	$32,957	$988,724
115 kV Breaker	2	Ring bus		2025	$473,599	$947,198
69 kV Breaker	2	Single Exit		2025	$431,084	$862,168
34.5 kV Breaker	1			2025	$283,228	$283,228
Total				2025		**$18,417,787**



14.6.3 San Pedro 34.5 / 22 kV transformers

Diagnostic.

Given the load growth at San Pedro the existing 34.5/22 kV transformers rated 7/10 MVA for San Pedro 1 and 5.4/7 MVA for San Pedro 2 are expected to overload.

San Pedro 1 substation load is above the normal rating (ONAN 7.5 MVA) and will exceed the single 34.5/22 kV transformer emergency rating (ONAF 10 MVA), by 2031, according to the load forecast (Figure 14-23). San Pedro 2 substation load is at the normal rating (ONAN 5.5 MVA) and will exceed the single 34.5/22 kV transformer emergency rating (ONAF 7 MVA), by 2031 (Figure 14-24) during peak load conditions and load shedding will be required. These transformers are also rather old.

Hence, both substations require transformer replacements to address the overloads shown below and have firm capacity (N-1 security). BEL is replacing one transformer with a 15/25 MVA, which mitigates the loading issues, but the second transformer should also be replaced. Also replacing this single transformer does not improve the N-1 situation as the worst contingency would be to lose the larger transformer and the remaining transformer would not be able to carry even today’s load (SP1 + SP 2 = 13.3MW 2022 and the rating would be at best 10 MVA ONAF).

Figure 14-23: San Pedro 1 transformer loading (ONAF)

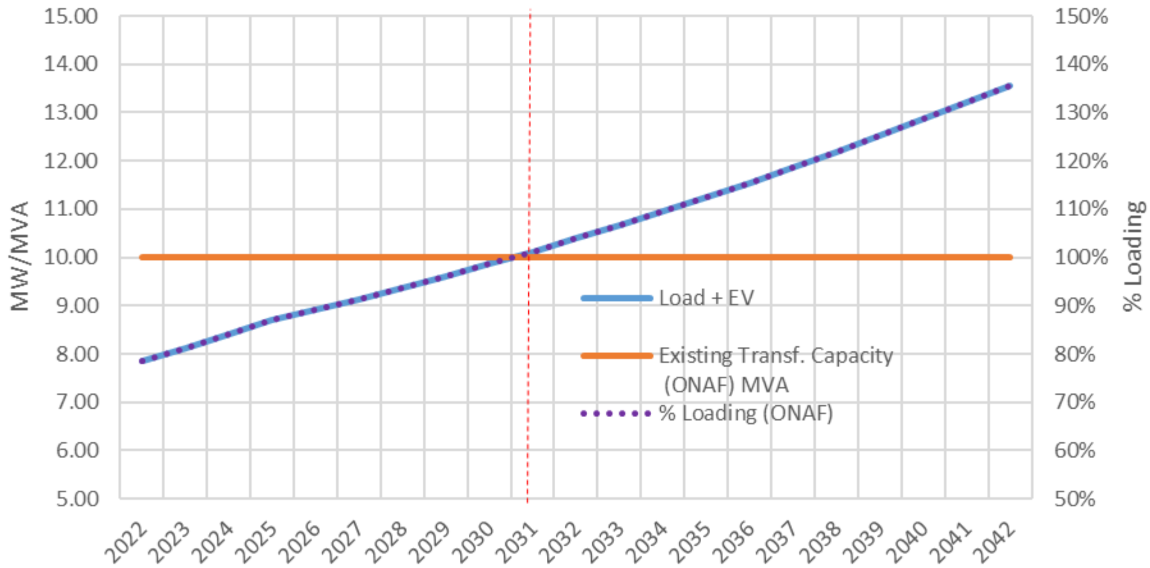
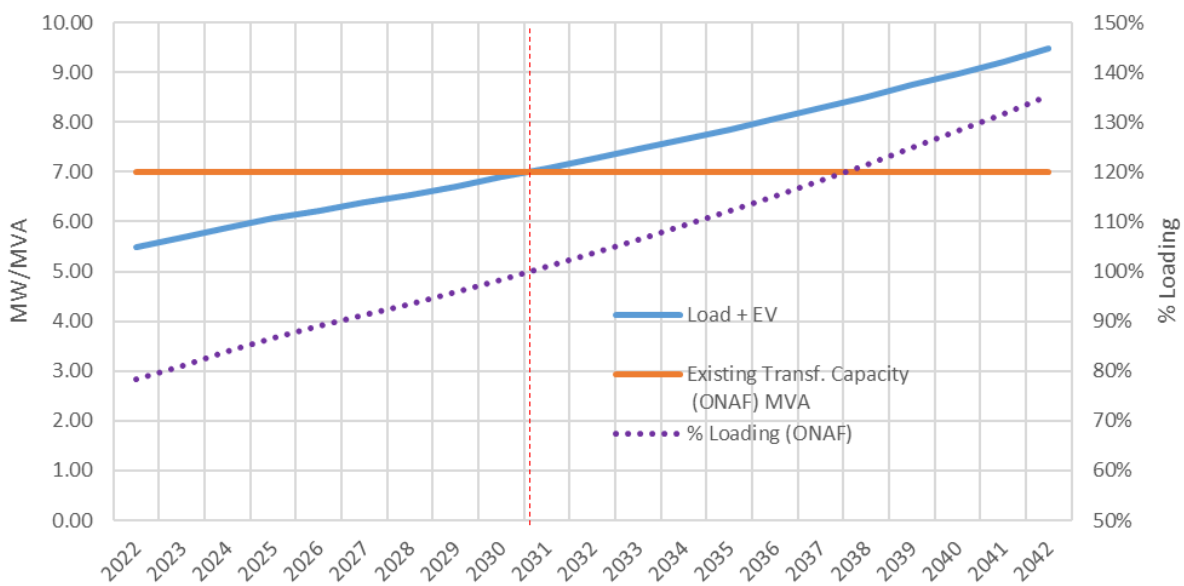


Figure 14-24: San Pedro 2 transformer loading (ONAF)



Solution

Based on the above a second 15/25 MVA transformer at San Pedro should be installed as soon as possible to provide N-1 security and allowing the serving of the load in case of losing the transformer that is replaced by BEL. If this is not done, then by 2030 at the latest the second transformer should be added to San Pedro 1 (assuming that the larger new transformer is installed in San Pedro 2). Note that the total combined load of San Pedro is projected to reach 26 MW is indicated earlier (Table 14-15) and if the new transformer 25 MVA ONAF and the existing 10 MVA ONAF were operated in parallel, they would be able to carry the load. However, this operation is not recommended as for planning the ONAN or normal rating should not be exceed under normal conditions leaving the ONAF for contingencies or unforeseen load development, also the operation of the two transformers in parallel will be complicated at this high levels.

The table below shows the recommended transformer fleet to be in service by year and the resulting 2042 loading if it were not further upgraded. In this table the first two rows show the current condition and the second two show the future conditions. Note that during N-1 load is assumed to be transferred between San Pedro 1 and 2 or the link operated closed. The loadings for N-0 are over normal (ONAN) ratings and for N-1 over emergency (ONAF) ratings.

Table 14-18: San Pedro 1 & 2 transformers

			Rating		2042 loading	
Investment Year	**Voltage**	**Units**	**Normal**	**Emergency**	**N-0**	**N-1**
Existing San Pedro 1	34.5/22 kV	1	7.5	10	181%	N/A
Existing San Pedro 2	34.5/22 kV	1	5.5	7	172%	N/A
2023 San Pedro 1	34.5/22 kV	1	15	25	90%	92%
2030 San Pedro 2 (2026 for N-1)	34.5/22 kV	1	15	25	63%	

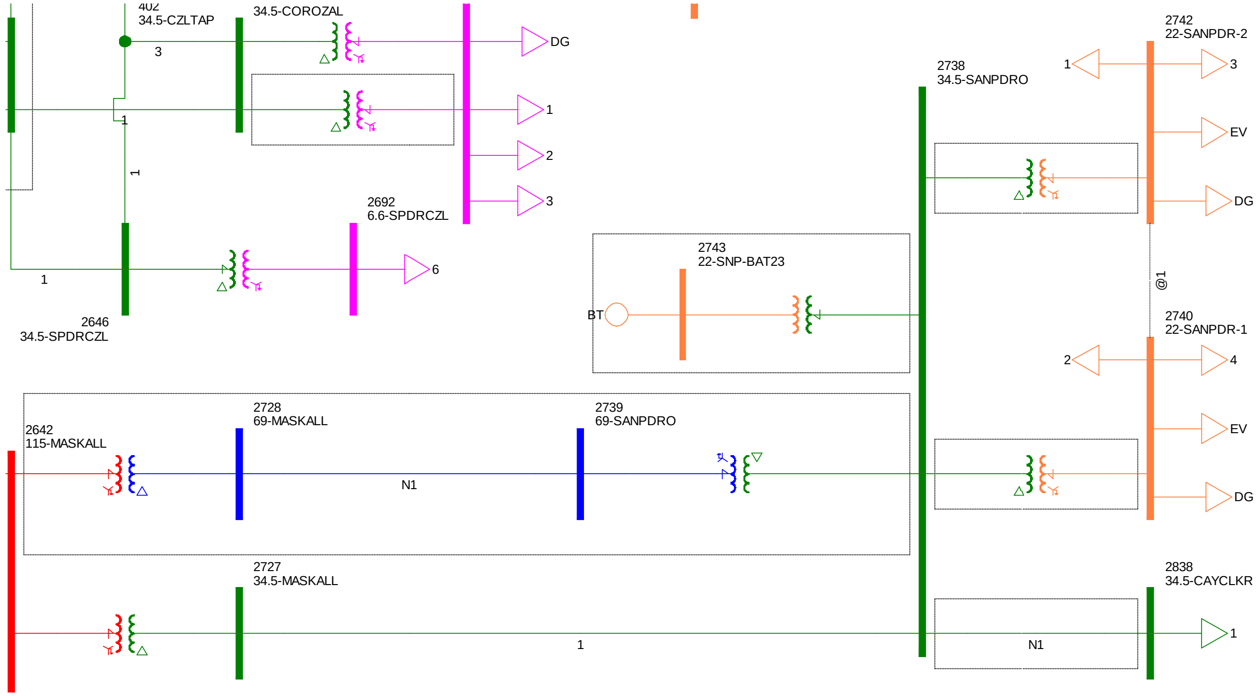
Capital Costs

As shown in the table below the total capital expenditures on the transformers to reliably supply San Pedro adds to US$ 2.1 million. In this table one new 34.5 breaker position is required for the new transformer and the new 22 kV breakers is one for each of the transformers and one for the bus-tie. This will allow ease for operations and automated transfers upon the loss of one transformer. Figure 14-25 shows an overview of the supply to San Pedro including the new transformers and the cable.

Table 14-19: San Pedro Transformers (2022 US$)

Investment	Number	Length (miles) or MVA (normal) or layout	N-1 / heavy loading recommended year	ONAF Overload Required year	Unit Cost $/Mile (lines/cables) $/MVA Transformers $/unit (breakers)	Cost
34.5/22 kV Transformer	1	15	2023	2023	$32,957	$494,362
34.5/22 kV Transformer	1	15	2026	2030	$32,957	$494,362
34.5 kV Breaker	1		2026	2030	$283,228	$283,228
22 kV Breaker	3		2026	2030	$283,228	$849,685
Total			2026	2030		**$2,121,637**

Figure 14-25: San Pedro Supply Overview 2042 Night Peak



14.6.4 Independence Supply

Diagnostic.

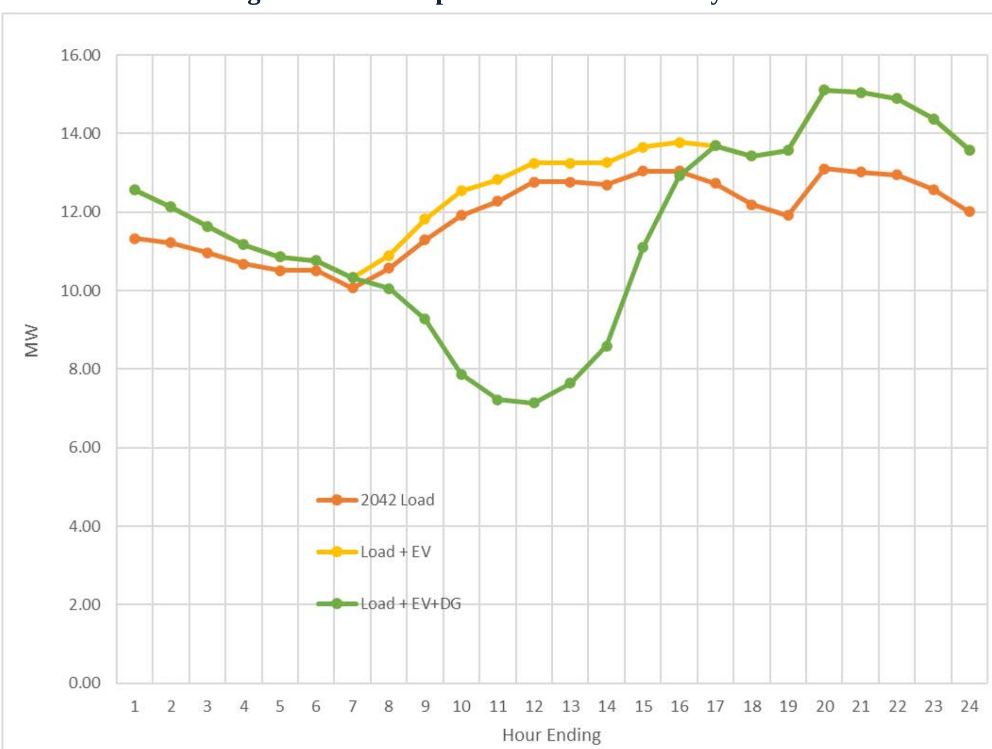
Independence is near the south end of the BEL system dependent on a single 69 kV line from Dangriga (approximately 42 miles). Although the BAPCOL generation as about 21 miles north this plant connects with a simple tap on the line and a fault along the line would trip the plant and the line from Dangriga. Thus, any fault along the line results in the interruption of supply.

Independence is expected to reach by 2042 a peak load of 13.0 MW (including 0.6 MW of EV charging load) for the day peak and 15.3 MW for the night peak including 2.0 MW of EV charging load (see table and figure below).

Table 14-20: 2042 Projected load at Independence

	Base Load	EV	Total
Day Peak	13.04	0.62	13.66
Night Peak	13.10	2.03	15.13

Figure 14-26: Independence Peak Load Day 2042



The load at Independence currently exceeds the normal rating of the single transformer in place (Figure 14-26). The ONAF (emergency) 10.5 MVA rating of this transformer will be exceeded by year 2027 (Figure 14-27) A second larger transformer is recommended by 2026 at the latest. With the second transformer in place, by 2027, the remaining existing transformer would overload under N-1 and replacement is necessary for N-1 security (Figure 14-28).

Figure 14-27: Independence Transformer loading (ONAN Ratings)

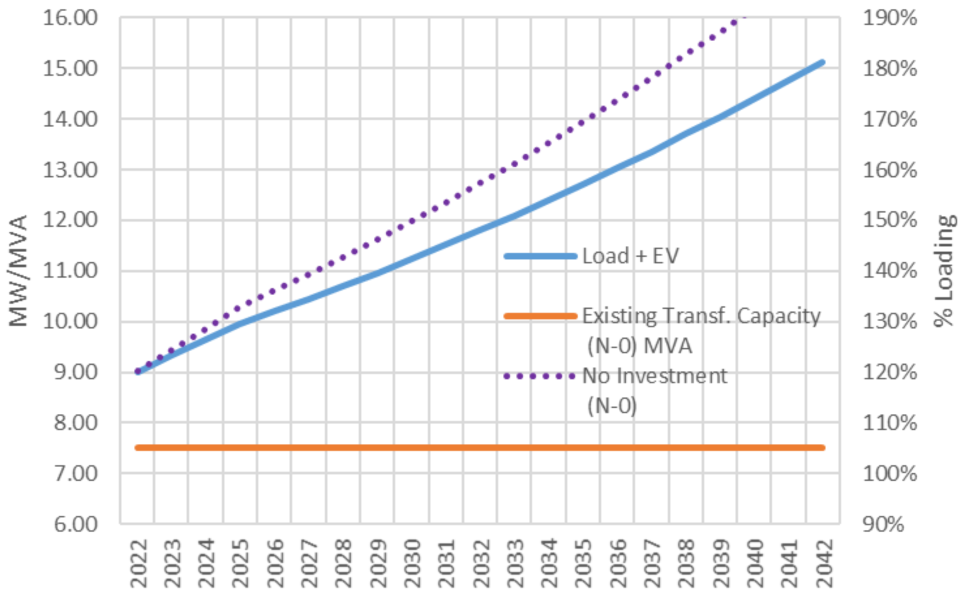
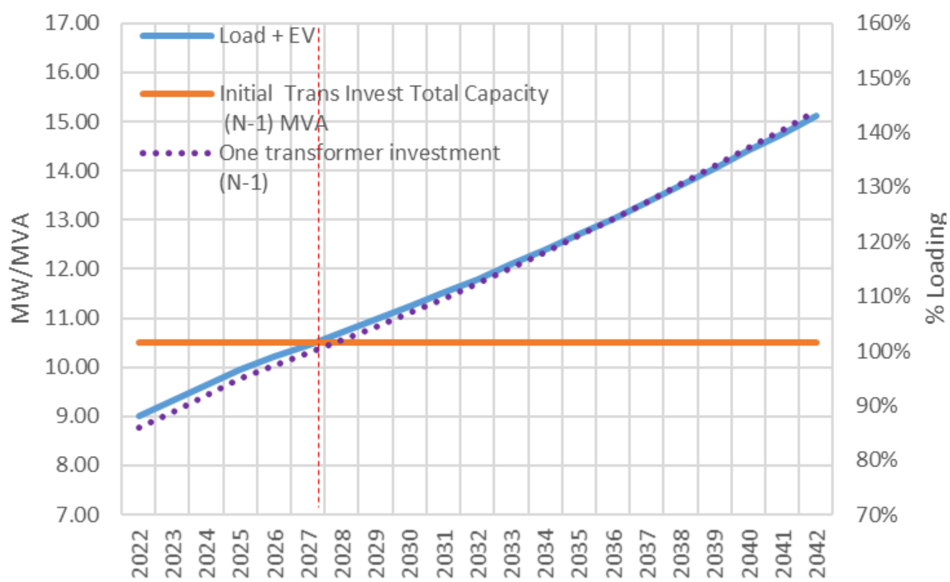


Figure 14-28: Independence Transformer loading (ONAF Ratings)



Independence Supply Solutions.

BAPCOL Tap Reconfiguration:

One straight forward mitigation that also addresses the reliability of the connection of the BAPCOL RICE is to eliminate BALTAP and bring both lines to BAPCOL. This is currently in progress and will reduce the likelihood of interruptions by more than 50% as BAPCOL would remain connected to Independence for faults along the more than 22 miles segment to Dangriga.

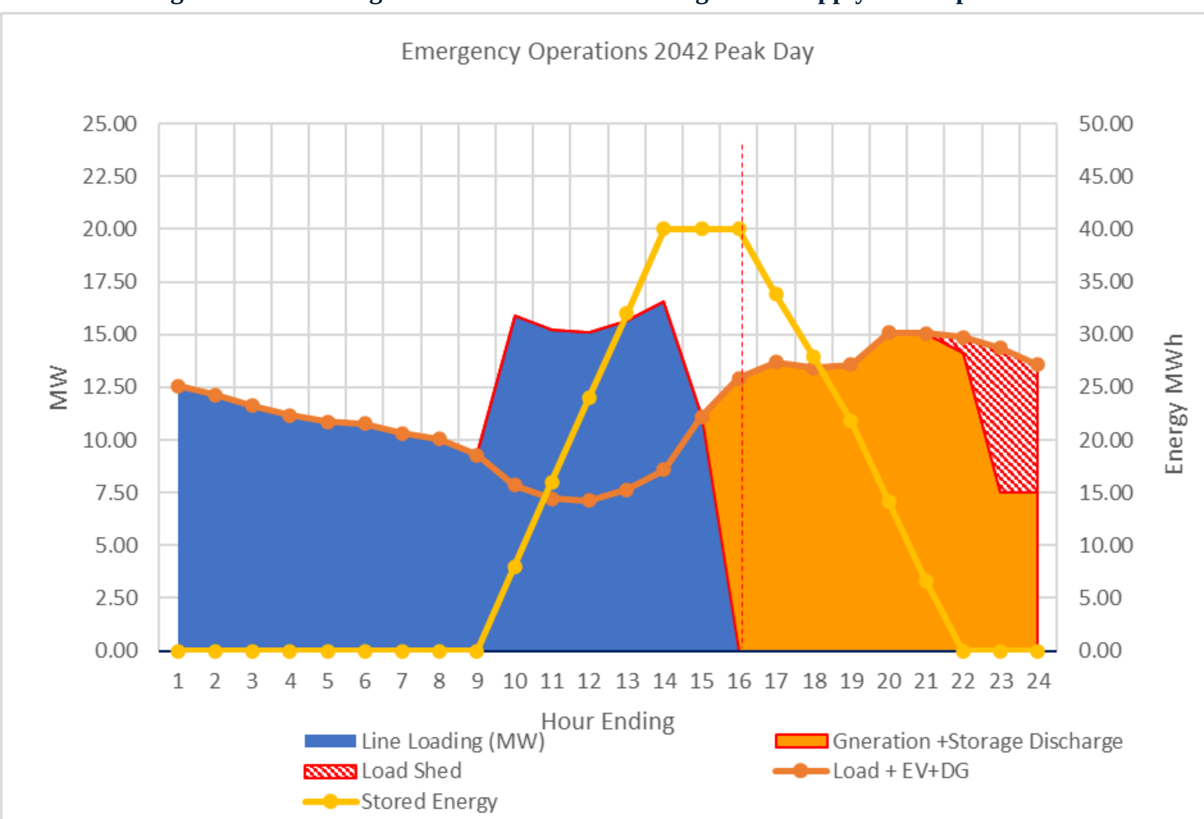
Independence RICE and Storage

Even after the implementation of the solution above there is still a significant risk for the single 69kV line supplying Independence to trip resulting in an immediate blackout. To address this and as indicated earlier in this report, it is proposed that a 7.5 MW (approximately) RICE unit to be installed at Independence (1/3 of the RICE recommended by the capacity expansion plan) and a 10 MW storage (the third recommended by the expansion plan).

The combination of the RICE and the storage are expected to carry the load in Independence for 6 or more hours if the fault were to occur in the evening (4 pm onwards) when the storage is expected to be at full capacity.

The figure below shows an event happening midafternoon (hour 16) with the storage at full capacity and we see that as the flow on the incoming line (blue) goes to zero the combination of generation plus storage discharging (red trace) is enough to supply the load until about hour 22 when the storage is depleted the generation continues at 7.5 MW and there is load shed. The support provided about 7 hours before the load shed happened. Note that these afternoon events are the most severe as during daytime the load is lower due to the DG and its natural profile (night peaking). Also, the results below are with a 4-hour storage, with 5 the support would be extended for 1 more hour.

Figure 14-29: Storage and Generation addressing loss of supply to Independence.

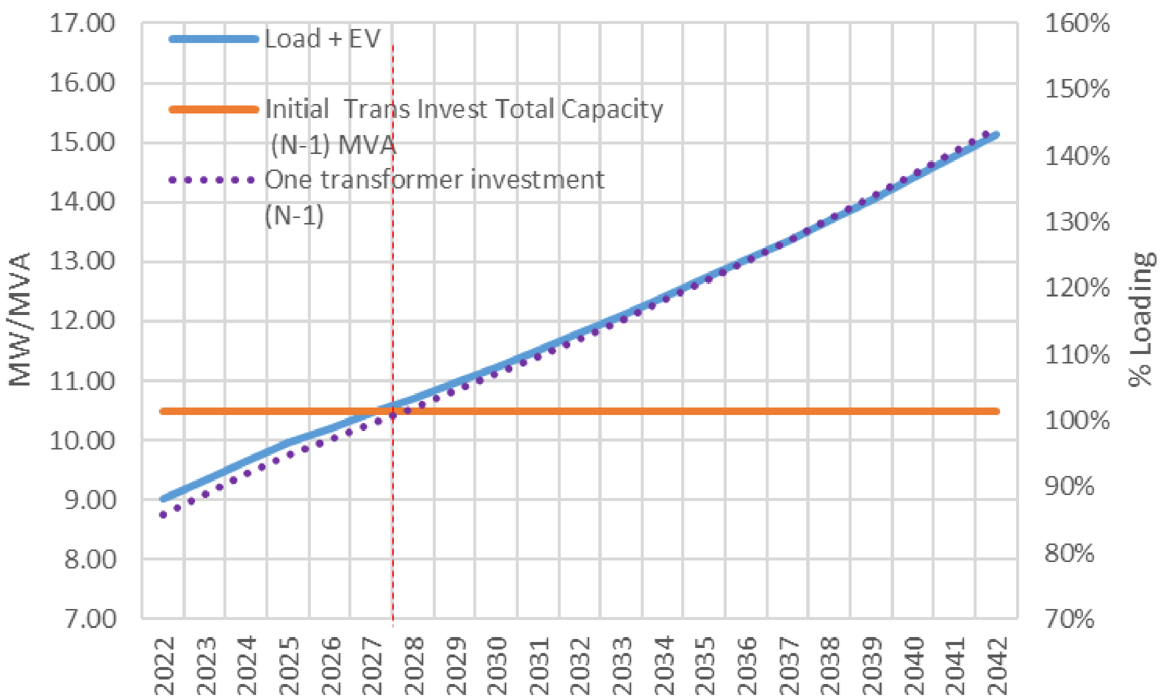


Transformers

Independence has a single 7.5/10.5 MVA transformer that is expected to be heavily loaded beyond its normal rating by 2022 as shown before, and its outage would create total load shed until repairs are made.

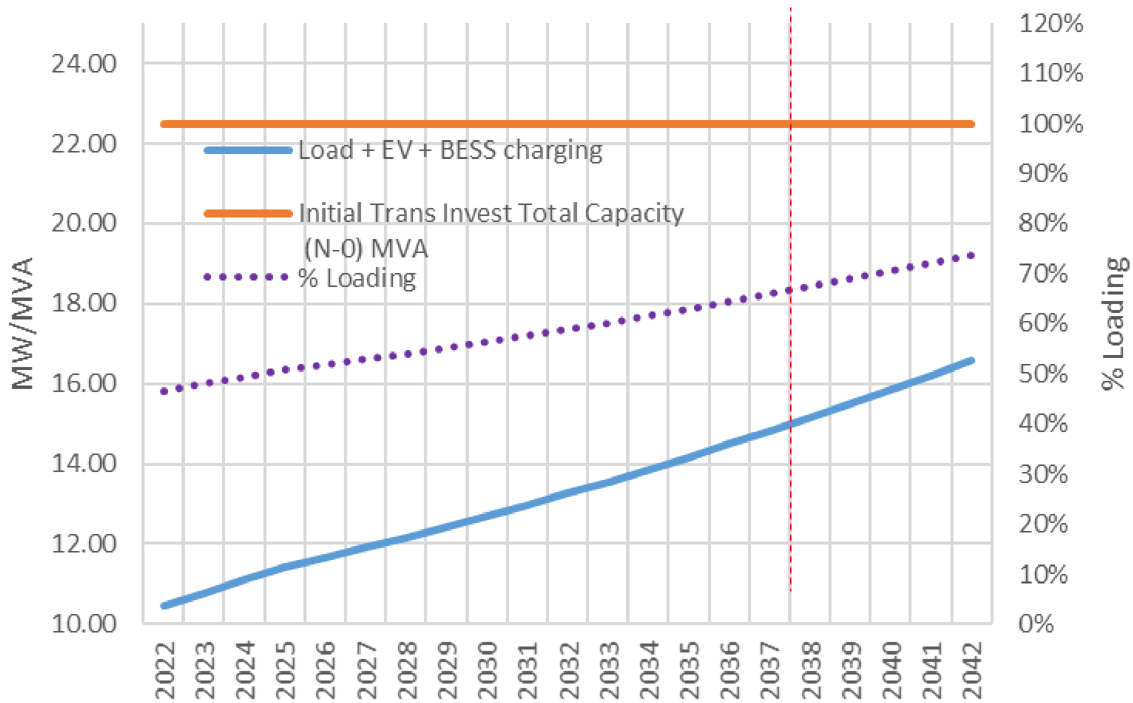
According to the planning criteria a new 15/25 MVA transformer should be added in the short term, and this would provide N-1 security until approximately 2027 when the load is expected to reach 10.7 MW overloading the remaining transformer beyond its emergency rating, as shown below. If not replaced for N-1 security as recommended, then it will have to be replaced by 2027 to avoid loading beyond its ONAF rating.

Figure 14-30: Independence Transformer loading (ONAF Ratings) for N-1



Note that the replacement of the existing transformer, after the first transformer is added, is only necessary for N-1 and without its replacement the charging of the battery under normal conditions does not result in overload (see below).

Figure 14-31: Independence Transformer loading with investment (ONAN Ratings)



If replaced, it is suggested to move the existing transformer to Punta Gorda.

The table below shows the recommended transformer fleet to be in service by year and the resulting 2042 loading if it were not further upgraded. The first row shows the existing transformer, the next two rows show the conditions when one transformer is added, and the last row show the conditions when both transformers are replaced. N-0 loading are over the normal rating (ONAN) and N-1 over the emergency (ONAF) rating.

Table 14-21: Independence transformers

			Rating		2042 loadings	
Investment Year	**Voltage**	**Units**	**Normal**	**Emergency**	**N-0**	**N-1**
Existing	69/24.9 kV	1	7.5	10.5	255%	N/A
2026 (latest) (as soon as possible for N-1)	69/24.9 kV	1	7.5	10.5	85%	182%
		1	15	25		
2026	69/24.9 kV	2	15	25	64%	76%

Capital Costs

As shown in the table below the total capital expenditures on the transformers to reliably supply Independence adds to US$ 2.3 million. In this table one new 69 breaker position is required for the new transformer and 3 new 24.9 kV breakers, one for each of the transformers and one for the bus-tie, are also required. This will allow ease for operations and automated transfers upon the loss of one transformer. The table indicates that the only mandatory investment for overloads needs to occur by 2026 at the latest, equal to US$ 0.7 million.

Table 14-22: Independence Transformers (2022 US$)

Investment	Number	Length (miles) or MVA (normal) or layout	N-1 / heavy loading recommended year	ONAF Overload Required year	Unit Cost $/Mile (lines/cables) $/MVA Transformers $/unit (breakers)	Cost
69/24.9 kV Transformer	1	15	2024	2026	$32,957	$494,362
69 kV Breaker	1		2024	2026	$431,084	$431,084
69/24.9 kV Transformer	3		2024	2026	$283,228	$849,685
24.9 kV Breaker	1	15	2026		$32,957	$494,362
Total						**$2,269,493**

14.6.5 Orange Walk Supply

Diagnostic.

34.5 kV supply

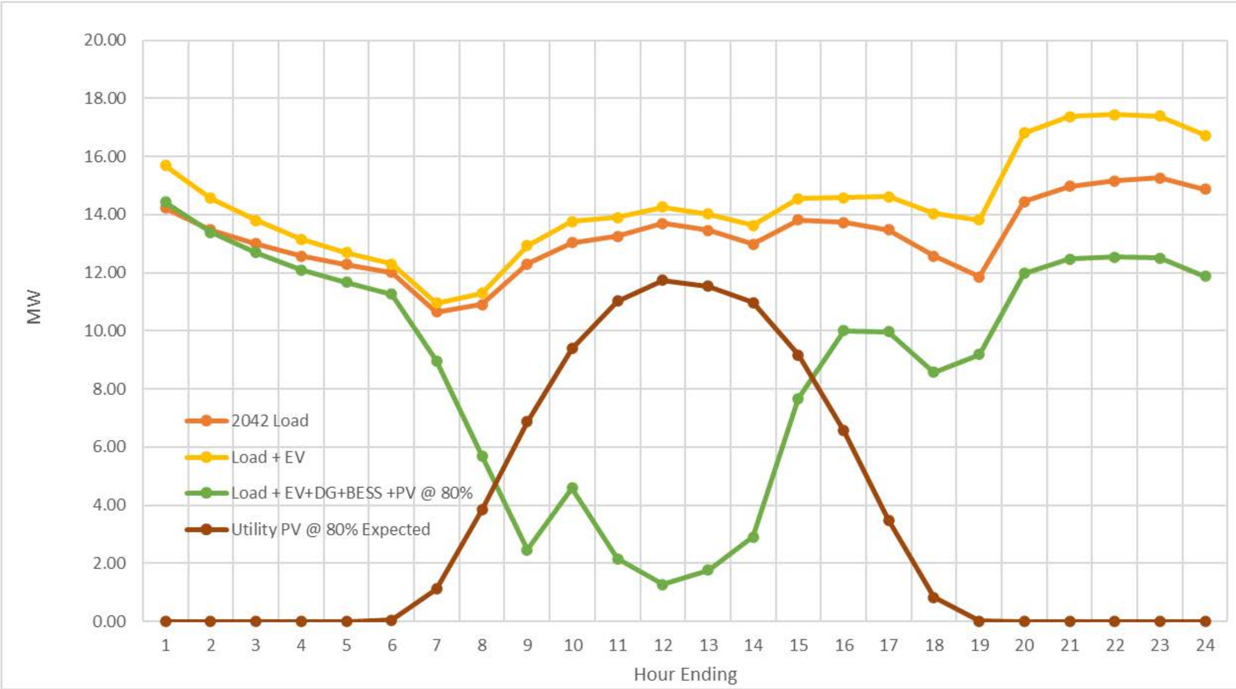
The Orange Walk (OWK) substation will be supplied by Belcogen substation which is a relatively reliable point with local generation and two 115 kV transmission lines. However, the supply is via a single 34.5 kV sub transmission line with about 4 miles length and its outage would result in total interruption which should be mitigated. As indicated earlier at OW we are proposing to install one PV solar facility (20 MW) and for it to be coupled with 10 MW battery storage.

OWK is expected to reach by 2042 a peak load of 14.6 MW (including 0.7 MW of EV charging load) for the day peak and 17.7 MW for the night peak including 2.4 MW of EV charging load (see table and figure below including the local solar at 80% of installed capacity).

Table 14-23: 2042 Projected load at Orange Walk

	Base Load	EV	Total
Day Peak	13.82	0.73	14.55
Night Peak	15.26	2.40	17.66

Figure 14-32: Orange Walk Peak Load Day 2042



Although the probability of failure is low, given the length of the single line, the load is considered too high to be interrupted under a single contingency and a mitigation was investigated.

34.5MVA Transformers

Orange Walk 6.6 kV load is not expected to grow significantly and about 2.5 MVA load is going to be transferred from 6.6 kV to the 22 kV bus. In consequence the load at 6.6 kV can be supplied with the single 34.5/6.6 kV transformer of 7.5 MVA (normal/emergency) rating (Figure 14-33) and a second transformer is required for N-1 security only.

Together with the transferring of the load to the 22 kV bus, BEL plans to relocate the existing transformer at San Pedro to Orange Walk (7.5 / 10 MVA). With this transformer the normal ONAN loading will not be exceeded until 2030 and the emergency (ONAF) will only be exceeded by 2041 (Figure 14-34). Therefore, the main concern is N-1 security.

Figure 14-33: Orange Walk 6.6 kV system intact loading

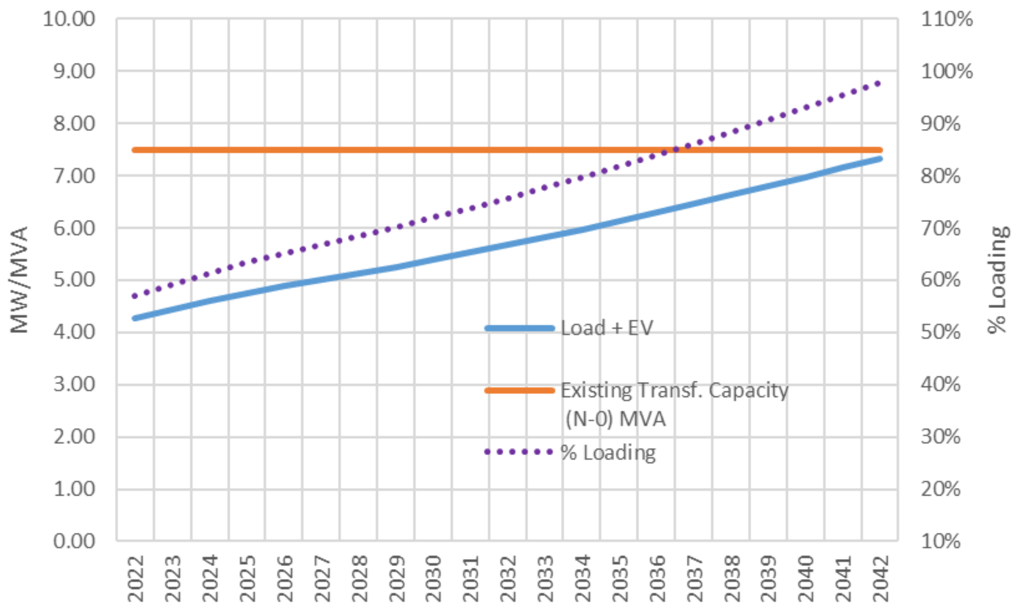
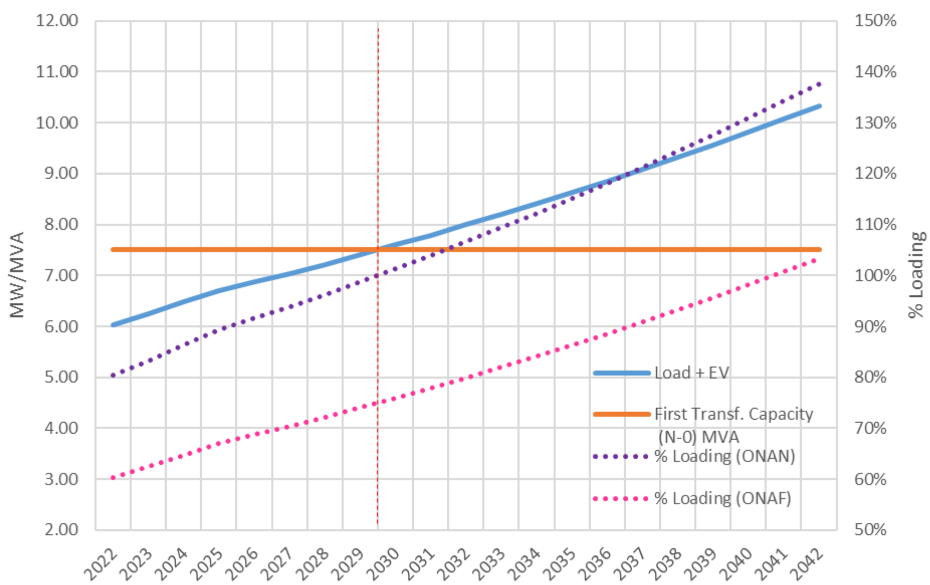


Figure 14-34: Orange Walk 22 kV system intact loading



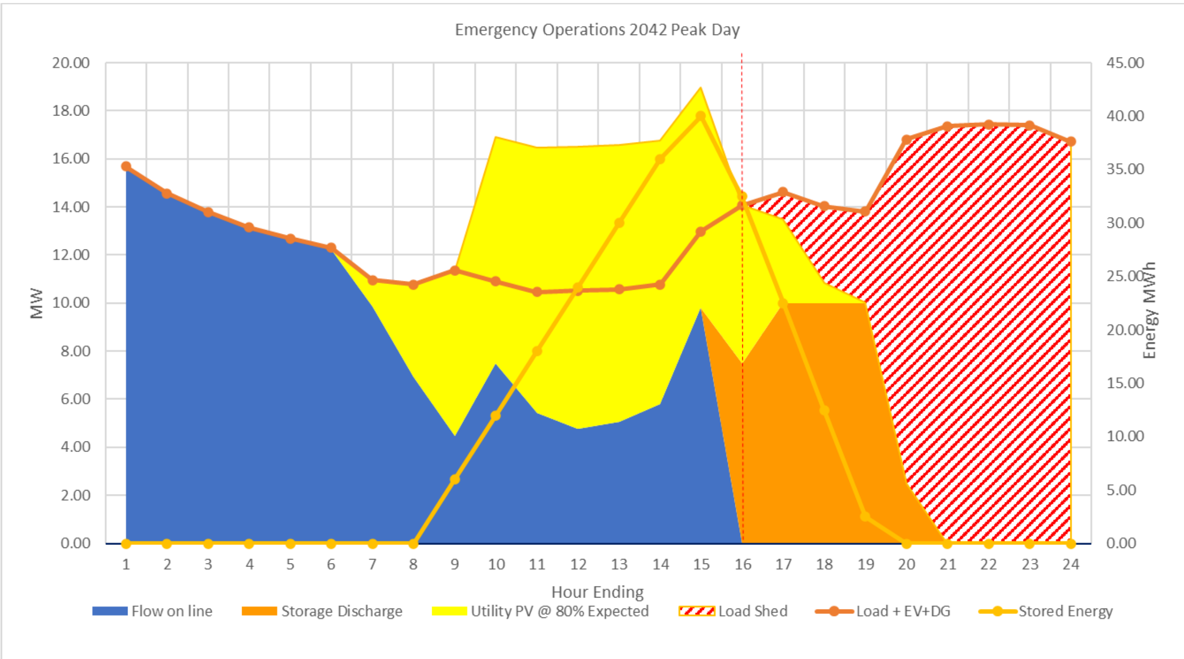
Orange Walk Supply Solutions.

Orange Walk PV and Storage

The PV and the storage proposed will not eliminate the need for load shed but mitigates the impact of the contingency. The figure below shows an event happening midafternoon (hour 16) with the storage near full capacity and we see that as the flow on the incoming line (blue trace) goes to zero the combination of the remaining PV output and the storage discharging (red trace) is enough to partially supply the load until about hour 20 when the storage is depleted and the entire load shed.

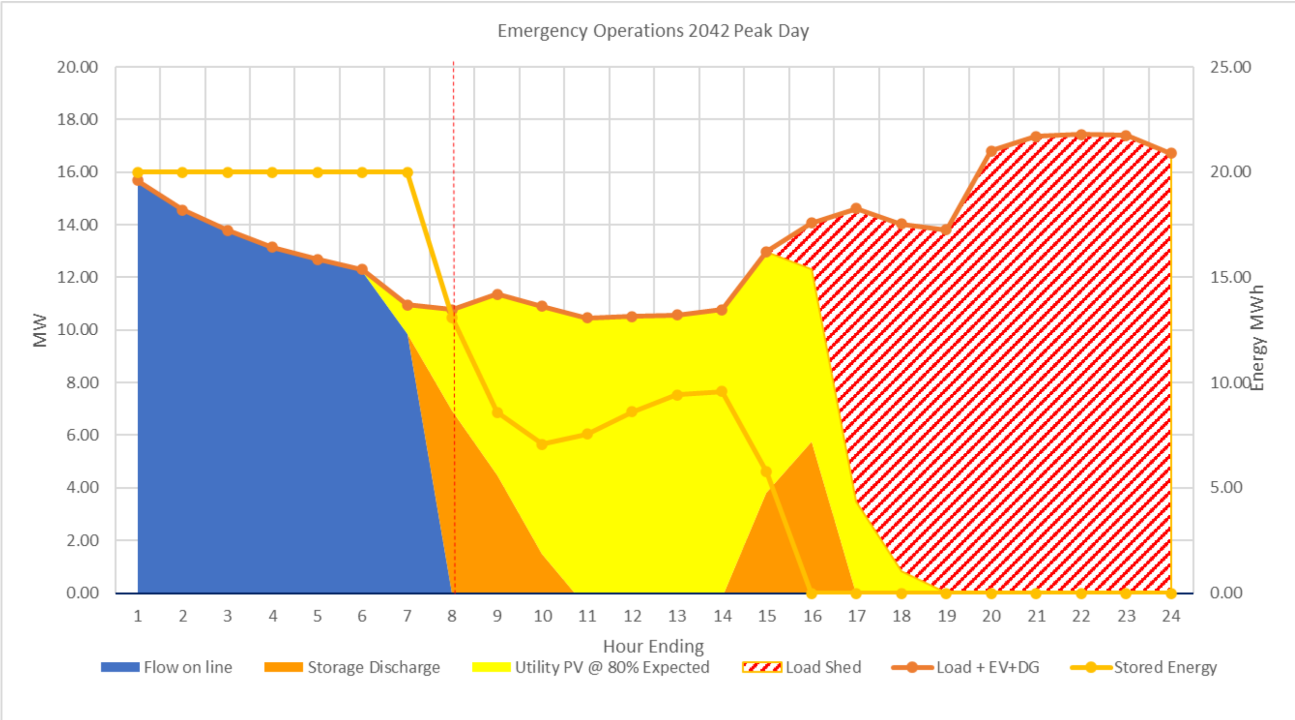
The support provided about 4 hours after which significant load shed starts and at hour 5 there is full load shed. This should allow riding through the repairs on this short time. Note that the PV and the Storage must have "Grid Forming" capabilities, i.e., be able to operate without an external 60 Hz source and 4 hours storage was assumed.

Figure 14-35: Storage and PV addressing loss of supply to Orange Walk for evening fault



The situation portrait above is severe and does not consider that operators would likely keep the battery at full charge during bad weather conditions that could lead to the outage. If the fault were to occur in the morning the situation would be less severe and the need to shed load could be postponed. This is shown in the figure below, where we observe that thanks to the PV and the storage that started the day at 50% charge, the load can be supplied for about 9 hours without significant interruption.

Figure 14-36: Storage and PV addressing loss of supply to Orange Walk for morning fault with 50% initial charge



Transformers

For OWK load at 6.6 kV, it is recommended to add a parallel transformer of 7.5/10 MVA to the existing, to provide firm capacity, i.e., N-1 security, as shown in Table 14-24, where the first row is the current situation and the second shows the situation with 2 transformers. The investment date for the second transformer of 2023 is recommended to coincide with the other investments in the substation below.

Table 14-24:Orange Walk 6.6 kV transformers

6.6 kV			Rating		2042 loadings	
Investment Year	Voltage	Units	Normal	Emergency	N-0	N-1
Existing	34.5/6.6 kV	1	7.5	10	98%	N/A
2023 (N-1)	34.5/6.6 kV	2	7.5	10	49%	73%

For OWK 22 kV load the replaced transformer is adequate as shown before, but its outage would create total load shed until repairs are made. To provide N-1 security to OWK load at 22 kV, a parallel 15/25 MVA transformer should be added in the short term.

The tables below the recommended transformer fleet to be in service by year and the resulting 2042 loading if it were not further upgraded. In this table the first row is the existing condition, the second the situation with the exiting transformer replaced and the third is the future condition with two transformers.

Note that by 2042 there would be no N-1 security as the remaining transformer would overload above its emergency (ONAF) rating by 2041. However, BEL could implement distribution level solutions to address this including Energy Efficiency, Demand Response or Volt Var optimization.

Table 14-25:Orange Walk 6.6 kV transformers

22 kV			Rating		2042 loadings	
Investment Year	Voltage	Units	Normal	Emergency	N-0	N-1
Existing		1	3	4.2	344%	N/A
2023	34.5/22 kV	1	7.5	10	138%	N/A
2023*	34.5/22 kV	2	7.5	10	69%	103%

* Investment for N-1 Security (Firm Capacity)

Capital Costs

As shown in the table below the total capital expenditures on the transformers to reliably supply Orange Walk adds to US$ 2.42 million. In this table the first 34.5/22 kV transformer is the repositioned transformer from San Pedro and the unit cost reflects the refurbishment of this unit prior to redeployment. As before the new 34.5 breaker positions are required for the new transformers when added and the 3 new 6.6 kV as well as the 3 new 22 kV breakers are required when a parallel transformer is added, one for each of the transformers and one for the bus-tie. This will allow ease for operations and automated transfers upon the loss of one transformer.

Table 14-26: Orange Walk Transformers (2022 US$)

Investment	Number	Length (miles) or MVA (normal) or layout	N-1 / heavy loading recommended year	ONAF Overload Required year	Unit Cost $/Mile (lines/cables) $/MVA Transformers $/unit (breakers)	Cost
34.5/6.6 kV Transformer	1	7.5		2023	$32,957	$247,181
34.5 kV Breaker	1			2023	$283,228	$283,228
6.6 kV Breaker	3			2023	$205,984	$617,953
34.5/22 kV Transformer 1	1	7.5	2023	2023	$16,479	$123,591
34.5 kV Breaker	1			2023	$283,228	$283,228
34.5/22 kV Transformer 2	1	7.5		2023	$32,957	$247,181
22 kV Breaker	3			2023	$205,984	$617,953
Total						**$2,420,315**

14.6.6 Belcogen Supply

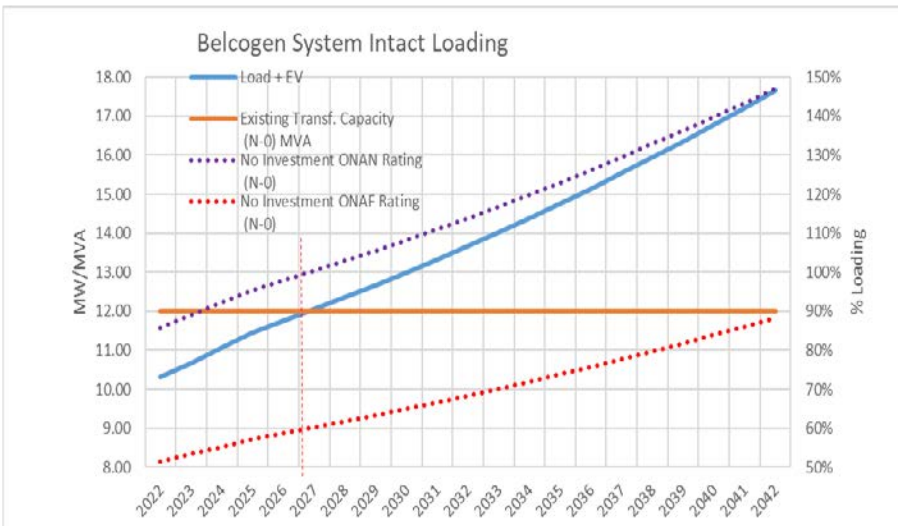
Diagnostic.

Belcogen, located in the north-west of the BEL system, it has generation in the 115 kV transmission side, and has 115/34.5 kV transformation to supply to the Orange Walk (OWK) substation load via a single subtransmission line with about 4 miles length. The outage of this line may result in some loads shed, partially addressed by the proposed OWK 20 MW PV solar generation and the 10 MW battery storage.

The load supplied from Belcogen (currently 10.3 MW) will exceed the normal rating (12 MVA) of the single existing transformer by 2027 (blue dotted line in the graph in Figure 14-37). The emergency rating will not be exceeded.

A second transformer is recommended to be installed as soon as possible to provide N-1 security. With the second transformer in place, and in case of contingency, emergency rating (20 MW) will not be exceeded, and the remaining transformer could supply the load. Note that a transformer failure may take months to repair if not longer and the local PV and storage is not an option to address this.

Figure 14-37: Belcogen system intact loading



Belcogen Supply Solutions.

Transformers

A second transformer is necessary to address heavy loadings by 2026 and provide N-1 security. The table below shows the recommended transformer addition to be in service by year and the resulting 2042 loading if it were not further upgraded. The first row is the current situation and the second the future with two transformers

Table 14-27: Belcogen transformers

			Rating		2042 loadings	
Investment Year	Voltage	Units	Normal	Emergency	N-0	N-1
Existing	115/34.5 kV	1	12	20	147%	N/A
2026 (heavy load & N-1)	115/34.5 kV	2	12	20	74%	88%

Capital Costs

As shown in the table below the total capital expenditures on the transformers to reliably supply OWK from Belcogen adds to US$ 1.7 million. In this table one new 115 kV breaker position is required for the new transformer and the 3 new 34.5 kV breakers are one for each of the transformers and one for the bus-tie. This will allow ease for operations and automated transfers upon the loss of one transformer.

Table 14-28: Belcogen Transformers (2022 US$)

Investment	Number	Length (miles) or MVA (normal) or layout	N-1 / heavy loading recommended year	ONAF Overload Required year	Unit Cost $/Mile (lines/cables) $/MVA Transformers $/unit (breakers)	Cost
115/34.5 kV Transformer	1	12	2026		$32,957	$395,490
115 kV Breaker	1		2026		$473,599	$473,599
34.5 kV Breaker	3		2026		$283,228	$849,685
Total						**$1,718,773**

14.6.7 San Ignacio Supply

Diagnostic.

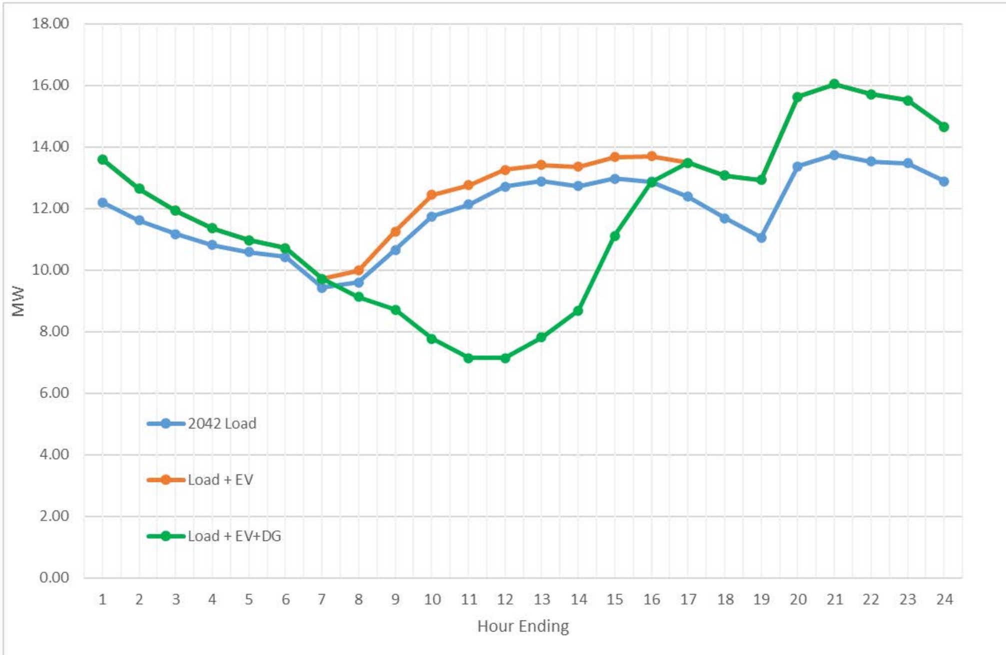
San Ignacio substation is in the west side of the BEL system, near to the border with Guatemala. It is supplied by two 115 kV lines, one from Westlake (approximately 60 miles), and secondly from the hydro generation from the south-east, Vaca, Chalillo, and Mollejon. Hence, no supply interruption is expected in this substation caused by any primary single contingency (N-1) in the 115 kV system. However, the expected load growth by 2042 would result in overloads in the transformer if the proposed reinforcements for San Ignacio are not implemented and some load shed may take place.

San Ignacio is expected to reach by 2042 a peak load of 13.7 MW (including 0.7 MW of EV charging load) for the day peak and 16 MW for the night peak including 2.3 MW of EV charging load (see table and figure below).

Table 14-29: 2042 Projected load at San Ignacio

	Base Load	EV	Total
Day Peak	13	0.7	13.7
Night Peak	13.70	2.3	16.0

Figure 14-38: San Ignacio Peak Load Day 2042



The load at San Ignacio is expected to exceed the normal rating of the single transformer (10 MVA) by 2025 (Figure 14-39) and the emergency rating by 2037. The outage of this single transformer results in load shed. Hence a second transformer is recommended for N-1 security. With the second transformer in place, the emergency rating of the remaining transformer can be exceeded by year 2037 during contingency conditions N-1 (Figure 14-40). Also, if a second transformer is not added by 2037 the single existing transformer will overload above its emergency ratings (ONAF).

Figure 14-39: San Ignacio transformer loading (ONAN rating)

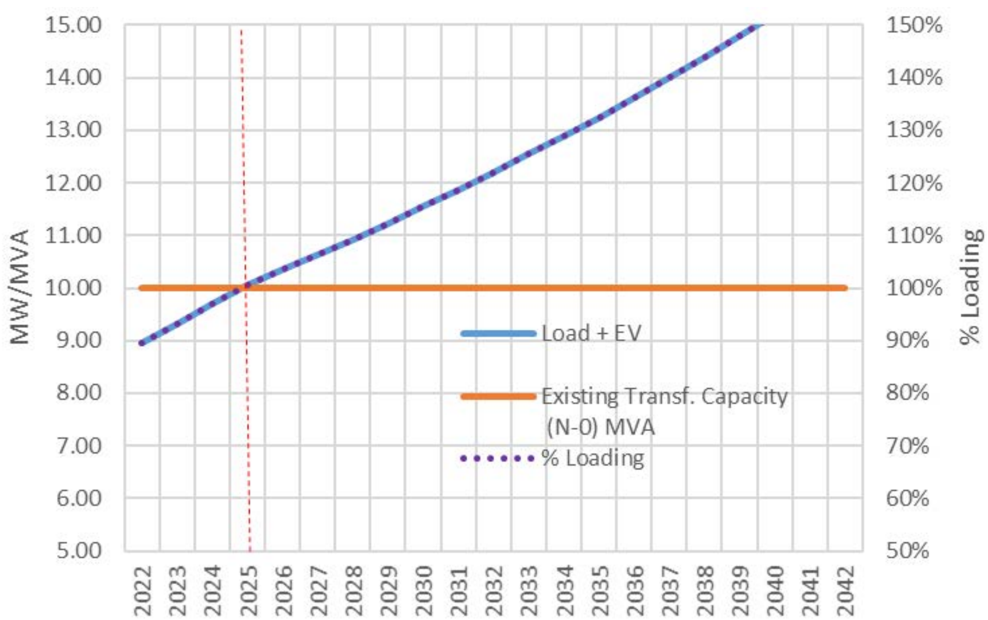
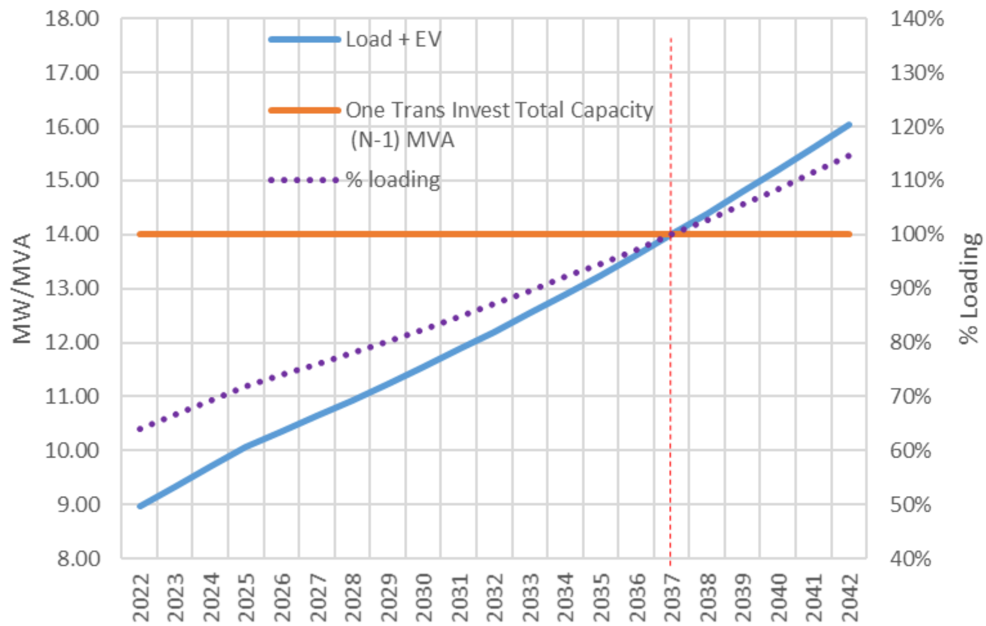


Figure 14-40: San Ignacio N-1 system loading with 1st transformer investment



San Ignacio Supply Solutions.

According to the planning criteria a new transformer should be added in the short term, and this would provide N-1 security until approximately 2036, when the load is expected to reach 14 MW, and overloading the remaining transformer above its emergency rating, upon the failure of the parallel unit (N-1), as mentioned above. Being in violation in the long term, instead of recommending a third transformer to provide firm capacity by 2037, BEL should monitor the load growth in the area and assess if other local remedies can be implemented as is the case of Energy Efficiency, Demand Response and/or Volt-Var Optimization.

The table below shows the recommended transformer addition to be in service by year and the resulting 2042 loading if it were not further upgraded. Although the transformer would be useful to have been upgraded sooner for N-1 security, we are displacing it to 2026 to manage the large investments in 2025.

Table 14-30: San Ignacio transformers

			Rating		2042 loadings	
Investment Year	Voltage	Units	Normal	Emergency	N-0	N-1
Existing	115/22 kV	1	10	14	160%	N/A
2026	115/22 kV	2	10	14	80%	115%

Capital Costs

As shown in the table below the total capital expenditures on the transformers to reliably supply Independence adds to US$ 2.0 million. In this table one new 115 kV breaker position is required for the new transformer and 3 new 22 kV breakers, one for each of the transformers and one for the bus-tie, are also required. This will allow ease for operations and automated transfers upon the loss of one transformer. The table indicates that the mandatory investment for overloads needs to occur by 2036 at the latest but should be much sooner for N-1.

Table 14-31: San Ignacio Transformers (2022 US$)

Investment	Number	Length (miles) or MVA (normal) or layout	N-1 / heavy loading recommended year	ONAF Overload Required year	Unit Cost $/Mile (lines/cables) $/MVA Transformers $/unit (breakers)	Cost
115/22 kV Transformer	1	10	2025	2036	$329,575	$329,575
115 kV Breaker	1		2025	2036	$473,599	$473,599
22 kV Breaker	3		2025	2036	$431,084	$1,293,251
Total						**$2,096,425**

14.6.8 Corozal Supply

Diagnostic.

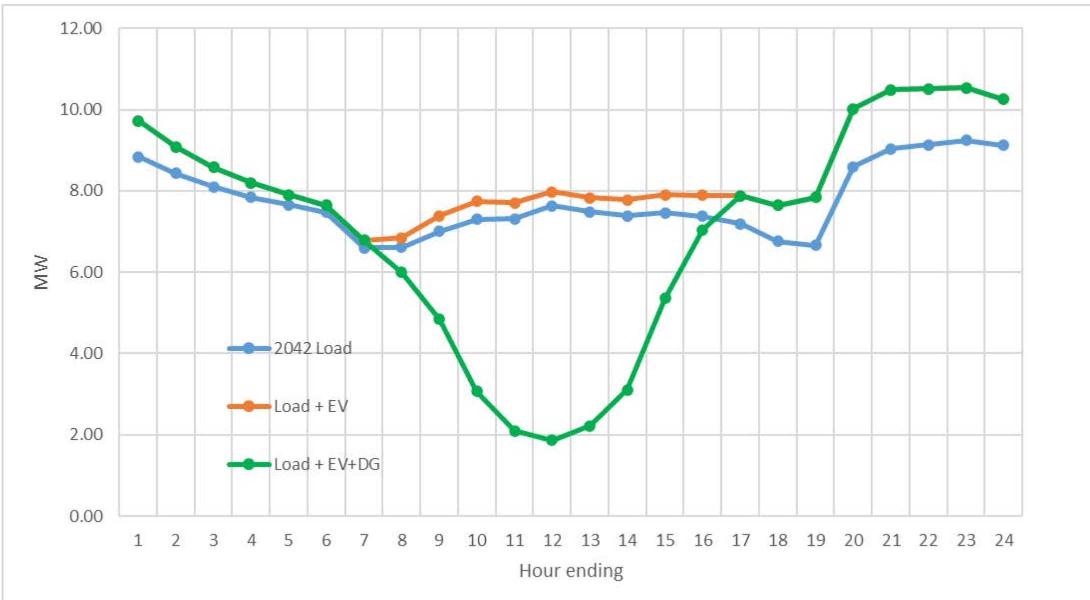
In the North side of the BEL system, Corozal substation is located, near to the border with Mexico. By 2042, this substation will be sourced by two circuits, both transmitting power from Chan Chen substation in 34.5 kV. Due to the two circuits above, no supply interruption is expected in this substation caused by single contingency in the in the 34.5 kV side.

Corozal is expected to reach by 2042 a peak load of 8.1 MW (including 0.4 MW of EV charging load) for the day peak and 10.7 MW for the night peak including 1.5 MW of EV charging load (see Table 14-32 and figure below).

Table 14-32: 2042 Projected load at Corozal

	Base Load	EV	Total
Day Peak	7.64	0.44	8.1
Night Peak	9.2	1.5	10.7

Figure 14-41: Corozal Peak Load Day 2042

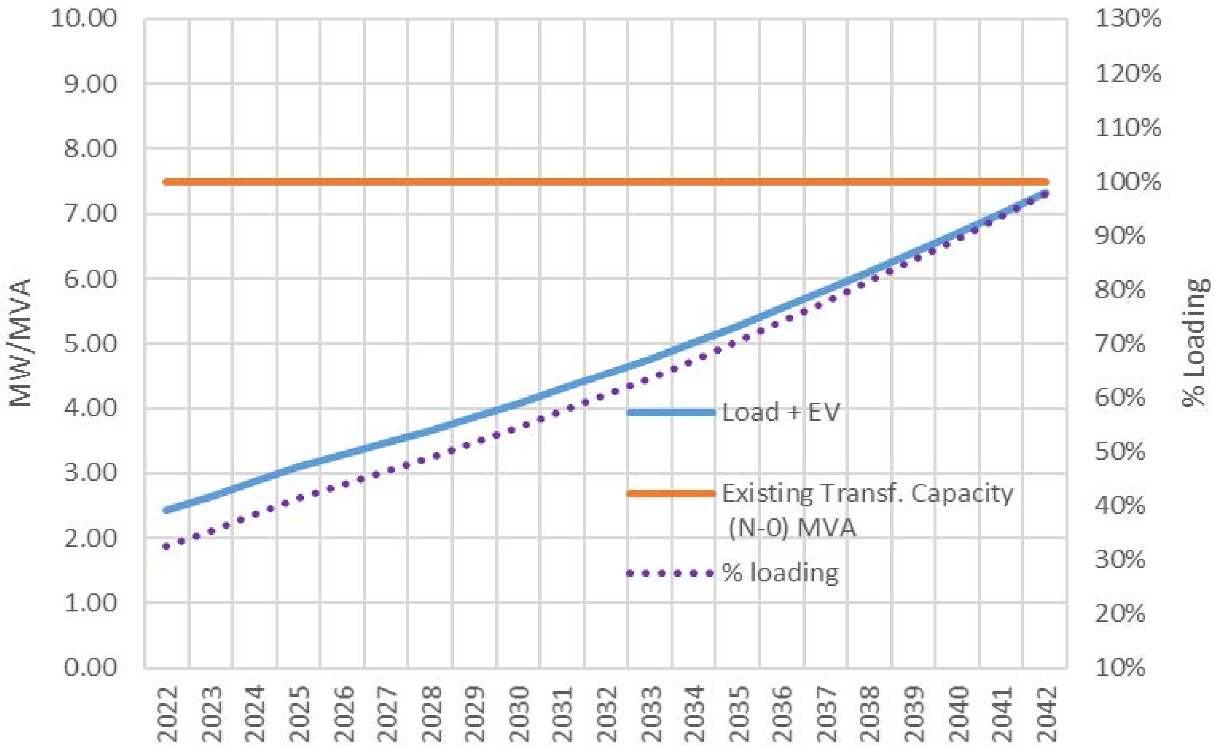


The loads on Corozal F1, F2, F3, and F4, are supplied by a single 34.5/6.6, 7.5 MVA transformer. These loads have a Day Peak and Night Peak of 4.3 MW and 7.33 MW respectively (see Table 14-33). The single transformer is not expected to be overloaded by 2042. However, a second transformer is recommended for N-1 security (Figure 14-42). Other loads at Corozal (e.g., F6) are also supplied by a single transformer but are small enough so that the loss of the transformer could be addressed at the distribution level or accept the shed.

Table 14-33: 2042 Projected load at Corozal F1, F2, F3, F4

	Load	EV	Total
Day Peak	4.85	0.44	5.30
Night Peak	5.88	1.45	7.33

Figure 14-42: Corozal F1-F4 system transformer loading (ONAN)



Corozal Supply Solutions.

According to the planning criteria, a new parallel transformer should be added in the short term, and this would provide N-1 security.

The table below shows the recommended transformer fleet to be in service by year and the resulting 2042 loadings. The investment is recommended by 2023 as it should be an investment inside the existing substation and could be advanced, reducing the otherwise large amounts of investments expected by 2024 and 2025.

Table 14-34: Corozal 34.5/6.6 kV transformers

			Rating		2042 loadings	
Investment Year	Voltage	Units	Normal	Emergency	N-0	N-1
Existing	34.5/6.6 kV	1	7.5	7.5	98%	N/A
2023*	34.5/6.6 kV	2	7.5	7.5	49%	98%

* Investment for N-1 Security (Firm Capacity)

Capital Costs

As shown in the table below the total capital expenditures on the transformers to reliably supply Corozal F1 to F4 adds to US$ 1.15 million. In this table one new 34.5 breaker position is required for the new transformer and 3 new 6.6 kV breakers, one for each of the transformers and one for the bus-tie, are also required. This will allow ease for operations and automated transfers upon the loss of one transformer. These investments are only to provide firm capacity.

Table 14-35: Corozal Transformers

Investment	Number	Length (miles) or MVA (normal) or layout	N-1 / heavy loading recommended year	ONAF Overload Required year	Unit Cost $/Mile (lines/cables) $/MVA Transformers $/unit (breakers)	Cost
34.5/6.6 kV Transformer	1	7.5		2023	$32,957	$247,181
34.5 kV Breaker	1			2023	$283,228	$283,228
6.6 kV Breaker	3			2023	$205,984	$617,953
Total						**$1,148,362**

14.6.9 Chan Chen Supply

Diagnostic.

Chan Chen is a new substation located at the north of the BEL system and connects directly to Xul-Ha. It is projected to have local 20 MW PV generation connected to the 34.5kV side and it connects at 115 kV the south to Belcogen. The 115 kV supply is considered reliable.

Chan Chen currently has one 115/34.5 kV transformation to the total Corozal load via 34.5 kV sub-transmission lines with variable lengths from 5 to 7 miles approximately.

Chan Chen substation supplies the total load at Corozal that indicated previously, is expected to reach a peak load of 8.1 MW (including 0.4 MW of EV charging load) for the day peak and 10.7 MW for the night peak including 1.5 MW of EV charging load by 2042.

The existing 7.5/10 MVA transformer is expected to be loaded by 2034 to its ONAN rating and by 2041 to its ONAF ratings (Figure 14-43).

Additionally, having a single transformer means that there would be no firm capacity (N-1 security), which should be addressed.

A second transformer (7.5/10 MVA) is recommended to be in place by 2034 to address heavy loadings and sooner to provide N-1 Security. With a second transformer, there would be an overload on the remaining transformer under emergency condition by year 2041 (Figure 14-44), thus the transformers should be replaced by 2040 or distribution solutions implemented as indicated below.

Figure 14-43: Chan Chen Transformer loading

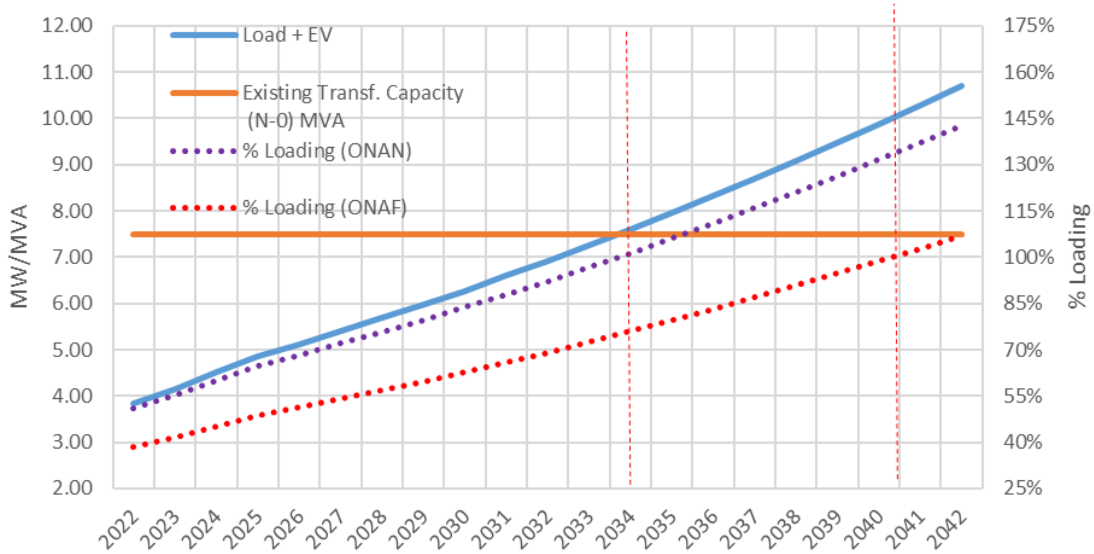
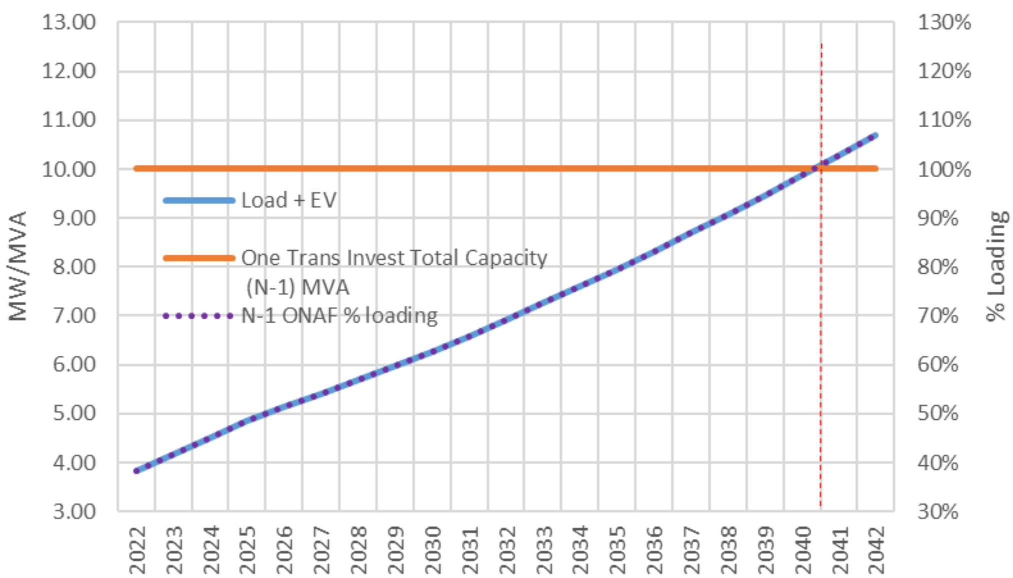


Figure 14-44: Chan Chen system N-1 loading with 1st transformer investment



Chan Chen Supply Solutions.

As indicated above Chan Chen has a single 7.5/10 MVA, 115/34.5 kV transformer that is expected to be overloaded beyond its normal rating by 2034. A second parallel transformer is recommended to provide N-1 security. We considered initially for this second transformer to be larger (15/20 MVA) and long term replace the existing transformer. However, given that the ONAF rating of the existing transformers is only exceeded in the long term (2041) under emergency conditions, it is recommended instead to add the second transformer with the same size as the existing for BEL to monitor the load served and implement as required distribution level solutions (e.g., Energy Efficiency, Demand Response and/or Volt-Var Optimization). The table below shows the recommended investments, where the first row is the current condition, and the second row has the future condition with two transformers. The second transformer for N-1 is recommended for 2026 to manage the investments by year, although the reliability need is immediate.

Table 14-36: Chan Chen transformers

			Rating		2042 loadings	
Investment Year	Voltage	Units	Normal	Emergency	N-0	N-1
Existing	34.5/6.6 kV	1	7.5	10	143%	N/A
2034 (2026 N-1)	34.5/6.6 kV	1	7.5	10	71%	107%
	34.5/6.6 kV	1	7.5	10		

Capital Costs

As shown in the table below the total capital expenditures on the transformers to reliably supply Independence adds to US$ 1.57 million. In this table one new 115 kV breaker position is required for the new transformer and 3 new 34.5 kV breakers, one for each of the transformers and one for the bus-tie, are also required. The investments are required for N-1 security.

Table 14-37: Chan-Chen Transformers (2022 US$)

Investment	Number	Length (miles) or MVA (normal) or layout	N-1 / heavy loading recommended year	ONAF Overload Required year	Unit Cost $/Mile (lines/cables) $/MVA Transformers $/unit (breakers)	Cost
115/34.5 kV Transformer	1	7.5	2041	2026	$32,957	$247,181
115 kV Breaker	1		2041	2026	$473,599	$473,599
34.5 kV Breaker	3		2041	2026	$283,228	$849,685
Total						**$1,570,465**

14.6.10 Belmopan Supply

Diagnostic.

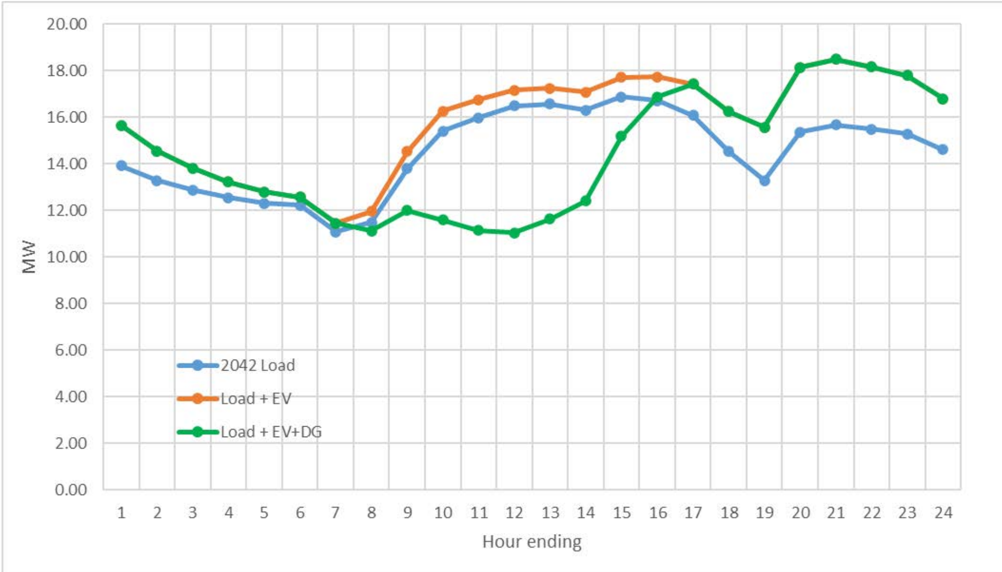
The Belmopan substation serves the capital city of Belmopan and is in the middle region of the BEL system. It is currently supplied by a single 115kV circuit coming from Camalote substation approximately 2.2 miles away. Load at Belmopan is supplied by 22 kV and 11 kV substations, with single 115/22 kV and 22/11 kV transformers. Both the single circuit and transformers are important vulnerabilities for the supply.

Belmopan total load (11 kV and 22 kV buses) is expected to reach by 2042 a peak load of 17.9 MW (including 1.04 MW of EV charging load) for the day peak and 18.5 MW for the night peak including 2.8 MW of EV charging load (see table and figure below).

Table 14-38: 2042 Projected total load at Belmopan

	Load	EV	Total
Day Peak	16.87	0.85	17.72
Night Peak	15.67	2.82	18.48

Figure 14-45: Belmopan Peak Load Day 2042



According to our conversations with BEL distribution the 11 kV system that serves the center of the city will not be expanded and most of the new load will be supplied by the 22 kV system. Thus the 11 kV is projected to reach 7.6 MW by 2042 from 6.3 MW currently due to EV load and vegetative growth on existing customers and the balance of the load will be supplied at 22 kV. The 115/22 kV transformers see both the 22 kV load and the 11 kV load as they serve a 22/11 kV transformer.

The existing 115/22 kV transformer (10/16 MVA) that supplies both the 22 kV load and the 11 kV load, has its normal rating exceeded and its emergency rating is projected to be exceeded by 2037 (Figure 14-46). A second transformer with larger capacity (15/20 MVA) should be in service as soon as possible to address the heavy loadings and to provide N-1 security. The original transformer emergency rating (ONAF = 16 MVA) will be exceeded by year 2036 in case of contingency and should be replaced by a larger transformer (15/20 MVA) by 2035 (Figure 14-47).

The existing 22/11 kV transformer will be loaded above its normal rating by 2041 according to the load forecast and there is no firm capacity for (N-1 security) (Figure 14-48).

Figure 14-46: Belmopan 22 kV transformer loading

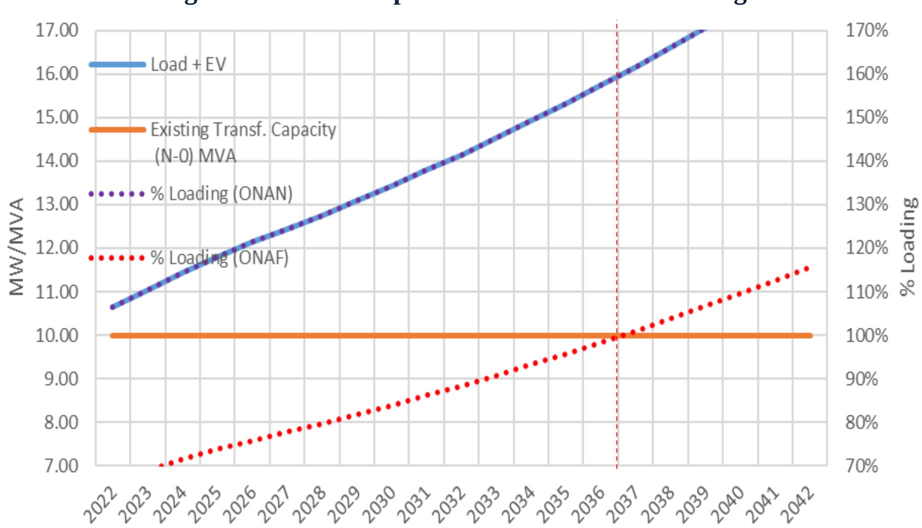


Figure 14-47: Belmopan 22 kV system N-1 loading with 1st transformer investment

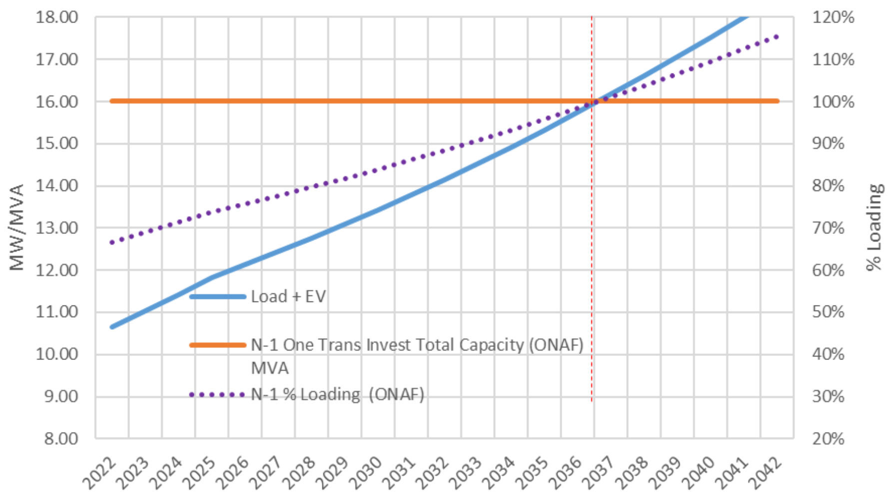
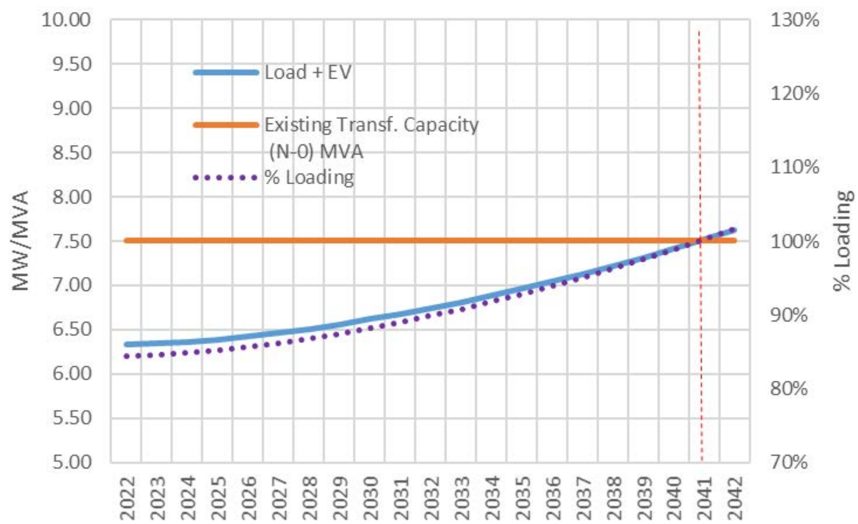


Figure 14-48: Belmopan 11 kV system intact loading



Belmopan Supply Solutions.

115 kV Supply

By 2042, it is recommended to build a second 115 kV supply to Belmopan. According to our conversations with BEL this can be achieve by redirecting the line from La Democracia / Camalote to Belmopan. This rerouting can be achieved with a short 2 miles line and adding a new 115 kV breaker at Belmopan. The existing line to Camalote will remain and it is possible as that the existing 115 kV breaker will need to be upgraded. The breakers at Camalote can be dismantled and redeployed (e.g., at Belmopan). This arrangement will effectively provide Belmopan with a single bus arrangement. However, more reliability can be achieved by making Belmopan a ring bus substation. The recommended date is 2025 selected to coincide with the reinforcements at the substation discussed below.

Transformers

According to the planning criteria, new parallel transformer 115/22 kV should be added in the short term to provide firm capacity (N-1 security) and address heavy loadings above the ONAN ratings; this is not critical and 2025 date was selected. This second transformer must alternatively be in place by 2035 to address loadings above the ONAF (emergency) ratings. By 2035, if firm capacity is required (as recommended) the existing transformer must be replaced.

The table below shows the recommended 22 kV transformer fleet to be in service by year and the resulting 2042 loadings. The first row is the current condition, the following two rows is the situation with one new larger transformer added to the substation and the last row is the situation with two larger transformers recommended to be online by 2035; replace the existing with a larger unit.

Table 14-39: Belmopan 115/22 kV transformers

			Rating		2042 loadings	
Investment Year	**Voltage**	**Units**	**Normal**	**Emergency**	**N-0**	**N-1**
Existing	115/22 kV	1	10	16	185%	N/A
2025	115/22 kV	1	10	16	74%	185%
	115/22 kV	1	15	20		
2035	115/22 kV	2	15	20	62%	92%

The existing 22/11 kV transformer is adequate for the planning, but a second transformer provided N-1 Security as shown below. In this table the second line shows the situation with two transformers. The transformer should be added at the same time as the work on 115/22 kV, recommended 2025.

Table 14-40: Belmopan 22/11 kV transformers

			Rating		2042 loadings	
Investment Year	**Voltage**	**Units**	**Normal**	**Emergency**	**N-0**	**N-1**
Existing	22/11 kV	1	7.5	10.5	102%	N/A
2025	22/11 kV	2	7.5	10.5	51%	73%

Capital Costs

As shown in the table below the total capital expenditures on the transformers to reliably supply Belmopan adds to US$ 3.9 million; US$ 1.2 million for the new line and US$ 2.6 million for the new transformers and associated investments.

Table 14-41: Belmopan Transformers (2022 US$)

Investment		Number	Length (miles) or MVA (normal) or layout	N-1 / heavy loading recommended year	ONAF Overload Required year	Unit Cost $/Mile (lines/cables) $/MVA Transformers $/unit (breakers)	Cost
Santander tap to Belmopan 115 kV transmission line section and substation upgrade							
	Overhead line 115 kV	1	2.19	2024	N/A	$345,000	$755,550

[redacted]	Breaker 115 kV	1	single entry	2024	N/A	$473,598.90	$473,599
	Subtotal						$1,229,149
Belmopan supply							
[redacted]	Transformer 115/22 kV	1	15	2024	2035	$32,957	$494,362
	Breaker 115 kV	1	15	2024	2035	$542,166	$542,166
	22 kV Breaker	3		2024	2035	$10,299	$30,898
	Transformer 115/22 kV	1	15	2035		$32,957	$494,362
	Transformer 22 /11 kV	1	7.5	2024		$32,957	$247,181
	11 kV Breaker	3		2024		$283,228	$849,685
[redacted]	Subtotal						$2,658,654
	Total						**$3,887,803**

14.6.11 Dangriga Supply

Diagnostic.

The coastal city of Dangriga is expected to reach by 2042 a peak load of 10.1 MW (including 0.5 MW of EV charging load) for the day peak and 11.6 MW for the night peak including 1.6 MW of EV charging load (see table and figure below).

Table 14-42: 2042 Projected load at Dangriga

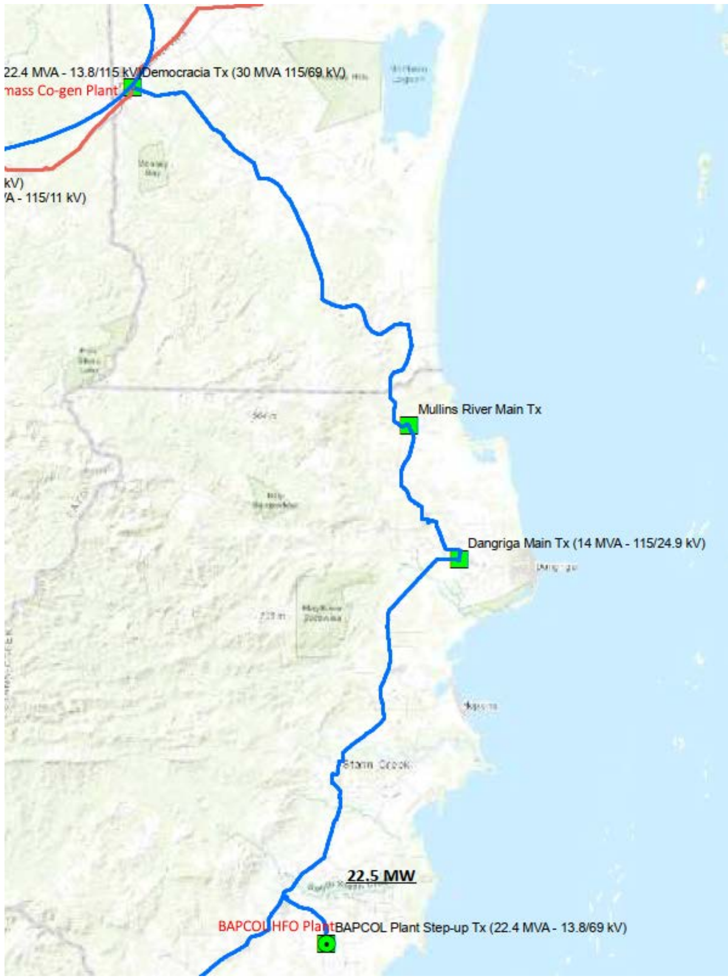
	Base Load	EV	Total
Day Peak	9.66	0.47	10.13
Night Peak	10.03	1.55	11.59

Figure 14-49: Dangriga Peak Load Day 2042

In addition to this load the new RICE generator is recommended to be installed at this location by 2024, given the closeness of the Dangriga and the Independence port that can be leveraged for the containerized LNG delivery.

Another aspect to be considered when assessing Dangriga is that the existing 69 kV line from Dangriga to La Democracia (see figure below) has had historically fairly poor performance and its outage isolates Dangriga, all the loads to the south (Independence and Punta Gorda) as well as the RICE generation at BAPCOL.

Figure 14-50: Dangriga Area System (blue = 69 kV, red 115 kV)



The combination of these factors; increased generation at Dangriga (2024), loads to be served (when the thermal generation is offline) and the poor reliability of the existing 69 kV lines makes it advisable that together with the incorporation of the new RICE a new La Democracia – Dangriga 115 kV be added to the system as presented below.

In addition, there is a single 69/24.9 kV transformer at Dangriga, whose outage would result in immediate load shed and should be addressed as per the planning criteria.

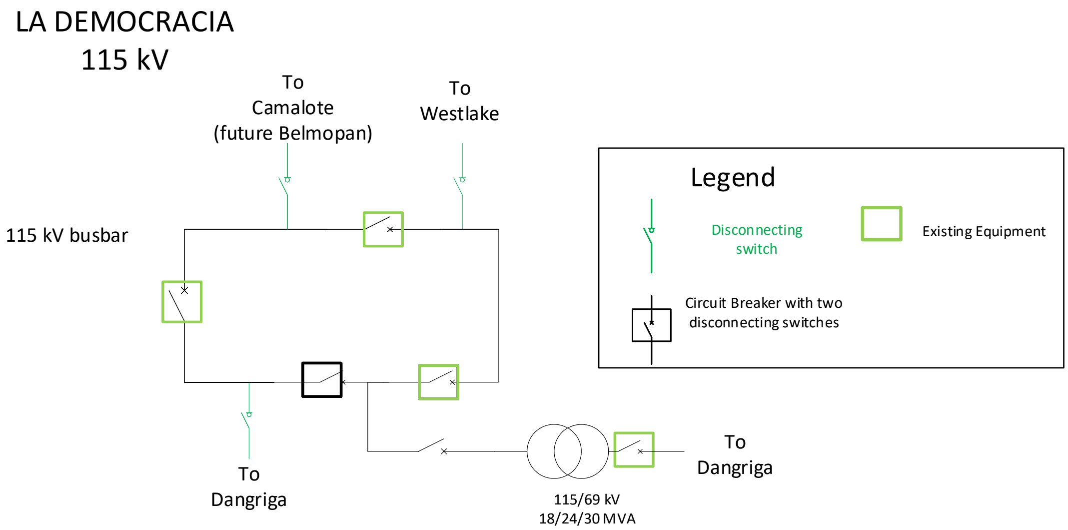
Dangriga La Democracia 115 kV System

This is the new 115 kV circuit described above linking Dangriga with La Democracia 115 kV.

La Democracia Switching Substation.

La Democracia Switching should be upgraded to ring bus configuration with four exits, one for the existing line to Camalote (future to Belmopan), a second for the line to Westlake, a third for the 115/69 kV transformer and the fourth for the new line to Dangriga. The figure below shows a simplified one-line diagram of the substation.

Figure 14-51: La Democracia Substation Upgrade Simplified One-Line



La Democracia – Dangriga 115 kV line.

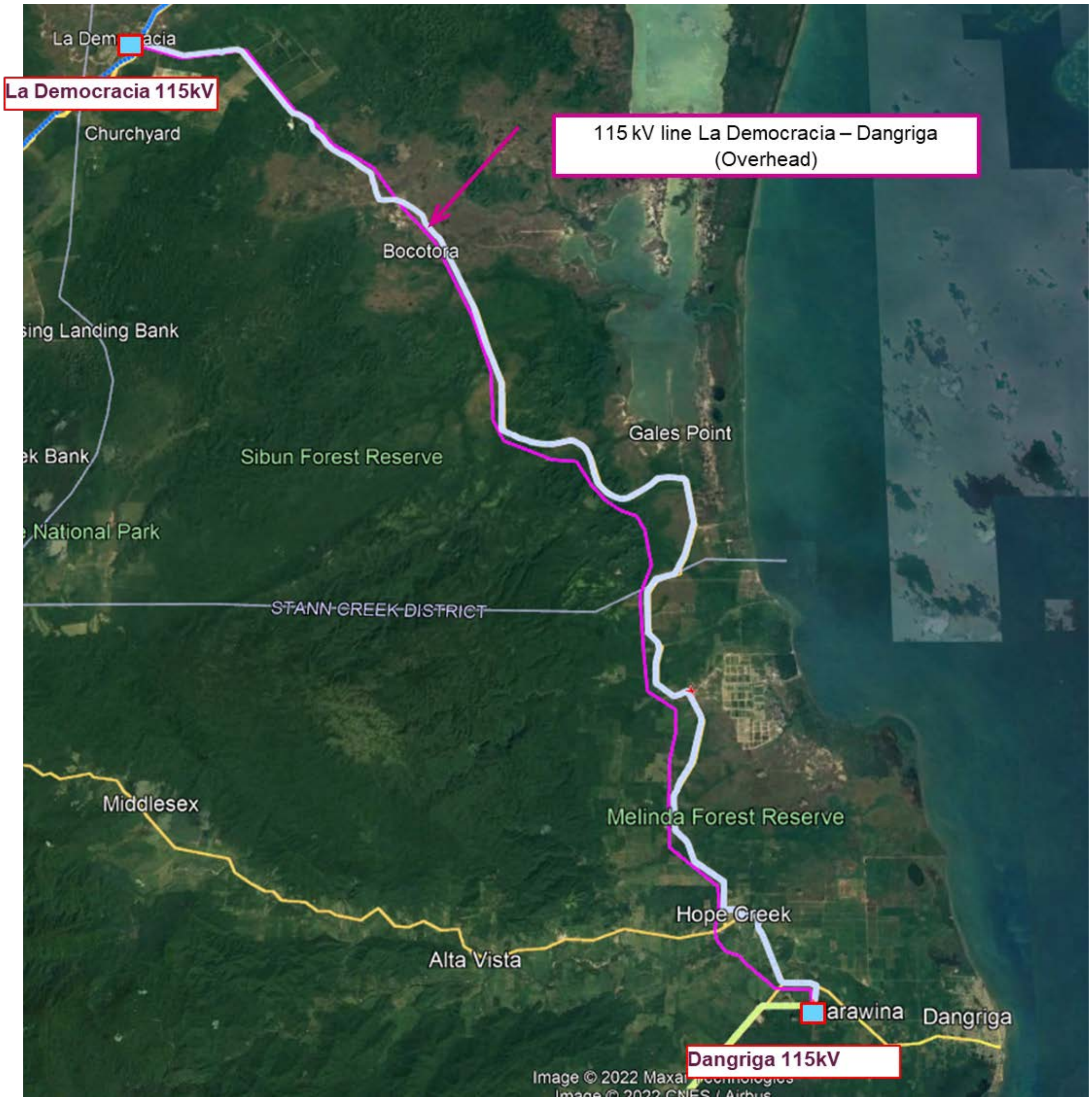
This overhead line should have similar configuration and conductor as the lines La Democracia to West (106 MVA rating) and La Democracia to Camalote. The line is expected to have a total length of about 35 to 39 miles depending on the actual ROW obtained. The route should generally follow the Coastal Hwy out of La Democracia to the south, until Hope Creek where it will remain to the west of the Hummingbird Hwy until reaching Dangriga Substation. Figure 14-52 below shows the possible route for this line.

Dangriga 115 kV / 69 kV switchyard and transformer.

At Dangriga the new 115 kV line can terminate on a circuit switcher on the high voltage side of the new 115 kV/69 kV transformer. The 69 kV side should be upgraded to ring bus configuration with three exits, one for the new 115/69 kV transformer, one for the existing 69 kV line to BAPCOL and one for the 69 kV line to La Democracia 69 kV.

The 115/69 kV transformer should be similar to the existing transformer at La Democracia, with three windings (115 / 69 / 13.8 kV) and ratings 18 / 24 / 30 MVA. The transformer should have onload tap changers ± 10% 32 steps.

Figure 14-52: Dangriga – La Democracia 115 kV line



Dangriga Transformers

As indicated above there is a single 69/24.9 kV transformer at Dangriga which does not provides N-1 security. Moreover, given the expected load growth at Dangriga the existing transformer normal capacity is expected to be exceeded by 2036 (Figure 14-53). Based on the above BEL should consider adding a second transformer in the short term and as soon as the new RICE plant is interconnected in case that as expected this plant interconnects at the 24.9 kV level. The recommended date is 2024 to coincide with other investments in the area (new RICE and new 115 kV line).

With parallel transformer in place, and in the case of a contingency N-1, load can be supplied beyond 4042 without overloading (Figure 14-54).

Figure 14-53: Dangriga Transformer loading (ONAN /ONAF)

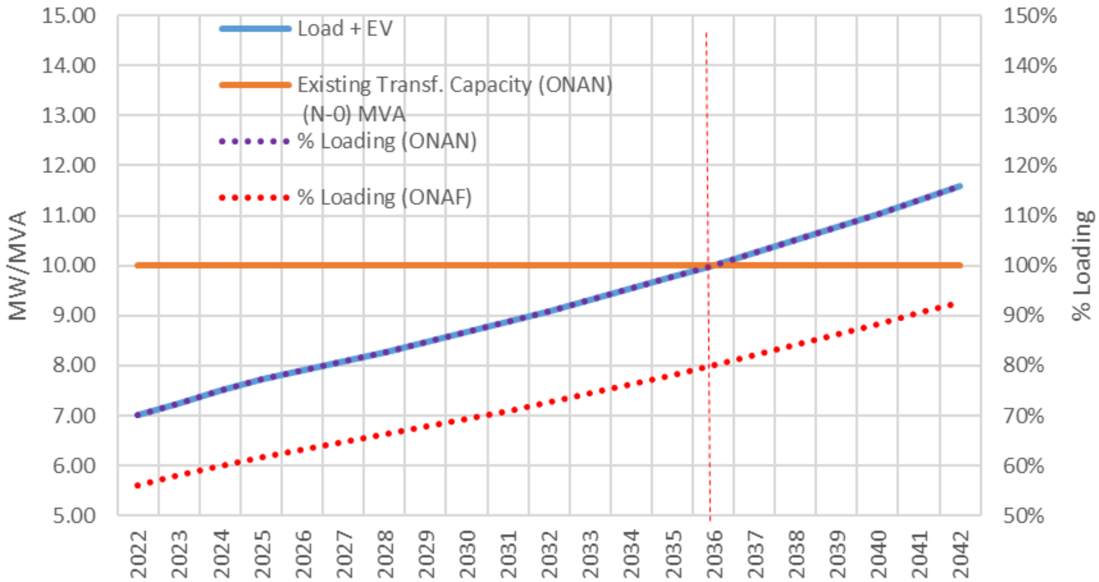
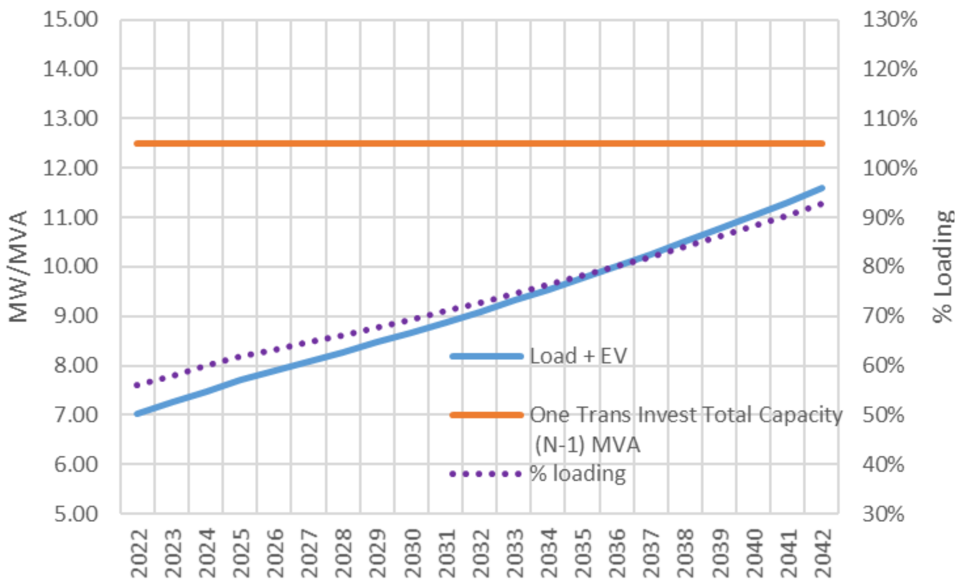


Figure 14-54: Dangriga system N-1 loading with 1st transformer investment



As indicated above there is a single 69/24.9 kV transformer at Dangriga which does not provides N-1 security, and its normal capacity is expected to be exceeded by 2035. Based on the above BEL should consider adding a second transformer in the short term for N-1 security and 2024 is recommended coinciding with other investments at the substation. The table below shows the recommended transformer fleet to be in service by year and the resulting 2042 loading if it were not further upgraded.

Table 14-43: Dangriga transformers

			Rating		2042 loading	
Investment Year	**Voltage**	**Units**	**Normal**	**Emergency**	**N-0**	**N-1**
Existing	115/22 kV	1	10	12.5	116%	N/A
2024 (N-1)	115/22 kV	2	10	12.5	58%	93%

Capital Costs

As shown in the table below the total capital expenditures on the transmission system to enhance the supply to the Dangriga and the load to the south adds to US$ 16.9million, where the new transmission line is the largest component representing 91% of the costs. This line however is an important asset as it serves more than Dangriga and will benefit all the loads to the south.

Table 14-44: Dangriga Supply (2022 US$)

Investment		Number	Length (miles) or MVA (normal) or layout	N-1 / heavy loading recommended year	RICE Interconnection year	Unit Cost $/Mile (lines/cables) $/MVA Transformers $/unit (breakers)	Cost
La Democracia to Dangriga 115 kV transmission line							
	Overhead line 115 kV	1	39.77		2024	$345,000	13,720,650
	Breakers 115 KV	1	single entry		2024	$473,598.90	473,599
	Breakers 115 KV	1	Ring bus		2024	$473,598.90	473,599
	15/69 kV Transformer	1	18		2024	$32,957.47	593,235
	Subtotal						15,261,082
Dangriga transformers							
	69/24.9 kV Transformer	1	10	2024		$32,957	329,575
	69 kV Breaker	1		2024		$431,084	431,084
	24 kV Breaker	3		2024		$283,228	849,685
	Subtotal						1,610,343
	Total						**$16,871,426**

14.6.12 Substation Standardization

In addition to the needs and investments above, BEL informed us that four substations in its system need to be upgraded to become up to code and meet minimum acceptable standards.

These substations are shown in the table below together with the expected investments and in-service date provided by BEL considering the time for engineering and procurement.

Table 14-45: Substation Standardization Investments US$ 2022

Substation	Capital Costs 2022 M$	Date
Santander	$1.75	2023
San Pedro	$1.75	2024
Corozal	$1.25	2025
Orange Walk	$1.25	2026

We reviewed the current layout ot the substations above and concur with BEL. Santander is a simple t-off on the La Democracia – Camalote 115 kV line so any fault on this line would trip the generator. With the upgrade the generation would remain connected to the system either to the east towards La Democracia or to the west towards Camalote.

San Pedro needs to be upgraded to a full substation layout as required for the connection of the new supply and the storage. It currently only has disconnect switches and a recloser on the incoming line. There are breakers on the transformers.

At Corozal we understand that it like San Pedro has an issue with the layout. There is a recloser on the transformer, but minimum isolating devices on the incoming 34.5 kV line and the lines to loads as the Las Vegas Casino, Corozal Free Zone. San Pedro Corozal is also supplied from a t-off on the same incoming 34.5 kV line.

At Orange Walk, we see a similar situation only reclosers on the transformers but a very limited layout with disconnect switches.

These investments are included in the Minimum Required Investment Group.

14.7 Contingency Analysis for the 2042 Day Peak Conditions.

For the day peak case, the reinforced system was subjected to a contingency analysis to identify overloads and/or voltage violations. The assessed dispatch was as presented in Table 14-8, where we observe that PV (including DG) and wind was modeled at 80% of rated capacity, hydro close to its minimum and the BEL system is selling about 17 MW to Mexico. This condition was selected as representative of the two modes in which the system will operate, exporting in this case and importing from Mexico in the night case.

The analysis looked both at performance violations (voltage and loading) as well as the formation of electrical islands when the single transmission or sub-transmission ties are open and assessed the generation – demand balance of the electrical island and determined any residual load shed.

The study's findings are presented below.

14.7.1 Contingency with potential overloads

Seven contingencies were identified as resulting in potential overloads as shown in Table 14-46. Some of these contingencies are equivalent since the contingency opens elements connected in series. This is indicated as “OR” in the first, fifth, and sixth rows of the table.

The first-row contingency is the outage of the 115/69 kV transformer at La Democracia, or the outage of the 69 kV line between La Democracia and Mullin Rivers, both elements are in series and would open the 69 kV path to Dangriga. When the 69 kV path is open, the flow is diverted to the new 115 kV link and the new projected 115/69 kV transformer at Dangriga would experience and overload of 126%. This overload driven by the fact that the battery at Independence is charging at 10 MW and can be addressed by sending a signal to the battery to stop charging (i.e., a transfer command via for example a Remedial Action Scheme).

The contingency is the alternate, where the 115 kV link opens and the transformer 115/69 kV at La Democracia overload. Again, the overload can be addressed by a transfer command to stopping charging the battery at Independence.

All the remaining contingencies describe small overloads that can be addressed with exactly the same strategy, reducing the charging level of the batteries in a few MW.

As mentioned above a Remedial Action Scheme will need to be put in place to rapidly stop charging the battery at Independence or San Pedro in the event of the occurrence of the contingency AND the detection of the overload.

14.7.2 Contingency with potential for load shed

Six contingencies were identified as resulting with potential load shed (see Table 14-47)

Contingencies with sequence #1, 2 3 and 5 are faults associated with feeders from Ladyville and Belize I and II and can be addressed by transferring loads between these substations. The other contingency driven load shed was expected due to lack of local generation in the case of Caye Caulker and can be addressed by keeping stand-by diesel in the Caye.

Given the distributed generation and PV, the Day case has virtually no-load shed, except the Caye Caulker situation above.

14.7.3 Contingency with important generation islanding

The occurrence of electrical islands and the requirement for generation redispatch were found because of sixteen contingencies. For these contingencies, the governor would need to take action to increase the generation and prevent frequency collapse in the area that became short in generation or reduce it in the area with excess to prevent over-frequency in the island.

In Table 14-48 we provide the results of this analysis and in addition to the frequency increase in the area that lost the generation, we also provide an estimation of the drop in frequency in that area assuming a uniform droop of 5%, the generation decrease in the area that loss the load as well as the delta that can be thought as the change in the losses. We note that the drop in frequency can be substantial in some cases, and this is the final steady state value, thus the frequency can transiently go much lower and perhaps triggering some load shed as discussed later in this document in the stability section.

The first 3 contingencies in Table 14-48 (sequence # 1 to 3) and contingencies sequence # 15 and 16 separates BEL from Mexico, but the impacts are small as in this daytime case Belize is exporting energy to Mexico.

In the first contingency BEL system is slightly short in generation, as the Mexican Wind generation is also lost and there is the need for a slight increase in the generation and a small drop in frequency is expected. Same situation occurs in the second contingency where the PV at Orange Walk is also separated. On the third contingency the exports to Mexico are dropped and BEL generation needs to reduce, and the Mexican generation increase. The drop in frequency would be negligible as the generation shortage occurs in Mexico.

A critical need for generation increase occurs when the contingency isolates the south portions of the network, which include Savannah, Independence, Punta Gorda (#4, 5, 6, & 9). Note also that contingency 4 considers the system in its current design and contingencies 5 and 6 model a new switching substation at BAPCOL tap (where the line from the BAPCOL plant meets the line Dangriga – Savannah), this is equivalent of bringing the lines to BAPCOL as it is currently the plan. In all these contingencies the critical element is the separation of the load in the south and mostly at Independence, which requires the battery to move from fully charging to fully discharging. In this case a large drop in frequency is expected and it is likely to be more as shown in the stability section of this report. The value reported in the table can be considered optimist as it assumed that:

1. As the RICE is off during daytime, the battery would be able to supply the entire peak load of 13.7 MW, provided that the DG supplies about 3.7 MW.
2. The battery has grid forming capability to generate 60 Hz and have a droop of about 1% to prevent extreme frequency drop and a collapse.

An alternative to the situation above, is to run the RICE unit at its minimum capacity, during high load days like the one modelled. This is the recommendation of the stability study.

The largest frequency drop occurs for the contingencies that form an island to the west isolating hydro generation with load (#7 and 8) as the hydro generation needs to increase significantly. Also, as will be shown later as the governor of these units is slow a larger frequency drop is expected.

On Table 14-49 to Table 14-61, details on the redispatch for each contingency is provided by contingency sequence number. These contingencies are verified in stability to confirm that the frequency will recover, and no collapse occurs.

Table 14-46: Contingencies resulting in thermal overloads.

Opened Facility	Monitored element (Worst overload)	Overload before corrective actions (%)	Initial Load Shed	Note or corrective actions
BUS 2390 [115-LADMRCIA115.00] TO BUS 2391 [69-LADMRCIA 69.000] TO BUS 2563 [22-LADMRCIA 22.000] CKT 1 Or BUS 2391 [69-LADMRCIA 69.000] TO BUS 2403 [69-MULRIVER 69.000] CKT 1	2405 115-DANGRG-1115.00 3WNDTR WND 1 1	126.31	0	Increase Independence Battery from -10 to 0 MW to address the overload
BUS 2404 [69-DANGRG-1 69.000] TO BUS 2405 [115-DANGRG-1115.00] TO BUS 2505 [13.8-LAD-GRD13.800] CKT 1	2390 115-LADMRCIA115.00 3WNDTR TXF-DEM WND 1 1	154.24	0	Increase Independence Battery from -10 to 0 MW to address the overload
OPEN LINE FROM BUS 2467 [69-INDPNC_TX69.000] TO BUS 2468 [24.9-INDPDNC24.900] CKT 1	2467 69-INDPNC_TX69.000 2468 24.9-INDPDNC24.900 N1	105.57	0	Increase Independence Battery from -10 to -9 MW to address the overload
OPEN LINE FROM BUS 2467 [69-INDPNC_TX69.000] TO BUS 2468 [24.9-INDPDNC24.900] CKT 1	2467 69-INDPNC_TX69.000 2468 24.9-INDPDNC24.900 N2	105.57	0	Increase Independence Battery from -10 to -9 MW to address the overload
BUS 2642 [115-MASKALL 115.00] TO BUS 2727 [34.5-MASKALL34.500] CKT 1 Or OPEN LINE FROM BUS 2727 [34.5-MASKALL34.500] TO BUS 2738 [34.5-SANPDRO34.500] CKT 1	2642 115-MASKALL 115.00 2728 69-MASKALL 69.000 N1	104.6		Increase San Pedro Battery from -10 to -9 MW to address the overload
BUS 2642 [115-MASKALL 115.00] TO BUS 2727 [34.5-MASKALL34.500] CKT 1 Or OPEN LINE FROM BUS 2727 [34.5-MASKALL34.500] TO BUS 2738 [34.5-SANPDRO34.500] CKT 1	2728 69-MASKALL 69.000 2739 69-SANPDRO 69.000 N1	101.95	0	Increase San Pedro Battery from -10 to -9 MW to address the overload

Table 14-47: Contingencies resulting in load shed

Seq	Opened Facility	Initial Load Shed	Note or corrective actions
1	BUS 502 [22-LDV-F1 22.000] TO BUS 2324 [22-LADYVILLE22.000] CKT @1	4.53	Transfer load to Palloti and Belize II
2	BUS 701 [22-PALLOTI 22.000] TO BUS 2788 [22-BELIZE-2 22.000] CKT N1	6.48	Transfer load from 6.6-BELIZE_B to 6.6-BELIZE (Belize I)
3	BUS 801 [22-BANAK 22.000] TO BUS 2788 [22-BELIZE-2 22.000] CKT 1	5.9	Transfer load from 6.6-BELIZE_A to 6.6-BELIZE (Belize I)
4	BUS 2738 [34.5-SANPDRO34.500] TO BUS 2838 [34.5-CAYCLKR34.500] CKT N1	3.29	Accept load shed
5	BUS 2785 [115-BELIZE 115.00] TO BUS 2787 [115-BELIZE-2115.00] CKT 3	-2.3	Transfer load from 6.6-BELIZE to 22-BELIZE-2 (Belize II via Banak and Palloti)

Table 14-48: Contingencies resulting in formation of electrical islands but no-load shed.

Seq	Opened Facility	Total Generation Increase MW	Total Generation Decrease MW	Delta Generation MW	Area with Gen. Increase Freq. Drop Hz	Note or corrective actions
1	BUS 202 [115-CHANCHEN115.00] TO BUS 303 [VTSCRBE 115.00] CKT 1	10.9	12	-1.1	0.60	Table 14-49
2	BUS 202 [115-CHANCHEN115.00] TO BUS 2725 [115-BELCOGEN115.00] CKT 1	21.2	22.8	-1.6	1.17	Table 14-50
3	BUS 303 [VTSCRBE 115.00] TO BUS 2694 [115-XULHA 115.00] CKT 1	18	16.9	1.1	N/A	Table 14-51
4	DANGRIGA BAPCOL SAVANNAH	21.6	23.6	-2.0	1.04	Table 14-52
5	BUS 401 [69-DANGRG-2 69.000] TO BUS 2406 [69-BALTAP 69.000] CKT 1	21.6	23.6	-2.0	1.04	Table 14-53
6	BUS 2406 [69-BALTAP 69.000] TO BUS 2407 [69-SAVANNAH 69.000] CKT 1	21.6	23.4	-1.8	1.04	Table 14-54
7	BUS 2389 [115-WEST-W 115.00] TO BUS 2390 [115-LADMRCIA115.00] CKT 1	17.5	19.4	-1.9	2.15	Table 14-55
8	CAMALOTE SANTANDER LA DEMOCRACIA	15.6	16.5	-0.9	2.19	Table 14-56
9	BUS 2407 [69-SAVANNAH 69.000] TO BUS 2466 [69-INDEPNDNC69.000] CKT 1	20.3	22.5	-2.2	1.22	Table 14-57
10	BUS 2466 [69-INDEPNDNC69.000] TO BUS 2467 [69-INDPNC_TX69.000] CKT @1	20.3	22.5	-2.2	1.22	Table 14-57
11	BUS 2564 [115-CAMALOTE115.00] TO BUS 2565 [115-SANIGNC 115.00] CKT 1	4.5	4.6	-0.1	0.15	Table 14-58
12	MOLLEJON VACA SAN INGNACIO	5.8	6.3	-0.5	0.41	Table 14-59
13	BUS 2580 [115-VACATAP 115.00] TO BUS 2594 [115-VACA 115.00] CKT 2	5.8	6.3	-0.5	0.41	Table 14-59
14	BUS 2581 [115-MOLLEJON115.00] TO BUS 2582 [115-CHALILLO115.00] CKT 2	5.8	6.3	-0.5	0.41	Table 14-59
15	BUS 2642 [115-MASKALL 115.00] TO BUS 2648 [115-WST2MSK 115.00] CKT 1	2.7	3	-0.3	0.24	Table 14-60
16	BUS 2642 [115-MASKALL 115.00] TO BUS 2725 [115-BELCOGEN115.00] CKT 1	16.4	18.2	-1.8	1.11	Table 14-61

Table 14-49: Islanding Contingency Seq. 1 CHAN CHEN TO VTSCRBE

Generator	Initial		Post Contingency		Change
	MW	MVAr	MW	MVAr	
[22-LDV-BAT2322.000]	-10	1.2	-7.7	0.8	23%
[22-IND-BAT2322.000]	-10	4.8	-7.7	4.8	23%
[22-SNP-BAT2322.000]	-10	4.8	-7.7	4.8	23%
[22-OW-BAT23 22.000]	-10	0.1	-7.7	-0.1	23%
[6.9_MOLLEJON6.9000]	4.2	-1.4	5.2	-2.4	24%
[6.9_CHALLILO6.9000]	1.8	2	2.2	2	22%
[4.16-HYDROMY4.1600]	1.2	2	1.5	1.2	25%
[22-LDV-PV26 22.000]	16	0.4	14.8	0.1	-8%
[115-XULHA 115.00]	-17	4.2	-27.8	2.9	-64%
Total Increase MW	10.9				
Total Decrease MW	12				
Net Change MW	-1.1				
Freq Drop Hz.	0.60	Hz			

Table 14-50: Islanding Contingency Seq. 2 CHAN CHEN1 TO BELCOGEN

Generator	Initial		Post Contingency		Change
	MW	MVAr	MW	MVAr	
[22-LDV-BAT2322.000]	-10	1.2	-5.5	0.4	45%
[22-IND-BAT2322.000]	-10	4.8	-5.5	3.8	45%
[22-SNP-BAT2322.000]	-10	4.8	-5.5	4.2	45%
[22-OW-BAT23 22.000]	-10	1.2	-5.5	0.3	45%
[6.9_MOLLEJON6.9000]	4.2	-2	6.1	-3.7	45%
[6.9_CHALLILO6.9000]	1.8	2	2.5	1.9	39%
[4.16-HYDROMY4.1600]	1.2	1.9	1.8	0.8	50%
[22-LDV-PV26 22.000]	16	0.4	14.3	-0.4	-11%
[115-XULHA 115.00]	-17	4.5	-38.1	10.8	-124%
Total Increase MW	21.2				
Total Decrease MW	22.8				
Net Change MW	-1.6				
Freq Drop Hz.	1.17	Hz			

Table 14-51: Islanding Contingency Seq. 3 VTSCRBE TO XULHA

Generator	Initial		Post Contingency		Change
	MW	MVAr	MW	MVAr	
[115-XULHA 115.00]	-17	4.5	0	0	100%
[34.5-VTSCRBE34.500]	28	-0.7	29	1.2	4%
[4.16-HYDROMY4.1600]	1.2	1.9	1	2	-17%
[6.9_CHALLILO6.9000]	1.8	2	1.3	2	-28%
[6.9_MOLLEJON6.9000]	4.2	-2	3.2	-0.9	-24%
[22-LDV-PV26 22.000]	16	0.4	14.1	0.9	-12%
[22-WST-PV33 22.000]	16	-6.6	14.1	-6.6	-12%
[22-WST-PV37 22.000]	16	-6.6	14.1	-6.6	-12%
[22-LD-PV40 22.000]	16	2.2	14.1	2.8	-12%
[22-LD-PV42 22.000]	16	-2.2	14.1	-1.3	-12%
[22-MSK-PV27 22.000]	16	-1.6	14.1	-0.1	-12%
[22-CHA-PV-2922.000]	16	-6.6	14.1	-6.6	-12%
[22-OW-PV29 22.000]	16	2.2	14.1	2.8	-12%

Total Increase MW	18	
Total Decrease MW	16.9	
Net Change MW	1.1	
Freq Drop Hz.	0.40	Hz

Table 14-52: Islanding Contingency Seq. 4: DANGRIGA BAPCOL SAVANNAH

Generator	Initial		Post Contingency		Change
	MW	MVAr	MW	MVAr	
[22-IND-BAT2322.000]	-10	4.8	10.3	1.5	203%
[4.16-HYDROMY4.1600]	1.2	1.5	2.5	0.3	108%
[6.9_CHALLILO6.9000]	1.8	2	1.2	2	-33%
[115-XULHA 115.00]	-17	4.5	-17.8	4.5	-5%
[6.9_MOLLEJON6.9000]	4.2	-1.9	2.8	-3.7	-33%
[22-LDV-PV26 22.000]	16	0.4	13.4	1.2	-16%
[22-WST-PV33 22.000]	16	-6.6	13.4	-6.6	-16%
[22-WST-PV37 22.000]	16	-6.6	13.4	-6.6	-16%
[22-LD-PV40 22.000]	16	2.2	13.4	2.4	-16%
[22-LD-PV42 22.000]	16	-2.1	13.4	-4.9	-16%
[22-MSK-PV27 22.000]	16	-1.5	13.4	-2.4	-16%
[22-CHA-PV-2922.000]	16	-6.6	13.4	-6.6	-16%
[22-OW-PV29 22.000]	16	2.2	13.4	2.4	-16%

Total Increase MW	21.6		
Total Decrease MW	23.6		
Net Change MW	-2.0		
Freq Drop Hz.	1.04	Hz	*Droop changed to 1%

*Note:

1. If the RICE is off during daytime, the battery would be almost enough to supply the entire peak load of 13.7 MW, provided that the DG supplies about 3.4 MW
2. In the situation above, the battery must have grid forming capability to generate 60 Hz and have a droop of about 1% to prevent large frequency drops.
3. An alternative to the situation above, is to run the RICE unit at its minimum capacity, during high load days like the one modelled.

Table 14-53: Islanding Contingency Seq. 5 DANGRG TO BALTAP

Generator	Initial		Post Contingency		Change
	MW	MVAr	MW	MVAr	
[22-IND-BAT2322.000]	-10	4.8	10.3	1	203%
[4.16-HYDROMY4.1600]	1.2	1.9	2.5	0.1	108%
[6.9_CHALLILO6.9000]	1.8	2	1.2	2	-33%
[115-XULHA 115.00]	-17	4.5	-17.8	4.5	-5%
[6.9_MOLLEJON6.9000]	4.2	-2	2.8	-3.7	-33%
[22-LDV-PV26 22.000]	16	0.4	13.4	1.2	-16%
[22-WST-PV33 22.000]	16	-6.6	13.4	-6.6	-16%
[22-WST-PV37 22.000]	16	-6.6	13.4	-6.6	-16%
[22-LD-PV40 22.000]	16	2.2	13.4	2.4	-16%
[22-LD-PV42 22.000]	16	-2.2	13.4	-4.9	-16%
[22-MSK-PV27 22.000]	16	-1.6	13.4	-2.4	-16%
[22-CHA-PV-2922.000]	16	-6.6	13.4	-6.6	-16%
[22-OW-PV29 22.000]	16	2.2	13.4	2.4	-16%
Total Increase MW	21.6				
Total Decrease MW	23.6				
Net Change MW	-2.0				
Freq Drop Hz.	1.04	Hz	*Droop changed to 1%		

Table 14-54: Islanding Contingency Seq. 6 BALTAP TO -SAVANNAH

Generator	Initial		Post Contingency		Change
	MW	MVAr	MW	MVAr	
[22-IND-BAT2322.000]	-10	4.8	10.3	1.5	203%
[4.16-HYDROMY4.1600]	1.2	1.9	2.5	0.3	108%
[6.9_CHALLILO6.9000]	1.8	2	1.2	1.9	-33%
[6.9_MOLLEJON6.9000]	4.2	-2	2.9	-3.7	-31%
[115-XULHA 115.00]	-17	4.5	-18.5	4.5	-9%
[22-LDV-PV26 22.000]	16	0.4	13.5	1.2	-16%
[22-WST-PV33 22.000]	16	-6.6	13.5	-6.6	-16%
[22-WST-PV37 22.000]	16	-6.6	13.5	-6.6	-16%
[22-LD-PV40 22.000]	16	2.2	13.5	2.3	-16%
[22-LD-PV42 22.000]	16	-2.2	13.5	-5.5	-16%
[22-MSK-PV27 22.000]	16	-1.6	13.5	-2.6	-16%
[22-CHA-PV-2922.000]	16	-6.6	13.5	-6.6	-16%
[22-OW-PV29 22.000]	16	2.2	13.5	2.3	-16%
Total Increase MW	21.6				
Total Decrease MW	23.4				
Net Change MW	-1.8				
Freq Drop Hz.	1.04	Hz	*Droop changed to 1%		

*Note:
1. If the RICE is off during daytime, the battery would be almost enough to supply the entire peak load of 13.7 MW, provided that the DG supplies about 3.4 MW
2. In the situation above, the battery must have grid forming capability to generate 60 Hz and have a droop of about 1% to prevent large frequency drops.
3. An alternative to the situation above, is to run the RICE unit at its minimum capacity, during high load days like the one modelled.

Table 14-55: Islanding Contingency Seq.7 WEST TO LADMRCIA

Generator	Initial		Post Contingency		Change
	MW	MVAr	MW	MVAr	

[22-IND-BAT2322.000]	-10	4.8	0.3	1.9	103%
[6.9_MOLLEJON6.9000]	4.2	-1.4	8.4	-3.6	100%
[6.9_CHALLILO6.9000]	1.8	2	3.5	2	94%
[4.16-HYDROMY4.1600]	1.2	2	2.5	0.3	108%
[22-LD-PV40 22.000]	16	-0.1	14.6	-2.6	-9%
[22-LDV-PV26 22.000]	16	0.4	13	1.2	-19%
[22-WST-PV33 22.000]	16	-6.6	13	-6.6	-19%
[22-WST-PV37 22.000]	16	-6.6	13	-6.6	-19%
[22-MSK-PV27 22.000]	16	-1.7	13	-0.7	-19%
[22-CHA-PV-2922.000]	16	-6.6	13	-6.6	-19%
[22-OW-PV29 22.000]	16	-0.1	13	0.4	-19%

Total Increase MW	17.5	
Total Decrease MW	19.4	
Net Change MW	-1.9	
Freq Drop Hz.	2.15	Hz

Table 14-56: Islanding Contingency Seq. 8 CAMALOTE SANTANDER LA DEMOCRACIA

Generator	Initial		Post Contingency		Change
	MW	MVAr	MW	MVAr	
[6.9_VACA 6.9000]	0	0	9.7	-0.3	999%
[6.9_MOLLEJON6.9000]	4.2	-1.9	8.4	-2.4	100%
[6.9_CHALLILO6.9000]	1.8	2	3.5	2	94%
[115-XULHA 115.00]	-17	4.5	-17.1	4.7	-1%
[4.16-HYDROMY4.1600]	1.2	1.5	0.9	1.9	-25%
[22-LDV-PV26 22.000]	16	0.4	13.7	1.1	-14%
[22-WST-PV33 22.000]	16	-6.6	13.7	-6.6	-14%
[22-WST-PV37 22.000]	16	-6.6	13.7	-6.6	-14%
[22-LD-PV40 22.000]	16	2.2	13.7	2.4	-14%
[22-LD-PV42 22.000]	16	-2.1	13.7	-2.9	-14%
[22-MSK-PV27 22.000]	16	-1.5	13.7	-1.6	-14%
[22-CHA-PV-2922.000]	16	-6.6	13.7	-6.6	-14%

Total Increase MW	15.6	
Total Decrease MW	16.5	
Net Change MW	-0.9	
Freq Drop Hz.	2.19	Hz

Table 14-57: Islanding Contingency Seq 9 & 10 SAVANNAH - INDEPNDNC69 -INDPNC_TX

Generator	Initial		Post Contingency		Change
	MW	MVAr	MW	MVAr	
[22-IND-BAT2322.000]	-10	4.8	10.3	2.8	203%
[4.16-HYDROMY4.1600]	1.2	1.9	0.9	-0.7	-25%
[6.9_CHALLILO6.9000]	1.8	2	1.2	1.6	-33%
[6.9_MOLLEJON6.9000]	4.2	-2	3	-3.7	-29%
[115-XULHA 115.00]	-17	4.5	-19	4.6	-12%
[22-LDV-PV26 22.000]	16	0.4	13.7	1.1	-14%
[22-WST-PV33 22.000]	16	-6.6	13.7	-6.6	-14%
[22-WST-PV37 22.000]	16	-6.6	13.7	-6.6	-14%
[22-LD-PV40 22.000]	16	2.2	13.7	2.3	-14%
[22-LD-PV42 22.000]	16	-2.2	13.7	-5.8	-14%
[22-MSK-PV27 22.000]	16	-1.6	13.7	-2.7	-14%
[22-CHA-PV-2922.000]	16	-6.6	13.7	-6.6	-14%
[22-OW-PV29 22.000]	16	2.2	13.7	2.3	-14%

Total Increase MW	20.3		
Total Decrease MW	22.5		
Net Change MW	-2.2		
Freq Drop Hz.	1.22	Hz	*Droop changed to 1%

Table 14-58: Islanding Contingency Seq. 11 CAMALOTE115.00] TO SANIGNC

Generator	Initial		Post Contingency		Change
	MW	MVAr	MW	MVAr	
[6.9_MOLLEJON6.9000]	4.2	-1.4	7.4	-0.8	76%
[6.9_CHALLILO6.9000]	1.8	2	3.1	-0.3	72%
[115-XULHA 115.00]	-17	4.2	-21.6	5.5	-27%

Total Increase MW	4.5	
Total Decrease MW	4.6	
Net Change MW	-0.1	
Freq Drop Hz.	0.15	Hz

*Note:

1. If the RICE is off during daytime, the battery would be almost enough to supply the entire peak load of 13.7 MW, provided that the DG supplies about 3.4 MW
2. In the situation above, the battery must have grid forming capability to generate 60 Hz and have a droop of about 1% to prevent large frequency drops.
3. An alternative to the situation above, is to run the RICE unit at its minimum capacity, during high load days like the one modelled.

Table 14-59: Islanding Contingency Seq.12, 13 & 14 MOLLEJON VACA SAN INGNACIO

Generator	Initial		Post Contingency		Change
	MW	MVAr	MW	MVAr	
[22-LDV-BAT2322.000]	-10	1.2	-8.6	1	14%
[22-IND-BAT2322.000]	-10	4.8	-8.6	4.8	14%
[22-SNP-BAT2322.000]	-10	4.8	-8.6	4.8	14%
[22-OW-BAT23 22.000]	-10	1.2	-8.6	0.9	14%
[4.16-HYDROMY4.1600]	1.2	1.5	1.4	1.7	17%
[115-XULHA 115.00]	-17	4.5	-17.4	4.7	-2%
[6.9_MOLLEJON6.9000]	4.2	-1.9	-1.7	-0.7	-140%

Total Increase MW	5.8	
Total Decrease MW	6.3	
Net Change MW	-0.5	
Freq Drop Hz.	0.41	Hz

Table 14-60: Islanding Contingency Seq. 15 MASKALL TO BELCOGEN

Generator	Initial		Post Contingency		Change
	MW	MVAr	MW	MVAr	
[22-LDV-BAT2322.000]	-10	1.2	-5.6	0.3	44%
[22-IND-BAT2322.000]	-10	4.8	-5.6	3.7	44%
[22-SNP-BAT2322.000]	-10	4.8	-5.6	4.1	44%
[6.9_MOLLEJON6.9000]	4.2	-2	6.1	-3.7	45%
[6.9_CHALLILO6.9000]	1.8	2	2.5	1.3	39%
[4.16-HYDROMY4.1600]	1.2	1.9	1.8	0.7	50%
[22-LDV-PV26 22.000]	16	0.4	14.4	-0.5	-10%
[22-CHA-PV-2922.000]	16	-6.6	7.7	-6.6	-52%
[22-OW-PV29 22.000]	16	2.2	7.7	3.6	-52%

Total Increase MW	16.4	
Total Decrease MW	18.2	
Net Change MW	-1.8	
Freq Drop Hz.	1.11	Hz

Table 14-61: Islanding Contingency Seq 16 MASKALL TO WST2MSK (New Switching for Belize II)

Generator	Initial		Post Contingency		Change
	MW	MVAr	MW	MVAr	
[22-LDV-BAT2322.000]	-10	1.2	-9	1	10%
[22-IND-BAT2322.000]	-10	4.8	-9	4.8	10%
[6.9_MOLLEJON6.9000]	4.2	-2	4.6	-3.7	10%
[6.9_CHALLILO6.9000]	1.8	2	1.9	2	6%
[4.16-HYDROMY4.1600]	1.2	1.9	1.4	1.4	17%
[22-LDV-PV26 22.000]	16	0.4	15.7	0.2	-2%
[22-MSK-PV27 22.000]	16	-1.6	15.1	0.3	-6%
[22-CHA-PV-2922.000]	16	-6.6	15.1	-6.6	-6%
[22-OW-PV29 22.000]	16	2.2	15.1	2.6	-6%

Total Increase MW	2.7	
Total Decrease MW	3	
Net Change MW	-0.3	
Freq Drop Hz.	0.24	Hz

14.8 Contingency Analysis for the 2042 Night Peak Conditions. Secure Case

The reinforced system as described above was subject to a contingency analysis (N-1) to identify any remaining overloads and/or voltage violations for the night peak and the Max Security case. The analysis considered the formation of electrical islands and after dispatching the online generation to its max (for thermal and hydro) identified any remaining load shed. We present below the results of the study. The dispatch analyzed was as presented in Table 14-9.

In the following sections, the contingency analysis for daytime and the Max Economy is provided.

14.8.1 Contingency with potential overloads

Three contingencies were identified as resulting in potential overloads (see Table 14-62). The first contingency is the outage of the Battery storage at Ladyville that is dispatched at 5 MW. In this case the 22 kV line from Westlake would see a small overload and this can be addressed by transferring part of the load to Belize II via the proposed 22 kV line.

The remaining contingencies result in the outage of the new 69 kV link to San Pedro overloading the existing 34.5 kV system. These overloads are addressed by increasing the dispatch of the battery. Note that possibly a Remedial Action Scheme will need to be put in place to rapidly discharge the battery in the event of an outage.

14.8.2 Contingency with potential load shed

Thirteen contingencies were identified as resulting with potential load shed (see Table **14-63**).

The first contingency is the outage of the single supply to Orange Walk that as we showed earlier depending on time can result in load shed. The reported value assumes peak load and the storage dispatching at 10 MW (no PV as this was night conditions).

Contingencies with sequence # 2 to 4 are faults associated with feeders from Ladyville and Belize I and II and can be addressed by transferring loads between these substations.

Contingencies 5 and 6 result in the interruption of the connection from Ladyville to Westlake and it is addressed by using the storage and connecting Ladyville to Belize II.

Contingencies 7 to 11 result in smaller load shed and it is accepted.

Contingency 12 is the loss of the 115 kV supply to Belize I and is addressed by transferring load to Belize II via Banak and Palloti.

14.8.3 Contingency with important generation islanding

Sixteen contingencies were identified as resulting is the creation of electrical islands and need for significant generation redispatch, i.e., need for governor action to increase the generation and prevent frequency collapse in the electrical island (see Table 14-64).

As can be observed in Table 14-64 the first 3 contingencies (sequence # 1 to 3) and contingencies sequence # 15 and 16 that imply separation from Mexico result in the greatest need for increase of generation in Belize (except #15). In this table we provide, in addition to the required generation increase, an estimation of the drop in frequency in the area that required the generation increase assuming a uniform droop of 5%, the generation decrease in the area that loss the load (Mexico and northern part of BEL system in this case) as well as the delta that can be thought as the change in the losses. We note that the drop in frequency can be substantial (1.73 Hz), and this is the final steady state value, thus the frequency can transiently go much lower and perhaps triggering some load shed as discussed later in this document in the stability section.

We also note that losses were reduced in these events that cut the supply from Mexico.

The next largest need for increase occurs when the contingency isolates the hydro generation to the west (#7, 8,11,12,13 & 14) but in this case the bulk of the BEL system remains connected to Mexico and the expected drop in frequency in the island short of generation is relatively small (0.7 Hz max for # 12 that separates the hydro generation and leaves all the load connected to the balance of internal generation and Mexico).

Finally, contingencies # 4,5,6, 9 & 10 consider outages affecting the load to the south of the system and we note that as the isolated areas are limited in generation there is potential for large drops in frequency (1.65 Hz max). Note also that contingency 4 considers the system in its current design and contingencies 5 and 6 consider that there is a new switching substation at BAPCOL tap (where the line from the BAPCOL plant meets the line Dangriga – Savannah). This is exactly equivalent to the now proposed project that will bring the lines to BAPCOL.

In tables 7-32 to 7-44 we provide details on the redispatch for each contingency in by sequence number.

These contingencies are verified in stability to confirm that the frequency will recover, and no collapse occurs.

Table 14-62: Contingencies resulting in thermal overloads.

Opened Facility	Monitored element (Worst overload)	Overload before corrective actions (%)	Initial Load Shed	Note or corrective actions
BUS 2324 [22-LADYVILLE22.000] TO BUS 2334 [22-LDV-BAT2322.000] CKT 1	2323 22-WST-LDV 22.000 2324 22-LADYVILLE22.000 2	103.85	0	Transfer load from 22-LDV-F1 to Belize II
BUS 2642 [115-MASKALL 115.00] TO BUS 2728 [69-MASKALL 69.000] CKT N1	2642 115-MASKALL 115.00 2727 34.5-MASKALL34.500 1	128.06	0	Increase San Pedro Battery from 5 to 10 MW to address the overload
BUS 2728 [69-MASKALL 69.000] TO BUS 2739 [69-SANPDRO 69.000] CKT N1	2642 115-MASKALL 115.00 2727 34.5-MASKALL34.500 1	143.99	0	Increase San Pedro Battery from 5 to 10 MW to address the overload
BUS 2738 [34.5-SANPDRO34.500] TO BUS 2739 [69-SANPDRO 69.000] CKT N1	2642 115-MASKALL 115.00 2727 34.5-MASKALL34.500 1	140.3	0	Increase San Pedro Battery from 5 to 10 MW to address the overload

Table 14-63: Contingencies resulting in load shed

Seq	Opened Facility	Initial Load Shed	Note or corrective actions
1	BUS 203 [34.5-BELCOGE34.500] TO BUS 2705 [34.5-OWK 34.500] CKT 1	7.71	Storage partially addresses it
2	BUS 502 [22-LDV-F1 22.000] TO BUS 2324 [22-LADYVILLE22.000] CKT @1	4.6	Transfer load to Palloti and Belize II
3	BUS 701 [22-PALLOTI 22.000] TO BUS 2788 [22-BELIZE-2 22.000] CKT N1	5.34	Transfer load from 6.6-BELIZE_B to 6.6-BELIZE (Belize I)
4	BUS 801 [22-BANAK 22.000] TO BUS 2788 [22-BELIZE-2 22.000] CKT 1	4.86	Transfer load from 6.6-BELIZE_A to 6.6-BELIZE (Belize I)
5	BUS 2322 [115-WST-LDV 115.00] TO BUS 2323 [22-WST-LDV 22.000] CKT 1	5.47	Same solution as below
6	BUS 2323 [22-WST-LDV 22.000] TO BUS 2324 [22-LADYVILLE22.000] CKT 2	5.24	Transfer load from 22-LADYVILLE to 22-BELIZE-2, via Palloti as battery alone is not enough
7	BUS 2403 [69-MULRIVER 69.000] TO BUS 2561 [24.9-MULRIVE24.900] CKT 1	0.14	OK just report
8	BUS 2407 [69-SAVANNAH 69.000] TO BUS 2417 [69-PUNTAGORD69.000] CKT 1	1.74	Load shed after Hydro Maya goes to max
9	BUS 2417 [69-PUNTAGORD69.000] TO BUS 2418 [PG_TX_HS 69.000] CKT @1	1.74	Load shed after Hydro Maya goes to max
10	BUS 2418 [PG_TX_HS 69.000] TO BUS 2419 [24.9-PUNTGRD24.900] CKT 1	1.74	Load shed after Hydro Maya goes to max
11	BUS 2738 [34.5-SANPDRO34.500] TO BUS 2838 [34.5-CAYCLKR34.500] CKT N1	3.19	Accept load shed
12	BUS 2785 [115-BELIZE 115.00] TO BUS 2787 [115-BELIZE-2115.00] CKT 3	7.68	Transfer load from 6.6-BELIZE to 22-BELIZE-2 (Belize II via Banak and Palloti)

Table 14-64: Contingencies resulting in formation of electrical islands but no-load shed.

Seq	Opened Facility	Total Generation Increase MW	Total Generation Decrease MW	Delta Generation MW	F Area with Gen. Increase req. Drop Hz	Note or corrective actions
1	BUS 202 [115-CHANCHEN115.00] TO BUS 303 [VTSCRBE 115.00] CKT 1	83.6	87.6	-4.0	1.73	Table 14-65
2	BUS 202 [115-CHANCHEN115.00] TO BUS 2725 [115-BELCOGEN115.00] CKT 1	71.9	76.8	-4.9	1.49	Table 14-66
3	BUS 303 [VTSCRBE 115.00] TO BUS 2694 [115-XULHA 115.00] CKT 1	54.5	59.8	-5.3	1.13	Table 14-67
4	DANGRIGA BAPCOL SAVANNAH	11.0	12.1	-1.1	1.65	Table 14-68
5	BUS 401 [69-DANGRG-2 69.000] TO BUS 2406 [69-BALTAP 69.000] CKT 1	7.4	8.4	-1.0	0.52	Table 14-69
6	BUS 2406 [69-BALTAP 69.000] TO BUS 2407 [69-SAVANNAH 69.000] CKT 1	11.0	12.1	-1.1	1.65	Table 14-70
7	BUS 2389 [115-WEST-W 115.00] TO BUS 2390 [115-LADMRCIA115.00] CKT 1	6.9	7.5	-0.6	0.29	Table 14-71
8	CAMALOTE SANTANDER LA DEMOCRACIA	11.5	10.9	0.6	0.15	Table 14-72
9	BUS 2407 [69-SAVANNAH 69.000] TO BUS 2466 [69-INDEPNDNC69.000] CKT 1	8.9	9.9	-1.0	1.53	Table 14-73
10	BUS 2466 [69-INDEPNDNC69.000] TO BUS 2467 [69-INDPNC_TX69.000] CKT @1	8.9	9.9	-1.0	1.53	Table 14-73
11	BUS 2564 [115-CAMALOTE115.00] TO BUS 2565 [115-SANIGNC 115.00] CKT 1	32.3	29.9	2.4	0.43	Table 14-74
12	MOLLEJON VACA SAN INGNACIO	52.0	46.1	5.9	0.70	Table 14-75
13	BUS 2580 [115-VACATAP 115.00] TO BUS 2594 [115-VACA 115.00] CKT 2	52.0	46.1	5.9	0.70	Table 14-75
14	BUS 2581 [115-MOLLEJON115.00] TO BUS 2582 [115-CHALILLO115.00] CKT 2	46.1	5.9	0.70	46.1	Table 14-75
15	BUS 2642 [115-MASKALL 115.00] TO BUS 2648 [115-WST2MSK 115.00] CKT 1	43.6	-3.6	1.07	43.6	Table 14-77
16	BUS 2642 [115-MASKALL 115.00] TO BUS 2725 [115-BELCOGEN115.00] CKT 1	66.6	-4.8	1.52	66.6	Table 14-77

Table 14-65: Islanding Contingency Seq. 1 CHAN CHEN TO VTSCRBE

Generator	Initial		Post Contingency		Change
	MW	MVAr	MW	MVAr	
[13.8-GT-LM 13.800]	6.2	0.7	23.9	-1.8	285%
[13.8-2/3RICE13.800]	2.4	0.7	12.9	0.4	438%
[13.8_BELCOGE13.800]	3.1	1	11.9	-0.4	284%
[13.8-1/3RICE13.800]	1.2	1.6	6.5	0.4	442%
[BAL-G3-13.8 13.800]	1.2	0.2	6.5	-0.3	442%
[BAL-G1-13.8 13.800]	1.2	0.2	6.5	-0.3	442%
[BAL-G2-13.8 13.800]	1.2	0.2	6.5	-0.3	442%
[22-LDV-BAT2322.000]	5	3.9	10	2.1	100%
[22-IND-BAT2322.000]	5	1.7	10	0.5	100%
[22-SNP-BAT2322.000]	5	4.8	10	4.3	100%
[22-OW-BAT23 22.000]	5	2.8	10	1.2	100%
[6.9_MOLLEJON6.9000]	22.7	-0.3	25.2	-0.9	11%
[6.9_VACA 6.9000]	17.1	1.2	19	0.2	11%
[6.9_CHALLILO6.9000]	6.3	0.2	7	-0.3	11%
[4.16-HYDROMY4.1600]	2.2	0.3	2.5	0	14%
[115-XULHA 115.00]	59.8	-5.2	-27.8	2.9	-146%

Total Increase MW	83.6
Total Decrease MW	87.6
Freq Drop Hz.	1.73

Table 14-66: Islanding Contingency Seq. 2 CHAN CHEN1 TO BELCOGEN

Generator	Initial		Post Contingency		Change
	MW	MVAr	MW	MVAr	
[13.8-GT-LM 13.800]	6.2	0.7	21.4	-3.1	245%
[13.8-2/3RICE13.800]	2.4	0.7	10.5	-0.2	338%
[13.8_BELCOGE13.800]	3.1	1	9.9	-1.7	219%
[22-LDV-BAT2322.000]	5	3.9	10	2.2	100%
[22-IND-BAT2322.000]	5	1.7	10	0.5	100%
[22-SNP-BAT2322.000]	5	4.8	10	3.4	100%
[22-OW-BAT23 22.000]	5	2.8	10	0.3	100%
[13.8-1/3RICE13.800]	1.2	1.6	5.3	0.4	342%
[BAL-G3-13.8 13.800]	1.2	0.2	5.3	-0.4	342%
[BAL-G1-13.8 13.800]	1.2	0.2	5.3	-0.4	342%
[BAL-G2-13.8 13.800]	1.2	0.2	5.3	-0.4	342%
[6.9_MOLLEJON6.9000]	22.7	-0.3	25.2	-1.4	11%
[6.9_VACA 6.9000]	17.1	1.2	19	-0.4	11%
[6.9_CHALLILO6.9000]	6.3	0.2	7	-0.3	11%
[4.16-HYDROMY4.1600]	2.2	0.3	2.5	0	14%
[115-XULHA 115.00]	59.8	-5.2	-17	4.2	-128%
Total Increase MW	71.9				
Total Decrease MW	76.8				
Freq Drop Hz.	1.49				

Table 14-67: Islanding Contingency Seq. 3 VTSCRBE TO XULHA

Generator	Initial	Post Contingency	Change

	MW	MVAr	MW	MVAr	
[13.8-GT-LM 13.800]	6.2	0.7	14.1	-3	127%
[13.8-2/3RICE13.800]	2.4	0.7	8.7	-0.4	263%
[13.8_BELCOGE13.800]	3.1	1	8.4	-1.6	171%
[22-LDV-BAT2322.000]	5	3.9	9.2	2.4	84%
[22-IND-BAT2322.000]	5	1.7	9.2	0.6	84%
[22-SNP-BAT2322.000]	5	4.8	9.2	3.8	84%
[22-OW-BAT23 22.000]	5	2.8	9.2	0.4	84%
[13.8-1/3RICE13.800]	1.2	1.6	4.4	0.5	267%
[BAL-G3-13.8 13.800]	1.2	0.2	4.4	-0.4	267%
[BAL-G1-13.8 13.800]	1.2	0.2	4.4	-0.4	267%
[BAL-G2-13.8 13.800]	1.2	0.2	4.4	-0.4	267%
[6.9_MOLLEJON6.9000]	22.7	-0.3	25.2	-1.4	11%
[6.9_VACA 6.9000]	17.1	1.2	19	-0.3	11%
[6.9_CHALLILO6.9000]	6.3	0.2	7	-0.3	11%
[4.16-HYDROMY4.1600]	2.2	0.3	2.5	0	14%
[115-XULHA 115.00]	59.8	-5.2	0	0	-100%
Total Increase MW	54.5				
Total Decrease MW	59.8				
Freq Drop Hz.	1.13				

Table 14-68: Islanding Contingency Seq. 4: DANGRIGA BAPCOL SAVANNAH

Generator	Initial		Post Contingency		Change
	MW	MVAr	MW	MVAr	
[13.8-1/3RICE13.800]	1.2	1.6	6.9	1.2	475%
[22-IND-BAT2322.000]	5	1.7	10	1.4	100%
[4.16-HYDROMY4.1600]	2.2	0.3	2.5	0.2	14%
[6.9_CHALLILO6.9000]	6.3	0.2	6.1	0.3	-3%
[22-LDV-BAT2322.000]	5	4.1	4.7	4.1	-6%
[22-SNP-BAT2322.000]	5	4.8	4.7	4.8	-6%
[22-OW-BAT23 22.000]	5	4.1	4.7	4	-6%
[13.8_BELCOGE13.800]	3.1	1.7	2.7	1.4	-13%
[13.8-2/3RICE13.800]	2.4	0.9	1.9	1.1	-21%
[6.9_VACA 6.9000]	17.1	1.4	16.5	1.2	-4%
[6.9_MOLLEJON6.9000]	22.7	-0.1	21.9	-0.4	-4%
[13.8-GT-LM 13.800]	6.2	1.3	5.2	1	-16%
[BAL-G3-13.8 13.800]	1.2	0.2	-2.4	1.5	-300%
[115-XULHA 115.00]	60.1	-3.5	56	-3.6	-7%
Total Increase MW	11				
Total Decrease MW	12.1				
Freq Drop Hz.	1.65				

Table 14-69: Islanding Contingency Seq. 5 DANGRG TO BALTAP

Generator	Initial		Post Contingency		Change
	MW	MVAr	MW	MVAr	
[22-IND-BAT2322.000]	5	1.7	6.9	1.2	38%
[13.8-1/3RICE13.800]	1.2	1.6	2.5	1.1	108%
[BAL-G3-13.8 13.800]	1.2	0.2	2.5	-0.1	108%
[BAL-G1-13.8 13.800]	1.2	0.2	2.5	-0.1	108%
[BAL-G2-13.8 13.800]	1.2	0.2	2.5	-0.1	108%
[4.16-HYDROMY4.1600]	2.2	0.3	2.5	0.2	14%
[6.9_CHALLILO6.9000]	6.3	0.2	6.1	0.3	-3%
[22-LDV-BAT2322.000]	5	3.9	4.7	3.9	-6%
[22-SNP-BAT2322.000]	5	4.8	4.7	4.8	-6%
[22-OW-BAT23 22.000]	5	2.8	4.7	2.7	-6%

[13.8_BELCOGE13.800]	3.1	1	2.7	0.8	-13%
[13.8-2/3RICE13.800]	2.4	0.7	1.9	0.9	-21%
[6.9_VACA 6.9000]	17.1	1.2	16.5	1	-4%
[6.9_MOLLEJON6.9000]	22.7	-0.3	21.9	-0.6	-4%
[13.8-GT-LM 13.800]	6.2	0.7	5.2	0.5	-16%
[115-XULHA 115.00]	59.8	-5.2	55.8	-5.3	-7%
Total Increase MW	7.4				
Total Decrease MW	8.4				
Freq Drop Hz.	0.52				

Table 14-70: Islanding Contingency Seq. 6 BALTAP TO -SAVANNAH

Generator	Initial		Post Contingency		Change
	MW	MVAr	MW	MVAr	
[13.8-1/3RICE13.800]	1.2	1.6	6.9	1.2	475%
[22-IND-BAT2322.000]	5	1.7	10	1.4	100%
[4.16-HYDROMY4.1600]	2.2	0.3	2.5	0.2	14%
[BAL-G3-13.8 13.800]	1.2	0.2	0.9	-0.1	-25%
[BAL-G1-13.8 13.800]	1.2	0.2	0.9	-0.1	-25%
[BAL-G2-13.8 13.800]	1.2	0.2	0.9	-0.1	-25%
[6.9_CHALLILO6.9000]	6.3	0.2	6	0.4	-5%
[22-LDV-BAT2322.000]	5	3.9	4.6	3.9	-8%
[22-SNP-BAT2322.000]	5	4.8	4.6	4.8	-8%
[22-OW-BAT23 22.000]	5	2.8	4.6	2.6	-8%
[13.8_BELCOGE13.800]	3.1	1	2.6	0.7	-16%
[13.8-2/3RICE13.800]	2.4	0.7	1.8	0.4	-25%
[6.9_VACA 6.9000]	17.1	1.2	16.3	0.8	-5%
[6.9_MOLLEJON6.9000]	22.7	-0.3	21.6	-0.9	-5%
[13.8-GT-LM 13.800]	6.2	0.7	4.9	0.2	-21%
[115-XULHA 115.00]	59.8	-5.2	54.4	-5.4	-9%
Total Increase MW	11				
Total Decrease MW	12.1				
Freq Drop Hz.	1.65				

Table 14-71: Islanding Contingency Seq.7 WEST TO LADMRCIA

Generator	Initial		Post Contingency		Change
	MW	MVAr	MW	MVAr	
[6.9_MOLLEJON6.9000]	22.7	-0.3	24.3	0	7%
[6.9_VACA 6.9000]	17.1	1.2	18.3	1.1	7%
[13.8-2/3RICE13.800]	2.4	0.7	3.3	0.5	38%
[22-IND-BAT2322.000]	5	1.7	5.6	1.5	12%
[13.8-1/3RICE13.800]	1.2	1.6	1.7	1.4	42%
[BAL-G3-13.8 13.800]	1.2	0.2	1.7	0.1	42%
[BAL-G1-13.8 13.800]	1.2	0.2	1.7	0.1	42%
[BAL-G2-13.8 13.800]	1.2	0.2	1.7	0.1	42%
[6.9_CHALLILO6.9000]	6.3	0.2	6.7	-0.2	6%
[4.16-HYDROMY4.1600]	2.2	0.3	2.4	0.3	9%
[22-LDV-BAT2322.000]	5	3.9	4.6	4.2	-8%
[22-SNP-BAT2322.000]	5	4.8	4.6	4.8	-8%
[22-OW-BAT23 22.000]	5	2.8	4.6	2.8	-8%
[13.8_BELCOGE13.800]	3.1	1	2.6	0.9	-16%
[13.8-GT-LM 13.800]	6.2	0.7	5	1.2	-19%
[115-XULHA 115.00]	59.8	-5.2	55.2	-4.9	-8%

Total Increase MW	6.9
Total Decrease MW	7.5
Freq Drop Hz.	0.29

Table 14-72: Islanding Contingency Seq. 8 CAMALOTE SANTANDER LA DEMOCRACIA

Generator	Initial		Post Contingency		Change
	MW	MVAr	MW	MVAr	
[115-XULHA 115.00]	60.1	-3.5	65.5	-3.3	9%
[13.8-GT-LM 13.800]	6.2	1.3	7.6	1.5	23%
[13.8-2/3RICE13.800]	2.4	0.9	3.1	0.7	29%
[13.8_BELCOGE13.800]	3.1	1.7	3.7	1.9	19%
[22-LDV-BAT2322.000]	5	4.1	5.5	4	10%
[22-IND-BAT2322.000]	5	1.7	5.5	1.6	10%
[22-SNP-BAT2322.000]	5	4.8	5.5	4.8	10%
[22-OW-BAT23 22.000]	5	4.1	5.5	4.2	10%
[13.8-1/3RICE13.800]	1.2	1.6	1.5	1.5	25%
[BAL-G3-13.8 13.800]	1.2	0.2	1.5	0.2	25%
[BAL-G1-13.8 13.800]	1.2	0.2	1.5	0.2	25%
[BAL-G2-13.8 13.800]	1.2	0.2	1.5	0.2	25%
[4.16-HYDROMY4.1600]	2.2	0.3	2.4	0.3	9%
[6.9_CHALLILO6.9000]	6.3	0.2	4.9	1.3	-22%
[6.9_VACA 6.9000]	17.1	1.4	13.2	2.9	-23%
[6.9_MOLLEJON6.9000]	22.7	-0.1	17.1	-0.2	-25%
Total Increase MW	11.5				
Total Decrease MW	10.9				
Freq Drop Hz.	0.15				

Table 14-73: Islanding Contingency Seq 9 & 10 SAVANNAH - INDEPNDNC69 -INDPNC_TX

Generator	Initial		Post Contingency		Change
	MW	MVAr	MW	MVAr	
[22-IND-BAT2322.000]	5	1.7	10.1	1.8	102%
[13.8-1/3RICE13.800]	1.2	1.6	5	1.6	317%
[6.9_CHALLILO6.9000]	6.3	0.2	6.1	0.3	-3%
[22-LDV-BAT2322.000]	5	3.9	4.7	3.9	-6%
[BAL-G3-13.8 13.800]	1.2	0.2	0.9	-0.2	-25%
[BAL-G1-13.8 13.800]	1.2	0.2	0.9	-0.2	-25%
[BAL-G2-13.8 13.800]	1.2	0.2	0.9	-0.2	-25%
[22-SNP-BAT2322.000]	5	4.8	4.7	4.8	-6%
[22-OW-BAT23 22.000]	5	2.8	4.7	2.6	-6%
[13.8_BELCOGE13.800]	3.1	1	2.7	0.7	-13%
[13.8-2/3RICE13.800]	2.4	0.7	1.9	0.2	-21%
[6.9_VACA 6.9000]	17.1	1.2	16.5	0.8	-4%
[6.9_MOLLEJON6.9000]	22.7	-0.3	21.8	-0.9	-4%
[13.8-GT-LM 13.800]	6.2	0.7	5.2	0.2	-16%
[115-XULHA 115.00]	59.8	-5.2	55.3	-5.5	-8%
Total Increase MW	8.9				
Total Decrease MW	9.9				
Freq Drop Hz.	1.53				

Table 14-74: Islanding Contingency Seq. 11 CAMALOTE115.00] TO SANIGNC

Generator	Initial		Post Contingency		Change
	MW	MVAr	MW	MVAr	
[115-XULHA 115.00]	59.8	-5.2	75.6	-2.9	26%
[13.8-GT-LM 13.800]	6.2	0.7	10.1	4.3	63%
[13.8-2/3RICE13.800]	2.4	0.7	4.3	1.9	79%
[13.8_BELCOGE13.800]	3.1	1	4.7	2.4	52%
[22-LDV-BAT2322.000]	5	3.9	6.3	4.6	26%
[22-IND-BAT2322.000]	5	1.7	6.3	1.6	26%
[22-SNP-BAT2322.000]	5	4.8	6.3	4.8	26%
[22-OW-BAT23 22.000]	5	2.8	6.3	3.6	26%
[13.8-1/3RICE13.800]	1.2	1.6	2.1	1.5	75%
[BAL-G3-13.8 13.800]	1.2	0.2	2.1	0.2	75%
[BAL-G1-13.8 13.800]	1.2	0.2	2.1	0.2	75%
[BAL-G2-13.8 13.800]	1.2	0.2	2.1	0.2	75%
[4.16-HYDROMY4.1600]	2.2	0.3	2.5	0.3	14%
[6.9_CHALLILO6.9000]	6.3	0.2	2.3	2.6	-63%
[6.9_VACA 6.9000]	17.1	1.2	6.2	-1.9	-64%
[6.9_MOLLEJON6.9000]	22.7	-0.3	7.7	-0.3	-66%
Total Increase MW	32.3				
Total Decrease MW	29.9				
Freq Drop Hz.	0.43				

Table 14-75: Islanding Contingency Seq.12, 13 & 14 MOLLEJON VACA SAN INGNACIO

Generator	Initial		Post Contingency		Change
	MW	MVAr	MW	MVAr	
[115-XULHA 115.00]	60.1	-3.5	86.3	3.3	44%
[13.8-GT-LM 13.800]	6.2	1.3	12.3	10.2	98%
[13.8-2/3RICE13.800]	2.4	0.9	5.3	3.9	121%
[13.8_BELCOGE13.800]	3.1	1.7	5.6	5	81%
[22-LDV-BAT2322.000]	5	4.1	7	4.8	40%
[22-IND-BAT2322.000]	5	1.7	7	1.8	40%
[22-SNP-BAT2322.000]	5	4.8	7	4.8	40%
[22-OW-BAT23 22.000]	5	4.1	7	4.8	40%
[13.8-1/3RICE13.800]	1.2	1.6	2.7	1.7	125%
[BAL-G3-13.8 13.800]	1.2	0.2	2.7	0.5	125%
[BAL-G1-13.8 13.800]	1.2	0.2	2.7	0.5	125%
[BAL-G2-13.8 13.800]	1.2	0.2	2.7	0.5	125%
[4.16-HYDROMY4.1600]	2.2	0.3	2.5	0.4	14%
[6.9_CHALLILO6.9000]	6.3	0.2	0	0	-100%
[6.9_VACA 6.9000]	17.1	1.4	0	0	-100%
[6.9_MOLLEJON6.9000]	22.7	-0.1	0	-1	-100%
Total Increase MW	52				
Total Decrease MW	46.1				
Freq Drop Hz.	0.70				

Table 14-76: Islanding Contingency Seq. 15 MASKALL TO BELCOGEN

Generator	Initial		Post Contingency		Change
	MW	MVAr	MW	MVAr	
[13.8-GT-LM 13.800]	6.2	0.7	23.5	-2.9	279%
[13.8-2/3RICE13.800]	2.4	0.7	10.5	-0.2	338%
[22-LDV-BAT2322.000]	5	3.9	10	2.3	100%

[22-IND-BAT2322.000]	5	1.7	10	0.5	100%
[22-SNP-BAT2322.000]	5	4.8	10	3.6	100%
[13.8-1/3RICE13.800]	1.2	1.6	5.2	0.4	333%
[BAL-G3-13.8 13.800]	1.2	0.2	5.2	-0.4	333%
[BAL-G1-13.8 13.800]	1.2	0.2	5.2	-0.4	333%
[BAL-G2-13.8 13.800]	1.2	0.2	5.2	-0.4	333%
[6.9_MOLLEJON6.9000]	22.7	-0.3	25.2	-1.4	11%
[6.9_VACA 6.9000]	17.1	1.2	19	-0.3	11%
[6.9_CHALLILO6.9000]	6.3	0.2	7	-0.3	11%
[4.16-HYDROMY4.1600]	2.2	0.3	2.5	0	14%
[13.8_BELCOGE13.800]	3.1	1	0	-0.4	-100%
[22-OW-BAT23 22.000]	5	2.8	0	2.7	-100%
[115-XULHA 115.00]	59.8	-5.2	1.3	1.2	-98%
Total Increase MW	61.8				
Total Decrease MW	66.6				
Freq Drop Hz.	1.52				

Table 14-77: Islanding Contingency Seq 16 MASKALL TO WST2MSK (New Switching for Belize II)

Generator	Initial		Post Contingency	
	MW	MVAr	MW	MVAr
[13.8-GT-LM 13.800]	6.2	0.7	17.4	-3.2
[13.8-2/3RICE13.800]	2.4	0.7	7.8	-0.5
[22-LDV-BAT2322.000]	5	3.9	8.6	2.5
[22-IND-BAT2322.000]	5	1.7	8.6	0.7
[13.8-1/3RICE13.800]	1.2	1.6	3.9	0.6
[BAL-G3-13.8 13.800]	1.2	0.2	3.9	-0.4
[BAL-G1-13.8 13.800]	1.2	0.2	3.9	-0.4
[BAL-G2-13.8 13.800]	1.2	0.2	3.9	-0.4
[6.9_MOLLEJON6.9000]	22.7	-0.3	25.2	-1.5
[6.9_VACA 6.9000]	17.1	1.2	19	-0.4
[6.9_CHALLILO6.9000]	6.3	0.2	7	-0.3
[4.16-HYDROMY4.1600]	2.2	0.3	2.5	0.1
[13.8_BELCOGE13.800]	3.1	1	0	0.8
[22-SNP-BAT2322.000]	5	4.8	1.9	4.8
[22-OW-BAT23 22.000]	5	2.8	1.9	3.1
[115-XULHA 115.00]	59.8	-5.2	25.5	-0.9
Total Increase MW	40			
Total Decrease MW	43.6			
Freq Drop Hz.	1.07			

14.9 Contingency Analysis for the 2042 Night Peak Conditions. Economy Case

These results correspond as mentioned above to a case where the thermal generation in Belize is minimized for economic reasons and the imports from the Mexican Market are maximized.

14.9.1 Contingency with potential overloads

The same contingency overloads as in the Max Economy case were identified in this case with the same solutions as these overloads are independent of the dispatch. However, as the imports from Mexico were maximized and the line Vientos del Caribe to Chan -Chen is close to its maximum tripping of the remaining generation in country results in overloads. For example, the trip of the generation at Vaca results in 113% overload and would require immediate redispatch of the generation. This further highlights the issues with this case.

14.9.2 Contingency with potential load shed

The same base contingencies with potential load shed as in the Max Security case were identified in this case with the same solutions. However, there was important load shed for islanding conditions as presented below.

14.9.3 Contingency with important generation islanding

At least five contingencies imply a severe event to the system with important amounts of load shed as shown in Table 14-79. The load shed identified is the minimum required for the electrical islands formed to achieve load – generation balance.

In the table the frequency drop was estimated assuming that BEL implements an under-frequency load shedding. The table below, shows what was assumed in this initial analysis and the steps were preliminary and further adjustments were carried out during the stability assessment. Note that the first level of load shed happens when the frequency drops under 58.5 Hz, which is derived from the fact that the system frequency needs to recover above this value within 5 minutes and the load shed is designed to achieve this goal. Also, we note that when the frequency breaches the 57.8 Hz limit above which it needs to recover within 30 seconds, 40% of the load would be shed helping the recovery and by 57.5 Hz 50% of load is shed.

Table 14-78: Initial Under-frequency load shed strategy (see stability for final)

	Frequency	% Load Shed
Step 1	58.5	5.0%
Step 2	58.0	30.0%
Step 3	57.9	35.0%
Step 4	57.8	40.0%
Step 5	57.7	45.0%
Step 6	57.5	50.0%

Contingency 6, in Table 14-79 maintains the system connected with Mexico and represents the loss of all the hydroelectric generation. Thus, in this the load shed is not driven by frequency drop but in reality, for preventing the voltage collapse.

Finally in contingency 7 the electric island is the loads west of Westlake substation and the load shed is the required in the electric island formed due to the loss of supply from Mexico via the line Westlake to La Democracia 115 kV.

Table 14-79: Contingencies resulting in formation of electrical islands and load shed.

Seq	Contingency (Facility Opened)	Total Shed MW	% Load Shed	Possible Min Frequency Hz	Note
1	BUS 202 [115-CHANCHEN115.00] TO BUS 303 [VTSCRBE 115.00] CKT 1	81.74	50.1%	57.5	Loss of Mex Supply to the north
2	BUS 202 [115-CHANCHEN115.00] TO BUS 2725 [115-BELCOGEN115.00] CKT 1	63.67	41.8%	57.7	Loss of Mex Supply to the north
3	BUS 2642 [115-MASKALL 115.00] TO BUS 2725 [115-BELCOGEN115.00] CKT 1	54.45	40.2%	57.7	Loss of Mex Supply to the north
4	BUS 303 [VTSCRBE 115.00] TO BUS 2694 [115-XULHA 115.00] CKT 1	44.1	38.0%	57.8	Loss of Mex Supply to the north
5	BUS 2642 [115-MASKALL 115.00] TO BUS 2648 [115-WST2MSK 115.00] CKT 1	37.68	34.4%	57.8	Loss of Mex Supply to the north
5	SAN IGNACIO - VACA TAP - MOLLEJON (Possible voltage collapse)	50.0	30.6%	N/A	Loss of Mex Supply to the north
5	BUS 2389 [115-WEST-W 115.00] TO BUS 2390 [115-LADMRCIA115.00] CKT 1	3.93	6.0%	58.2	Loss of Mex Supply to the north

14.10 Stability Assessment

The objective of the dynamic simulation is to verify the transient stability of the Belize power grid for the critical contingencies and in particular those that create electrical islands.

The impact on the grid frequency is one of the critical aspects for scenarios with large penetration of inverter-based resources, solar PV, wind generation and storage.

The implementation of an underfrequency load shedding scheme is critical for the security of the system and in particular when there are important imports from Mexico as in the night peak conditions.

14.10.1 Dynamic Models

This section describes the general assumptions for the elaboration of the dynamic model setup.

- The dynamic models for the existing units were elaborated based on the information, generator datasheets and curves provided by Belize Electricity Limited.
- Storage and PV were modeled with a Power Convert model to represent the reactive and active power injection at the generator's terminal and a Plant Master Controller to control the injection at the POI.
- Storage was modeled with over-frequency response (4% droop) and underfrequency response (2% droop).
- PV modeled only with over-frequency response (4% droop).
- The gas turbine generator (LM2500) was modeled operating in synchronous condenser mode during day peak (no speed governor model) and as a regular gas turbine during the night peak, providing largely spinning reserves.
- The Mexican Wind (Vientos del Caribe) was modeled with a plan master to control voltage at the POI. No frequency response was considered, but it could be part of the actual project.
- The two cogeneration facilities (Belcogen and Santander) were modeled without speed governor model.
- The hydro plants were modeled with speed governor model and contributes to the frequency control.
- Reciprocating engines (RICE) were modeled with voltage and frequency control (3% droop).

14.10.2 Load Shedding Scheme

It is central for the security of the system that load is shed under certain critical events to prevent frequency collapse. In the design of the proposed load shedding scheme, we balanced the need to arrest the frequency drop as rapidly as possible and prevent reaching levels that will result in the trip of generation on one hand and avoid the tripping of excessive amounts of load on the other that would result in over-frequency after the system recovers and interruption to customers.

The load shedding scheme considered:

- Load is shed uniformly among the loads in the area with underfrequency.
- Stages 1 and 2 are designed to shed small amounts of load for typical frequency deviations and address small unbalances avoiding excessive trips of load.
- Stage 3 is designed to prevent frequency drops below 58 Hz.
- Stages 4 to 6 are designed to restore frequency for large system events and prevent the tripping of generation.

Table 14-80: Selected Under-frequency load shed strategy

	Frequency [Hz]	Load shed [%]	Timer [sec]
Stage 1	58.5	5	0.04
Stage 2	58.2	15	0.02
Stage 3	58.0	30	0.02
Stage 4	57.7	40	Inst.
Stage 5	57.6	45	Inst.
Stage 6	57.5	50	Inst.

14.10.3 Simulated Contingencies

This section introduces the contingencies that were simulated during the dynamic analysis. The contingency list is based on the findings of the steady state contingency analysis.

The contingencies in Table 14-81 were identified as critical due to the large impact they were producing on the generation-load balance of the Belize grid and its potential to create instabilities[21]. In the contingency list the first contingency is the opening of the line with no fault and the second with a 3-phase bolted fault opened in 5 cycles.

Table 14-82 shows additional contingencies that resulted with lesser impact on the Belize grid, however they require dispatch coordination to avoid generator trip or frequency collapse.

[21] Other contingencies as for example the failure of the submarine cable to San Pedro or a failure of a major transformer are critical for BEL due to the implied time for correction and the impact to the load, but these contingencies would not result instabilities and were addressed before on the steady state analysis.

Table 14-81: Critical Contingency list.

Identification	Description
F01	115 kV Line trip Vientos del Caribe - Chan Chen
F02	Three phase fault at 115 kV Line Vientos del Caribe – Chan Chen
F03	115 kV Line trip Vientos del Caribe - Xul-Ha
F04	Three phase fault at 115 kV Line Vientos del Caribe – Xul-Ha
F05	115 kV Line trip Chan Chen - Belcogen
F06	Three phase fault at 115 kV Line Chan Chen - Belcogen

Table 14-82: Additional Contingencies.

Identification	Description
F07	115 kV Line trip Camalote – La Democracia
F08	Three phase fault at 115 kV Line Camalote – La Democracia
F09	115 kV Line trip San Ignacio – Vaca Tap
F10	Three phase fault at 115 kV Line San Ignacio – Vaca Tap
F11	69 kV Line trip Bapcol Tap – Savannah
F12	Three phase fault at 115 kV Line Bapcol Tap – Savannah

14.10.4 2042 Daytime Peak Case Requirements.

Some important requirements for the operation of the system were identified during the setup of the daytime peak case and these are presented below.

The initial load flow case selected for the steady state analysis using economic dispatch considerations had high renewable dispatch penetration (95.6%).

When this was modeled in stability it was found that the inertia provided by the few online synchronous generators (hydro units) was insufficient. When a power system lacks inertia large frequency deviations with high gradient are observed during events of generation loss. Also, during a three-phase fault, the inverters most likely will be blocked because of the low voltage, and a large generation source (renewable) will cease to inject active power creating a large load-generation imbalance and a frequency drop until the voltage recovers to the point that the inverters start injecting power again.

These large frequency drop may trigger unacceptable amounts of load shedding as frequency may reach the low-frequency instantaneous relay settings. This will be followed by large over-frequency when renewable generation starts injecting again.

To address this situation, it is recommended and necessary to incorporate synchronous generation as detailed below.

The gas turbine at Mile 8 (Westlake) was modeled operating in synchronous condenser mode, as indicated earlier this unit must be given the possibility to operate in a synchronous condenser mode using a clutch. This avoids having to have it online and consuming fuel unnecessarily as it is not required for it to provide spinning reserves during daytime.

The Belcogen generation was brought online and operating at reduced load and one unit from Vaca Hydro plant was also incorporated.

In addition to the above, the RICE generation at Independence was brought online to provide spinning reserves and allow the load-generation balance to be recovered for the contingencies that separate the load to the south of BAPCOL.

The battery storage dispatch was also modified from -10 MW (charging state) to -9MW to provide 1 MW margin for over-frequency control.

Solar PV plants were also modeled contributing to the frequency control, but only for over-frequency (no “spilling” of irradiance and PV assumes to operate at maximum).

The hydro plants were modeled at minimum load, not being able to contribute during over-frequency events, however they contribute to the short-circuit level and the rotating inertia.

Table 14-83 below shows a summary of the dispatch modeled where we note that that 100% of the load is supplied by generation within Belize and 92.2% of this generation is supplied by inverter-based resources (PV and Wind). Mexico is importing 30.6 MW from Belize and 34 MW are delivered to storage.

Table 14-84 shows the dispatch of the 2042-day peak dynamic case and the changes with respect to the steady state case.

Table 14-83: 2042 Day Peak Case Summary.

Resource	Dispatch	% Load supplied
Storage	-34.00 MW	(charging)
PV	128.0 MW	75.7%
HYDRO	7.20 MW	4.3%
WIND	28.00 MW	16.5%
THERMAL	6.00 MW	3.5%
BELIZE GEN.	169.2 MW	100%
MEXICO	-30.6 MW	(export)

Table 14-84: 2042 Day Peak Case, Dynamic and Steady state case differences.

PSSE Bus	Name	Dynamic case		Steady state case		Pmax
		Status	Pgen	Status	Pgen	
313	Vientos del Caribe 1	ON	12	ON	12	15
313	Vientos del Caribe 2	ON	8	ON	8	10
313	Vientos del Caribe 3	ON	8	ON	8	10
2321	Westlake GT	**ON**	0	OFF	0	0
2334	Storage Ladyville	ON	-9	ON	-10	10
2335	PV Ladyville	ON	16	ON	16	20
2379	PV West 1	ON	16	ON	16	20
2380	PV West 2	ON	16	ON	16	20
2393	PV La Democracia 1	ON	16	ON	16	20
2394	PV La Democracia 2	ON	16	ON	16	20
2422	Hydro Maya	ON	1.25	ON	1.25	2.5
2469	Storage Independence	ON	-7	ON	-10	10
2470	RICE Independence	**ON**	4	OFF	0	7.5
2531	RICE Bapcol 1	OFF	0	OFF	0	7.5
2532	RICE Bapcol 2	OFF	0	OFF	0	7.5
2533	RICE Bapcol 3	OFF	0	OFF	0	7.5
2546	RICE Dangriga 1	OFF	0	OFF	0	7.5
2546	RICE Dangriga 2	OFF	0	OFF	0	7.5
2583	Chalillo 1	ON	1.75	ON	1.75	3.5
2583	Chalillo 2	OFF	0	OFF	0	3.5
2593	Mollejon 1	ON	2.2	ON	4.2	8.4
2593	Mollejon 2	OFF	0	OFF	0	8.4
2593	Mollejon 3	OFF	0	OFF	0	8.4
2595	Vaca 1	**ON**	2	OFF	0	9.5
2595	Vaca 2	OFF	0	OFF	0	9.5
2652	PV Maskall	ON	16	ON	16	20
2694	Mexico	ON	-30.6	ON	-17.0	100
2707	PV Chan Chen	ON	16	ON	16	20
2711	PV Orange Walk	ON	16	ON	16	20
2726	Belcogen	**ON**	2	OFF	0	0
2743	Storage San Pedro	ON	-9	ON	-10	10
2795	Storage OWK	ON	-9	ON	-10	10
2826	Santander	OFF	0	OFF	0	8

14.10.5 2042 Daytime Peak Case – Dynamic Simulation Results

The table below provides a summary of the stability analysis results for the daytime peak.

We see in this table that contingences F01 to F06 are stable, and no issues are expected. However, when there is island formation with hydro generation and load (F07 and F08) there is a risk of system collapse given the slow response of the hydro governors. This is also the situation of contingency F12 that results in the isolation of Independence and Punta Gorda.

Table 14-85: 2042 Day Peak Case Simulation Summary.

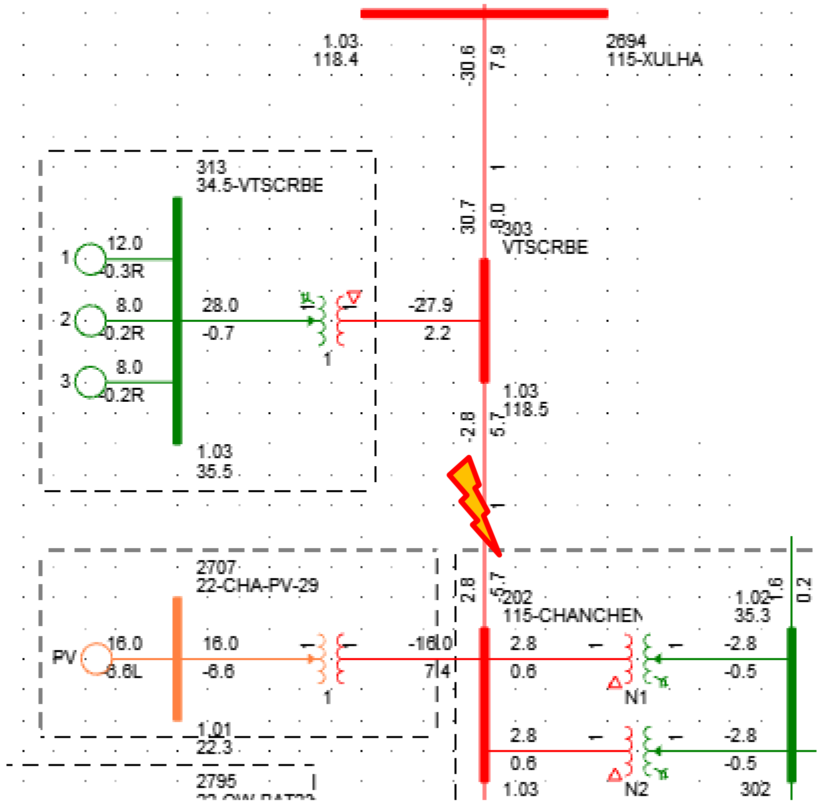
Contingency	Frequency Event	Load shedding	Comments
F01 Line trip V. del Caribe – Chan Chen	No	No	Stable
F02 3PF V. del Caribe – Chan Chen	No	No	Stable
F03 Line trip V. del Caribe – Xul-Ha	No	No	Stable
F04 3PF V. del Caribe – Xul-Ha	Over-frequency 61.6 Hz	No	Stable
F05 Line trip Chan Chen – Belcogen	No	No	Stable
F06 3PF Chan Chen - Belcogen	Underfrequency 59.0 Hz	No	Stable
F07 Line trip Camalote – (Santander) - La Democracia	Underfrequency 56.6 Hz	Yes, 16.9 MW	Probable collapse of the island
F08 3PF Line trip Camalote – (Santander) - La Democracia	Underfrequency 56.7 Hz	Yes, 16.9 MW	Probable collapse of the island
F09 Line trip San Ignacio – Vaca Tap	No	No	Stable
F10 3PF San Ignacio – Vaca Tap	No	No	Stable
F11 Line trip Bapcol Tap to Savannah	Underfrequency 57.3 Hz	Yes, 8.2 MW	Stable
F12 3PF Bapcol to Savannah	Underfrequency 55.8 Hz	Yes, 8.2 MW	Probable collapse of the island

The next sections below provide details of these contingencies.

F01 and F02: Loss of Vientos del Caribe – Chan Chen (115 kV Line)

The loss of the line results in very small generation surplus within BEL because there the line is exporting 2.8 MW from Chan Chen to Vientos del Caribe substation. See figure below.

Figure 14-55: F01 and F02: Loss of Vientos del Caribe – Chan Chen (115 kV Line)



With the line trip (F01), the over-frequency reached 60.09 Hz and is controlled by the Storage and PV resources (see red trace in Figure 14-56).

The three-phase fault (F02), results in underfrequency condition due to the large voltage drop and the inverter's power cessation during the fault condition. Once the fault is cleared, the inverter regains control and regulates the output to stabilize the grid frequency.

The synchronous generators were fundamental to prevent a larger frequency drop during the fault condition. The frequency reached a minimum of 58.93 Hz and load shedding was not triggered (see blue trace in Figure 14-56).

As shown in Figure 14-57 and Figure 14-58 the voltage recovered to acceptable values within 1 second for the short circuit event (F02) or never went out of range for the opening of the line (F01).

Figure 14-56: F01 & F02 Loss of Vientos del Caribe – Chan Chen (115 kV Line)

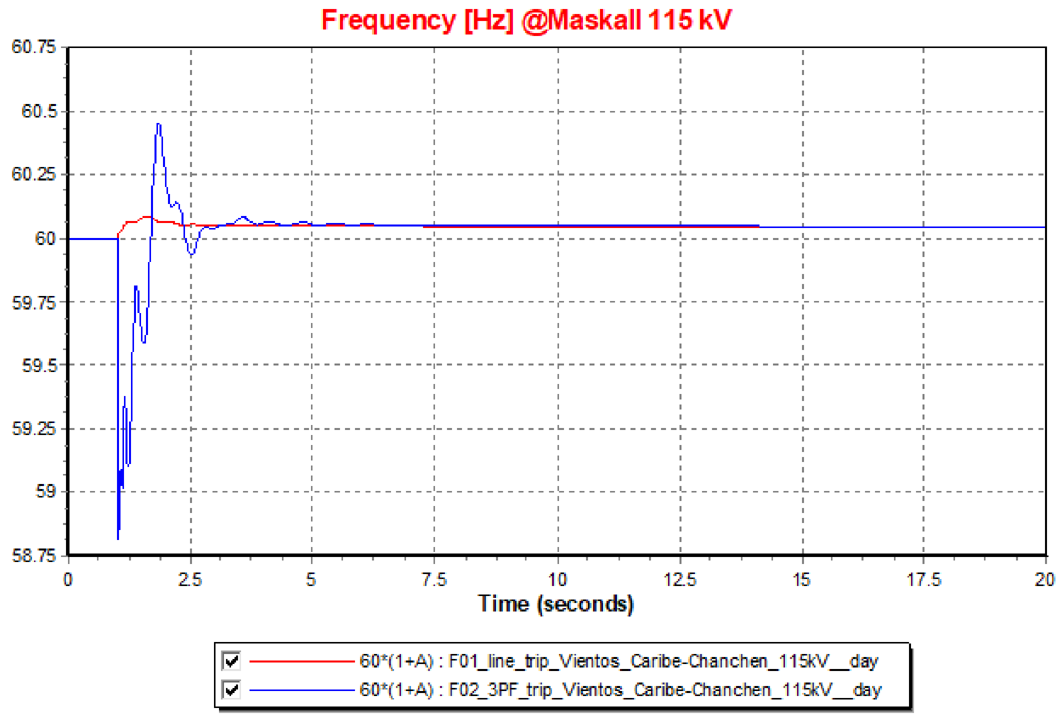


Figure 14-57: F01 Loss of Vientos del Caribe – Chan Chen (115 kV Line)

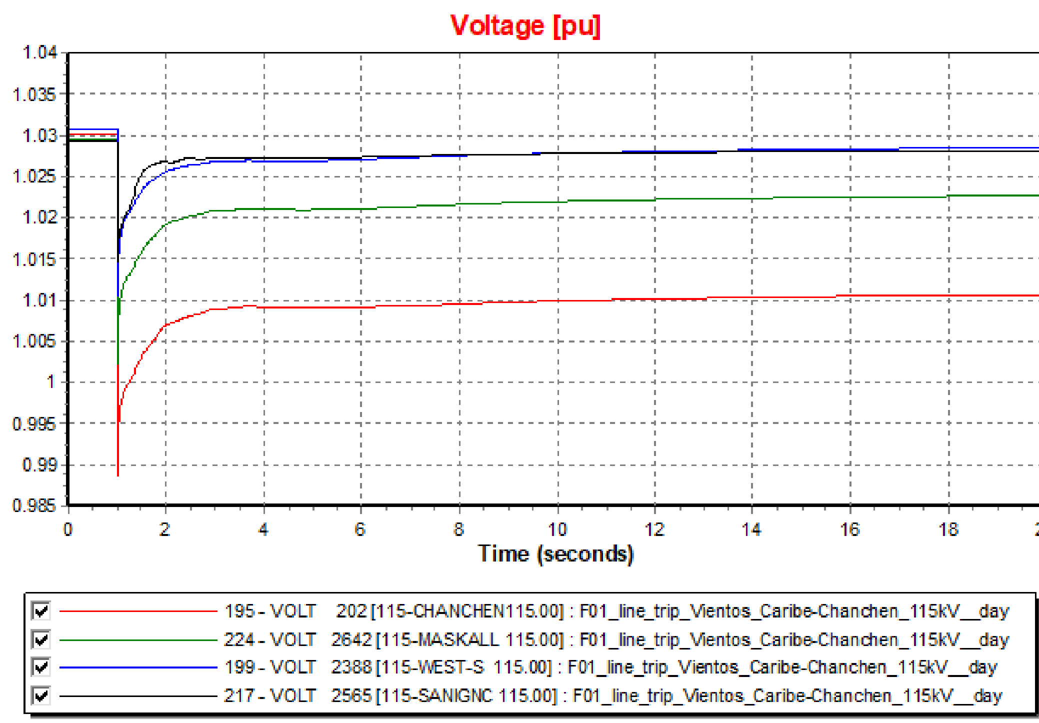
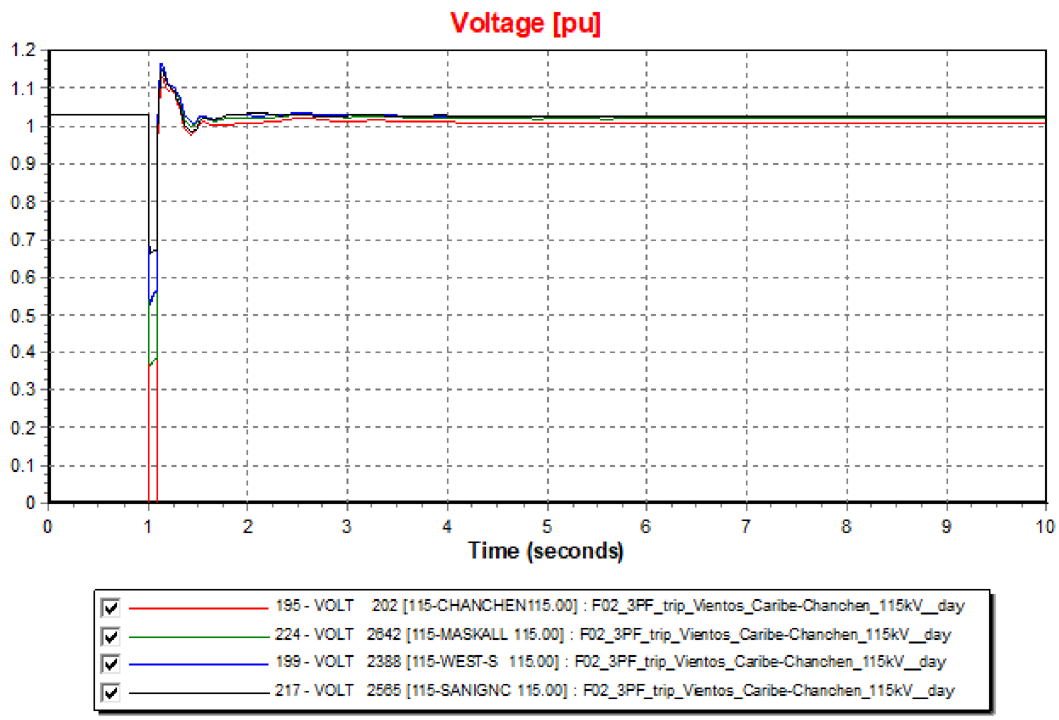


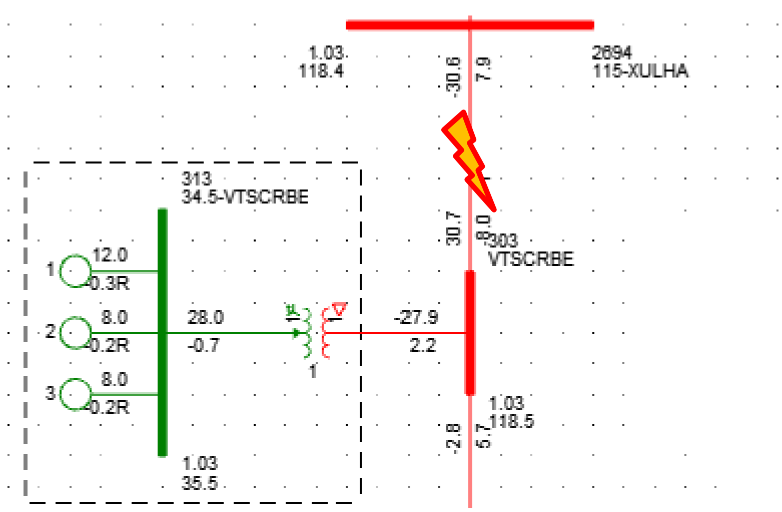
Figure 14-58: F02 Loss of Vientos del Caribe – Chan Chen (115 kV Line)



F03 & F04 Loss of Vientos del Caribe – Xul-Ha (115 kV Line)

The loss of the line results in a small generation surplus within BEL as the line is exporting 30.6 MW from Vientos del Caribe to the Xul-Ha substation. See figure below.

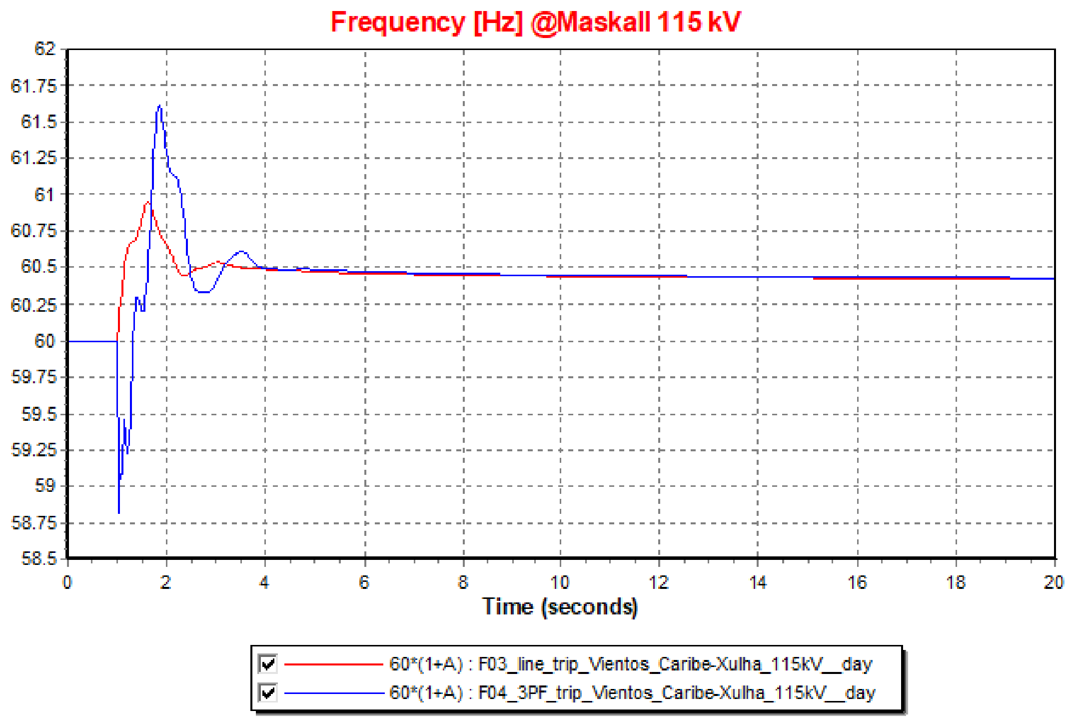
Figure 14-59: F03 & F04 Loss of Vientos del Caribe – Xul-Ha (115 kV Line)



With the sudden line trip (F03), the over-frequency reached 60.95 Hz and is controlled by the Storage and PV resources (see red trace in figure below).

Similarly, as with F02, the three-phase fault (F04) results in underfrequency condition due to the large voltage drop (58.8 Hz). The underfrequency condition was short and load shedding was not triggered (see blue trace in figure below).

Figure 14-60: F03 & F04 Loss of Vientos del Caribe – Xul-Ha (115 kV Line)



As shown in the following figures the voltage recovered to acceptable values within 1 second for the short circuit event (F04) or never went out of range for the opening of the line (F03).

Figure 14-61: F03 Loss of Vientos del Caribe – Xul-Ha (115 kV Line)

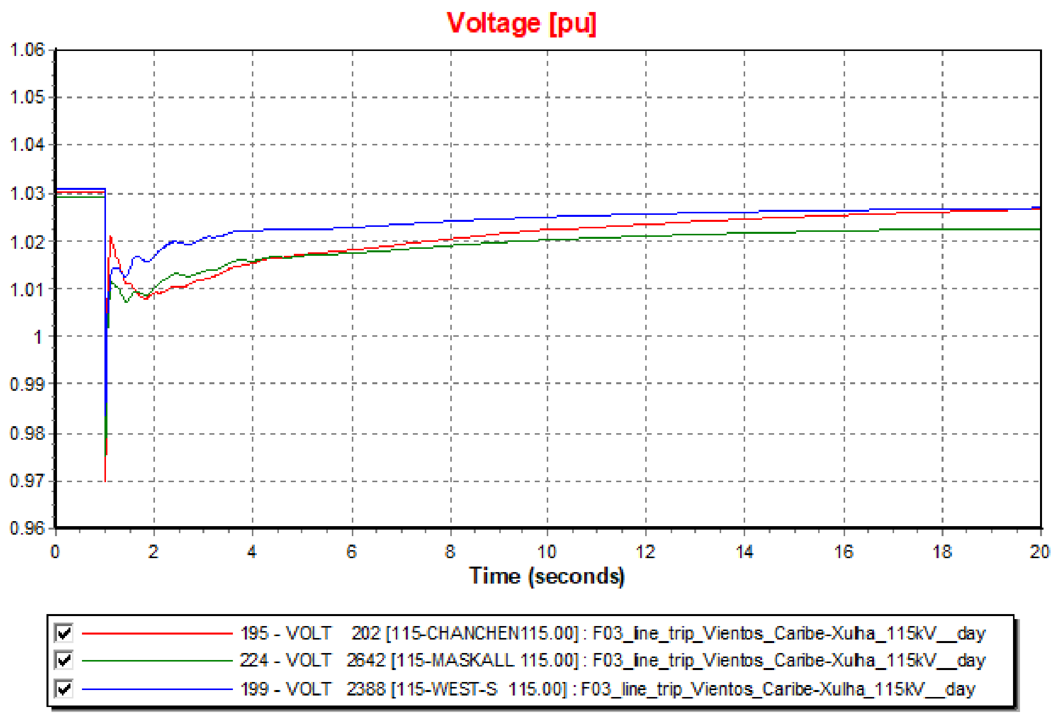
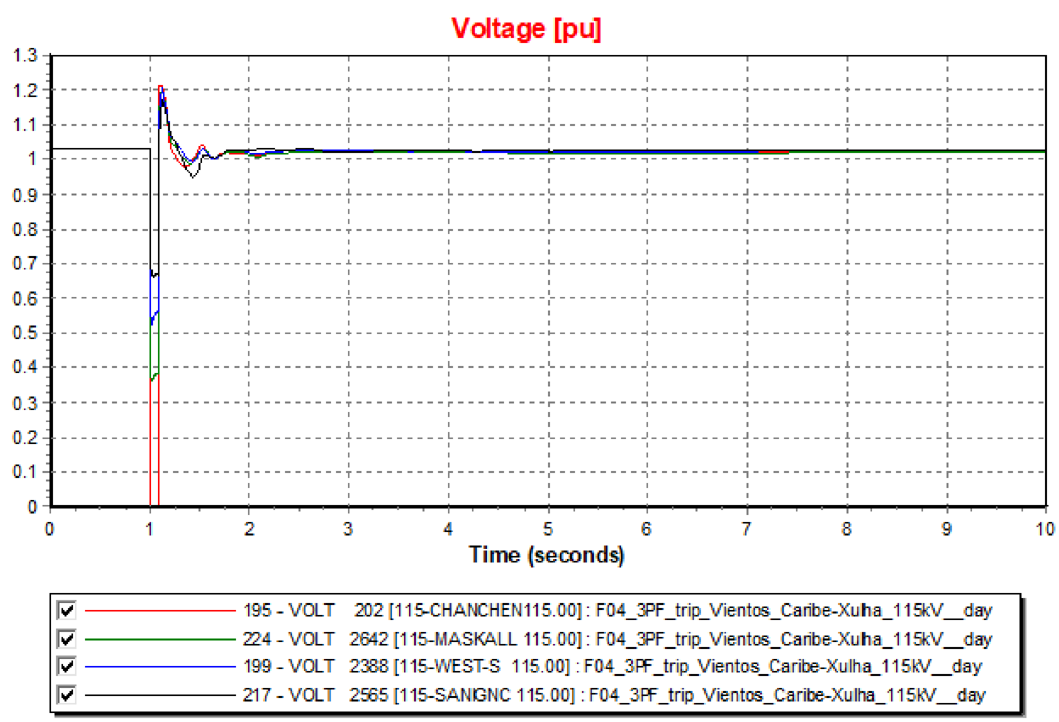


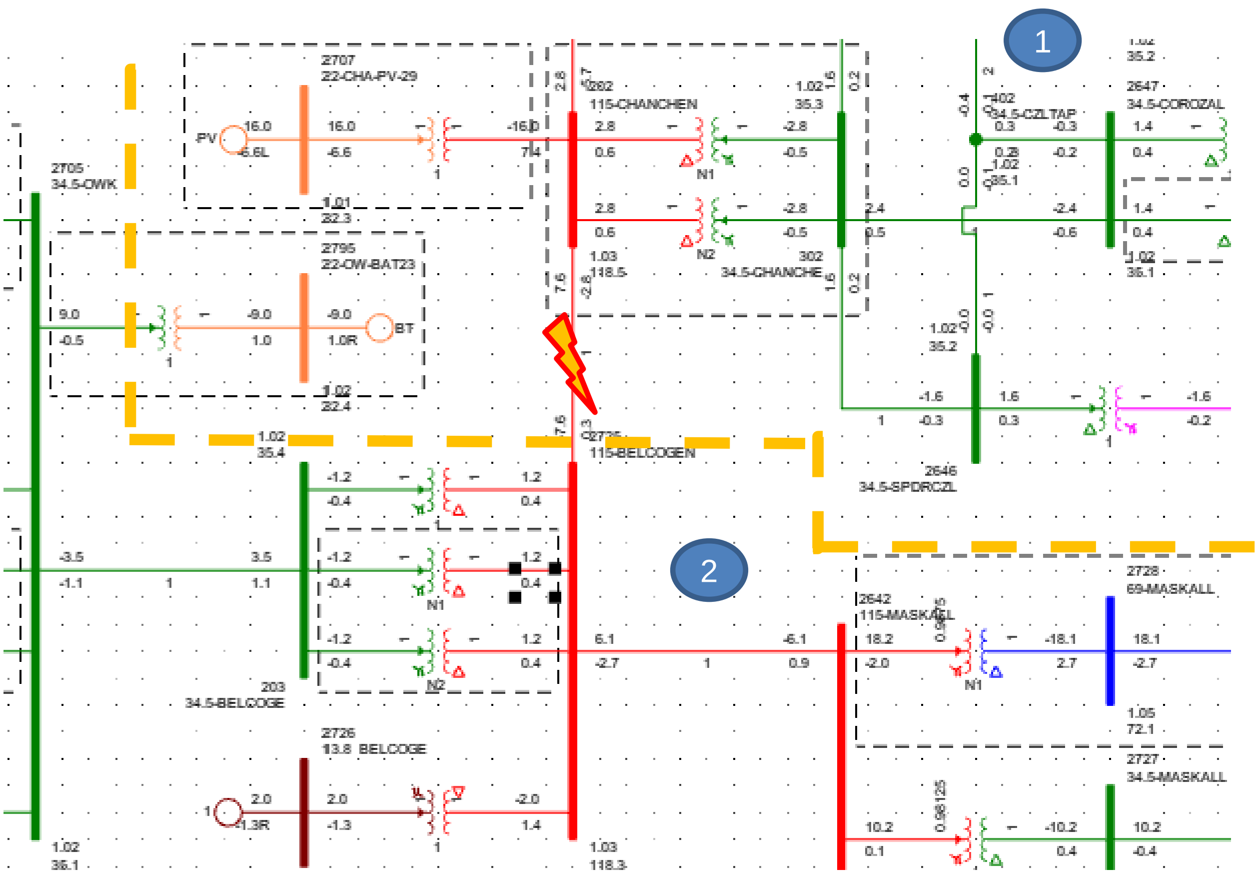
Figure 14-62: F04 Loss of Vientos del Caribe – Xul-Ha (115 kV Line)



F05 & F06 Loss of Chan Chen – Belcogen (115 kV Line)

The loss of the line results in the separation of the system in two. One system tied to Mexico from Chan Chen – Vientos del Caribe – Xul-Ha that will remain largely unaffected (Island 1 in figure below). Another electrical island (2 in figure below) with 7.6 MW shortage of generation that was being delivered from the north to it. The electrical island "2" experienced underfrequency and was controlled mostly by the Storage switching from charging to discharging mode. Underfrequency load shedding was not triggered.

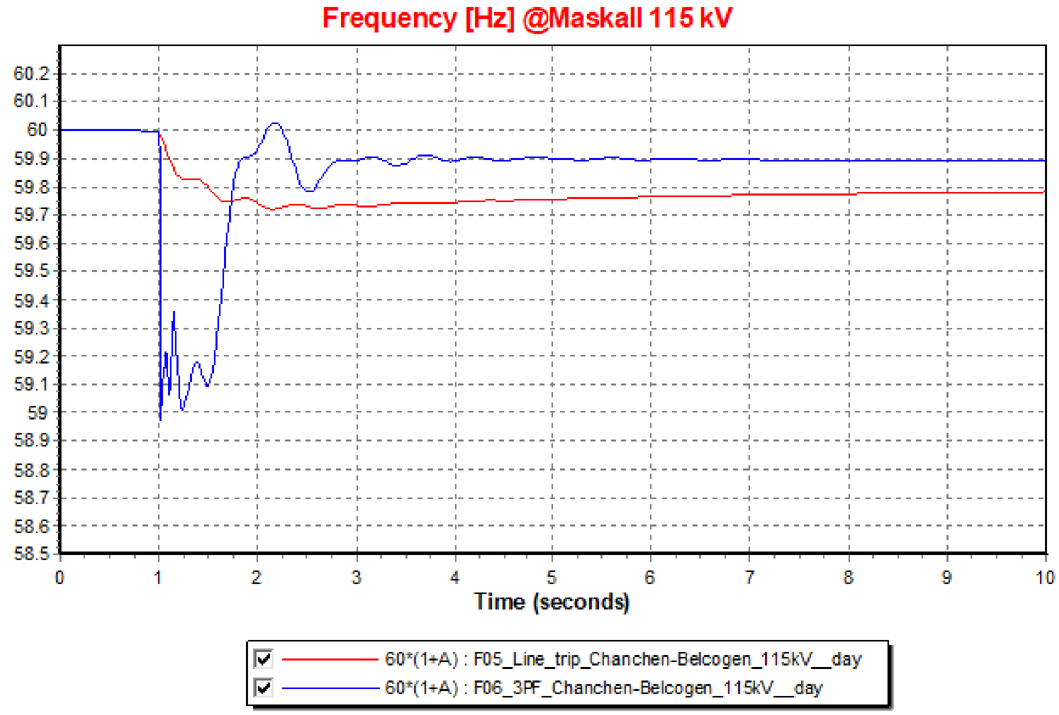
Figure 14-63: F05 & F06 Loss of Chan Chen – Belcogen (115 kV Line)



With the sudden line trip (F05), the frequency dropped slowly and was always above 59.7 Hz stabilizing at 59.7 Hz with the help of the Storage (see red trace in figure below).

With the three-phase fault (F06) there was an underfrequency condition (59.0 Hz). The underfrequency condition lasted under one second and load shedding was not triggered (see blue trace in figure below).

Figure 14-64: F05 & F06 Loss of Chan Chen – Belcogen (115 kV Line)



As shown in the following figures the voltage recovered to acceptable values within 1 second for the short circuit event (F06) or never went out of range for the opening of the line (F05).

Figure 14-65: F05 Loss of Chan Chen – Belcogen (115 kV Line)

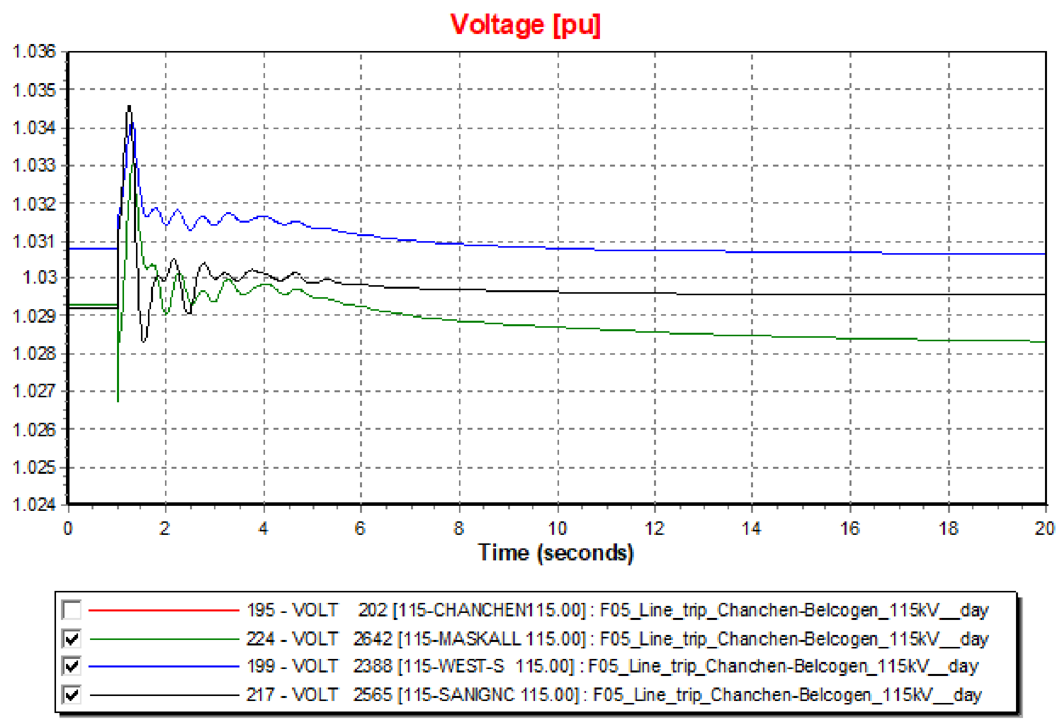
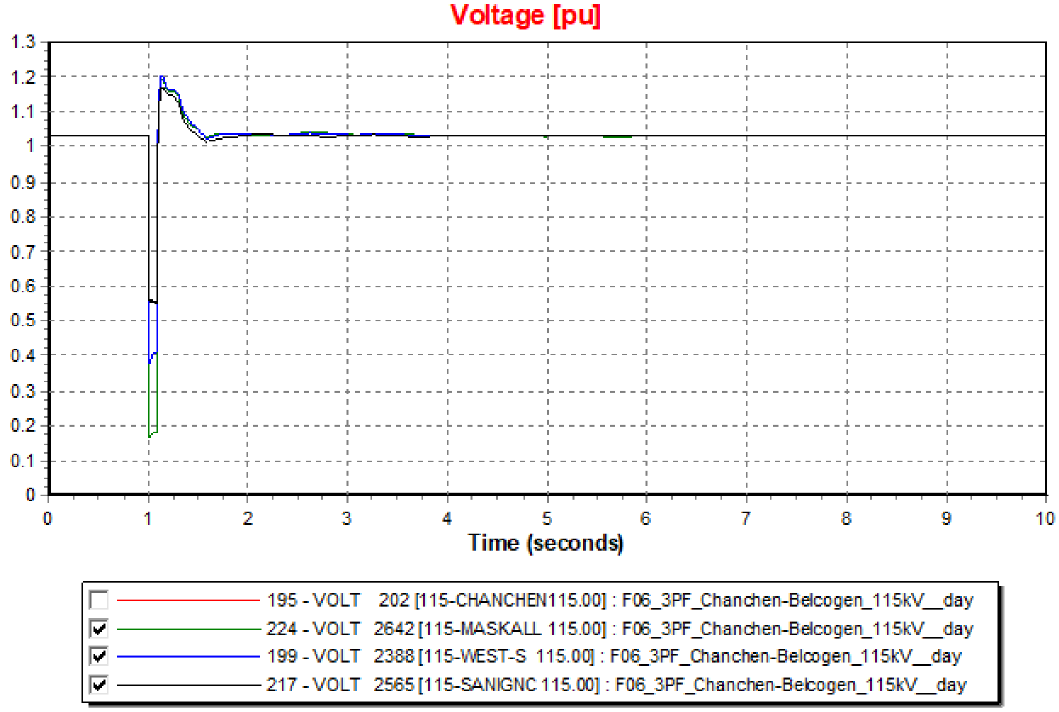


Figure 14-66: F05 Loss of Chan Chen – Belcogen (115 kV Line)



F07 & F08 Loss of Camalote – (Santander) - La Democracia (115 kV Line)

Prior to the contingency the hydro plants were operating at minimum load and the active power flowing from La Democracia (Island 1 below) to Camalote substation (Island 2) was 18.3 MW. The loss of the line creates a large load-generation unbalance for Island 2 conformed by the loads at San Ignacio and Belmopan to be supplied by the hydro plants.

The slow reaction of the speed governor of the hydro units results in a large frequency dip (56.6 Hz for F07 and 56.7 Hz for F08) and the 6 stages of the underfrequency protection operated (50% load shed) eventually addressing the drop (see Figure 14-68). This slow reaction can be observed in Figure 14-69 where we observe that by the time the frequency reaches its minimum as arrested by the load shed, the hydro units are at less than 50% of its maximum response.

The total load shed in the affected area was 16.9 MW, very similar to the generation lost by opening the line (18.3 MW), hence the contribution from the Hydro was minimal. Also, we note that at the 56.6 Hz level there could be hydro generation trip eventually leading to a collapse.

To prevent this large frequency excursion one potential solution is to coordinate the generation at the hydro plants with the active power flow through the contingency line and have immediate trip of load as required by a Remedial Action Scheme, rather than using the frequency as the signal. Note that this load could be rapidly restored as there is enough generation in the electric island, it just needs time to ramp-up.

Figure 14-67: F07 & F08 Loss of Camalote – (Santander) - La Democracia (115 kV Line)

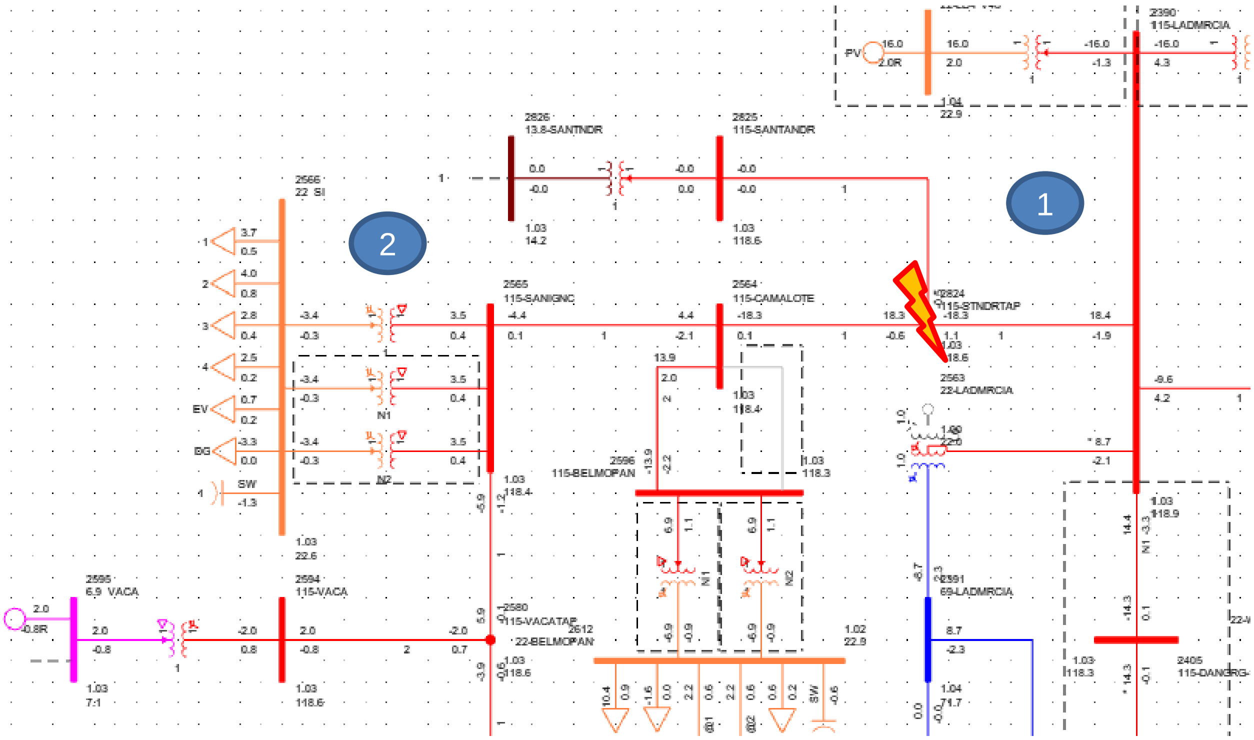


Figure 14-68: F07 & F08 Loss of Camalote – (Santander) - La Democracia (115 kV Line)

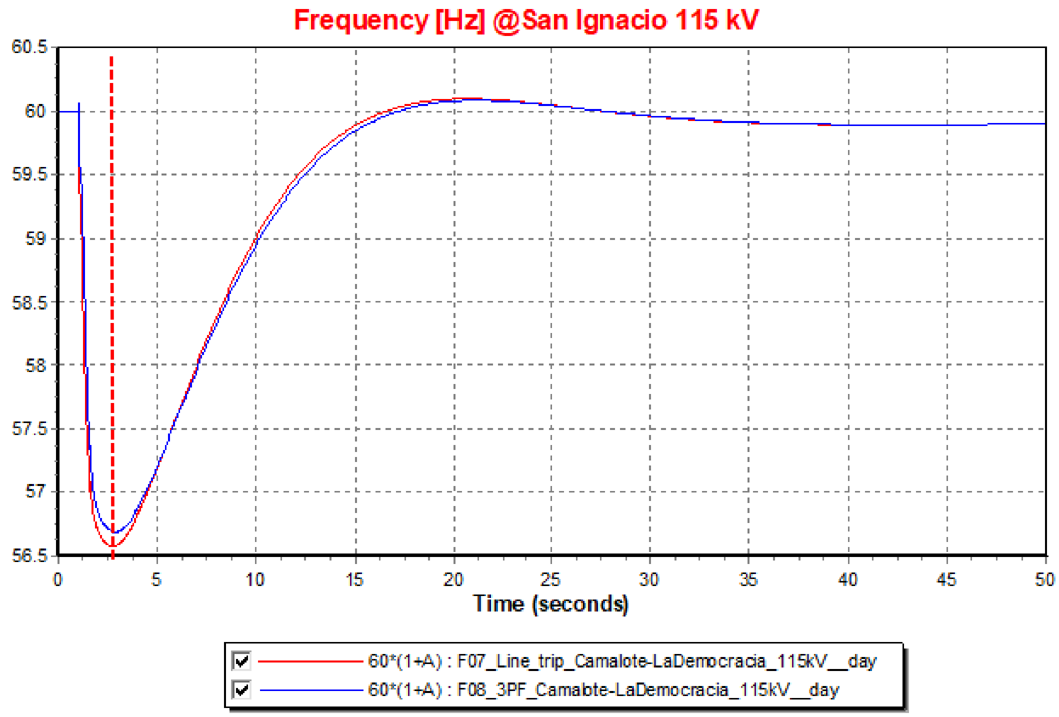
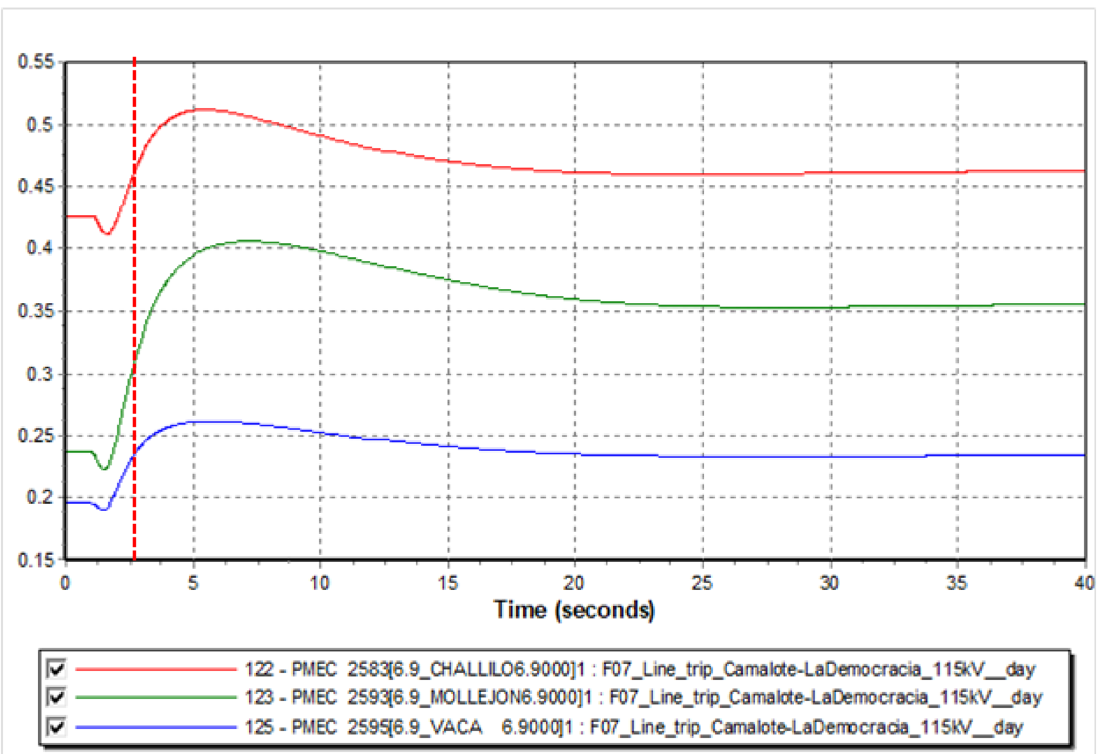


Figure 14-69: F07 & F08 Loss of Camalote – (Santander) - La Democracia (115 kV Line) Hydro Generation Response.



In general, there were no voltage issues as shown below.

Figure 14-70: F07 Loss of Camalote – (Santander) - La Democracia (115 kV Line)

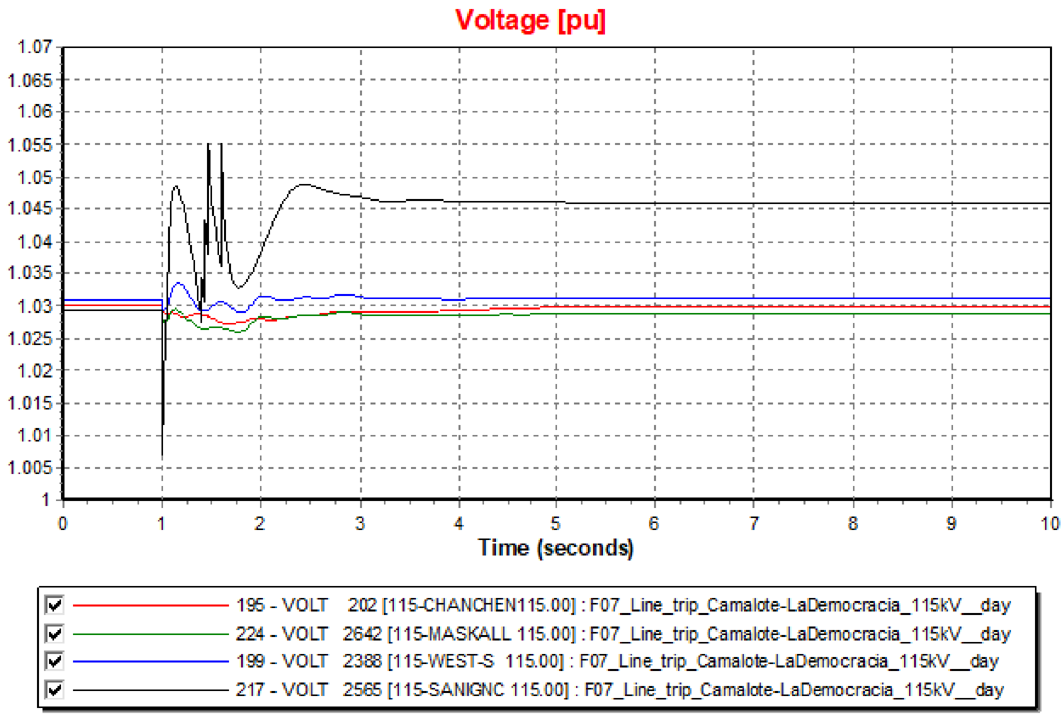
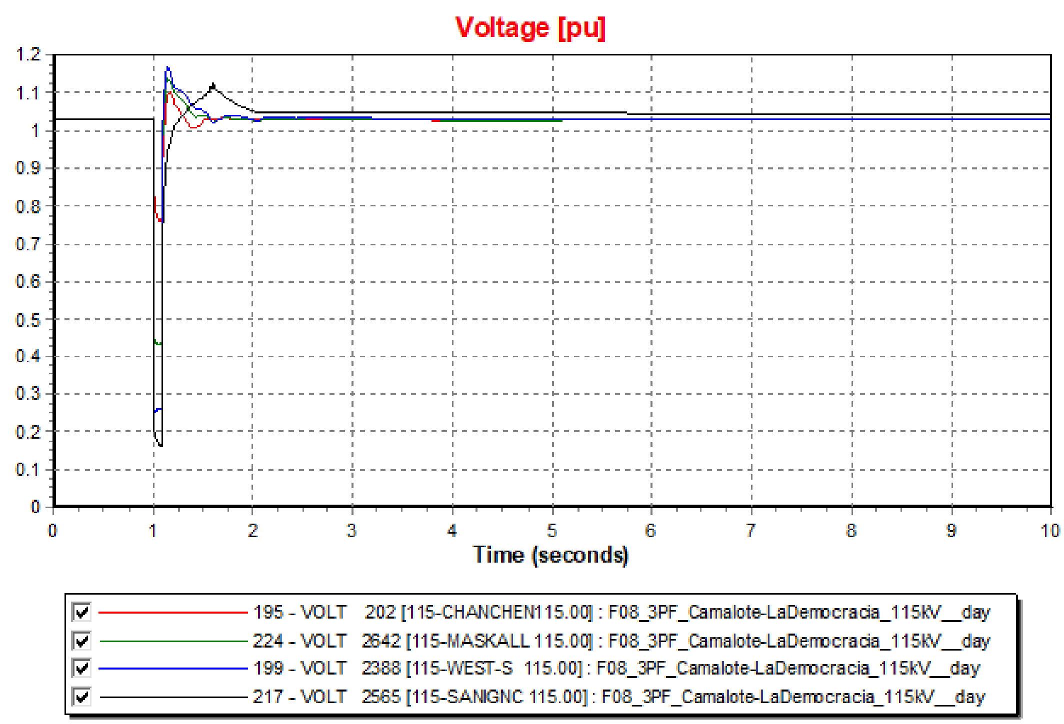


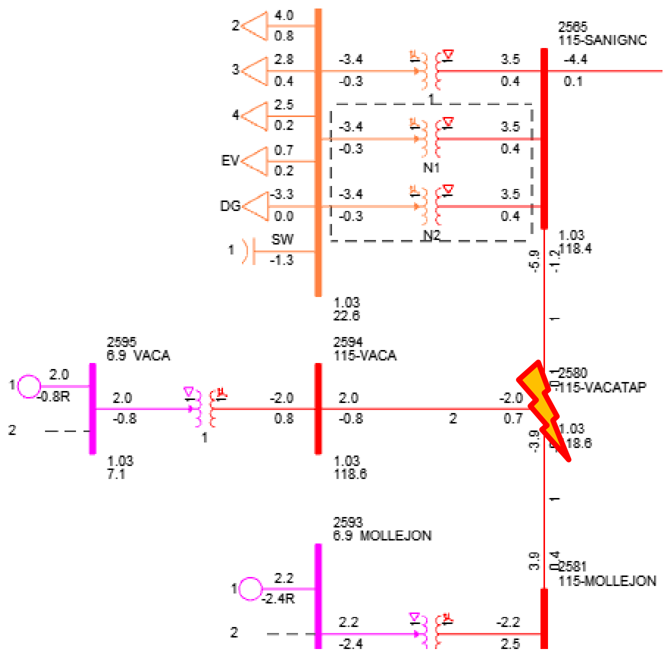
Figure 14-71: F08 Loss of Camalote – (Santander) - La Democracia (115 kV Line)



F09 & F10 Loss of San Ignacio – Vaca tap (115 kV Line)

The contingency results in the loss of 5.9 MW generated by the hydro plants, which would be operating at a lower level consistent with daytime conditions. The impact on the BEL grid is minimal as the frequency is maintained by the interconnection with Mexico. The impact on grid voltage is also negligible.

Figure 14-72: F09 & F10 Loss of San Ignacio – Vaca tap (115 kV Line)



F11 & F12 Loss of Bapcol – Savannah (69 kV Line)

The contingency results in the formation of a 69 kV island including Independence – Savannah and Punta Gorda substations (Island 2 in the figure below).

Prior the contingency the active power flow from Bapcol tap to Savannah was of 14.8 MW and the event results in an important generation – load imbalance.

The sudden line trip (F11) results with a frequency minimum of 57.3 Hz (red trace in the figure below), while the three phase fault results in an extreme frequency minimum of 55.8 Hz, but with very short duration (blue trace in the figure below). This second event could possibly lead to underfrequency protection trip for the hydro and the RICE generation. The total load shed was 8.2 MW (50% of load in the area).

During the event, the Storage that was in charging mode cease to take active power during the fault and once the fault is cleared it re-gains control and moves to inject active power.

To prevent this large frequency excursion one potential solution is to coordinate the generation at the RICE plant with the active power flow through the contingency line and immediately trip load and send a signal to the storage to discharge to full power without delay.

Figure 14-73: F11 & F12 Loss of Bapcol – Savannah (69 kV Line)

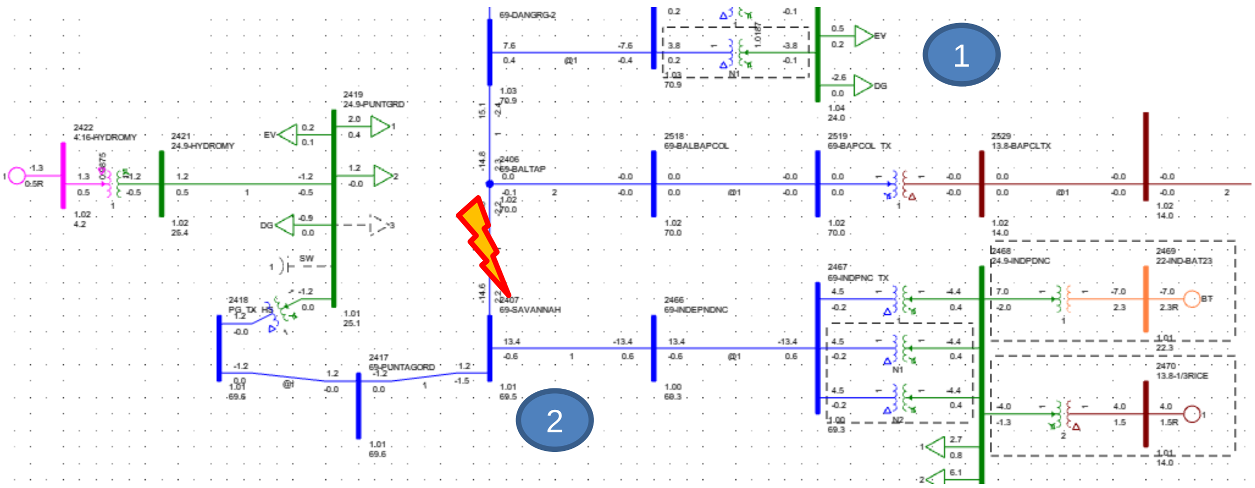
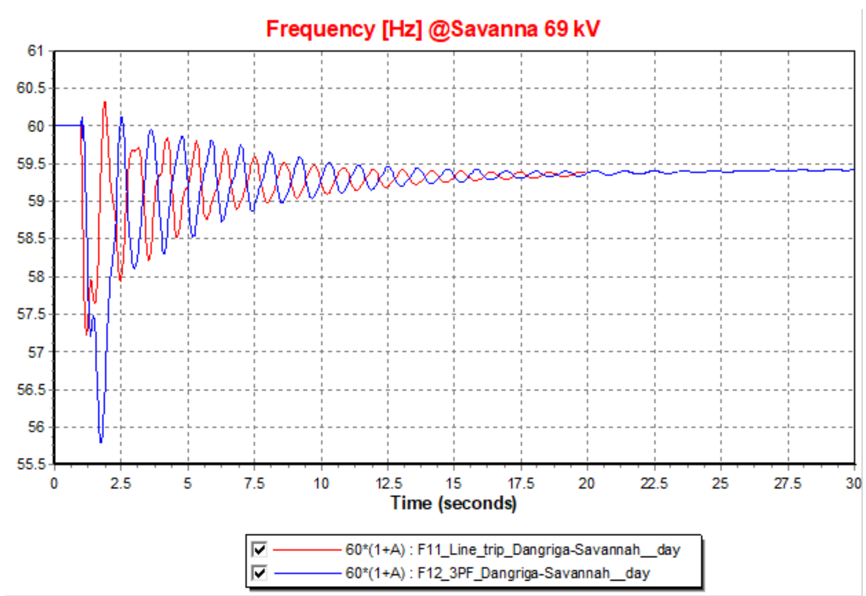


Figure 14-74: F11 & F12 Loss of Bapcol – Savannah (69 kV Line)



14.10.6 2042 Night Peak Case Description

The load flow case used for the dynamic simulation at night peak condition is the same as the steady state night peak "Maximum Security" load flow case. The Max Economy was identified to be insecure already from the steady state assessment. Table 14-87 below shows a summary of the dispatch modeled where we note that 65.3% of the load is supplied by generation within Belize and 34.7 % is supplied from Mexico.

Table 14-86: 2042 Night Peak Case Summary.

Resource	Dispatch	% Load supplied
Storage	20.00 MW	11.6%
PV	0.00 MW	0.0%
HYDRO	48.33 MW	27.9%
WIND	28.00 MW	16.2%
THERMAL	16.52 MW	9.6%
BELIZE GEN.	**84.86 MW**	**65.3%**
MEXICO	88.07 MW	34.7%
Total	**172.93 MW**	**100.0%**

The loss of the interconnection with Mexico, as shown in this report, results in a large load-generation imbalance that leads to an underfrequency condition. The frequency is restored by the generating units with primary frequency control (droop) and when the regulating reserve is insufficient, underfrequency load shedding is required.

Also, as will be shown that the frequency control is mostly performed by the Storage which are operating at 50% in discharge mode (50% margin) and by the Mile 8 (Westlake) GT.

Table 14-88 shows the dispatch modeled for the 2042-night peak case. Note that this dispatch was selected as representative of a stressed but likely condition to the system where for example Santander was offline which would likely be the case in the later part of the year (e.g., October to December).

Table 14-87: 2042 Night Peak Case Summary.

Resource	Dispatch	% Load supplied
Storage	20.00 MW	11.6%
PV	0.000 MW	0.0%
HYDRO	48.330 MW	27.9%
WIND	28.00 MW	16.2%
THERMAL	16.525 MW	9.6%
BELIZE GEN.	84.855 MW	65.3%
MEXICO	88.067 MW	34.7% (import)

Table 14-88: 2042 Night Peak Case Dynamic Case.

PSSE Bus	Name	Dynamic case		Pmax
		Status	Pgen	
313	Vientos del Caribe 1	ON	12	15
313	Vientos del Caribe 2	ON	8	10
313	Vientos del Caribe 3	ON	8	10
2321	Westlake GT	ON	6.2	0
2334	Storage Ladyville	ON	5	10
2335	PV Ladyville	OFF	0	20
2379	PV West 1	OFF	0	20
2380	PV West 2	OFF	0	20
2393	PV La Democracia 1	OFF	0	20
2394	PV La Democracia 2	OFF	0	20
2422	Hydro Maya	ON	2.25	2.5
2469	Storage Independence	ON	5	10
2470	RICE Independence	ON	1.2	7.5
2531	RICE Bapcol 1	ON	1.2	7.5
2532	RICE Bapcol 2	ON	1.2	7.5
2533	RICE Bapcol 3	ON	1.2	7.5
2546	RICE Dangriga 1	ON	1.2	7.5
2546	RICE Dangriga 2	ON	1.2	7.5
2583	Chalillo 1	ON	3.15	3.5
2583	Chalillo 2	ON	3.15	3.5
2593	Mollejon 1	ON	7.56	8.4
2593	Mollejon 2	ON	7.56	8.4
2593	Mollejon 3	ON	7.56	8.4
2595	Vaca 1	ON	8.55	9.5
2595	Vaca 2	ON	8.55	9.5
2652	PV Maskall	OFF	0	20
2694	Mexico	ON	60.07	100
2707	PV Chan Chen	OFF	0	20
2711	PV O Walk	OFF	0	20
2726	Belcogen	ON	3.125	0
2743	Storage San Pedro	ON	5	10
2795	Storage OWK	ON	5	10
2826	Santander	OFF	0	8

14.10.7 2042 Night Peak Case – Dynamic Simulation Results

The table below provides a summary of the stability analysis results for the nighttime peak. As before the first contingency in the list corresponds to opening the facility with no fault and the second with a 3-phase fault opened in 5 cycles.

As we note in this table contingences F01 to F06 that interrupt the flow from Mexico to the bulk of BEL system require some level of load shed. Particularly contingencies F01/02 that sever the supply from Mexico and the Mexico Wind require the largest level of load shed, followed by contingency F05/06 that in addition separated Belcogen and load.

F07/08 have severe over-frequency as an island with hydro generation and load is formed with significant over-generation. Possibly a transfer trip could address this. Finally, as before contingency F12 that results in the isolation of Independence and Punta Gorda, could result in the collapse of the electric island due to underfrequency.

Table 14-89: 2042 Night Peak Case Dynamic Simulation Summary.

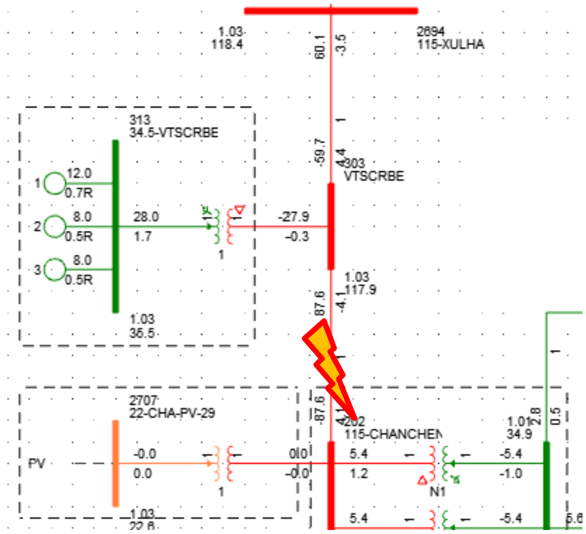
Contingency	Frequency Event	Load shedding	Comments
F01 Line trip V. del Caribe – Chan Chen	Underfrequency 57.74 Hz	Yes, 46.3 MW	Stable
F02 3PF V. del Caribe – Chan Chen	Underfrequency 57.74 Hz	Yes, 46.3 MW	Stable
F03 Line trip V. del Caribe – Xul-Ha	Underfrequency 58.5 Hz	Yes, 6.4 MW	Stable
F04 3PF V. del Caribe – Xul-Ha	Underfrequency 58.25 Hz	Yes, 6.4 MW	Stable
F05 Line trip Chan Chen – Belcogen	Underfrequency 58.0 Hz	Yes, 30.4 MW	Stable
F06 3PF Chan Chen – Belcogen	Underfrequency 58.0 Hz	Yes, 30.4 MW	Stable
F07 Line trip Camalote – La Democracia	Over-frequency 64.9 Hz	No	Probable trip of hydro units
F08 3PF Camalote – La Democracia	Over-frequency 64.9 Hz	No	Probable trip of hydro units
F09 Line trip San Ignacio – Vaca Tap - Mollejon	No	No	Stable
F10 3PF San Ignacio – Vaca Tap -Mollejon	No	No	Stable
F11 Line trip Bapcol Tap to Savannah	Underfrequency 57.3 Hz	Yes, 8.7 MW	Stable
F12 3PF Bapcol Tap to Savannah	Underfrequency 56.6 Hz	Yes, 8.7 MW	Probable collapse of the island

The next sections below provide details of these contingencies.

F01 and F02: Loss of Vientos del Caribe – Chan Chen (115 kV Line)

The loss of the line results in a large load-generation imbalance. The transmission line was supplying 87.6 MW to the Belize power system which represents 50.9% of the total load served.

Figure 14-75: F01 and F02: Loss of Vientos del Caribe – Chan Chen (115 kV Line)



The initial response of the Storage (+20 MW) and the Mile 8 GT for the frequency control results insufficient. The load shedding scheme was critical to restore the grid frequency and to avoid a frequency collapse. This can be appreciated in Figure 14-76 where we see that the frequency minimum was 57.74 Hz for both contingencies (F01 and F02) and to achieve this, three stages of load shed were activated (30% shed) and the total load shed was 46.3 MW.

Figure 14-77 below shows that the Storage and the Westlake GT reacted rapidly to the frequency drop, reaching their maximum or near maximum output and are key units for the frequency control. Hydro and the RICE units have much slower response time, in particular the Hydro that initially moves in the opposite direction, reducing its output.

Figure 14-76: F01 & F02 Loss of Vientos del Caribe – Chan Chen (115 kV Line)

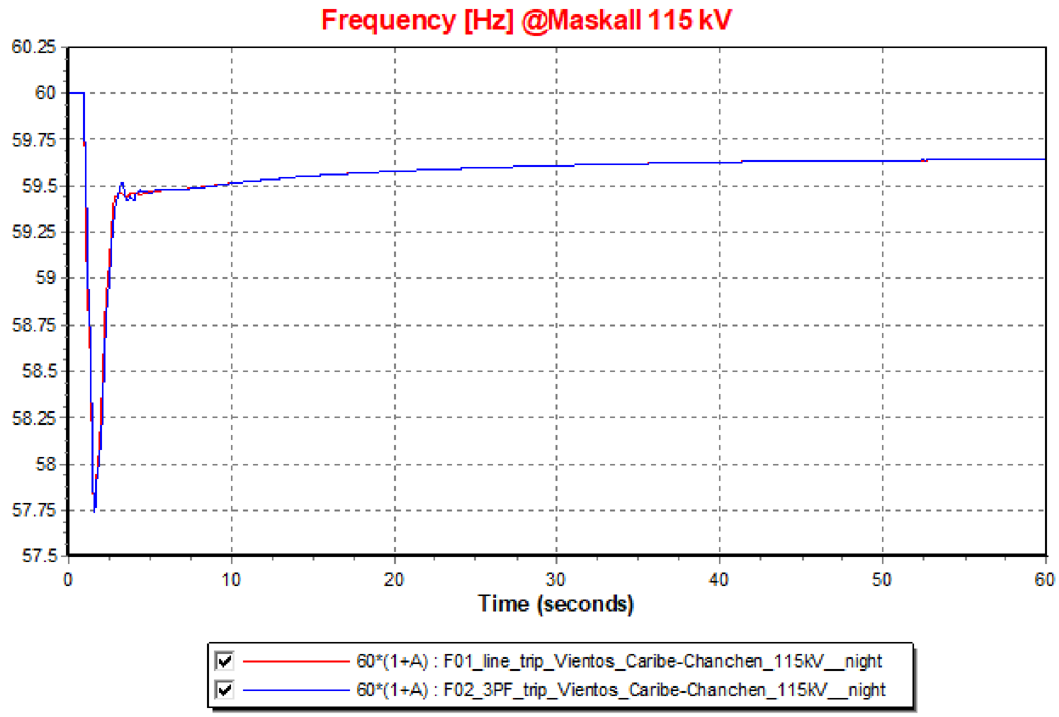
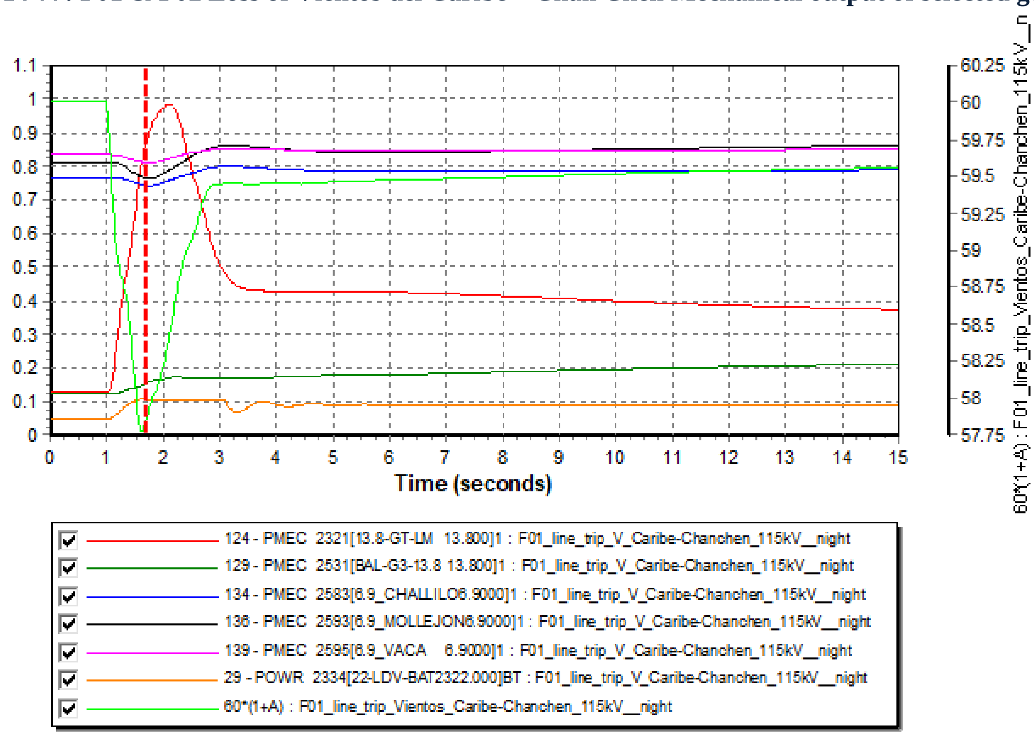


Figure 14-77: F01 & F02 Loss of Vientos del Caribe – Chan Chen Mechanical output of selected generators



As shown in the figures below the voltage recovered to acceptable values within 1 seconds entering the ± 10% band for the opening of the line (F01) or the short-circuit (F02).

Figure 14-78: F01 Loss of Vientos del Caribe – Chan Chen (115 kV Line)

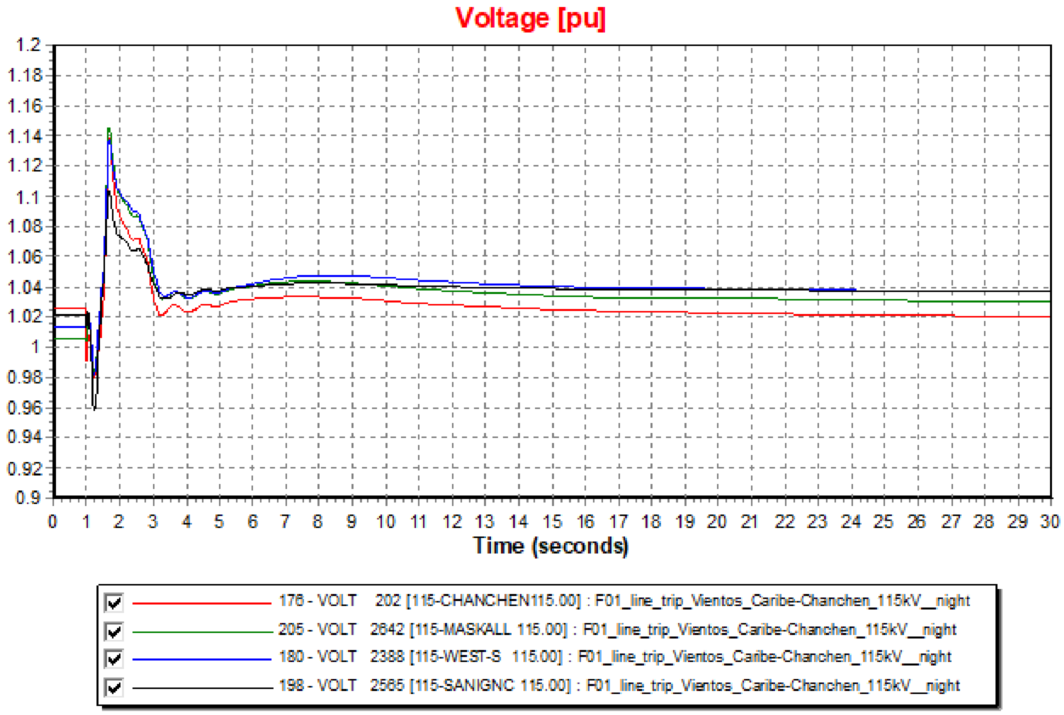
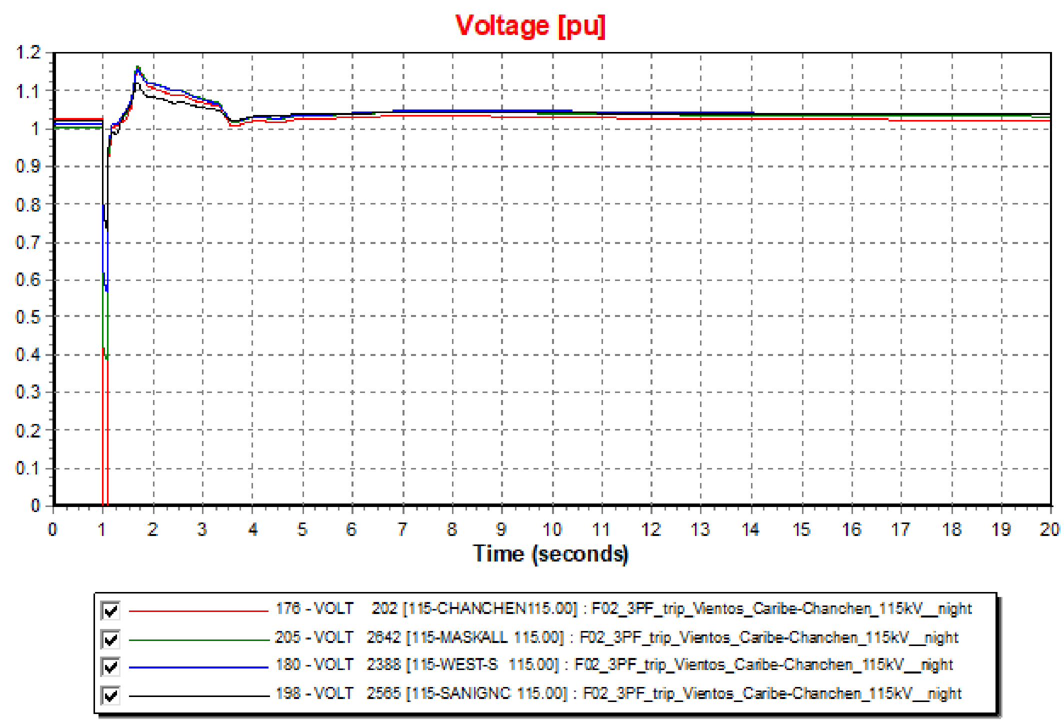


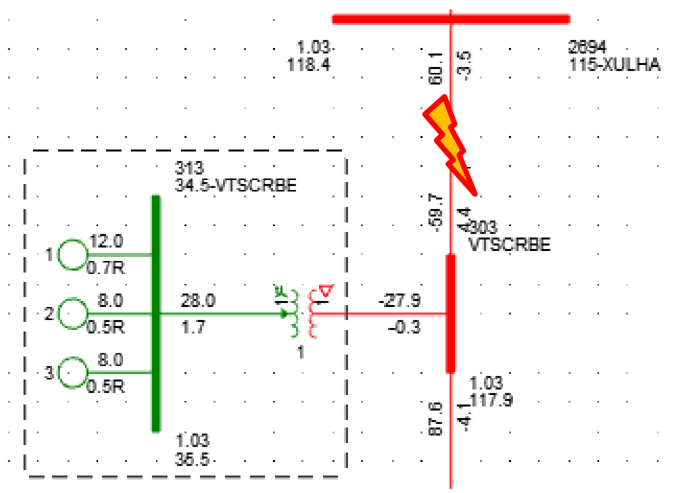
Figure 14-79: F02 Loss of Vientos del Caribe – Chan Chen (115 kV Line)



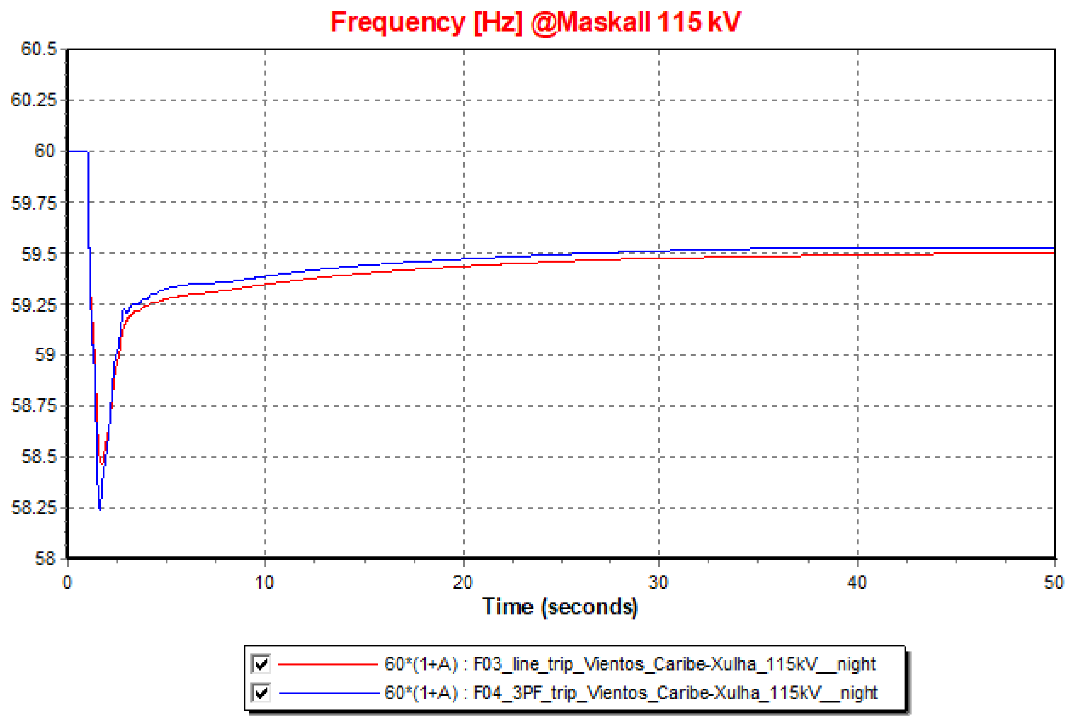
F03 & F04 Loss of Vientos del Caribe – Xul-Ha (115 kV Line)

This contingency is similar to the loss of Vientos del Caribe – Chan Chen 115 kV line but in this case the loss of the interconnection with Mexico represents 34.7% of the generation, as the Mexico wind remains connected to BEL and the load shed was only 5% (stage 1) equal to 6.4 MW.

Figure 14-80: F03 & F04 Loss of Vientos del Caribe – Xul-Ha (115 kV Line)



With the sudden line trip (F03), the underfrequency reached 58.5 Hz and is controlled by the Storage and the LM2500 GT (Mile 8), see red trace in figure below. For the short-circuit the frequency reached 58.25 Hz (blue trace).



As shown in the following figures the voltage never left the acceptable band for the opening of the line (F03) and recovered to acceptable values in less than 1 second for the short-circuit.

Figure 14-81: F03 Loss of Vientos del Caribe – Xul-Ha (115 kV Line)

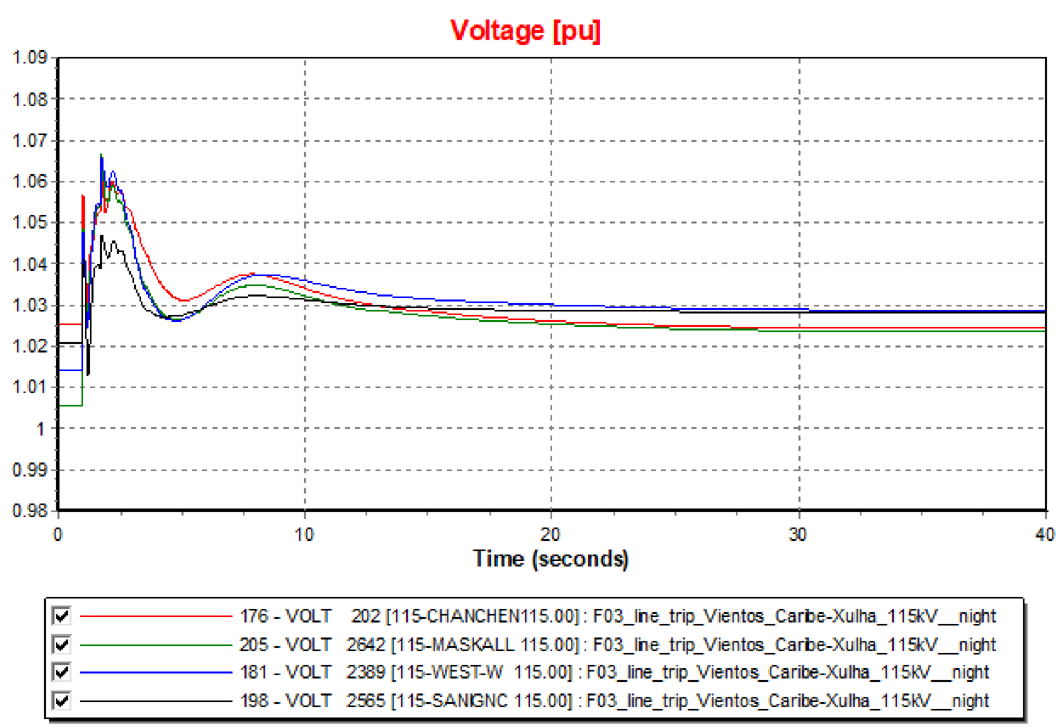
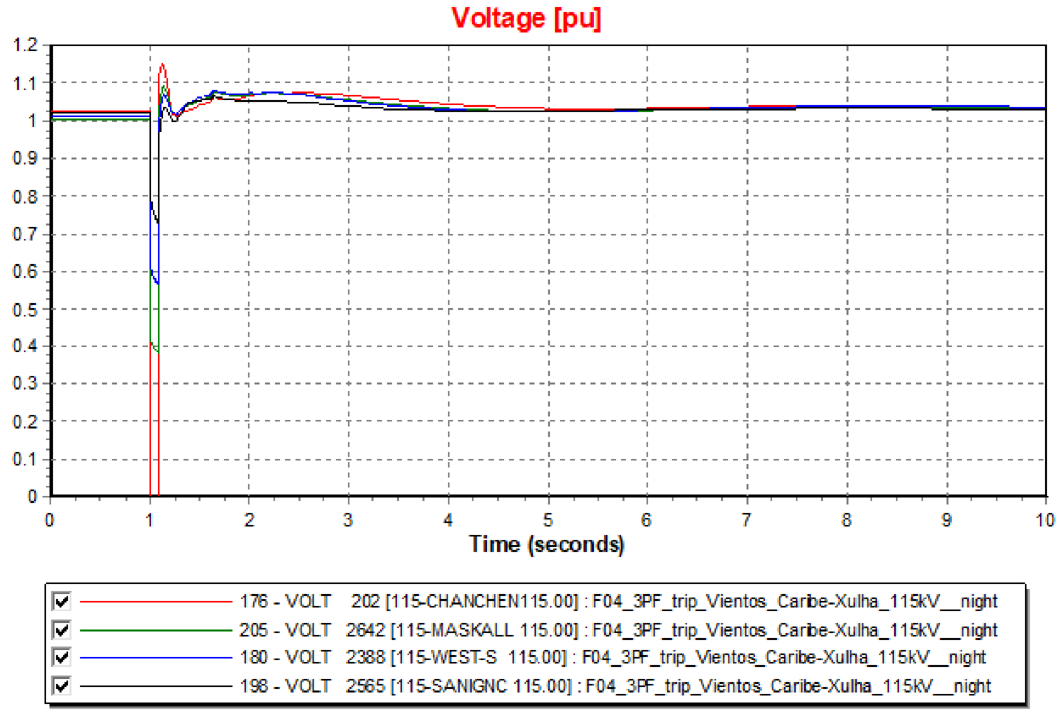


Figure 14-82: F04 Loss of Vientos del Caribe – Xul-Ha (115 kV Line)



F05 & F06 Loss of Chan Chen – Belcogen (115 kV Line)

As described for the daytime peak, this contingency results in the separation of the Belize power grid in two islands and the interconnection with Mexico is lost for the island to the south that loses 74 MW of generation that was coming from the north, see figure below. This large generation-load imbalance resulted in a large underfrequency condition. The load shed relays tripped 30% of the load (3 stages) and the frequency minimum resulted of 58.0 Hz for both faults (see Figure 14-84). The total load shed was 30.4 MW.

Figure 14-83: F05 & F06 Loss of Chan Chen – Belcogen (115 kV Line)

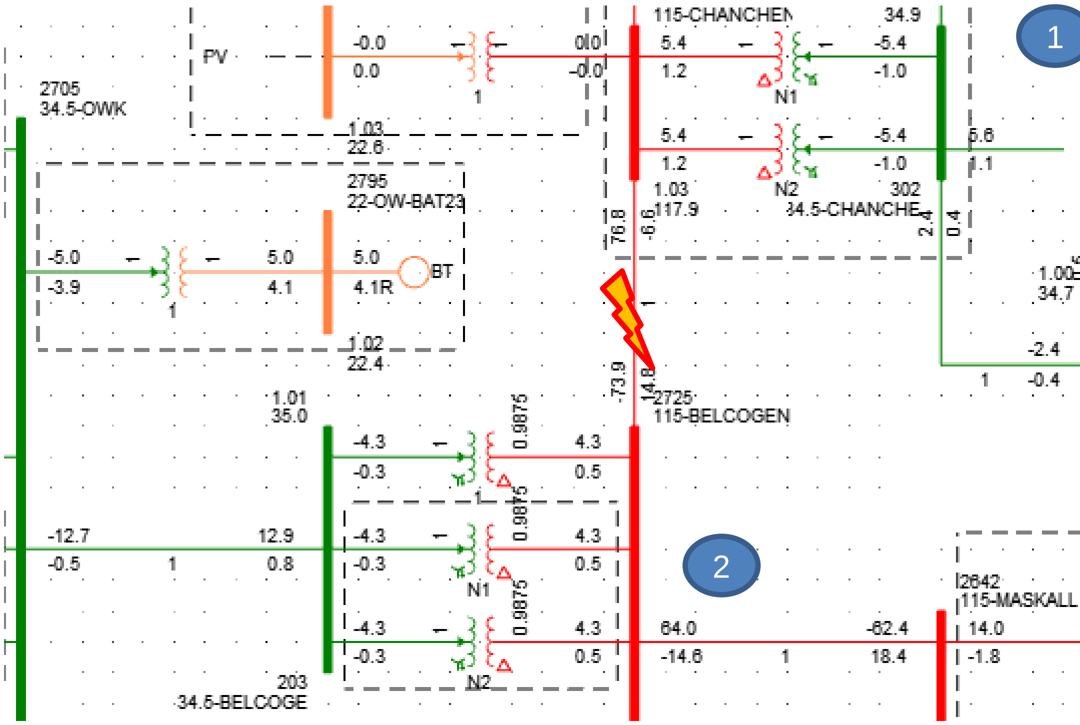
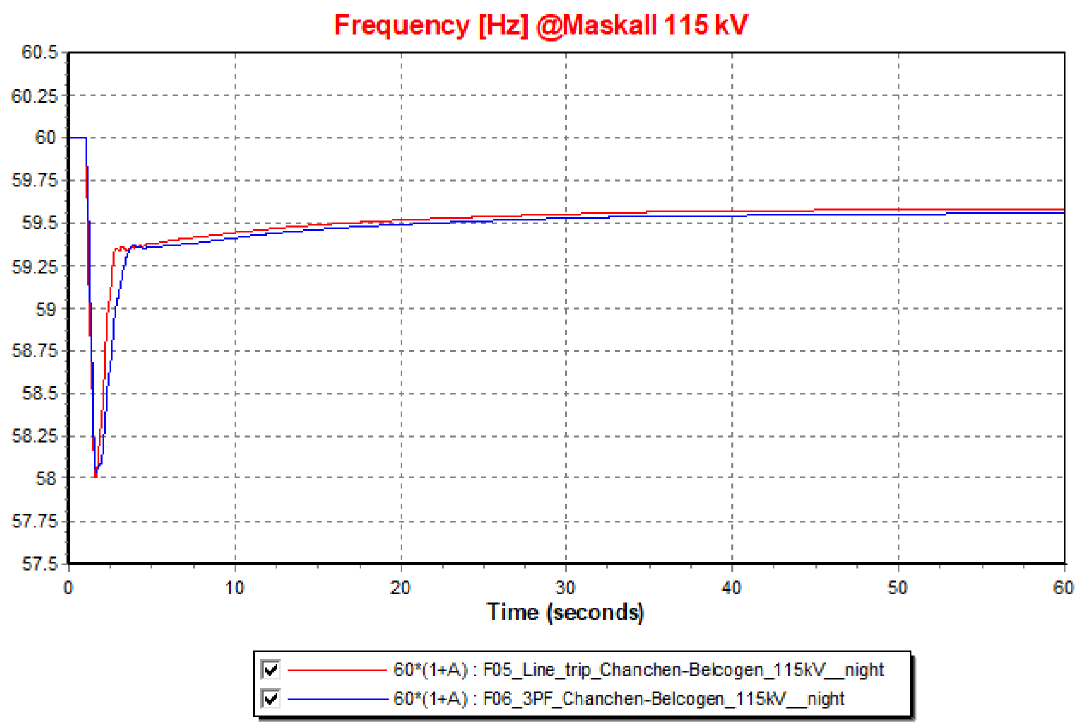


Figure 14-84: F05 & F06 Loss of Chan Chen – Belcogen (115 kV Line)



As shown in the following figures the voltage response remained largely within the acceptable range ±10% for both the short circuit event (F06) or and the opening of the line (F05), with very short exceptions.

Figure 14-85: F05 Loss of Chan Chen – Belcogen (115 kV Line)

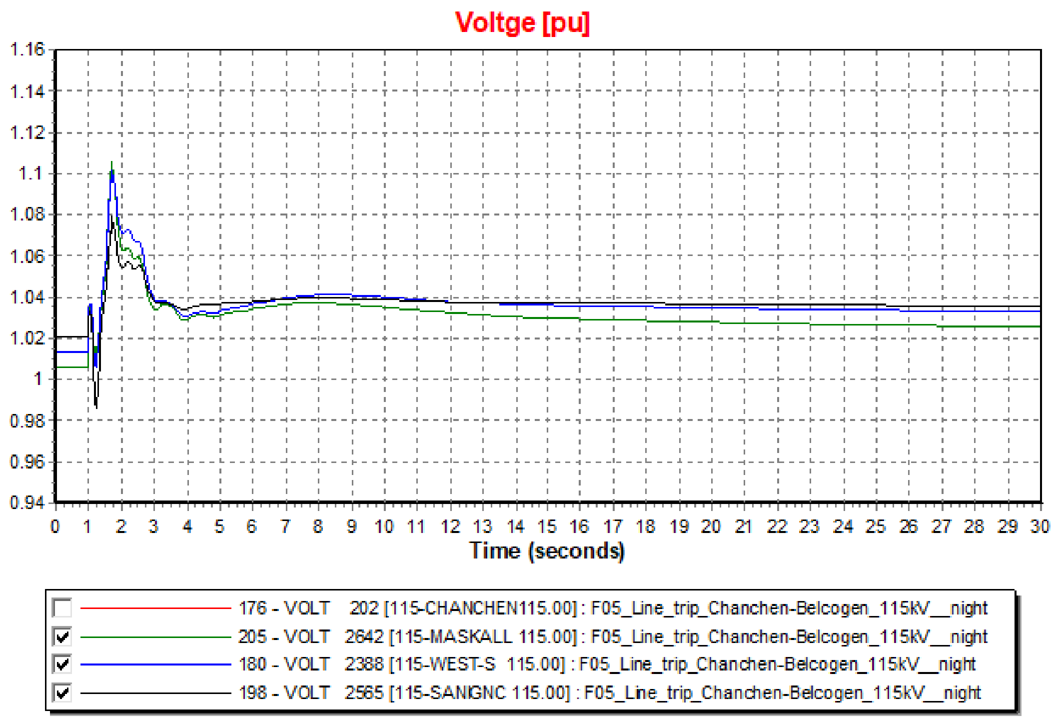
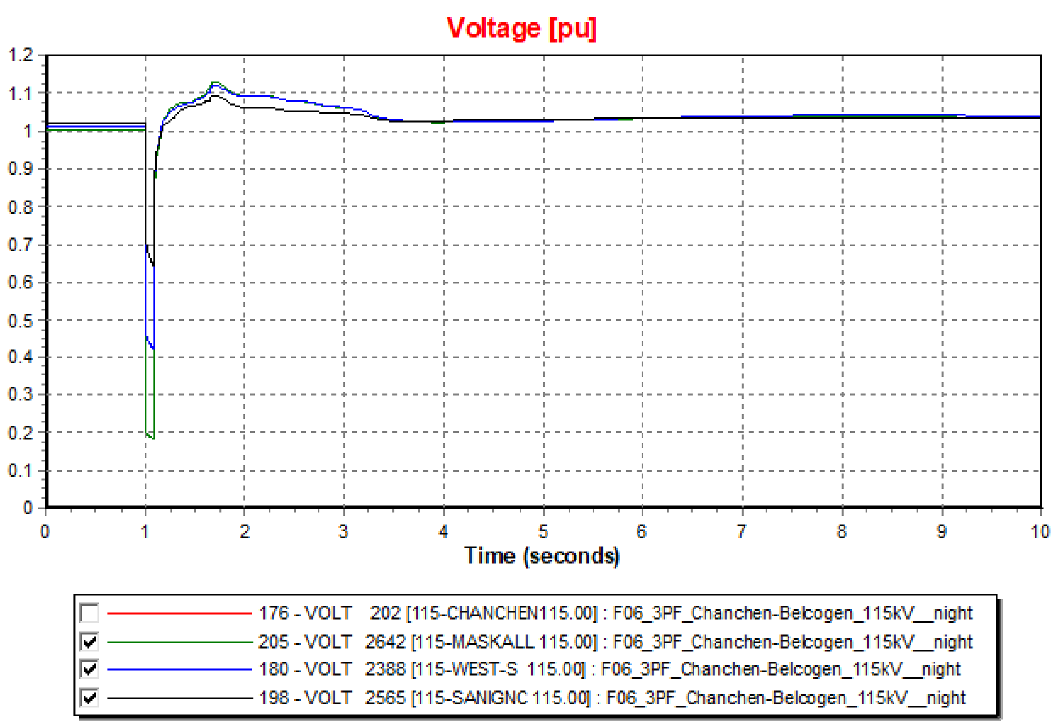


Figure 14-86: F05 Loss of Chan Chen – Belcogen (115 kV Line)



F07 & F08 Loss of Camalote – (Santander) - La Democracia (115 kV Line)

Prior to the contingency the hydro plants were operating near maximum load and active power flow from Camalote to La Democracia substation was 10.5 MW. The loss of the line creates a large load-generation unbalance for the island conformed by Camalote-San Ignacio-Belmopan and the hydro plants.

The island experienced a large over-frequency that reached a peak value of 64.9 Hz (see Figure 14-88) and could result in the tripping of the generation offline by the generator over-frequency/overspeed protection. The impact on the balance of the Belize power grid is negligible.

Similarly, to the day peak condition, one potential solution is to coordinate the generation from the hydro plants with the active power flow through the contingency line and perform a transfer trip to the generation as required.

Figure 14-87: F07 & F08 Loss of Camalote – (Santander) - La Democracia (115 kV Line)

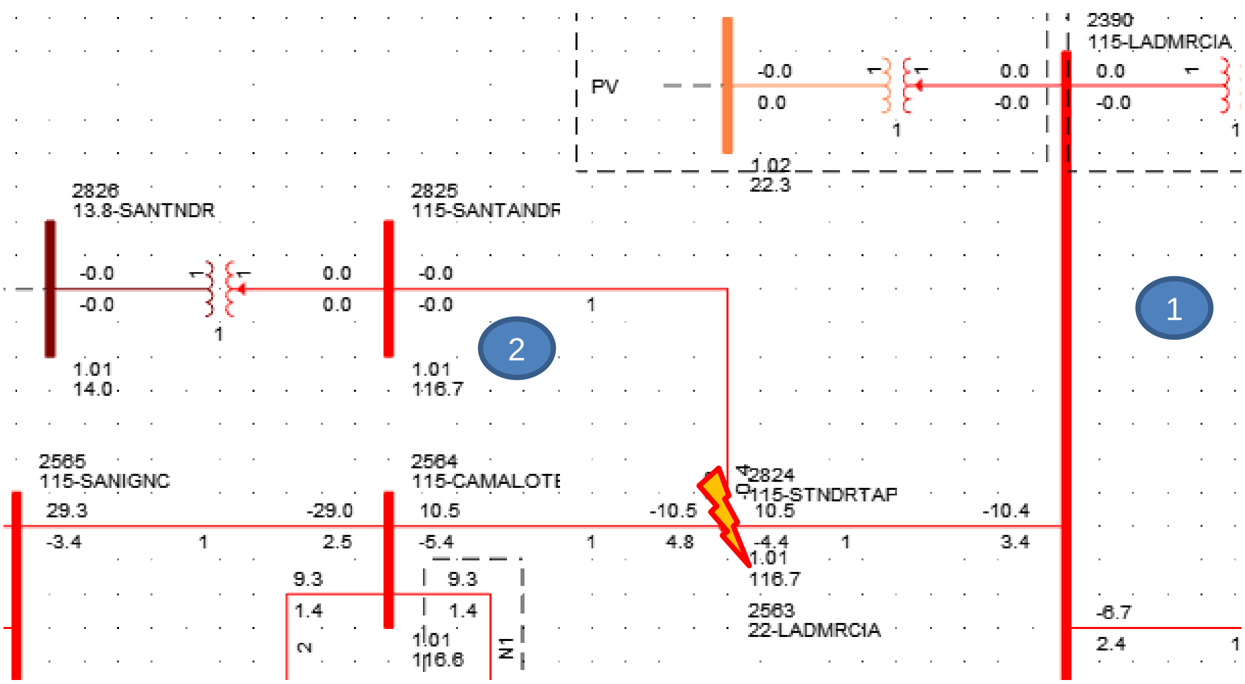
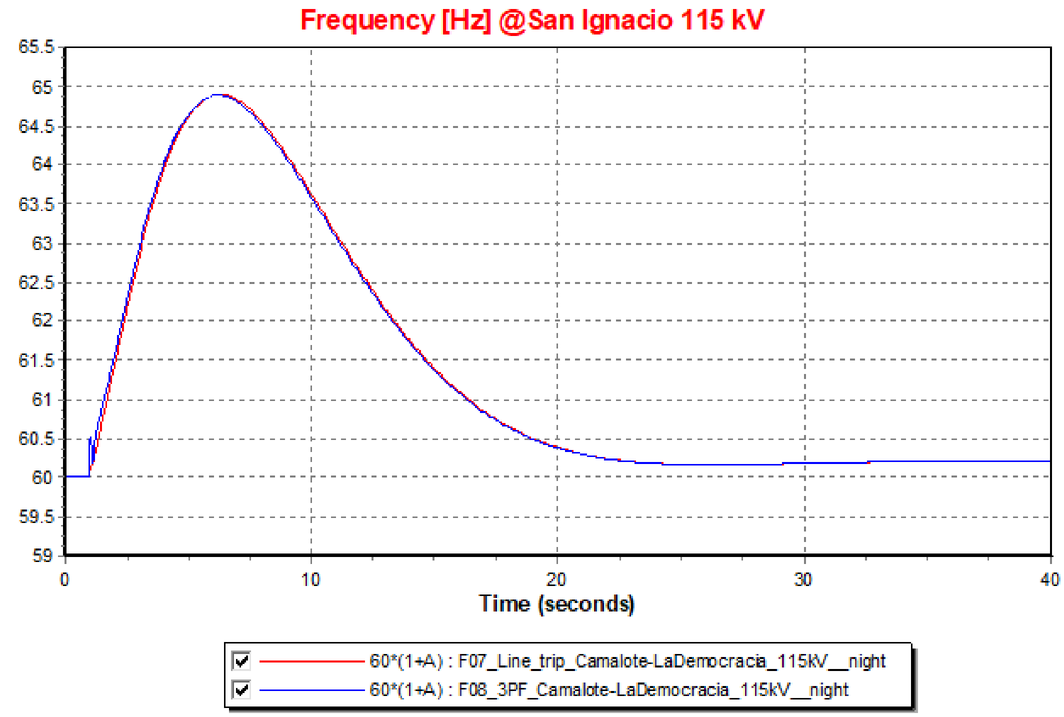


Figure 14-88: F07 & F08 Loss of Camalote – (Santander) - La Democracia (115 kV Line)



In general, there were no voltage issues as shown below.

Figure 14-89: F07 Loss of Camalote – (Santander) - La Democracia (115 kV Line)

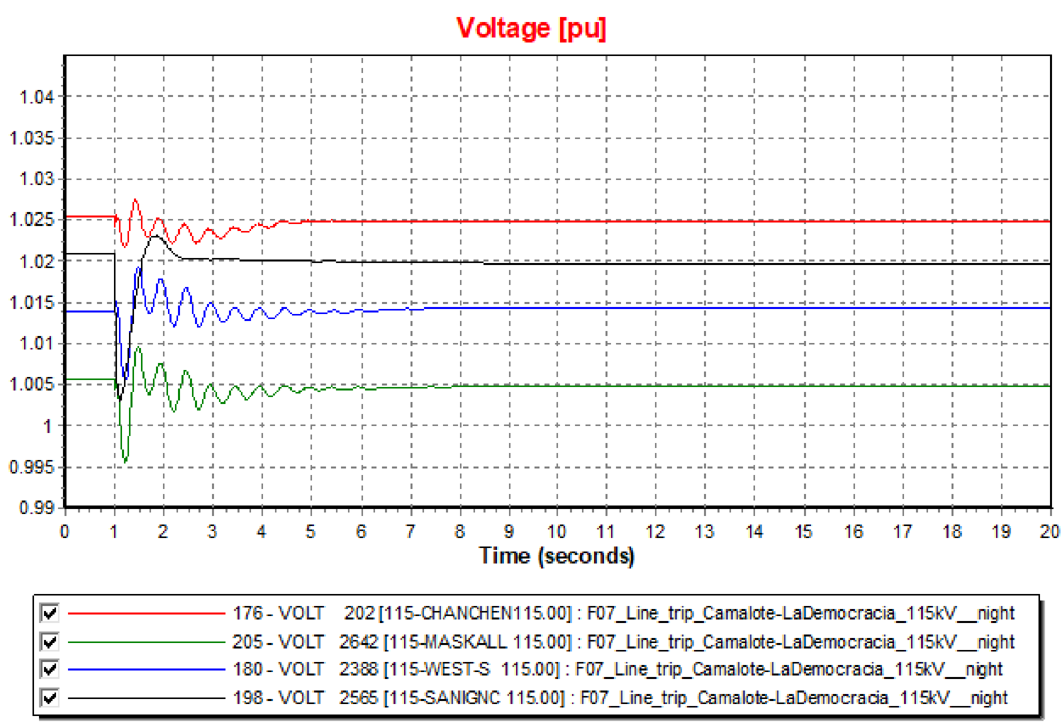
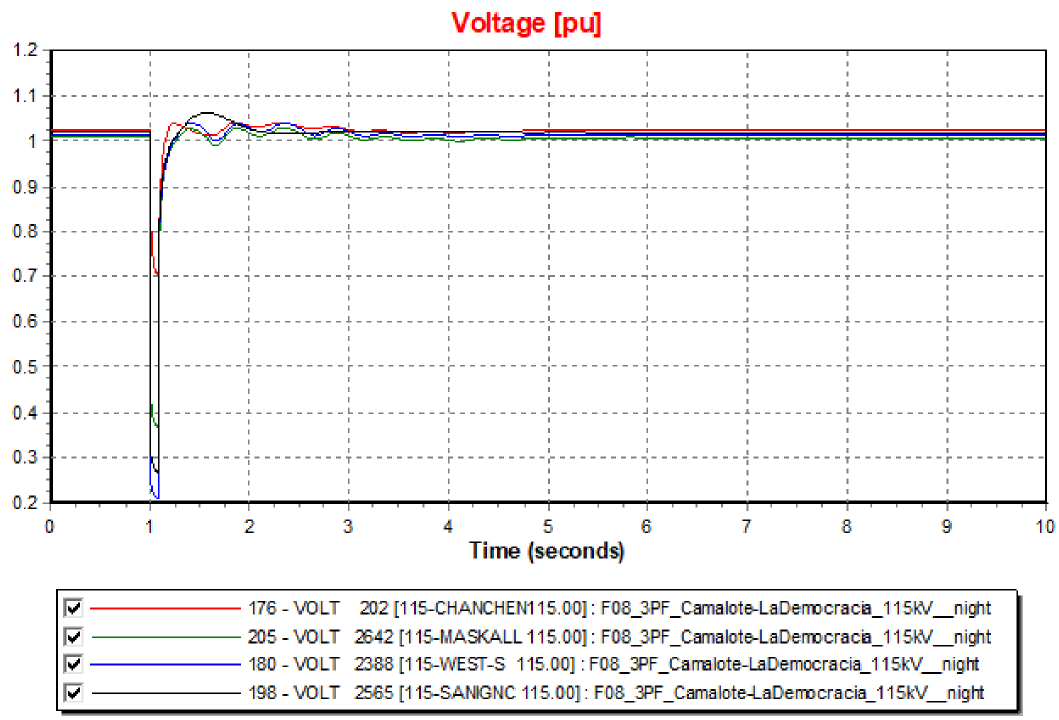


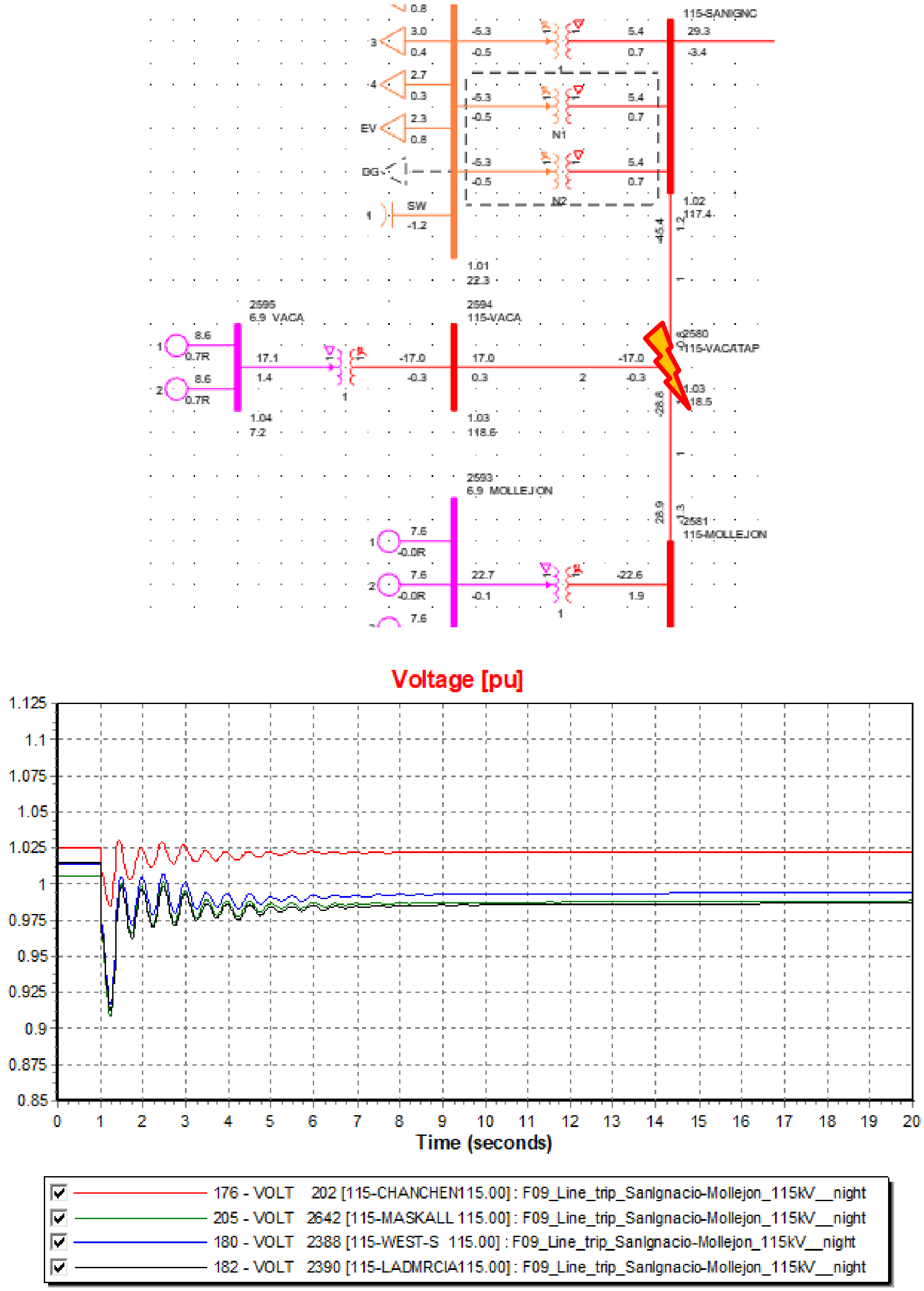
Figure 14-90: F08 Loss of Camalote – (Santander) - La Democracia (115 kV Line)



F09 & F10 Loss of San Ignacio – Vaca tap (115 kV Line)

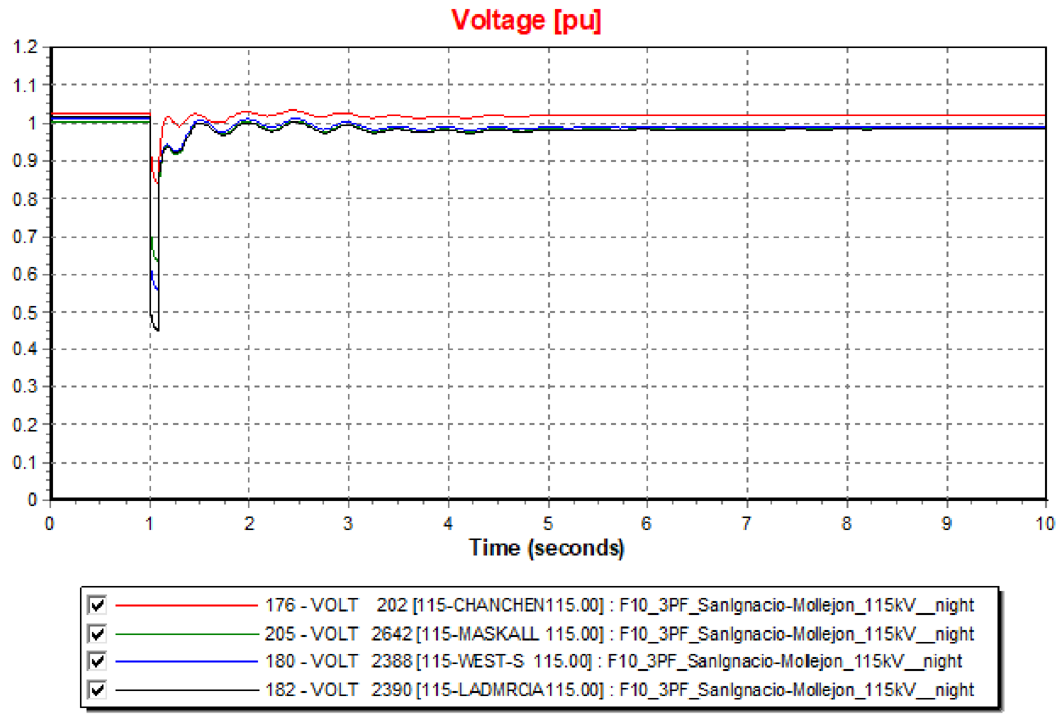
The contingency results in the loss of 45.9 MW generated by the hydro plants, as shown in the figure below. The impact on the grid frequency is minimal as because the interconnection with Mexico that is maintained.

Figure 14-91: F09 & F10 Loss of San Ignacio – Vaca tap (115 kV Line)



The voltage response is adequate as shown below for the short-circuit fault.

Figure 14-92: F10 Loss of San Ignacio – Vaca tap (115 kV Line)



F11 & F12 Loss of Bapcol – Savannah (69 kV Line)

The contingency results in the formation of a 69 kV island between Independence – Savannah and Punta Gorda substations (Island 2 in the figure below).

Prior the contingency the active power flow from Bapcol to Savannah was of 11.0 MW. There is a large frequency deviation and for both contingencies (F11 and F12) the load shedding scheme trip 50% of load of the affected area. The total load shed was 8.7 MW

As shown in Figure 14-94, the sudden line trip (F11) results with a frequency minimum of 57.3 Hz. The three phase fault results in very low frequency minimum of 56.6 Hz and may trip generation.

To prevent this large frequency excursion one potential solution is to coordinate the generation at the RICE plant with the active power flow through the contingency line and immediately trip load and send a signal to the storage to discharge to full power without delay.

Figure 14-93: F11 & F12 Loss of Bapcol – Savannah (69 kV Line)

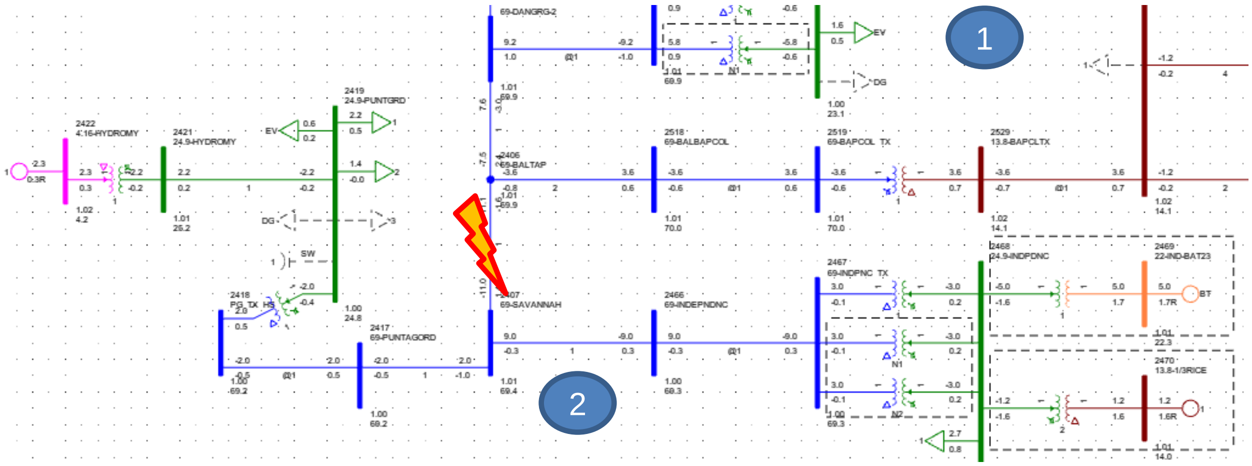
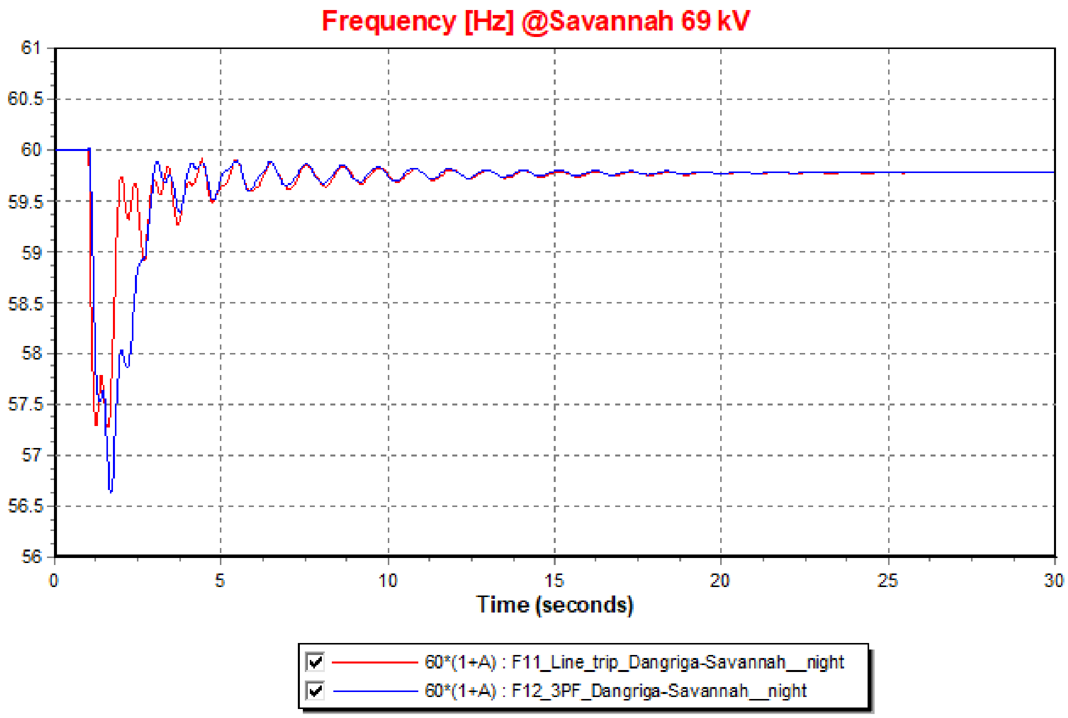


Figure 14-94: F11 & F12 Loss of Bapcol – Savannah (69 kV Line)



14.10.8 Stability Assessment - Conclusions

The Battery Energy Storage Systems and the Westlake GT resulted critical for the primary frequency control.

During peak load – day or night – the Storage needs to operate with sufficient margin to the full charging/discharging capacity in case they need to provide frequency support.

The reconversion of the GE LM2500 to synchronous converter results critical to provide inertia and adequate short-circuit level for high renewable penetration conditions such as the day peak (90% inverter-based generation).

PV plants resulted critical for controlling grid frequency during day peak condition. PV plants must be incorporated to the Belize grid with over-frequency control capabilities.

A proper load shedding scheme results critical for the frequency restoration during critical contingencies at night peak condition where large amount of active power is expected to be imported from Mexico (51%).

15.Transmission Action Plan

As can be observed in the prior section, BEL transmission system can transition to become a reliable state-of-the-art system by the implementation of targeted investments in the system and leveraging the assets that are recommended from the capacity expansion plan.

The Action Plan presented below considers two level of investments: a) the Minimum Investments and b) the Recommended Investments which expand the first group to achieve recommended performance. We detail these groups below.

The Minimum Investments are those necessary to address expected overloads under normal operating conditions that, in this case, are defined overloads beyond the ONAF (emergency rating) of the transformers. Note, however, that in general the ONAF (emergency) ratings are used to address contingencies and unforeseen increases in load, thus for system intact or N-0, the normal ONAN rating is preferred. This was not the case for the selection of these Minimum Investments. Whenever a transformer is beyond its ONAN rating, we call it heavily loaded.

Additionally, these investments include the bringing up to code and standards Santander, San Pedro, Corozal and Orange Walk as this is necessary for the availability of the generating resource for the first and the reliable supply of the load for the balance.

The Recommended Investments are those necessary to provide firm capacity (N-1 Security) at the substations to address the loss of a transformer and prevent the parallel (if one is present) to overload beyond its maximum emergency (ONAF) ratings. In addition, in some cases these investments also address heavy loadings as mentioned above.

The table below provides a summary of the minimum required investments and the in-service dates to address the projected overloads. BEL should use these dates as guide for starting the engineering and procurement process. The 2023 projects are associated with ongoing projects or require replacement of an asset inside a substation. Other projects have at least two years leeway or three in the case of new transmission additions.

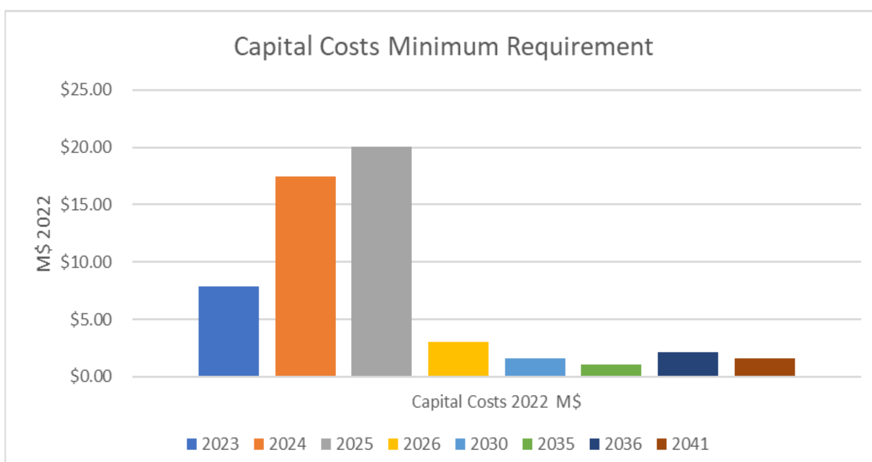
Table 15-1: Minimum Required Investments US$ 2022

Investment	Capital Costs 2022 M$	Overload Required Date	Load Affected MW	Notes
San Pedro 2 34.5/22 kV transformer	$0.49	2023	5.48	This is the smaller 5.4/7 MVA transformer to be replaced by BEL in 2023
Orange Walk transformer 1 34.5/22	$0.12	2023	6.03	San Pedro relocated here
Santander standardization	$1.75	2023	N/A	The substation layout is not up to code and standards (BEL reported)
La Democracia to Dangriga 115 kV transmission line	$15.67	2024	18.20	Required for RICE interconnection & reliability
San Pedro standardization	$1.75	2024	13.33	The substation layout is not up to code and standard (BEL reported)
Corozal standardization	$1.25	2025	7.33	The substation layout is not up to code and standards (BEL reported)
Orange Walk standardization	$1.25	2026	10.33	The substation layout is not up to code and standard (BEL reported)
Independence Transformer 1	$1.78	2026	9.01	N-1 main concern. ONAN currently exceeded
Belmopan 115/22 kV	$1.07	2035	16.97	N-1 main concern. ONAN currently exceeded
Maskall to San Pedro 69 kV Supply	$18.85	2025	17.51	by 2025 the cable will overload
San Pedro to Caye Caulker 34.5 kV cable	$5.46	2023	17.51	Ongoing project BEL
San Pedro 1 34.5/22 kV transformer	$1.63	2030	7.85	Existing XFR currently loaded above ONAN
San Ignacio transformers	$2.10	2036	8.96	N-1 main concern and loaded above ONAN by 2025
Chan-Chen transformers	$1.57	2041	5.95	N-1 main concern and loaded above ONAN by 2034
Total	**$54.73**			

These projects total US$ 54.73 million and are grouped as shown below by year. We observe that most of the investments are required by 2025 and 2026.

Table 15-2: Minimum Required Investments by year US$ 2022

Year	Capital Costs 2022 M$
2023	$7.83 $5.93
2024	$17.42 $15.26
2025	$20.10 $18.42
2026	$3.03 $1.78
2030	$1.63 $1.63
2035	$1.07 $1.07
2036	$2.10 $2.10
2041	$1.57 $1.57
Total	**$54.73 $47.75**



The Recommended Investments include the investments above, but they may be advanced in this table as for example to provide firm capacity (N-1 security) before the overload is present. We note below that all investments that require new transmission have in service dates of 2024 or 2025, although it is recognized that investments like the new Dangriga 115 kV line may experience further delays.

Table 15-3: Recommended Investments US$ 2022

Investment	Capital Costs 2022 M$	Planning Recommended Date	Load Affected MW	Notes
San Pedro 2 34.5/22 kV transformer	$0.49	2023	5.48	This is the smaller 5.4/7 MVA transformer to be replaced by BEL in 2023
Orange Walk transformer 1 34.5/22	$0.12	2023	6.03	San Pedro relocated here
Santander standardization	$1.75	2023	N/A	The substation layout is not up to code and standards (BEL reported)
Corozal Transformer	$1.15	2023	3.78	N-1 main concern
Orange Walk transformers 34.5/6.6	$1.15	2023	5.19	N-1 main concern
Orange Walk transformer 2 34.5/23	$1.15	2023	6.03	N-1 main concern. ONAN exceeded by 2030
La Democracia to Dangriga 115 kV transmission line	$15.67	2024	18.20	Required for RICE interconnection & reliability
San Pedro standardization	$1.75	2024	13.33	The substation layout is not up to code and standard (BEL reported)
Corozal standardization	$1.25	2025	7.33	The substation layout is not up to code and standards (BEL reported)
Orange Walk standardization	$1.25	2026	10.33	The substation layout is not up to code and standard (BEL reported)
Dangriga transformers	$1.61	2024	7.02	N-1 main concern. ONAN exceeded by 2035
Independence Transformer 1	$1.78	2024	9.01	N-1 main concern. ONAN currently exceeded
Belmopan 115/22 kV	$1.07	2024	16.97	N-1 main concern. ONAN currently exceeded
Santander tap to Belmopan 115 kV line section and substation upgrade	$1.25	2024	16.97	N-1 main concern
Belmopan 22/11 kV second unit	$1.10	2024	6.33	N-1 main concern
North Ladyville to Belize II 115 kV Transmission line	$10.66	2025	9.28	Reliability of Belize Metropolitan District
Switching substation North Ladyville	$1.42	2025	18.44	
New Belize II 115/22 kV substation	$7.10	2025	18.44	
Maskall to San Pedro 69 kV Supply	$18.85	2025	17.51	by 2025 the cable will overload
San Pedro to Caye Caulker 34.5 kV cable	$5.46	2023	17.51	Ongoing project BEL
San Pedro 1 34.5/22 kV transformer	$1.63	2026	7.85	Existing XFR currently loaded above ONAN
San Ignacio transformers	$2.10	2026	8.96	N-1 main concern and loaded above ONAN by 2025
Chan-Chen transformers	$1.57	2026	5.95	N-1 main concern and loaded above ONAN by 2034
Belcogen transformers	$1.72	2026	10.31	N-1 main concern. ONAN exceeded by 2027
Independence Transformer 2	$0.49	2026	9.01	Existing XFR currently loaded above ONAN
Belmopan 115/22 kV second unit	$0.49	2035	20.53	Replacing existing with larger capacity unit
Total	**$84.02**			

These projects total US$ 84.0 million and are grouped as shown below by year. We observe that most of the investments are required by 2024 and 2025.

Table 15-4: Recommended Investments by year US$ 2022

Year	Capital Costs 2022 M$
2023	$11.27
2024	$24.22
2025	$39.28
2026	$8.76
2035	$0.49
Total	**$84.02**

The cost for interconnection of new generation to the system, i.e., the gen-tie or line from the project to a BEL's substation and the cost of a new breaker bay at that substation, are normally included in the project's unit costs and are not in the costs above. However, as these costs will be funded by BEL and included in the rate-base instead of the PPA price, for the estimation of the delivery costs they were extracted from the PPA and added to the rest of transmission costs. A gen tie of 5 miles at 34.5 kV and one 34.5 breaker bay was assumed for each project with a cost 2022$ of $1.23 million.

Finally, from the stability analysis the following recommendations are derived:

d) The LM 2500 at Mile 8 should be modified so that it can easily transition from regular CT to a Synchronous Condenser with the use of a clutch. Also, its minimum load should be set up as low as possible as in the long term this unit will provide largely spinning reserves at night.

e) The storage must have frequency controls much like the governors in a conventional generator with adjustable droop.

f) Solar PV and wind generation must also have frequency controls much like the governors in a conventional generator with adjustable droop. Although most of the time this governor will actuate to reduce generation, the positive direction (reg-up) must also be available in case the resource is being curtailed.

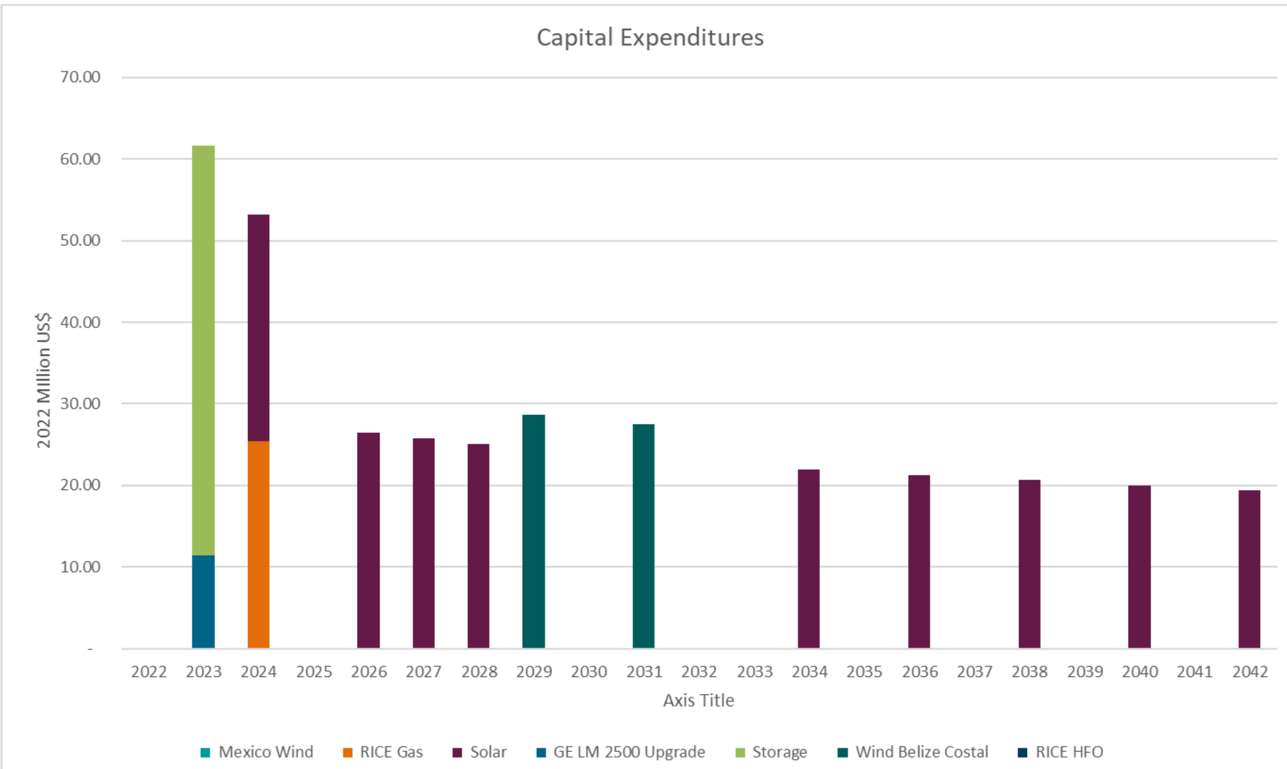
16. Cost of Delivery Impacts

16.1 Introduction

In this last section of the report, we provide an estimation of the total expected cost of delivery combining the transmission and supply costs presented in the prior sections.

For supply side we used the recommended Belize Centric Expert Plan whose capital expenditures by year we presented in Section 12 and summarized in the figure below.

Figure 16-1: Belize Centric Expert Design CapEx by Year



The dates shown are the earliest recommended and we realize that there could be delays given the issues currently affecting the renewable energy industry.

On these investments the Storage and the LM2500 repowering are funded by BEL, thus in the annual cost calculation they are treated in the same way as the transmission investments as a Regulated Asset. Regulated Assets (also called Rate Base) are modeled with a rate of return of 8% on the undepreciated balance plus the O&M expenditures.

The balance of the expenditures is assumed to be developed by third parties that will receive a PPA price estimated considering a) the return on capital expenditures with a Capital Cost Recovery factor derived from a cost of equity of 15%, a cost of debt of 7.2%, a 40%/60% equity / debt structure and the asset life as presented in Section 7.1.1. and b) the fixed and variable O&M.

For transmission expansion we considered both the expansion plan recommended to meet the proposed planning criteria that results in a reliable system with minimum interruptions due to the fault of a single element (see Table 15-4) and the minimum investments required to prevent overloads beyond the emergency rating of equipment (see Table 15-2). An additional O&M is added to the cost considering that in average the yearly O&M costs can be estimated as 2.5% of the invested capital.

To estimate the total delivery costs both the costs of the existing PPAs and the costs of the existing transmission need to be added the cost of the new resources in the Belize Centric Scenario and the new transmission costs.

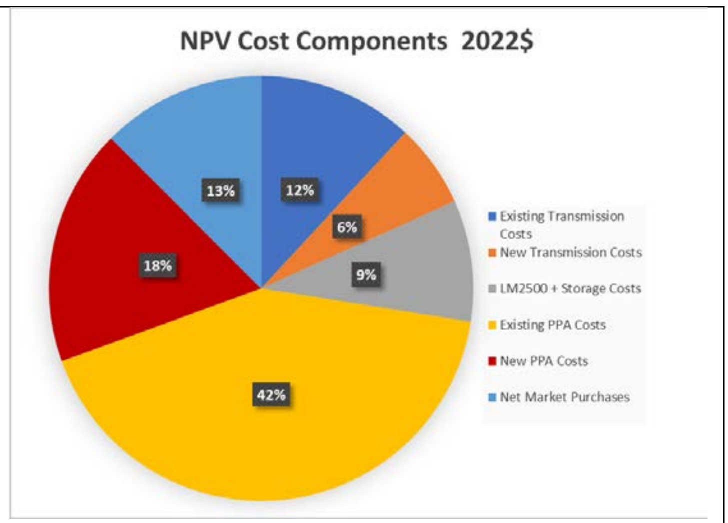
The projected cost of the current PPAs (Biomass, BAPCOL RICE and Hydro) were presented earlier in this report (see Section 6) and for the existing transmission BEL provided the undepreciated Regulated Assed Values for substations and transmission lines as well as the depreciation allowance that was used to project the return considering the rate of return of 8% on the undepreciated balance plus the O&M expenditures estimated as 2.5% of the Reproduction Construction New (RCN), that is the estimated value of the assets if they were to be built today.

16.2 Cost of Delivery with Minimum Transmission

The table below shows the NPV at a real discount rate of 6% of the revenue requirements in 2022 US$ for all components of supply and with minimum new transmission. In this table, as presented above, the Existing PPA costs are the cost of the PPA currently contracted by BEL projected for the planning period 2022 to 2042 and represent 42% of the total NPV, the New PPA are the costs of the new Solar, Wind and RICE resources to be contracted according to the Belize Centric Expert Design plan and represent 18%, the LM2500 + Storage costs represent the regulated return on these assets as developed by BEL and is 9% of the costs, the Mexican Market net purchases is the third largest component at 13% and finally existing transmission is 12% and the new transmission is 6% and includes the interconnection costs for new generation.

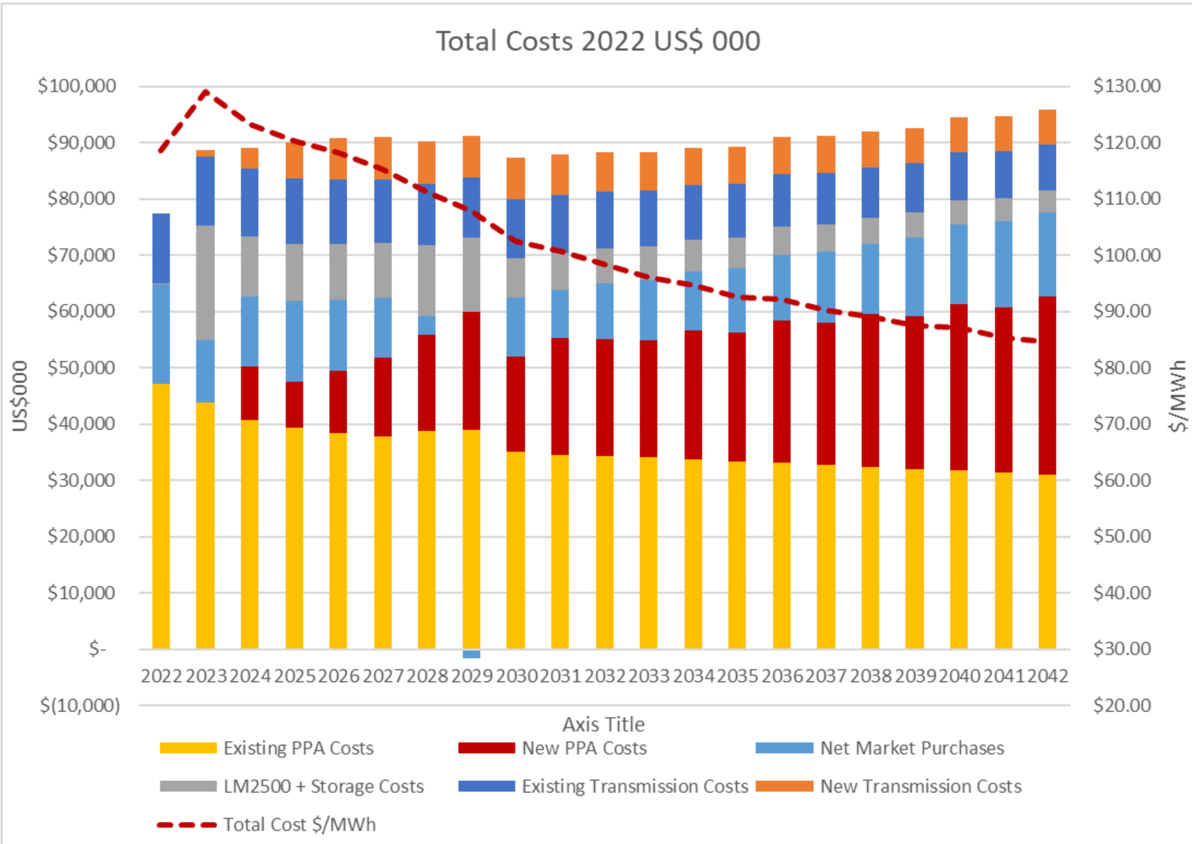
Table 16-1: 2022$ NPV Revenue Requirement for total delivery costs with minimum transmission

Total Costs Rate Impact (2022 000$)	NPV
Existing Transmission Costs	$124,684
New Transmission Costs	$66,918
LM2500 + Storage Costs	$96,811
Existing PPA Costs	$439,806
New PPA Costs	$189,254
Net Market Purchases	$131,111
Total	**$1,048,585**
Effective Cost $/MWh	**$104.8**



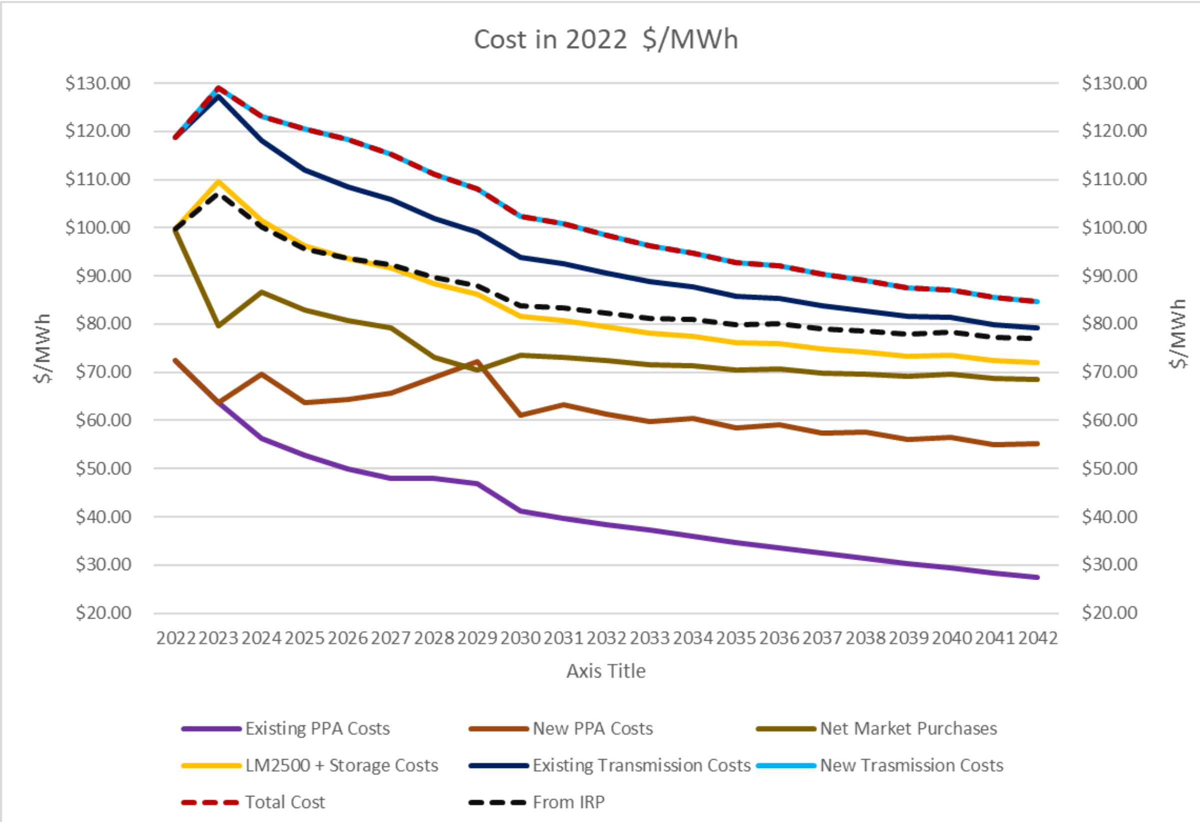
The figure below shows the total costs over time for the planning period in 2022$, where we observe the decline overtime of the cost of supply in real terms and that by the end of the planning period the largest component of costs are the New PPAs, Existing PPAs and Market Purchases in that order.

Figure 16-2: Total Delivery Costs 2022 US$ with Minimum Transmission



Finally, the figure below shows the effective costs in US$/MWh where each of the cost components above were divided by the yearly delivered energy. This figure uses "staked lines"; thus, the upper lines include the effect of the lines below. Therefore, the yellow line that corresponds to the LM2500 + Storage also includes the values on the lines below, i.e., Existing PPA costs, New PPA Cost and Net Market Purchases. This makes this line the total cost of resources before transmission and can be compared with the total cost from the IRP (dashed line). We note that the total cost of resources is somewhat lower than the IRP and this can be traced back to the way the LM2500 + Storage and the interconnection costs are being treated, now as a regulated asset with a nominal 8% rate of return, which is lower than the corresponding payments that a private would demand via a PPA and the way it was modeled in the IRP.

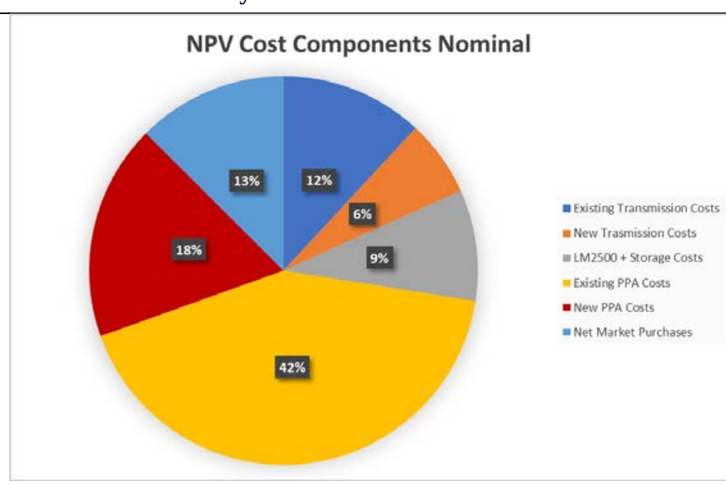
Figure 16-3: Effective Delivery Costs 2022 US$/MWh with Minimum Transmission



To complement the above, the table below shows the NPV in nominal terms at a discount rate of 8.7% for all components of supply. In this case the Existing PPA represent 42% of the NPV, the New PPA represent 18%, the LM2500 + Storage costs represent 9% of the costs, the Mexican Market net purchases 13% and finally existing transmission is 12% and the new transmission is 6%. These percentages are the same as before.

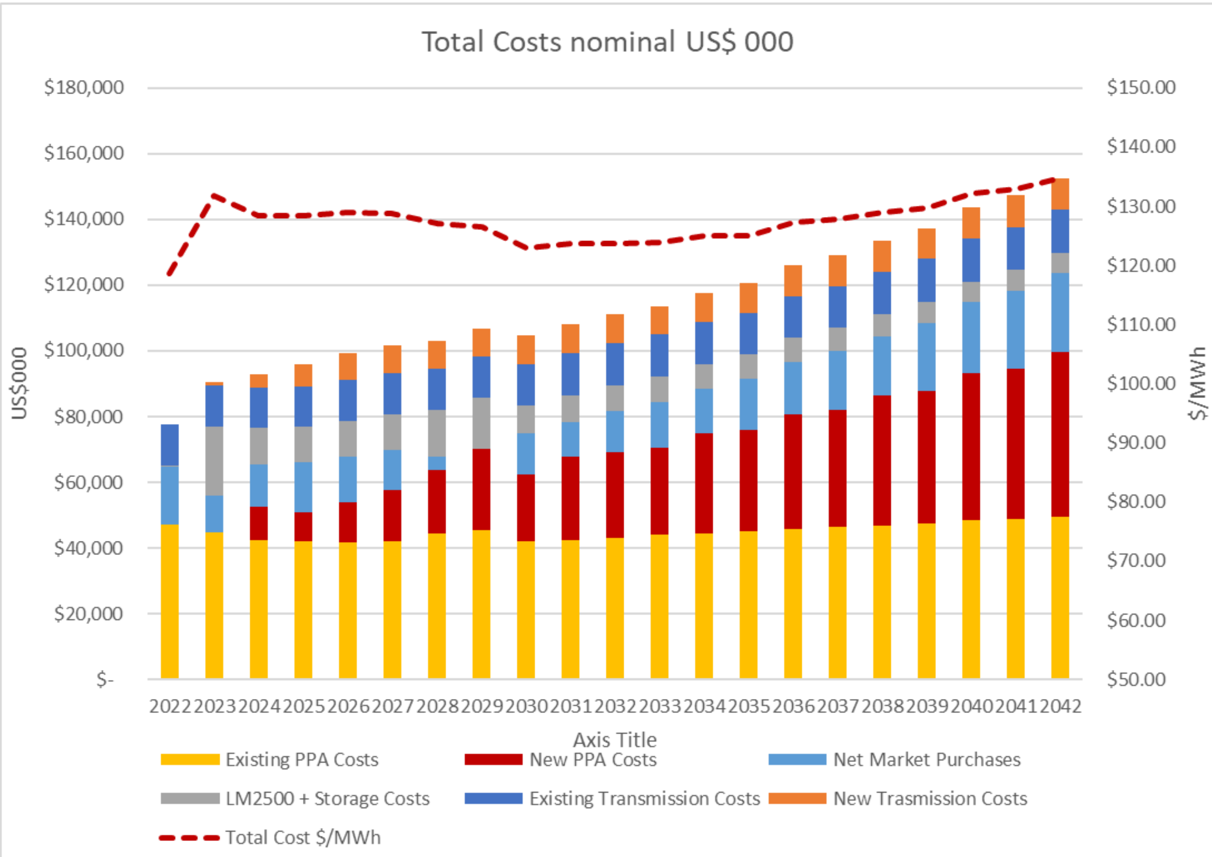
Table 16-2: Nominal NPV Revenue Requirement for total delivery costs with Minimum Transmission

Total Costs Rate Impact (Nominal 000$)	NPV
Existing Transmission Costs	$119,953
New Transmission Costs	$64,171
LM2500 + Storage Costs	$93,206
Existing PPA Costs	$423,126
New PPA Costs	$181,098
Net Market Purchases	$126,068
Total	**$1,007,623**
Effective Cost $/MWh	**$127.0**



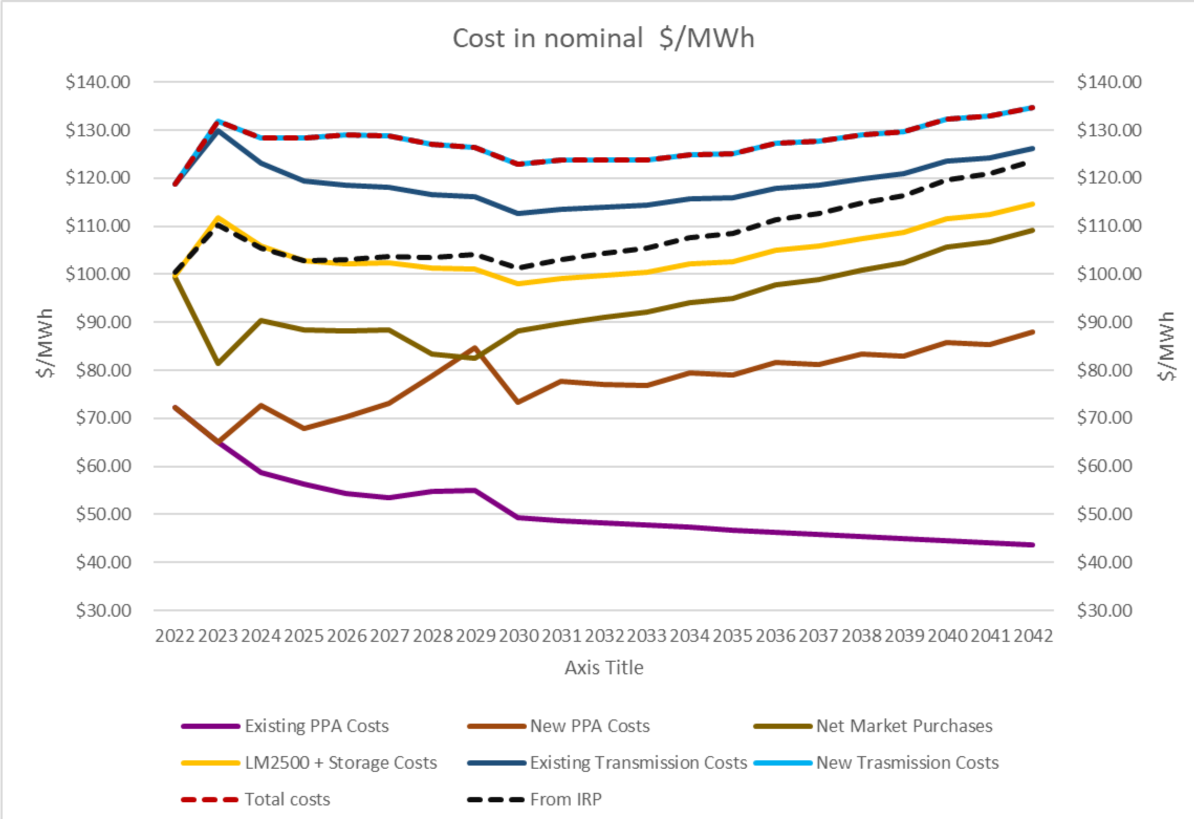
The figure below shows the total costs over time for the planning period in nominal terms. Note that although the cost seems to be going up this is the effect of inflation, and the rates are expected to decline in real terms. As before by the end of the planning period the largest component of costs are the New PPAs, Existing PPAs and Market Purchases in that order.

Figure 16-4: Total Delivery Costs Nominal with Minimum Transmission



Finally, the figure below shows the effective costs in US$/MWh with "staked lines". Again, we note that the total cost of resources is somewhat lower than the IRP due to the way the LM2500 + Storage and the interconnection costs are being treated as a regulated asset with a nominal 8% rate of return.

Figure 16-5: Effective Delivery Costs Nominal with Minimum Transmission



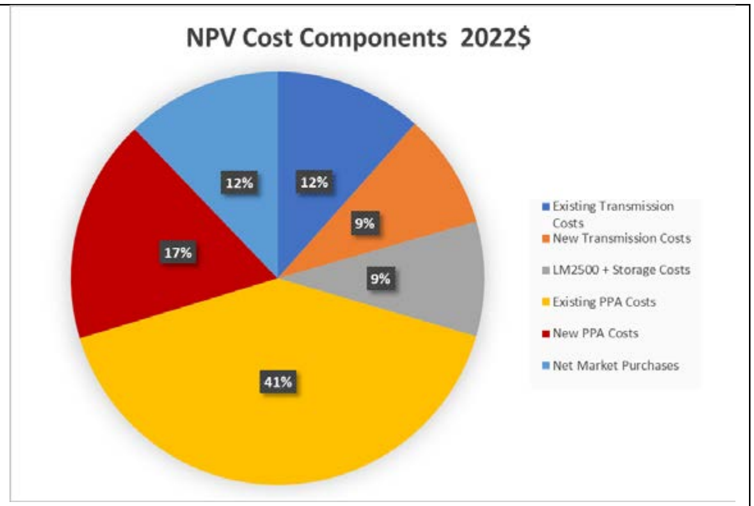
16.3 Cost of Delivery with Recommended Transmission

The table below shows the NPV at a real discount rate of 6% of the revenue requirements in 2022 US$ for all components of supply, for the case that transmission is developed as recommended transitioning to a state-of-the-art system that minimizes the interrupted load during single contingencies and increases the resiliency of supply.

In this table, as presented above, the Existing PPA represent 41% of the total NPV (down from 42% before), the New PPA represent 17% (18% before), the LM2500 + Storage costs represent 9 % of the costs (same as before), the Mexican Market net purchases represent 12% (down from 13%), the existing transmission is 12% (same as before) and in this case the recommended new transmission represents 9% of the costs, up from 6% with the minimum investments.

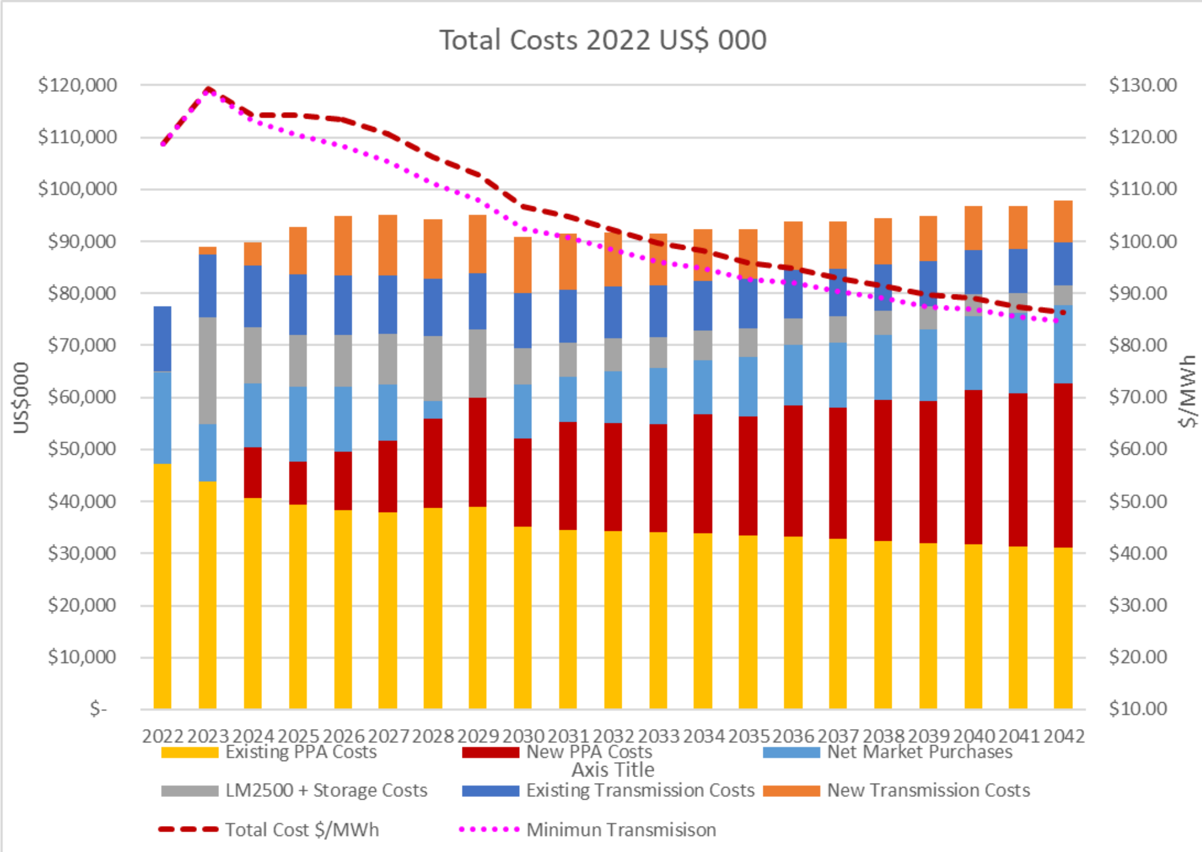
Table 16-3: 2022$ NPV Revenue Requirement for total delivery costs with Recommended Transmission

Total Costs Rate Impact (2022 000$)	NPV
Existing Transmission Costs	$124,684
New Transmission Costs	$97,122
LM2500 + Storage Costs	$96,811
Existing PPA Costs	$439,806
New PPA Costs	$189,254
Net Market Purchases	$131,111
Total	**$1,078,789**
Effective Cost $/MWh	**$107.8**



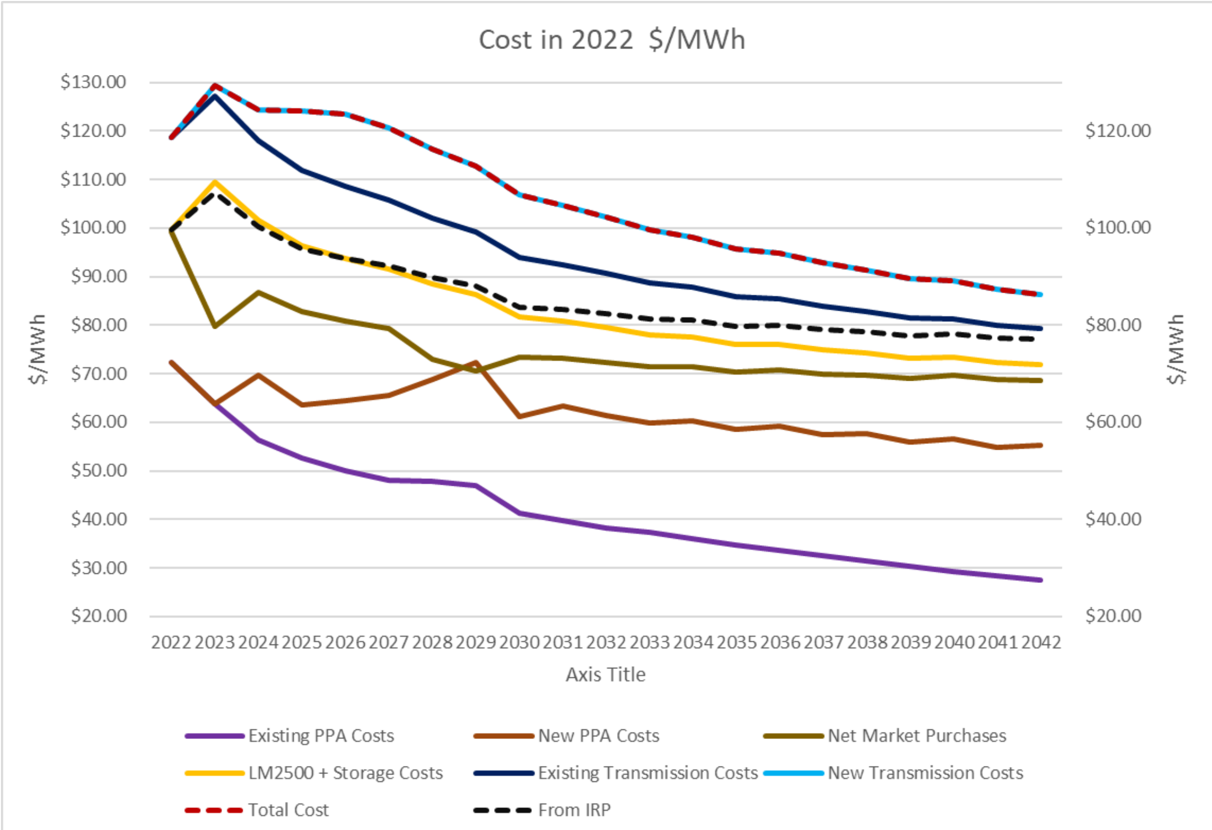
The figure below shows the total costs over time for the planning period in 2022$, where we observe the decline overtime of the cost of supply in real terms. In this figure we also added the cost of supply with the Minimum Transmission investments, and we note that on average the Recommended Transmission costs are about 3% higher or about $3.1/MWh. The main components of the cost remain the PPAs (new and existing) and the market purchase.

Figure 16-6: Total Delivery Costs 2022 US$ with Recommended Transmission



As before, the figure below shows the effective costs in US$/MWh where each of the cost components above were divided by the yearly delivered energy and used “staked lines”. We note in this figure the impact of the Recommended Transmission over the cost of the existing transmission that adds in total about $7.7/MWh (with minimum transmission this addition was about $ 9.7 / MWh).

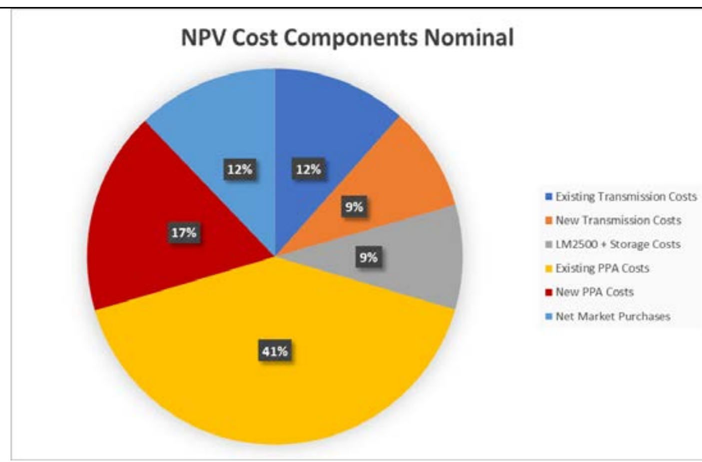
Figure 16-7: Effective Delivery Costs 2022 US$/MWh with Recommended Transmission



As before, the table below shows the NPV in nominal terms at a discount rate of 8.7% for all components of supply. We note the same decline of the participation of the Existing PPA, the New PPA, the LM2500 + Storage, the Mexican Market net purchases and existing transmission due to the increase of the new transmission participation to 9%.

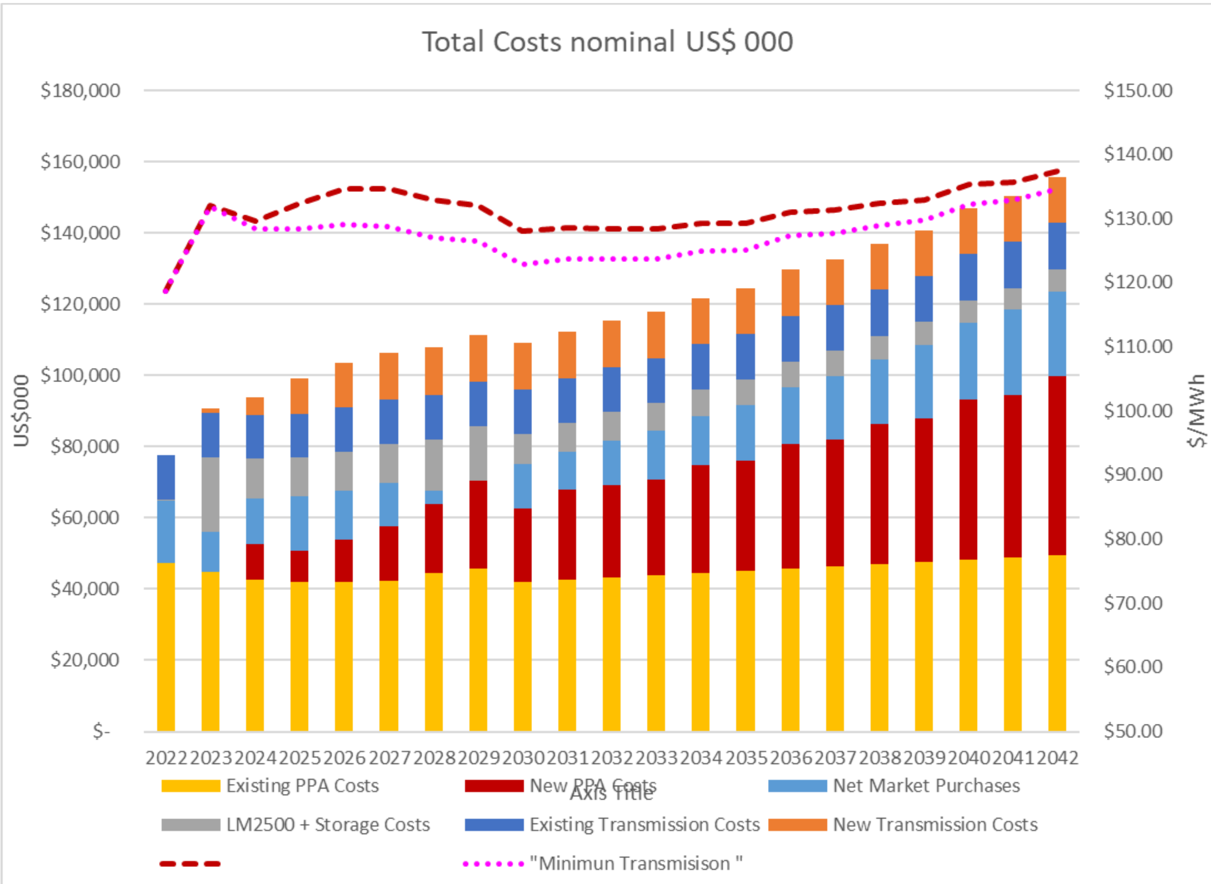
Table 16-4: Nominal NPV Revenue Requirement for total delivery costs with Recommended Transmission

Total Costs Rate Impact (Nominal 000$)	NPV
Existing Transmission Costs	$119,953
New Transmission Costs	$93,142
LM2500 + Storage Costs	$93,206
Existing PPA Costs	$423,126
New PPA Costs	$181,098
Net Market Purchases	$126,068
Total	**$1,036,594**
Effective Cost $/MWh	**$130.7**



The figure below shows the total costs over time for the planning period in nominal terms with the recommended transmission investments and as a reference the cost per MWh with the Minimum Transmission Investments. The main cost components continue being the New PPA, Existing PPA and the Market Purchases.

Figure 16-8: Total Delivery Costs Nominal with Recommended Transmission



Finally, the figure below shows the effective costs in US$/MWh with "staked lines" in nominal terms.

Figure 16-9: Effective Delivery Costs Nominal with Recommended Transmission