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U.S. Virgin Islands Virtual Power Plant (VPP) Analysis and Recommendations Report

December 20, 2024

Prepared for:
The Government of the U.S. Virgin Islands and the Virgin Islands Energy Office (VIEO)

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1 Introduction

1.1 Overview of territory

The United States Virgin Islands (USVI) consists of 4 main islands – St. Croix , St John, St Thomas, and Water Island. The territory has a population of 87,146 spread across a total land area of 346 square kilometers[1,2].

Spurred by the introduction of net-metering in 2009, and accelerated by grid reliability issues following the impact of two Category Five Hurricanes in 2017 (Irma and Maria), the USVI's share of renewable energy has seen tremendous growth, particularly with distributed energy resources (DERs). Over the past 4 years, the estimated distributed solar PV capacity has increased at a rate of 3.4 MW/yr, while the estimated BESS capacity has increased by 7.0 MWh/yr. The Virgin Islands Energy Office is interested in leveraging these distributed energy resources to achieve the territory's energy goals of 60% reduction in fossil-fuel based electricity production and 30% of peak capacity from renewables by 2025[3].

This report details the analysis carried out to assess the feasibility of using the distributed solar PV and BESS capacity present in the USVI as a virtual power plant (VPP) that can help to reduce energy production costs and increase reliability and resilience of the energy system.

1.2 Demand-side Management

Demand-side management refers to a strategy employed by utilities to control the electricity load by modifying customer demand. This can be carried out via incentives that encourage certain customer behavior, or through direct control of grid-connected devices such as thermostats, electric vehicles or battery storage. The latter is the technique by which virtual power plants (VPPs) operate. A virtual power plant is an aggregation of distributed energy resources like solar PV, wind or battery storage that can be dispatched to provide energy or services to the electrical grid. Aggregating the resources in this way can allow for grid needs to be met by resources that would be otherwise underutilized, and can allow the utility to reduce their usage of conventional thermal generators and avoiding the associated fuel and operational costs.

2 Current DER Landscape Assessment

2.1 Initial Data

Data on registered DERs in the USVI was obtained from three main sources and cross-referenced to develop three final "master lists" for each island respectively. The three sources of data were:

- The Net Energy Metering Master List which contained capacity and location data on customer-installed solar and wind data up to 2017
- A registry provided by the Virgin Islands Energy Office (VIEO) which provided a partial listing of customer solar PV and BESS from 2020 onward and,
- Geospatial data from an interconnection study carried out in 2022 which contained capacity and location data for customer solar and wind systems.

The following gaps in the available data were observed and managed as described in the following:

- Data on DERs installed between 2017and 2020 was not available. This meant that the figures obtained were likely a significant underestimation of the actual number of systems installed in the USVI.
- For several solar PV systems, only one out of the nameplate (MWdc) and actual (MWac) capacity were known. In the majority of cases, the actual capacity was known while the nameplate capacity

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[1] https://www.cia.gov/the-world-factbook/countries/virgin-islands/

[2] https://data.census.gov/profile/United_States_Virgin_Islands?g=040XX00US78

[3] NREL Energy Snapshot: U.S. Virgin Islands

had to be estimated based on the average DC/AC ratio of systems whose both capacities were known on each respective island. These ratios were as follows:
    - STT – 1.4
    - STJ – 1.1
    - STX – 1.3
- BESS data was only available for the DER systems installed after 2020. The number of BESS captured in the available data made up a markedly small percentage of the total number of DER systems. This implied a significant underestimation of BESS capacity because anecdotal evidence from on-island solar installers indicated that in recent years, BESS was almost always installed with solar PV. To address this, a scaling factor of 2.88 was applied to the solar PV nameplate capacity of the DERs with unknown BESS capacity from 2020 come forward. This factor was determined from the average ratio of BESS energy capacity (kWh) to nameplate solar capacity provided in the VIEO listing.
- A small amount of DERs did not have corresponding locational data and as such, the feeder on which they were located could not be determined. These were omitted from the final analysis.
- The list of feeders in the USVI grid network varied by data source, causing some uncertainty as to which feeders were currently in operation

2.1.1 DER Capacities

Table 1 shows the final results for DER capacities on each of the three islands after data cleaning and cross referencing of the original datasets was completed.

Feeder	Number of DERs	Solar PV Capacity (MWac)	BESS Power Capacity (MW)	BESS Energy Capacity (MWh)
ST. CROIX				
STX Feeder 01A	0	0.00	0	0
STX Feeder 02A	45	0.62	0.39	1.04
STX Feeder 03A	32	0.18	0.23	0.61
STX Feeder 04A	15	0.16	0.09	0.24
STX Feeder 05A	37	0.70	0.97	2.56
STX Feeder 06A	39	0.27	0.35	0.92
STX Feeder 06B	0	0.00	0.00	0.00
STX Feeder 08B	277	1.35	0.42	1.12
STX Feeder 09B	55	0.28	0.26	0.69
STX Feeder 09D	0	0.00	0.00	0.00
STX Feeder 10A	18	0.11	0.17	0.44
STX Feeder 10B	17	0.10	0.06	0.15
STX Total	535	3.77	2.95	7.76
ST. THOMAS				
STT Feeder 05A	6	0.09	0.00	0.00
STT Feeder 06A	156	0.98	0.46	0.65
STT Feeder 07A	91	0.76	0.09	0.13
STT Feeder 08A	16	0.26	0.41	0.57
STT Feeder 06B	15	0.32	0.01	0.01
STT Feeder 07B	127	1.01	0.37	0.52
STT Feeder 08B	133	1.26	0.41	0.58
STT Feeder 10B	88	0.97	0.33	0.46
STT Feeder 07C	76	0.68	0.29	0.40

STT Feeder 09C	101	1.07	0.36	0.50
STT Feeder 09D	0	0.00	0.00	0.00
STT Feeder 09A	0	0.00	0.00	0.00
STT Feeder 09B	0	0.00	0.00	0.00
STT Feeder Mall	0	0.00	0.00	0.00
STT Feeder YH	0	0.00	0.00	0.00
STT Total	809	7.41	2.73	3.81
ST. JOHN				
STJ Feeder 07E	91	0.68	0.38	0.99
STJ Feeder 09E	174	1.57	0.76	1.99
STJ Total	265	2.25	1.14	2.99
GRAND TOTAL	1609	13.4	6.8	17.9

Table 1 - Estimated DER Capacities in the USVI

2.1.2 DER Uptake Trends

Based on the available data, DERs have seen exponential growth since 2020. Figure 1 to 3 show that both St. Thomas and St Croix have seen significant growth in both PV and BESS capacity while St John has experienced less pronounced growth than the other two islands.

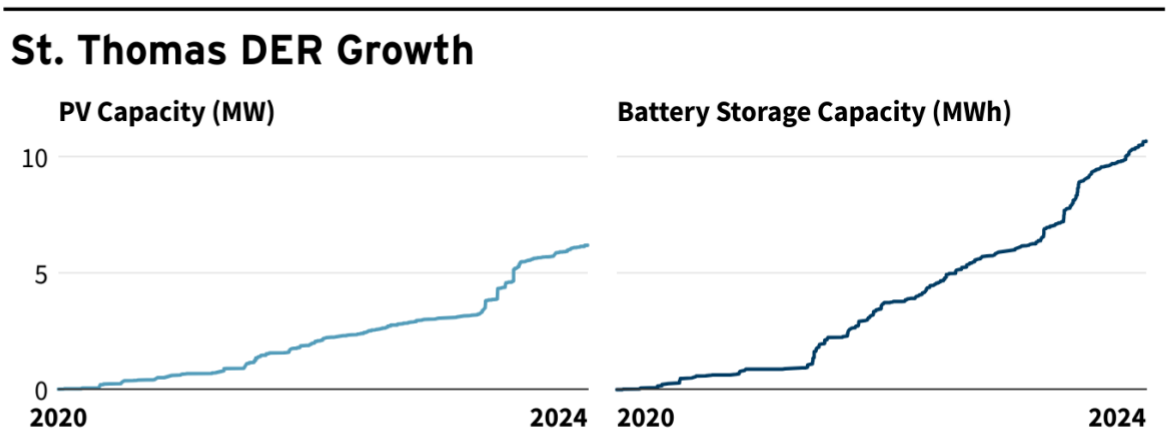


Figure 1 - DER Growth in St Thomas from 2020 to 2024

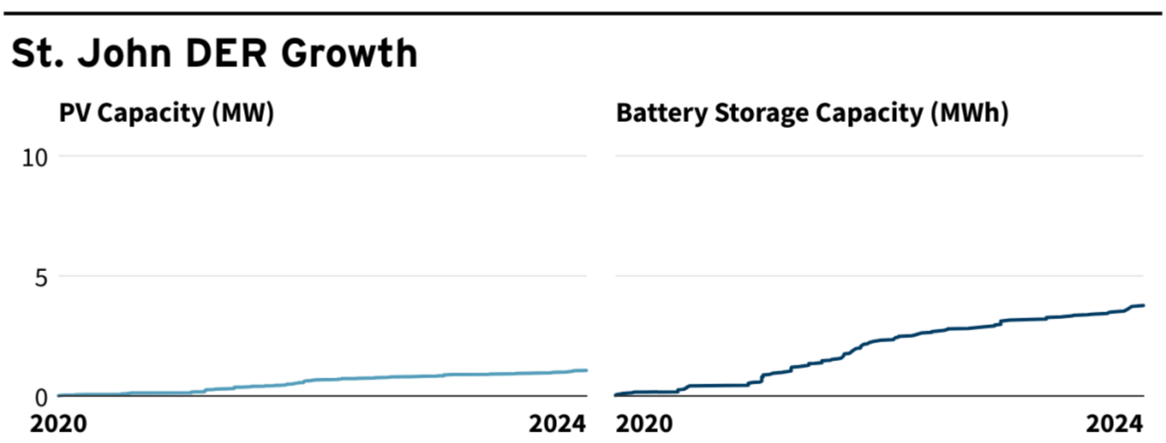


Figure 2 - DER Growth in St John from 2020 to 2024

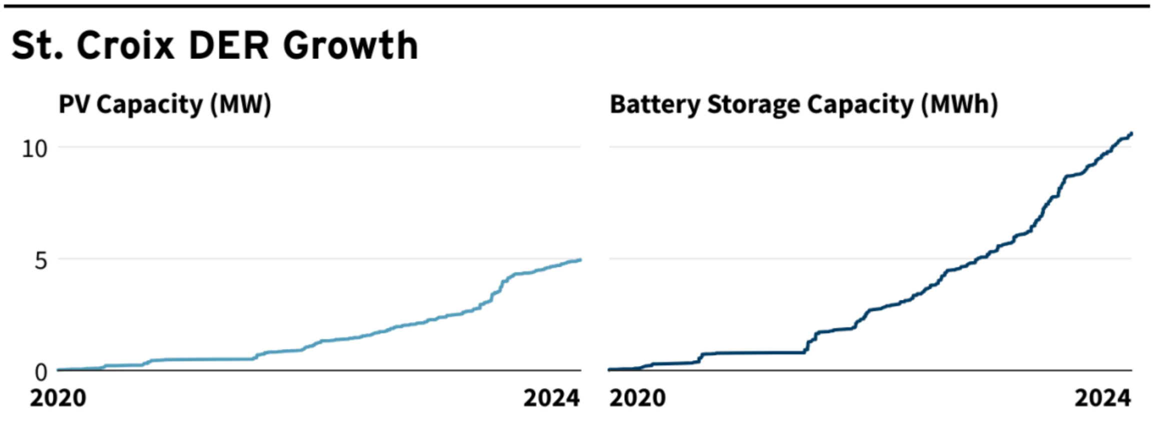


Figure 3 - DER Growth in St Croix from 2020 to 2024

2.1.3 DER Locations

Cross-referencing DER coordinates with the USVI's distribution network allowed for visualization of which feeders DERs are connected to throughout the territory. Figures 4 and 6 show that DERs are almost evenly distributed throughout St. Thomas and St. Croix, with the former having a noticeably higher density than the latter. On St. John, as shown in Figure 5, DERs are primarily situated in the populated areas on the west (Cruz Bay) and east (Coral Bay) of the island.

Figure 4 - DER locations on St. Thomas, colored by feeder

Figure 5 - DER locations on St. John, colored by feeder

Figure 6 - DER locations on St. Croix, colored by feeder

2.1.4 Renewable Energy (RE) Market in USVI

Equipment for DERs in the USVI include solar panels, inverters, battery energy storage systems and some small-scale wind turbines. As seen in Figure 7 batteries, Tesla, Enphase and Fortress are the top three manufacturers present in the territory.

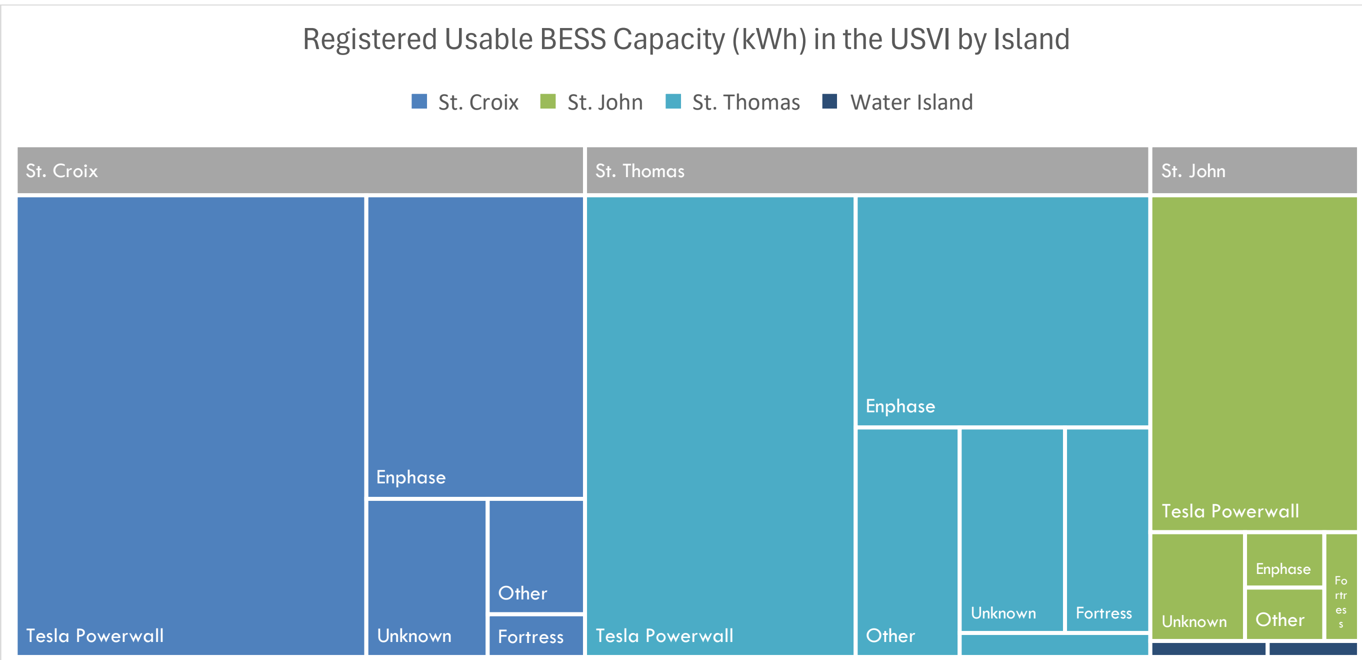


Figure 7 - Distribution of BESS Manufacturers throughout the USVI

2.2 Scaled Data

During the course of the analysis, the RMI team received information that 15 MW/40.5 MWh of Tesla batteries was confirmed to be installed throughout the territory. Based on this new information, the number of DERs and corresponding capacity on each feeder were scaled up to more accurately reflect the DER landscape. The scaled figures are shown in Table 2.

Feeder	Number of DERs	Solar PV Capacity (MWdc)	BESS Power Capacity (MW)	BESS Energy Capacity (MWh)
ST. CROIX				
STX Feeder 01A	0	0	0	0
STX Feeder 02A	78	0.87	1.09	2.91
STX Feeder 03A	55	0.42	0.64	1.69

STX Feeder 04A	26	0.32	0.26	0.68
STX Feeder 05A	64	1.50	2.69	7.15
STX Feeder 06A	68	0.60	0.97	2.57
STX Feeder 06B	0	0	0	0.00
STX Feeder 08B	484	2.76	1.18	3.13
STX Feeder 09B	96	0.69	0.73	1.94
STX Feeder 09D	0	0	0	0.00
STX Feeder 10A	31	0.30	0.46	1.22
STX Feeder 10B	29	0.25	0.16	0.43
STX Total	931	7.7	8.2	21.7
ST. THOMAS				
STT Feeder 05A	10	0.23	0	0
STT Feeder 06A	272	2.15	1.28	3.41
STT Feeder 07A	159	1.83	0.26	0.69
STT Feeder 08A	27	1.23	1.14	3.02
STT Feeder 06B	26	0.78	0.02	0.07
STT Feeder 07B	222	2.40	1.03	2.74
STT Feeder 08B	232	2.90	1.15	3.05
STT Feeder 10B	153	2.16	0.91	2.42
STT Feeder 07C	132	1.56	0.79	2.11
STT Feeder 09C	176	2.52	0.99	2.63
STT Feeder 09D	0	0	0	0
STT Feeder 09A	0	0	0	0
STT Feeder 09B	0	0	0	0
STT Feeder Mall	0	0	0	0
STT Feeder YH	0	0	0	0
STT Total	1,409	17.8	7.6	20.1
ST. JOHN				
STJ Feeder 07E	202	1	1.3	3.5
STJ Feeder 09E	386	3.5	2.7	7.1
STJ Total	588	5.0	4.0	10.6
GRAND TOTAL	2,928	30.5	19.7	52.5

Table 2 - Estimated DER Capacities in the USVI, scaled

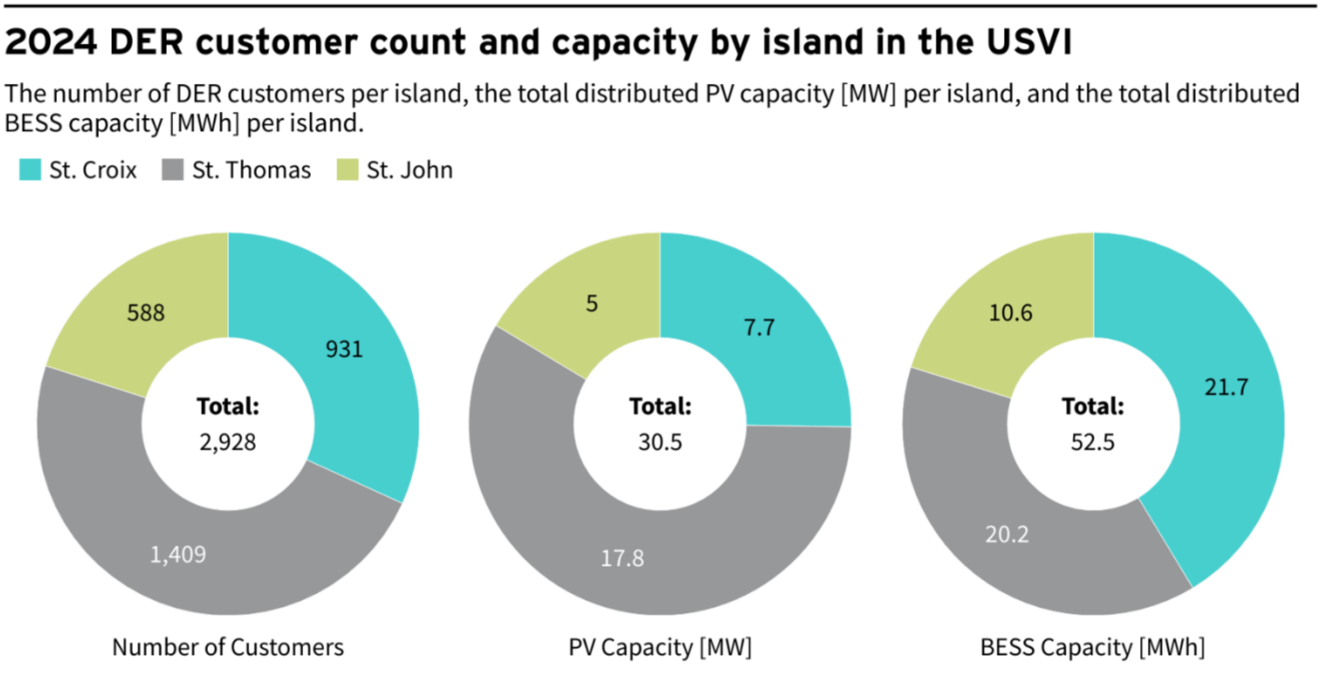


Figure 8. Estimated DERs in the USVI

2.3 DER Capacity Limits

In 2022, Sandia National Laboratories completed a hosting capacity analysis for the USVI's electricity distribution network. Table 3 shows the minimum, maximum and average hosting capacities of segments along the USVI feeders. Average feeder hosting capacities ranged from around 0.4 to 3.8 MW on St. Croix, 1.5 to 3.2 MW on St. Thomas and 0.9 to 1.5 MW on St. John.

Feeder	Hosting Capacity (MW)		
	Minimum	Maximum	Average
ST. CROIX			
STX Feeder 01A	1.02	5.00	3.85
STX Feeder 02A	0.06	5.00	0.44
STX Feeder 03A	0.42	5.00	1.84
STX Feeder 04A	0.40	5.00	1.78
STX Feeder 05A	0.46	5.00	2.08
STX Feeder 06A	0.48	5.00	1.85
STX Feeder 06B	1.77	5.00	3.42
STX Feeder 08B	0.28	5.00	2.65
STX Feeder 09B	1.60	5.00	3.63
STX Feeder 10A	1.87	5.00	3.56
STX Feeder 10B	0.85	5.00	3.09
ST. THOMAS			
Feeder 05A	0.61	3.08	1.96
Feeder 06A	0.11	4.61	2.31
Feeder 06B	1.00	3.71	3.22
Feeder 07A	0.15	3.68	1.56

Feeder 07B	0.84	2.22	1.67
Feeder 07C	0.52	8.02	2.85
Feeder 07D	0.24	3.87	1.82
Feeder 08A	0.38	2.53	1.77
Feeder 08B	0.15	3.06	1.56
Feeder 09A	0.66	2.83	2.20
Feeder 09B	1.04	3.00	2.77
Feeder 09C	0.25	3.35	1.51
Feeder 09D	0.75	2.11	1.57
Feeder 10A	0.58	3.51	3.12
Feeder 10B	0.33	5.18	2.48
Feeder RR	1.04	2.47	1.97
ST. JOHN			
STJ Feeder 07E	0.15	5	1.50
STJ Feeder 09E	0.07	4.11	0.98

Table 3 - Feeder Hosting Capacities in the USVI

3 Exploring Future VPP Net Benefits via Long Term (7-year) Grid Integration Study

3.1 Goal of Study

The primary objective of the VPP analysis was to assess how different levels of distributed solar and BESS penetration would impact the operation of a VPP over a seven-year horizon for the USVI grid. By running multiple scenarios with varying DER uptake trends, the analysis aimed to:

- **Evaluate the impact of DER growth on VPP performance**: The analysis sought to understand how the increasing adoption of DERs, namely solar PV and battery energy storage systems, would influence the operation, efficiency, and scalability of the VPP. This included assessing the operational dynamics under low, medium, and high levels of DER penetration, along with location-based DER penetration.
- **Compare against a base case (business-as-usual)**: To highlight the potential advantages of a VPP, the model compared each scenario to a base case where no VPP was implemented, and DERs remained unconnected. This comparison allowed for a detailed examination of the financial, operational, and environmental benefits of deploying a VPP.
- **Optimize grid benefits**: The analysis aimed to identify the optimal level of DER integration that would maximize the economic, environmental, and grid stability benefits, while considering potential limitations related to technical infrastructure or regulatory constraints.
- **Inform policy and planning decisions**: Finally, the analysis intended to provide actionable insights for policy makers, utility planners, and regulators by quantifying the long-term benefits of VPP implementation. These insights would help guide future decisions around DER integration, grid modernization, and energy resilience strategies for the USVI.

3.2 USVI Grid Setup in PLEXOS

3.2.1 Grid topography

The USVI power grid is separated into two regions (i.e. two separate grids), each with a number of distribution lines, generators and nodes, representing both larger substations and the smaller distribution feeders. A simplified PLEXOS Model of the USVI system was created to match these characteristics.

The first system is a dual-island system split between the islands of St. Thomas and St. John, with a simplified grid topology shown in Figure 9. This system has four (4) major substations (Randolph Harley, Tutu, Donald Francois, and East End) on St. Thomas and one major substation on St. John. The grid on St. John is interconnected with the St. Thomas grid via an undersea transmission line between the St. John Substation and the East End substation on St. Thomas. All utility scale generators, which includes twelve (12) fossil fuel gensets, one (1) utility solar PV system, and one (1) utility BESS are connected to the Randolph Harley substation. In addition to the major substations, there are fifteen (15) smaller feeders that serve electricity customers across the two islands and are split between the five (5) substations, as seen in Figure 9.

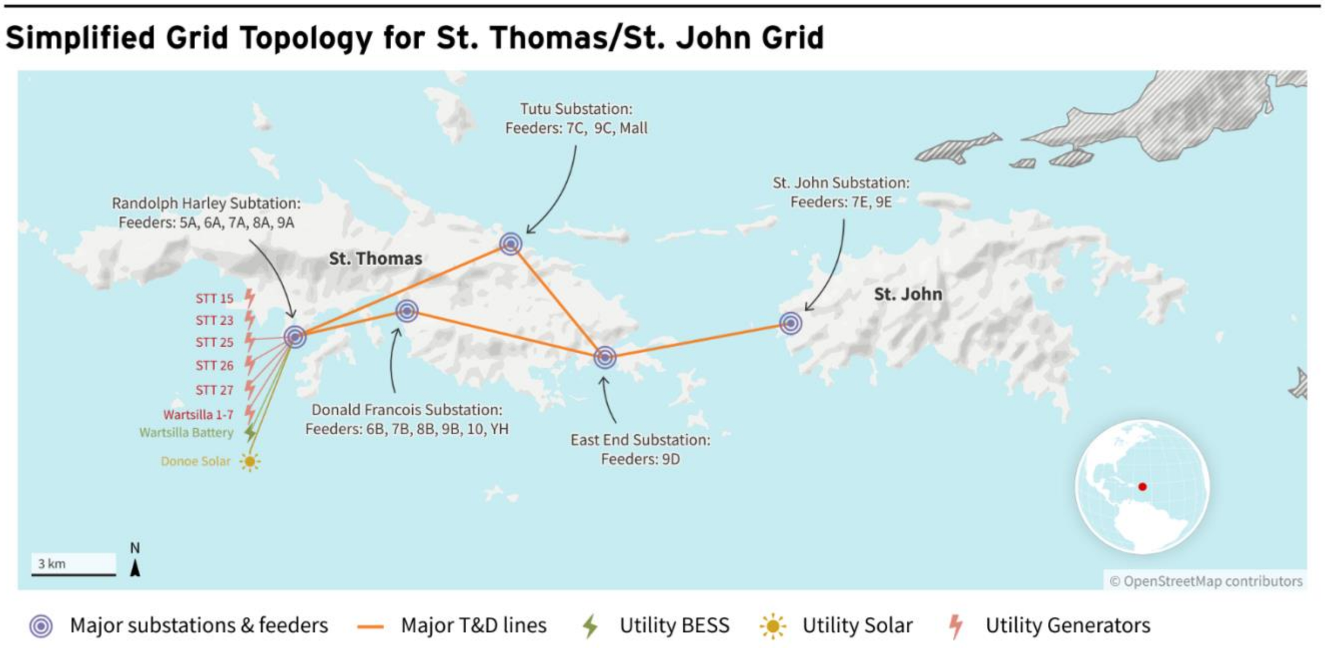


Figure 9 - Simplified grid topology for the St. Thomas/St. John grid used in the VPP PLEXOS analysis

The second electricity system is an isolated one located on the island of St. Croix. The simplified grid topology is shown in Figure 10. This system has two (2) major substations (Richmond and Midland) and eleven (11) additional feeders spread across the two substations that serve electricity customers on the island. Additionally, there are four (4) fossil fuel gensets that are all located at the Richmond substation and one utility-scale solar plus battery storage system, which is to commence operation in 2026 and is located at the Midland substation.

Simplified Grid Topology for St. Croix

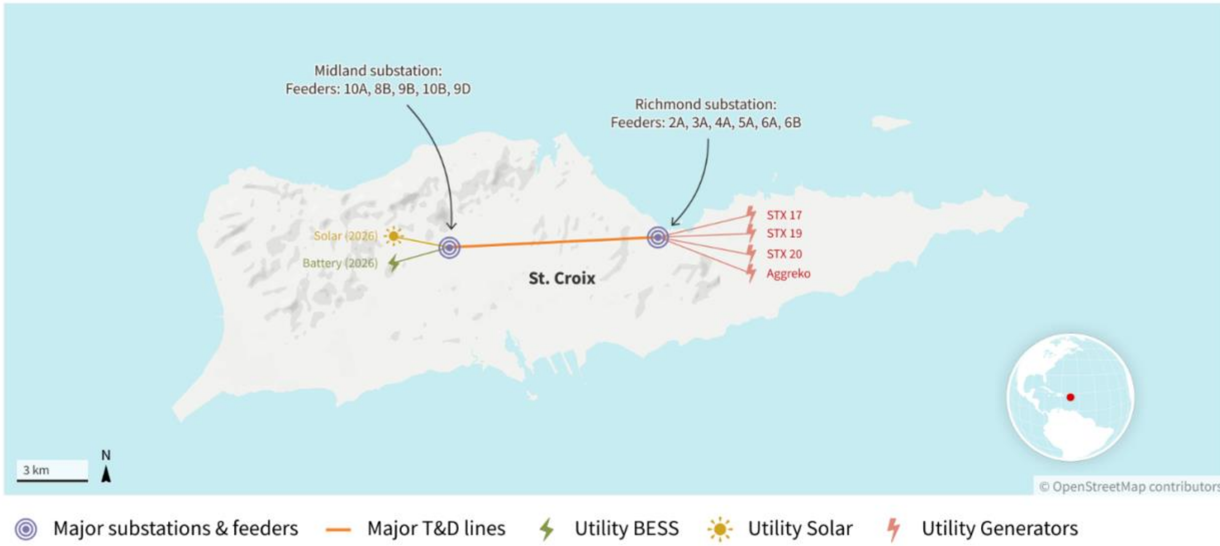


Figure 10 - Simplified grid topology for the St. Croix grid used in the VPP PLEXOS analysis.

3.2.2 Major Transmission and Distribution Lines

The major transmission and distribution lines modeled for the St. Thomas/St. John grid and their corresponding properties are shown in Table 4. The figure reveals that the reactance and resistance of all lines is kept constant at 0.1 and 0.2, respectively. The max flow of each lines varies slightly as the larger lines between the substations require a larger max flow. All lines are modeled as bidirectional lines in the PLEXOS model.

	Reactance [p.u.]	Resistance [p.u.]	Max Flow [MW]
Major Substation – Feeder	0.1	0.2	12
Long Bay – East End	0.1	0.2	30
East End – Tutu	0.1	0.2	30
Randolph Harley – Tutu	0.1	0.2	30
Randolph Harley – Long Bay	0.1	0.2	30
East End – St. John	0.1	0.2	12
St. John – East End	0.1	0.2	30

Table 4 - Major transmission and distribution lines modeled for St. Thomas/St. John and their properties

The major transmission and distribution lines modeled for the St. Croix grid and their corresponding properties are shown in Table 5. The figure reveals that again, the reactance and resistance of all lines is kept constant at 0.1 and 0.2, respectively. The max flow of feeder lines is kept at the lower value of 12 MW, while the max flow between the Midland and Richmond substations is 60 MW. All lines are modeled as bidirectional lines in the PLEXOS model.

	Reactance [p.u.]	Resistance [p.u.]	Max Flow [MW]
Major Substation – Feeder	0.1	0.2	12
Richmond – Midland	0.1	0.2	60

Table 5 - Major transmission and distribution lines modeled for St. Croix and their properties

3.2.3 Major Nodes (feeders and substations)

The major nodes, which include the substations and all feeders, that were modeled in St. Thomas/St. John are shown in Table 6. The figure shows the voltage and the load participation factor at each node. All substations have a 34.5 kV voltage, whereas the feeder nodes have a lower voltage of 13.85 kV. The load participation factor indicates the percentage of the total load that occurs at each node. For this reason, all major substations have a 0% participation factor as there is only generation and no direct load consumption taking place at the substation level. However, all feeders have a load, and the load participation factor indicates the percentage of the total. The load participation factors range from 1.58% of the total load on the lower end to 11.66% on the higher end, with an average of 5.88% at each node.

St. Thomas/St. John Nodes	Voltage [kV]	Load Participation Factor [%]
Randolph Harley	34.5	0
Donald Francois	34.5	0
Tutu	34.5	0
East End	34.5	0
St John	34.5	0
STT Feeder 05A	13.85	5.84
STT Feeder 06A	13.85	9.14
STT Feeder 06B	13.85	9.18
STT Feeder 07A	13.85	5.97
STT Feeder 07B	13.85	4.32
STT Feeder 07C	13.85	7.62
STJ Feeder 07E (St. John's)	13.85	7.11
STT Feeder 08A	13.85	3.67
STT Feeder 08B	13.85	3.13
STT Feeder 09A	13.85	5.58
STT Feeder 09B	13.85	7.34
STT Feeder 09C	13.85	6.31
STT Feeder 09D	13.85	1.78
STJ Feeder 09E (St. John's)	13.85	7.59
STT Feeder 10B	13.85	11.66
STT Feeder Mall	13.85	2.18
STT Feeder YH	13.85	1.58

Table 6 - Nodes modeled for St. Thomas/St. John and their properties

The major nodes that were modeled in St. Croix are shown in Table 7. The figure shows the voltage and the load participation factor at each node. Richmond and Midland have higher voltages than the substations of St. Thomas/St. John, at a level of 69 kV. Feeder nodes have lower voltages of either13.85 kV or 24.9 kV. The load participation factor is also presented in the figure and ranges from 1.5% to 16.59%, with an average of 9.09% at each feeder node, with participation factors of zero for the Midland and Richmond substations.

St. Croix Nodes	Voltage [kV]	Load Participation Factor [%]
Midland	69	0
Richmond	69	0
STX Feeder 2A	13.85	11.19
STX Feeder 3A	13.85	4.4
STX Feeder 4A	13.85	15.52
STX Feeder 5A	13.85	16.49
STX Feeder 6A	13.85	7.42
STX Feeder 6B	13.85	2.67
STX Feeder 8B	24.9	10.73
STX Feeder 9B	24.9	12.83
STX Feeder 9D	24.9	1.5
STX Feeder 10A	13.85	11.42
STX Feeder 10B	13.85	5.83

Table 7 - Nodes modeled for St. Croix and their properties

3.2.4 Utility-scale generators and batteries

St. Thomas/St. John Grid system:

The properties for the twelve (12) utility-scale fossil fuel generators for St. Thomas/St. John are shown in Table 8. The figure shows the rated capacity, fuel type, heat rate, maintenance rate, forced outage rate, minimum downtime and ramp up/ramp down rates for each generator. Generators in USVI use two types of fuel – liquified petroleum gas (LPG) and No. 2 Fuel Oil (#2FO). For all generators on the STT/STJ system, including solar and battery generators, the minimum, mean, and maximum time to repair during maintenance or forced outage is assumed to be 12 hours, 24 hours, and 48 hours, respectively. In addition to these key properties, each generator has unique variable operation and maintenance costs, fixed operation and maintenance costs, and startup costs that vary during the seven-year horizon, which can be found in Appendix A. Generators were assumed to operate during the entirety of the seven-year horizon, which is why expected retirement dates are not included in the properties. Furthermore, all twelve fossil fuel generators are located at the Randolph Harley substation.

STT/STJ	Unit Type	Rated Cap.	Fuel Type	Heat Rate	Maint. Rate	Forced Outage Rate [FOR]	Min. Down time	Ramp up/down rate
	-	MW	-	GJ/MWh	%	%	hr	MW/min
STT 15	CT	21	LPG/#2FO	16.025	3.8	4.16	1	20
STT 23	CT	40	#2FO	12.271	3.8	5	1	36
STT 25	CT	20.1	#2FO	10.911	3.8	4.28	1	5
STT 26	CT	22	#2FO	11.178	3.8	2.37	1	15
STT 27	CT	21	#2FO	11.34	3.8	8.6	1	15
Wärtsilä 1	RICE	7.03	LPG	9.003	3.01	2	1	3
Wärtsilä 2	RICE	7.03	LPG	9.003	3.01	2	1	3
Wärtsilä 3	RICE	7.03	LPG	9.003	3.01	2	1	3
Wärtsilä 4	RICE	9	LPG/#2FO	9.003	3.01	2	1	3
Wärtsilä 5	RICE	9	LPG/#2FO	9.003	3.01	2	1	3
Wärtsilä 6	RICE	9	LPG/#2FO	9.003	3.01	2	1	3
Wärtsilä 7	RICE	9	LPG/#2FO	9.003	3.01	2	1	3

Table 8 - Fossil fuel generators on St. Thomas/St. John

In addition to the fossil fuel generators there is also one utility-scale solar PV system (i.e. solar generator) on St. Thomas, located at Randolph Harley. Its properties are shown in Table 9. The model assumed no fixed or variable operation costs.

STT/STJ	Rated Cap.	Power Degradation	Maint. Rate	Forced Outage Rate [FOR]
	MW	% per year	%	%
Donoe Solar	5	0.7	5	4

Table 9 - Utility-scale solar generators on St. Thomas/St. John

The solar generator also needed a generation profile to distinguish its generation as one linked to peak sun hours. To create this profile, NREL's PV Watts tool was used to calculate the hourly generation of 1 MW of solar in USVI during a year (2024 was used), accounting for local irradiance and conditions. This profile was then used as a base profile to model all solar generation within the model over the 7-year horizon, including the DER assets. The profile can be seen in Figure 11. The zoomed in version (Figure 12) clearly shows that solar generation follows a typical profile peaking during the day and following to zero at night, with some days affected by occasional clouds and inclement weather.

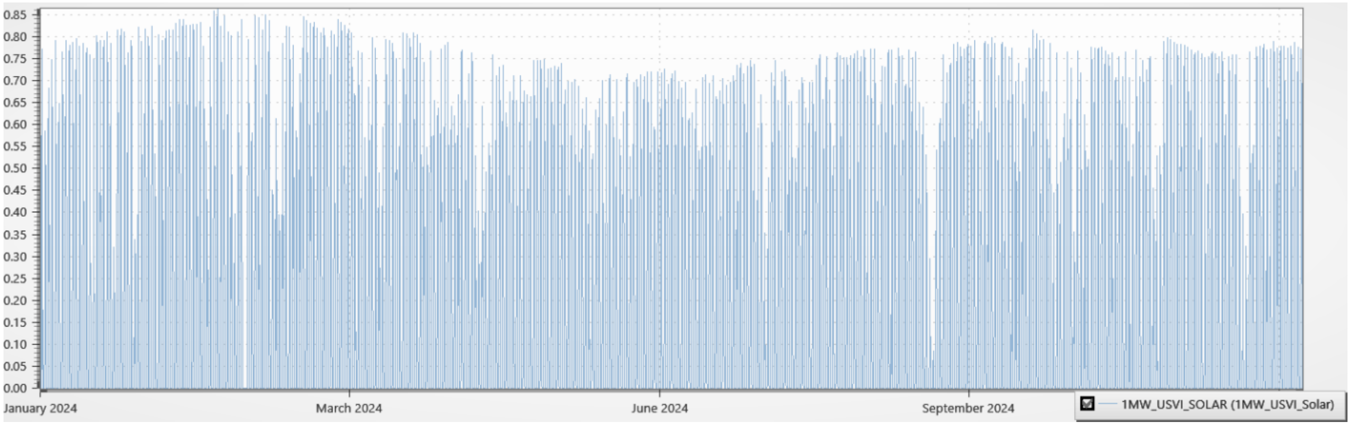


Figure 11 - Base generation profile used to model all solar generation in the PLEXOS model

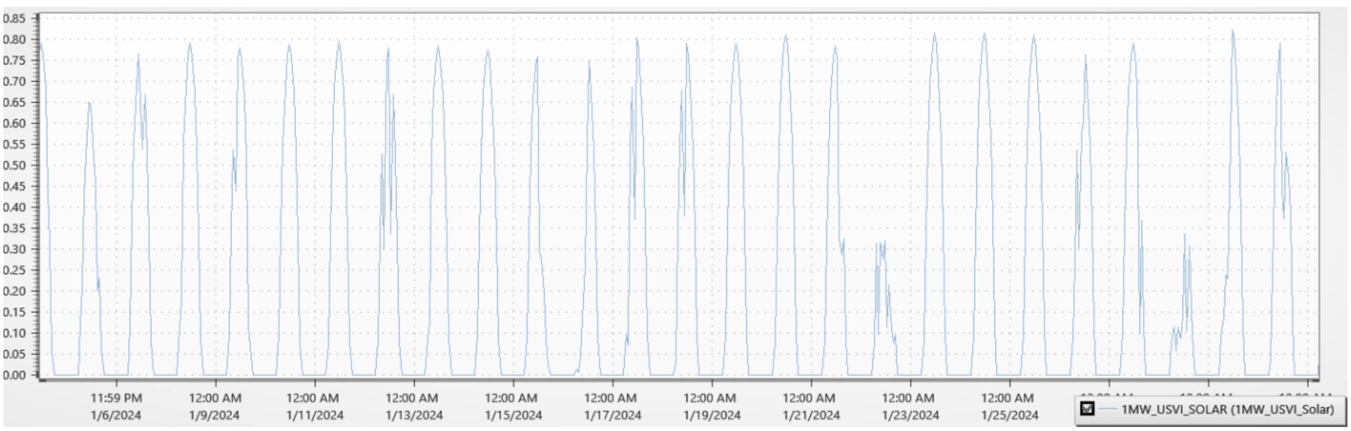


Figure 12 - Zoomed in view of base generation profile used to model all solar generation in the model

Finally, there is also one utility-scale battery storage system on St. Thomas, located at Randolph Harley. Its properties are shown in Table 10. This battery is coupled to the Wartsila generators and therefore an additional limitation was placed on this battery to ensure charging only occurred from the Wartsila generation. Additionally, an idealized charge and discharge efficiency of 100% was placed on the batteries to ensure that the algorithm was choosing batteries as the preferred method of generation, particularly to maximize distributed battery performance in the VPP.

STT/STJ	Rated Cap.	Max Power	Max S.O.C	Min S.O.C	Charge and Discharge Efficiency	Capacity Degradation
	MWh	MW	%	%	%	% per year
Wartsila Battery	18	9	5	95	100	0.1

Table 10 - Utility-scale batteries on St. Thomas/St. John

Apart from the basic properties shown in Table 8 for St. Thomas/St. John generators, some additional limitations were placed on the generators to help reflect current generation dispatch order. Specifically, minimum and maximum capacity factors were included to ensure that certain generators, despite economic competitiveness in the dispatch order curve, generate according to actual WAPA trends. Historical WAPA generation was pulled from WAPA's website and was used to determine the maximum and average capacity factors experienced for each generator since 2015. This capacity factor analysis was used to create the capacity factor limits that were utilized in the model, as shown in Table 11. The Wartsila generators have maximum capacity factor limits placed on them because, with the lowest operational costs and most efficient heat rates, their generation would normally be maximized by the algorithm. However, recent WAPA trends show that generators like STT15, STT25, and STT27 still have preferred generation. Therefore, minimum capacity factor limits were placed on these three generators and slowly reduced over the next four years to simulate a slow phase-out of these older, less efficient generators. Finally, a minimum capacity factor limitation of 15% was placed on the solar farm.

STT/STJ	Max Capacity Factor [%]	Min Capacity Factor [%] (date that the value applies)
STT 15	-	45 % (1/1/25-1/1/26) 30 % (1/1/26-1/1/27) 20 % (1/1/27-7/1/27) 15 % (7/1/27-1/1/28) 10 % (1/1/28-7/1/28) 5 % (7/1/28-1/1/29)
STT 23	-	30 % (1/1/25-1/1/26) 20 % (1/1/26-1/1/27) 15 % (1/1/27-7/1/27) 10 % (7/1/27-1/1/28) 5 % (1/1/28-7/1/28) 2.5 % (7/1/28-1/1/29)
STT 25	-	-
STT 26	-	-
STT 27	-	30 % (1/1/25-1/1/26) 20 % (1/1/26-1/1/27) 17.5% (1/1/27-7/1/27) 15 % (7/1/27-1/1/28) 10 % (1/1/28-7/1/28) 5 % (7/1/28-1/1/29)
Wärtsilä 1	78.1 %	-
Wärtsilä 2	77.3 %	-
Wärtsilä 3	73.2 %	-
Wärtsilä 4	78 %	-
Wärtsilä 5	78 %	-
Wärtsilä 6	78 %	-
Wärtsilä 7	78 %	-
Donoe Solar	-	15%

Table 11 - Capacity factor limits placed on generators in St. Thomas/St. John

St. Croix Grid system:

The properties for the four (4) utility-scale fossil fuel generators for St. Croix are shown in Table 12. These generators have the same fuel types and minimum, mean, and maximum time to repair during maintenance or forced outage as the generators on STT/STJ. Again, the figure shows the rated capacity, fuel type, heat rate, maintenance rate, forced outage rate, minimum downtime and ramp up/ramp down rates for each generator. In addition to these key properties, the operation costs for each generator can be found in Appendix A. Furthermore, all four fossil fuel generators are located at the Richmond substation. The Aggreko generator is part of a purchase power agreement and is a must-run with generation limits of 10 MW min and 18 MW max.

STX	Unit Type	Rated Cap.	Fuel Type	Heat Rate	Maint. Rate	Forced Outage Rate [FOR]	Min. Down time	Ramp up/down rate
	-	MW	-	GJ/MWh	%	%	hr	MW/min
STX 17	CT/CC	20	LPG/#2FO	15.865	3.8	2.23	1	20

STX 19	CT	20	#2FO	17.658	3.8	1	1	20
STX 20	CT/CC	20	LPG/#2FO	16.578	3.8	4.87	1	20
Aggreko	RICE	19.8 (min stable level of 10)	LPG	9.827	0	3	1	6.7

Table 12 - Fossil fuel generators on St. Croix

A future utility-scale solar and battery storage coupled system was also modeled to come online in 2026. The properties for these assets are shown in Table 13 and Table 14. Since the assets are coupled, an additional limitation was placed on the battery to ensure charging only occurred from the future solar system. The solar system was also assumed to have a similar generation profile to the base profile used in St. Thomas/St. John and for the distributed solar assets.

STX	Rated Cap.	Power Degradation	Maint. Rate	Forced Outage Rate [FOR]
	MW	% per year	%	%
Future STX Solar (2026)	5	0.7	5	4

Table 13 - Utility-scale solar generators on St. Croix

STX	Rated Cap.	Max Power	Max S.O.C	Min S.O.C	Charge and Discharge Efficiency	Capacity Degradation
	MWh	MW	%	%	%	% per year
Future STX Battery (2026)	9.2	3.2	5	95	100	0.1

Table 14 - Utility-scale batteries on St. Croix

Similar to St. Thomas/St. John some additional capacity factor limitations were put in place to ensure that no generator in St. Croix was overutilized in a way that wasn't reflective of reality. They can be seen in Table 15. Although historical generation data was not available for St. Croix, the algorithm maximized STX 17 and Aggreko, as they were the least-cost, most efficient generators. Therefore, maximum capacity limitations of 85% were placed on both of these generators. Finally, the minimum capacity factor limitation of 15% was placed on the solar farm.

STX	Max Capacity Factor [%]	Min Capacity Factor [%]
STX 17	85 %	-
STX 19	-	-
STX 20	-	-
Aggreko	85 %	-
Future Solar (2026)	-	15%

Table 15 - Capacity factor limits placed on generators in St. Croix

3.2.5 Demand Forecast

The demand forecast was developed based on the 2019 load, incorporating projected peak demand and energy consumption values for each island. This process involved adjusting the 2019 baseline to account for expected changes in population growth, economic activity, and energy efficiency improvements. The forecast was refined using historical consumption patterns, taking into consideration seasonal variability, as well as anticipated future developments such as the integration of distributed energy resources (DERs), electric vehicle adoption, and demand-side management initiatives.

The final demand forecast for each island is summarized in the four figures below, which includes projected peak demand (MW) and total energy consumption (MWh) through the 7-year planning horizon. The daily loads and historical consumption that were used to make the forecasts can be found in Appendix B.

Table 16 and Figure 13 show the demand forecast for St. Thomas/St. John with peak demand reaching 80.5 MW by 2031 and total energy consumption reaching 530.9 MWh. This represents a growth of about 24% over the 7 year horizon, or about 3.4% per year.

	Base Energy Consumption [MWh]	Peak Demand [MW]
2024	427.4	64.8
2025	440.9	66.8
2026	454.7	68.9
2027	469.0	71.1
2028	483.8	73.3
2029	499.0	75.7
2030	514.7	78.0
2031	530.9	80.5

Table 16 - St. Thomas/St. John 2024-2031 base energy consumption [kWh] and peak demand [MW] forecasts

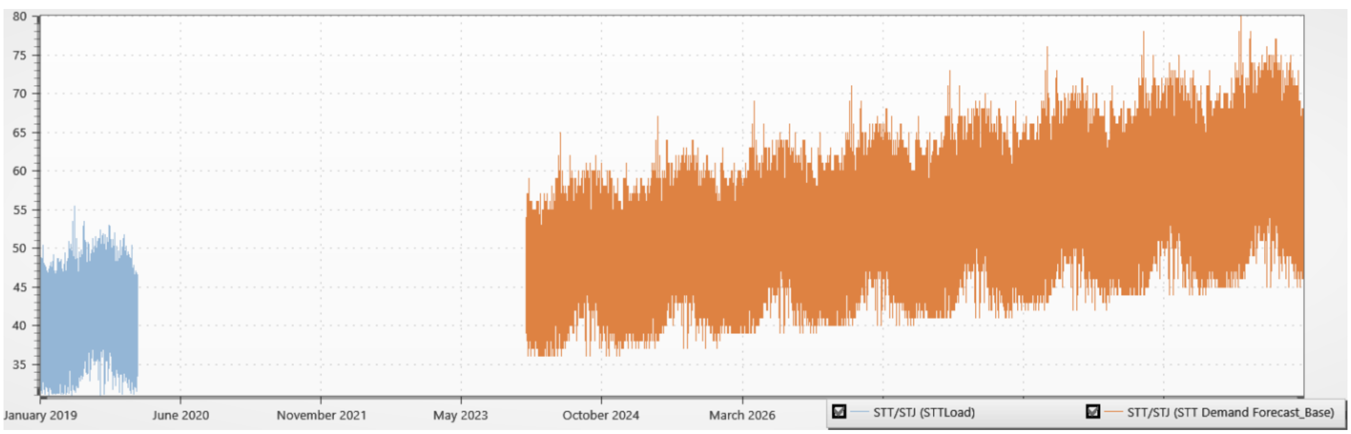


Figure 13 - St. Thomas/St. John 2019 daily load [kWh] (in blue) and the corresponding demand forecast created in PLEXOS (in orange)

Table 17and Figure 14 show the demand forecast for St. Croix with peak demand reaching 55.6 MW by 2031 and total energy consumption reaching 381.6 MWh. Again, this represents a growth of about 3.4% per year.

	Base Energy Consumption [MWh]	Peak Demand [MW]
2024	307.2	44.7
2025	316.9	46.1
2026	326.8	47.6
2027	337.1	49.1
2028	347.7	50.6
2029	358.7	52.2
2030	370.0	53.9
2031	381.6	55.6

Table 17 - St. Croix 2024-2031 base energy consumption [kWh] and peak demand [MW] forecasts

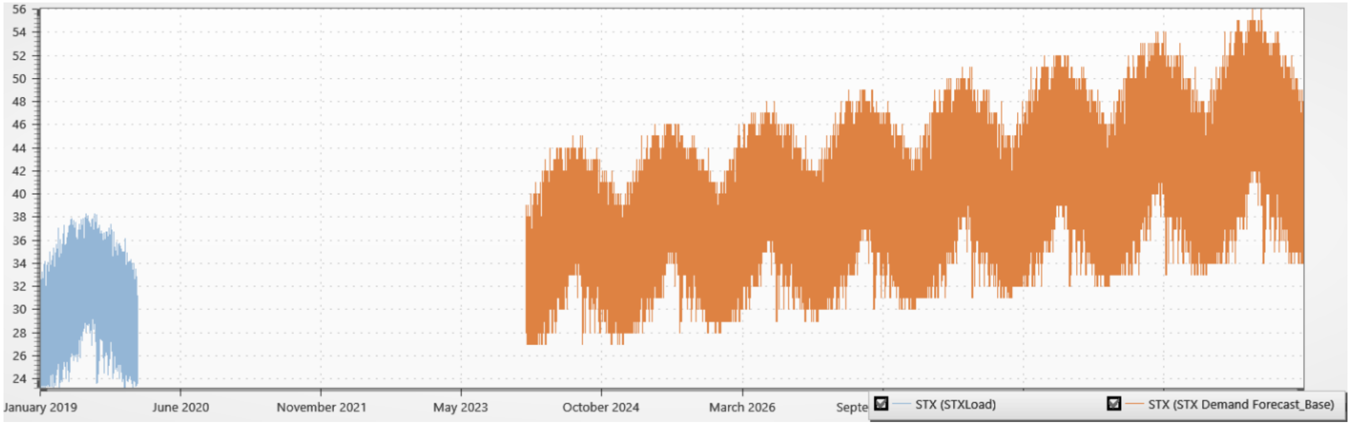


Figure 14 - St. Croix 2019 daily load [kWh] (in blue) and the corresponding demand forecast (in orange) created in PLEXOS

3.2.6 Fuel Prices and Emission Data

As seen in section 3.2.4, generators in USVI use two types of fuel, liquified petroleum gas (LPG) and No. 2 Fuel Oil (#2FO). Both fuels have an emission production rate and a price in the model. The emission production rate is the emissions in kg of CO_2 equivalent (CO_2e) produced per unit of the primary output in GJ. The emission production rate was 74.33 kg/Gj for #2FO and 59.59 kg/Gj for LPG. These values determine the monthly and annual emissions that are produced during each run of the model based on generation dispatch. The other key property for the fuel is the price, and the annual values for each fuel type can be seen in Table 18. The prices for the software are in USD per Gj. – For reference, one barrel of oil is roughly 5.8 million Btu, which is roughly 6.1 Gj.

Year	LPG Price [$/Gj]	Oil Price [$/Gj]
2020	9.11	19.92
2021	9.52	19.81
2023	9.82	19.54
2024	9.94	19.85
2025	10.42	20.6
2026	10.84	21.43
2027	11.21	22.47
2028	11.55	23.06
2029	12.2	24.07
2030	12.48	24.7
2031	12.76	25.33

Table 18 - Fuel Prices [$/Gj]

3.2.7 Reserves

In power systems, a reserve capacity is the extra generation capacity available to the power grid that can be quickly deployed to maintain stability during unexpected demand spikes or if a generator goes offline. It is essential to maintain grid stability and respond quickly to sudden changes in demand or unexpected generator outages. Reserve capacity ensures there is always a buffer of generation available that can be activated when needed to avoid disruptions. In the context of this VPP model, including a reserve allows us to simulate realistic grid operations, where additional capacity can be dispatched to maintain reliability and minimize unserved energy.

For each electricity system, a constant reserve capacity was put in place. For the St. Thomas/St. John system, the minimum provision for the constant reserve was 7 MW and all fossil fuel generators could provide up to half of their max capacity. For the St. Croix system, a minimum provision of 7 MW was also considered for the constant reserve and the fossil fuel generators could provide up to half of their max capacity, except for Aggreko that could only provide 9.8 MW in order to ensure that 10 MW was always kept available for the grid as part of the power purchase agreement.

3.3 Long-term Scenario setup

As part of the long-term analysis, six unique scenarios were created, each exploring a different potential future for VPPs in the USVI. These scenarios were organized on a 2x2 grid, as shown in Figure 15, which mapped DER penetration levels (low to high) on one axis and the overall goal of the scenario (from general exploration to a specific use case) on the other axis.

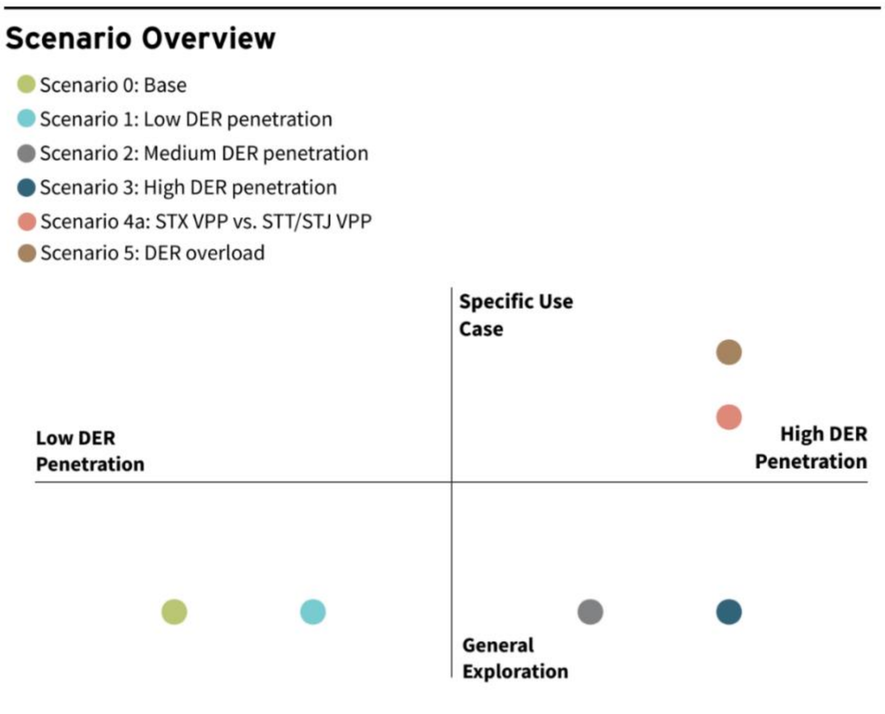


Figure 15 - Overview of the long-term scenarios modeled in the VPP PLEXOS analysis.

In the lower-left quadrant, representing low DER penetration and general exploration, two scenarios were defined. The first, **Scenario 0** (base case or business-as-usual), modeled a future in which no VPP efforts are undertaken, and all DER assets remain unconnected. The second, **Scenario 1** (low DER penetration), involved interconnecting only the existing DER assets into a VPP, with no future buildout of new DER assets

In the lower-right quadrant, which corresponds to high DER penetration and general exploration, there are also two scenarios: **Scenario 3** (medium DER penetration) and **Scenario 4** (high DER penetration). These scenarios assume new buildouts of DER assets, resulting in a growing VPP over the seven-year horizon, differing only in their build limits. The high DER penetration scenario allows for double the capacity of DERs to be built and at twice the rate compared to the medium penetration scenario.

In the upper-right quadrant, representing specific use cases and high DER penetration, two more scenarios were defined. **Scenario 4** is divided into two sub-scenarios, with one exploring a VPP being built exclusively in St. Croix, and the other only in St. Thomas/St. John. Both sub-scenarios assume high DER penetration. The final long-term scenario, **Scenario 5** (DER overload), represents a specific use case exploring a VPP with no restrictions on new DER buildouts, designed to represent the 'optimal' VPP according to the algorithm.

However, this scenario is not currently viable due to technical limitations and regulatory constraints, and it would require additional feeder and grid infrastructure.

Several high-level properties that were discussed in section 3.2 were kept constant across all scenarios including the demand, fuel prices, and utility generator properties.

3.3.1 Base Scenario

7-year analysis (2025 – 2031)
Existing thermal generators
Existing DERs are <u>not</u> connected via a VPP ie. they are excluded from the model
Capacity addition: no additional capacity for utility or DER assets
No retirement of fossil fuel (and continued use of leased generators)

Figure 16 - Properties of the base case scenario

For the base case, the USVI grid was modeled with no interconnected DER assets in a VPP. Therefore, only the existing thermal generators were available to the grid for electricity generation purposes. This scenario is meant to model the business-as-usual case if no VPP efforts were to be pursued over the next 7-years and DER assets were to remain unconnected. Furthermore, this scenario assumes that no further DER buildout occurs during the horizon.

3.3.2 Low DER penetration scenario

7-year analysis (2025 – 2031)
Existing thermal generators
Existing DERs: 30.5 MWdc of PV, 52.5 MWh of BESS, 2,928 customers
Capacity addition: no additional capacity for utility or DER assets
No new DER build out
No build out of new utility renewables
No retirement of fossil fuel (and continued use of leased generators)
Assumption: unfavorable policy and regulation for DER development

Figure 17 - Properties of the low DER penetration scenario

For the low DER penetration case, existing DER assets were assumed to be connected as a network of distributed residential solar and battery storage systems in addition to the existing thermal generators available to the grid. Similar to the base case, there is no additional buildout of DER assets, which could be attributed to unfavorable policy and regulation for DER development. Therefore, this scenario explores the impact of a VPP that consists only of the existing fleet of DER systems (i.e. up until 2024) and does not grow over the next 7 years.

3.3.3 Medium DER penetration scenario

7-year analysis (2025 – 2031)
Existing thermal generators
Existing DERs: 30.5 MWdc of PV, 52.5 MWh of BESS, 2,928 customers
Capacity Addition: DER solar PV allowed to expand to 50% of remaining feeder capacity, DER BESS allowed to expand to 0.6 MW/1.7 MWh per feeder, no utility scale buildout
No retirement of fossil fuel (and continued use of leased generators)

Figure 18 - Properties of the medium DER penetration scenario

The medium DER penetration scenario is the first one that allows for new DER buildout. Therefore, in addition the existing thermal generators and the aggregation of existing DER assets, the VPP is allowed to expand each year with new DERs coming online and joining the VPP. The build limits for DER assets are based on a determined portion of the maximum *remaining* feeder capacity. For the medium DER penetration, DER solar PV is allowed to expand to 50% of the remaining feeder capacity for each feeder. DER BESS is allowed to expand to 0.6 MW/1.7 MWh per feeder. In addition to the upper limit on overall total capacity, there are also yearly DER buildout limits. For the medium DER penetration scenario, the maximum amount of solar PV per feeder per year is 0.15 MW, which corresponds to around 15 systems per feeder per year.

3.3.4 High DER penetration scenario

7-year analysis (2025 – 2031)
Existing thermal generators
Existing DERs: 30.5 MWdc of PV, 52.5 MWh of BESS, 2,928 customers
Capacity Addition: DER solar PV allowed to expand to 100% of remaining feeder capacity, DER BESS allowed to expand to 1.2MW/3.2 MWh per feeder, no utility scale buildout
No retirement of fossil fuel (and continued use of leased generators)
Favorable policy and regulation for DER development

Figure 19 - Properties of the high DER penetration scenario

The high DER penetration scenario is similar to the medium DER penetration scenario in that it allows new DER buildout, but it allows for a larger amount being installed and at a faster pace. Again, the build limits for DER assets are based on a determined portion of the maximum remaining feeder capacity. For the high DER penetration, DER solar PV is allowed to expand to 100% of the *remaining* feeder capacity for each feeder. DER BESS is allowed to expand twice as fast as the medium DER penetration, at 1.2 MW/3.2 MWh per feeder. Similarly, there are also yearly DER buildout limits. For the high DER penetration scenario, the maximum amount of solar PV per feeder per year is 0.3 MW, which corresponds to around 30 systems per feeder per year.

3.3.5 STX VPP vs. STT/STJ VPP scenario

7-year analysis (2025 – 2031)
Existing thermal generators
Overall savings comparison of a high DER penetration VPP in STT/STJ vs. STX:
Existing DERs: Existing DERs are included on just one system based on which system is being modeled
Capacity addition: Same as the High DER penetration scenario but limited to just one system based on which system is being modeled
No retirement of fossil fuel (and continued use of leased generators)

Figure 20 - Properties of the STX vs STT/STJ VPP scenario

This scenario was devised to compare the overall impact of a VPP on the St. Croix grid versus one on the St. Thomas/St. John grid. Therefore, this scenario is split into two sub-scenarios, with each sub-scenario modeling a VPP on its respective system. For both sub-scenarios, only the existing DERs in the system being modeled are included in the VPP while the existing DERs in the other system are assumed to not be interconnected and to not contribute to the VPP. For DER buildout, the build limits are the same as those for the high DER penetration scenario and are just limited to the system being modeled.

3.3.6 DER overload scenario

7-year analysis (2025 – 2031)
Existing thermal generators
Existing DERs: 30.5 MWdc of PV, 52.5 MWh of BESS, 2,928 customers
Capacity Addition: DER solar PV and BESS capacity addition is unlimited, the goal is to find the "optimal" DER and BESS penetration needed, regardless of feeder limit or location, to impact utility dispatch order
No retirement of fossil fuel (and continued use of leased generators)

Figure 21 - Properties of the DER Overload scenario

This scenario was devised with the goal of finding the "maximum" VPP impact over the next 7 years, regardless of feeder limit or location. Therefore, DER solar PV and BESS capacity expansion is not capped, and can expand at a much higher rate than what may be currently technically feasible with existing grid infrastructure and feeder hosting capacity. This allowed PLEXOS to determine the optimal buildout of distributed solar and distributed battery storage in USVI. While this scenario is not feasible with today's grid infrastructure, it gives an indication of how favorable policy and necessary grid upgrades could support a VPP that has much greater impact for the territory.

3.4 VPP Setup

PLEXOS was used to model the power system of the US Virgin Islands to analyze the performance and impact of a virtual power plant (VPP) consisting of aggregated distributed solar and battery storage resources across the islands. Within PLEXOS each of the scenarios outlined in Section 3.3 was created and run over the 7-year horizon. Additional scenarios were also run to identify the short-term impact of VPPs over a period of two weeks, as explained in Section 5.

To understand how the VPP was modeled, it is important to understand how the distributed and battery assets currently operate. Today, these systems operate as completely individual assets operating, for the most part, behind the meter at the individual households or commercial buildings. Consider Figure 22.

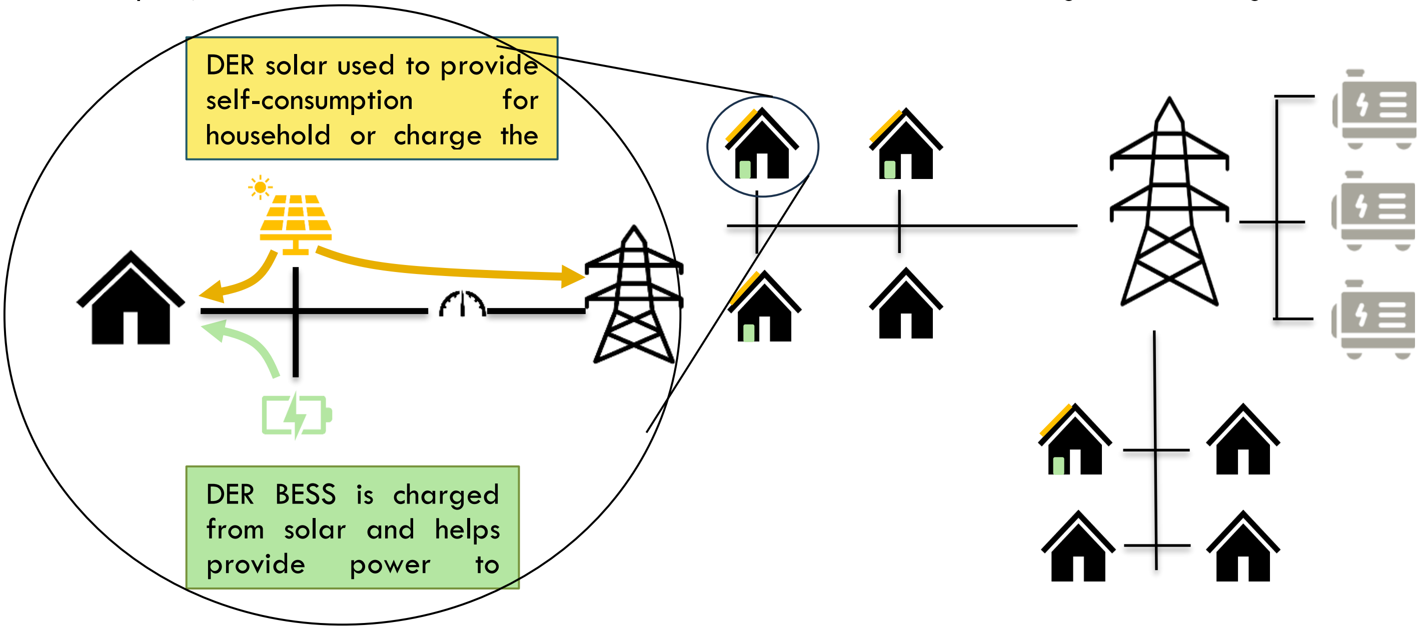


Figure 22 - Current operation of DER solar and BESS assets

In this figure, a household with a behind the meter solar system and BESS is shown on the left-hand side. The solar system generates electricity during the day and its production is used to provide self-consumption at the household and excess generation is used to charge the battery. If the battery system is already fully charged, then excess solar generation is sent to the grid and is reimbursed under the current net billing regulation. The net billing rate as of October 2024 was 17 cents per kWh of electricity sent to the grid from the interconnected solar system. In this situation, the battery is only used to provide power to the householder during off-peak solar hours and there is no back feed to the grid. On the righthand side, this household is shown to form part of the larger network of households on the grid that may or may not have distributed solar and BESS systems, but ultimately, these systems all operate as separate and individual assets.

A VPP is capable of aggregating the distributed BESS stored energy (or other capabilities from multiple systems) into a readily dispatchable, decentralized asset that could mimic the functioning of a centralized utility battery, as shown in Figure 23. Therefore, distributed BESS units would form the basis of the VPP and a VPP "Aggregator" would dispatch the aggregated BESS capacity to provide energy, capacity, and/or ancillary services to the grid.

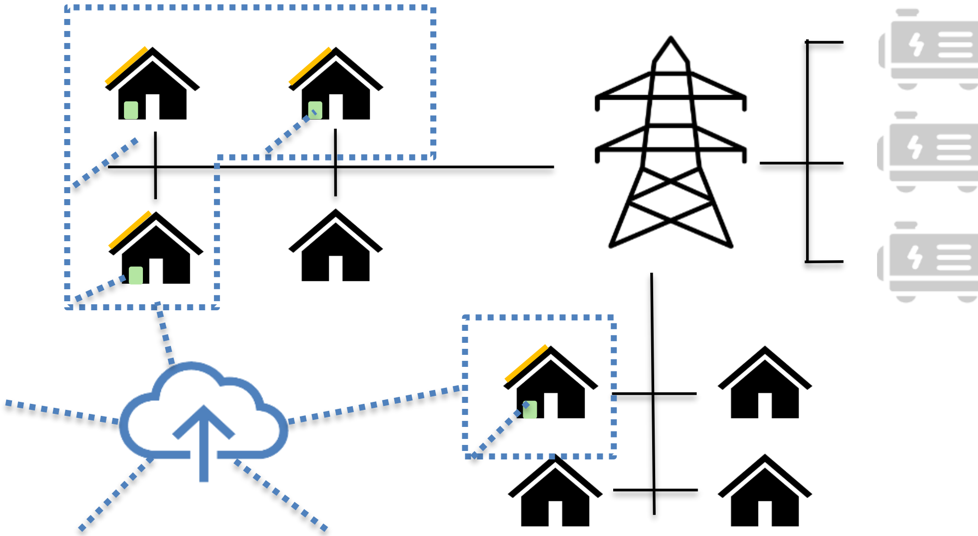


Figure 23 - Future grid aggregation of DER solar and BESS into a VPP. The cloud symbol represents a VPP aggregator that would have control of the participating VPP assets.

The VPP would be readily dispatchable, and each participating household would pre-determine the level of contribution (% of capacity) that they would make available to the VPP. For example, as shown in Figure 24, a participating household may agree to reserve 60% of its BESS capacity to be made available and dispatched by the VPP aggregator. The remaining 40% of the BESS capacity would continue to be used to provide household self-consumption during off solar peak hours. The participants would also be compensated for services provided by the BESS assets and reimbursed for the kWh that are sent from the BESS units into the grid. Additionally, the participants would continue to be reimbursed for any excess solar generation sent to the grid under the existing net billing regulation.

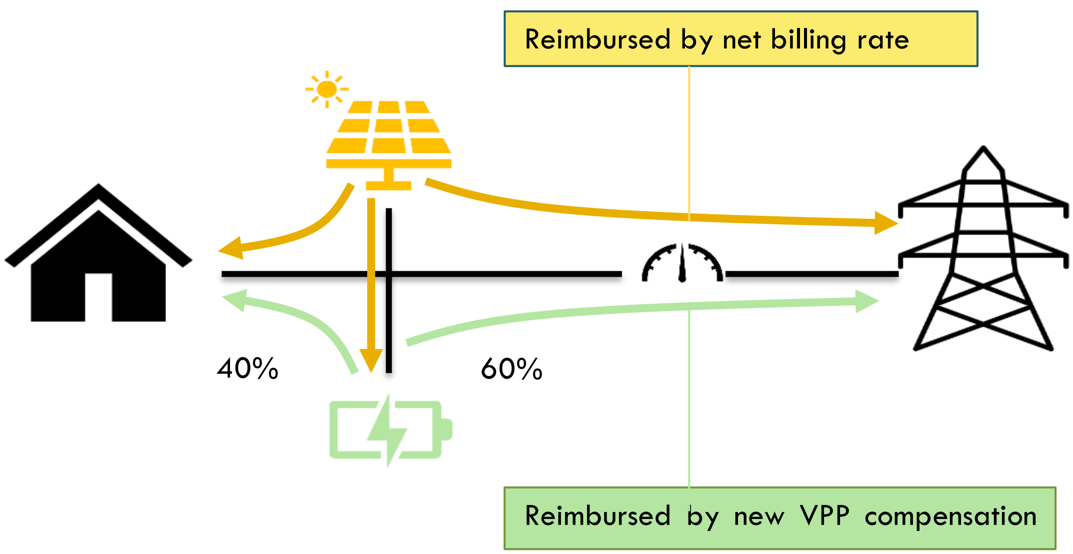


Figure 24 - Future household DER solar and BESS operation as a participant of the VPP

In PLEXOS, the VPP was modeled on a feeder level. This meant that the DER capacity at each feeder was aggregated into a single unit that mimicked the functioning of a centralized solar and BESS asset. Furthermore, the solar and BESS units were coupled at each feeder meaning that the batteries at each feeder could only be charged from the solar capacity at each feeder. Furthermore, the available BESS capacity that was assumed to be made available to the grid, called the offer quantity, was 60% of the existing capacity. An additional assumption was made that 90% of the distributed solar capacity was available to the grid but reserved 10% for the household. In reality, these variables may shift depending on grid needs, feeder capacity, and household preferences based on compensation programs that are in place and how incentivized people are to participate in the VPP. The offer quantities for the existing DERs are presented in Table 19, and any new buildout of DERs continue to offer 60% of their BESS capacity and 90% of their solar capacity for grid services.

Feeder	Solar PV Capacity (MWac)	BESS Power Capacity (MW)
ST CROIX		
STX Feeder 01A	0	0
STX Feeder 02A	0.98	0.66
STX Feeder 03A	0.29	0.38
STX Feeder 04A	0.26	0.15
STX Feeder 05A	1.1	1.61
STX Feeder 06A	0.42	0.58
STX Feeder 06B	0	0.00
STX Feeder 08B	2.13	0.71
STX Feeder 09B	0.43	0.44
STX Feeder 09D	0	0.00
STX Feeder 10A	0.17	0.28
STX Feeder 10B	0.16	0.10
STX Total	5.94	4.9
ST THOMAS		
STT Feeder 05A	0.16	0.00
STT Feeder 06A	1.72	0.77
STT Feeder 07A	1.19	0.16
STT Feeder 08A	0.41	0.68
STT Feeder 06B	0.50	0.01
STT Feeder 07B	1.59	0.62
STT Feeder 08B	1.99	0.69
STT Feeder 10B	1.53	0.55
STT Feeder 07C	1.07	0.48
STT Feeder 09C	1.68	0.59
STT Feeder 09D	0	0
STT Feeder 09A	0	0
STT Feeder 09B	0	0
STT Feeder Mall	0	0
STT Feeder YH	0	0
STT Total	11.67	4.55
ST JOHN		
STJ Feeder 07E	1.37	0.80
STJ Feeder 09E	3.14	1.60
STJ Total	4.5	2.4
GRAND TOTAL	22.11	11.85

Table 19 - Offer quantities for existing DER solar and BESS

4 Results: Highlighting long-term VPP DER benefits via scenario comparison

This section highlights the key findings from the long-term VPP analysis. The key findings considered for this analysis are as follows:

- VPP savings [$]
- VPP costs [$]
- Overall VPP benefits [$]

4.1 VPP Savings

The potential savings are calculated by looking at the total system costs for each scenario and comparing those costs with the total system costs in the Base scenario. The total cost is defined as the sum of all fixed and variable costs for all generators (including batteries) and physical contracts in the region and are made up of the following costs:

- The fixed charges include fixed O&M costs [$/kW] for installed capacity
- The variable charges include VO&M costs [$/kWh] for generation and fuel costs [$/kWh] (fuel offtake times the fuel price)
- Other generator costs include start and shutdown costs, emissions costs and abatement costs if they exist
- The physical contracts represent the external generation (offer quantity) and costs to acquire this generation (offer price) – i.e. Any PPAs currently in place

The difference between the total costs in a scenario and the base scenario is the savings that the VPP offers. Table 20 shows the VPP potential savings by scenario and year and highlights the ability of the VPP lower costs for the entire electricity system.

	Scenario 1: Low DER penetration	Scenario 2: Medium DER penetration	Scenario 3: High DER penetration	Scenario 4a: STX VPP	Scenario 4b. STT/STJ VPP	Scenario 5: DER overload
2025	$5,758,430	$6,773,250	$7,789,240	$7,702,540	-$585,610	$12,540,100
2026	$7,266,020	$9,096,050	$10,933,670	$9,691,310	$1,257,660	$20,834,400
2027	$16,230,210	$20,281,190	$24,210,950	$11,895,720	$12,363,770	$44,079,360
2028	$18,966,760	$25,160,140	$31,289,470	$13,710,020	$17,585,460	$68,924,840
2029	$19,506,010	$27,029,460	$34,514,770	$15,657,350	$18,861,560	$83,860,800
2030	$19,857,530	$28,192,340	$36,500,040	$16,777,470	$19,718,970	$98,708,210
2031	$19,898,670	$28,733,740	$37,553,820	$17,613,020	$19,236,170	$111,576,960
Avg.	$15,354,804	$20,752,310	$26,113,137	$13,292,490	$12,633,997	$62,932,096

Table 20 - VPP Savings [$] by scenario and year

The potential savings analysis reveals that the VPP has the potential to save USVI on average between $15.4M (scenario 1) and $26.1M (scenario 3) compared to the base case, which represent a 9.5% and a 16.1% cost reduction, respectively. However, by year 2031, scenario 1 is seeing a cost reduction of 12% annually and scenario 3 has reached a 23% annual cost reduction. Scenario 5 has potential annual savings of $62.9M compared to the base case, which is a 38.8% cost reduction. A graphical representation of these results is shown in Figure 25. The graphical representation clearly shows how, as more DERs are added to the VPP, the amount of savings can increase. And, in the extreme scenario of the DER overload, where no limits are placed on DER buildout, the savings are almost 70% by year 2031.

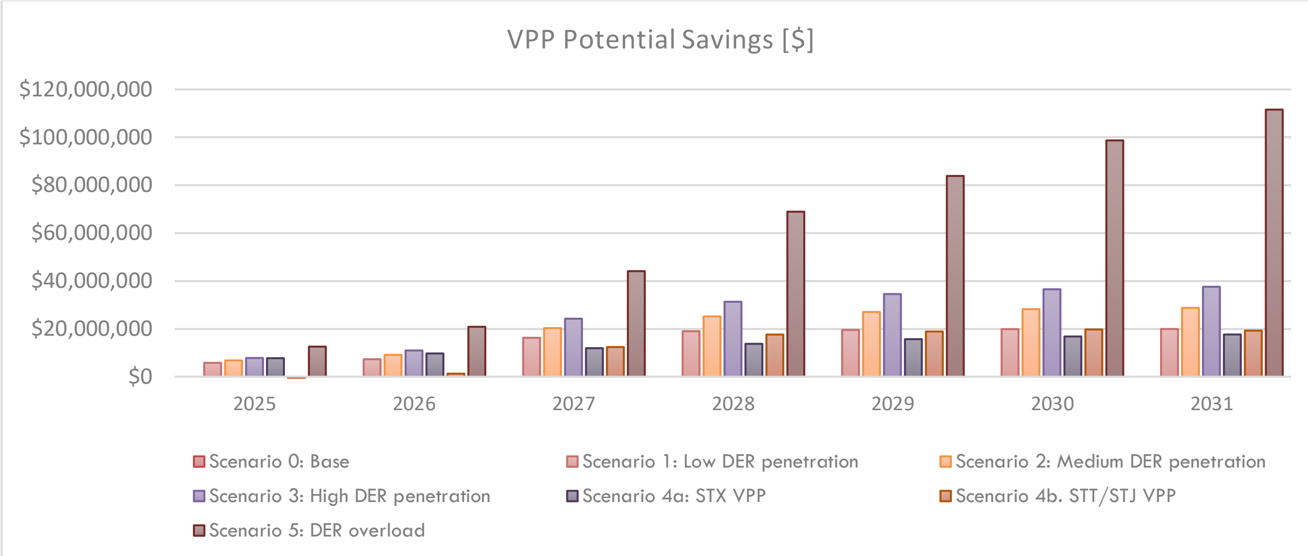


Figure 25 - VPP Savings [$] by scenario and year

4.2 VPP Costs

The VPP costs are calculated by quantifying the compensation costs according the chosen VPP modality. In the USVI case, the modality that has been selected is the battery compensation modality in which kWh's sent to the grid to provide grid services from the DER BESS assets are reimbursed at a given rate. For this model, the total generation [GWh] of all of the distributed batteries assets is reimbursed at 20 cents/kWh. A discussion on reimbursement and compensation schemes can be explored further in Section 6.1.1. Table 21 shows the VPP costs by scenario and year and shows the compensation costs to operate the VPP.

	Scenario 0: Base	Scenario 1: Low DER penetration	Scenario 2: Medium DER penetration	Scenario 3: High DER penetration	Scenario 4a: STX VPP	Scenario 4b. STT/STJ VPP	Scenario 5: DER overload
2025	$0	$974,000	$928,000	$1,026,000	$1,090,000	$26,000	$1,318,000
2026	$0	$1,396,000	$1,588,000	$1,840,000	$1,410,000	$426,000	$2,264,000
2027	$0	$3,130,000	$3,738,000	$4,346,000	$1,648,000	$2,732,000	$4,798,000
2028	$0	$2,728,000	$3,512,000	$4,322,000	$1,782,000	$2,806,000	$6,668,000
2029	$0	$2,680,000	$3,500,000	$4,368,000	$1,888,000	$2,706,000	$7,606,000
2030	$0	$2,732,000	$3,644,000	$4,530,000	$1,996,000	$2,716,000	$8,568,000
2031	$0	$2,774,000	$3,770,000	$4,736,000	$2,044,000	$2,886,000	$9,532,000

Table 21 - VPP Costs [$] by scenario and year

The average annual cost to reimburse participating assets is ~$1.7M-3.6M in **Scenarios 1-4. Scenario 5** reached much higher compensation levels with an average annual payout of $5.8M over the 7-year period. Figure 26 shows the graphical representation of these costs.

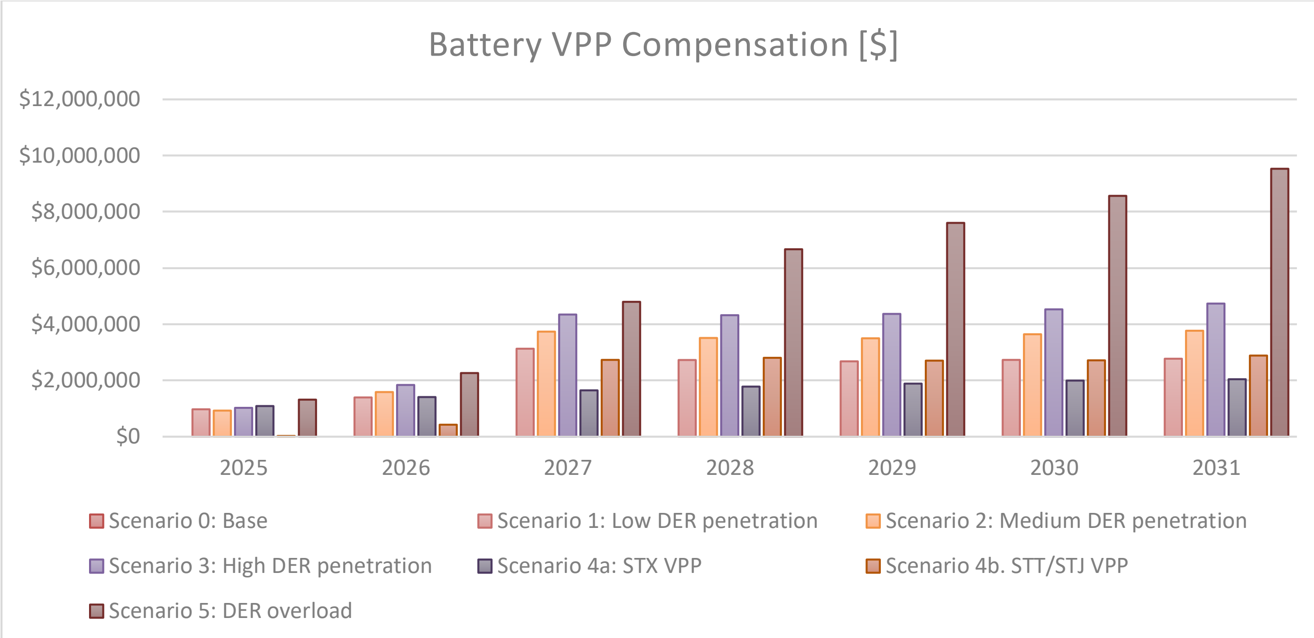


Figure 26 - VPP Costs [$] by scenario and year

4.3 VPP Net Benefits

The overall benefits are then assumed to be the difference between the potential savings and the potential costs of the VPP, and are shown in Table 22. The analysis reveals that there are large net benefits for all scenarios with the average annual benefits ranging from $10.6M to $22.5M for **Scenarios 1-4**. However, just interconnecting the DERs that exist on the grid today without any further DER buildout, represented by Scenario 1, can yield an average annual benefit of $13M on over the next 7 years. **Scenario 5**, sees an immense potential for overall benefits that average out to $57.1M annually over the next 7 years, but would require significant upgrades to T&D infrastructure at a feeder level in addition to very favorable regulation and policies, which are not included as part of this analysis.

	Scenario 1: Low DER penetration	Scenario 2: Medium DER penetration	Scenario 3: High DER penetration	Scenario 4a: STX VPP	Scenario 4b. STT/STJ VPP	Scenario 5: DER overload
2025	$4,784,430	$5,845,250	$6,763,240	$6,612,540	-$611,610	$11,222,100
2026	$5,870,020	$7,508,050	$9,093,670	$8,281,310	$831,660	$18,570,400
2027	$13,100,210	$16,543,190	$19,864,950	$10,247,720	$9,631,770	$39,281,360
2028	$16,238,760	$21,648,140	$26,967,470	$11,928,020	$14,779,460	$62,256,840
2029	$16,826,010	$23,529,460	$30,146,770	$13,769,350	$16,155,560	$76,254,800
2030	$17,125,530	$24,548,340	$31,970,040	$14,781,470	$17,002,970	$90,140,210
2031	$17,124,670	$24,963,740	$32,817,820	$15,569,020	$16,350,170	$102,044,960

Table 22 - VPP Overall Benefits [$] by scenario and year

The graphs in Figure 27 - Annual net benefits of a battery-based VPP in the USVI over a seven-year period illustrate the projected range of net benefits for a battery-based VPP in the USVI over the next seven years. The solid line represents the mean annual benefits, while the shaded area illustrates the range of potential outcomes across different scenarios. **Scenario 5**, which assumes unrestricted DER buildout, is shown as an outlier in green in the left graph, highlighting its significantly larger potential benefits compared to the other scenarios. The graph on the right focuses solely on the range of benefits for **Scenarios 1–4**, where the growth of DERs is more constrained. In both sets of graphs, the benefits increase notably as DER penetration expands over time, even though the most conservative scenarios still show substantial net gains year-over-year. In the initial years of VPP operation, the financial benefits are relatively modest across all scenarios, as the number of interconnected DERs remains limited. However, as DER penetration increases over time, the range of financial benefits begins to expand significantly. Even under the most conservative scenarios, where DER growth is slower, the annual net benefits remain substantial, underscoring the value of VPP integration from both an economic and operational perspective.

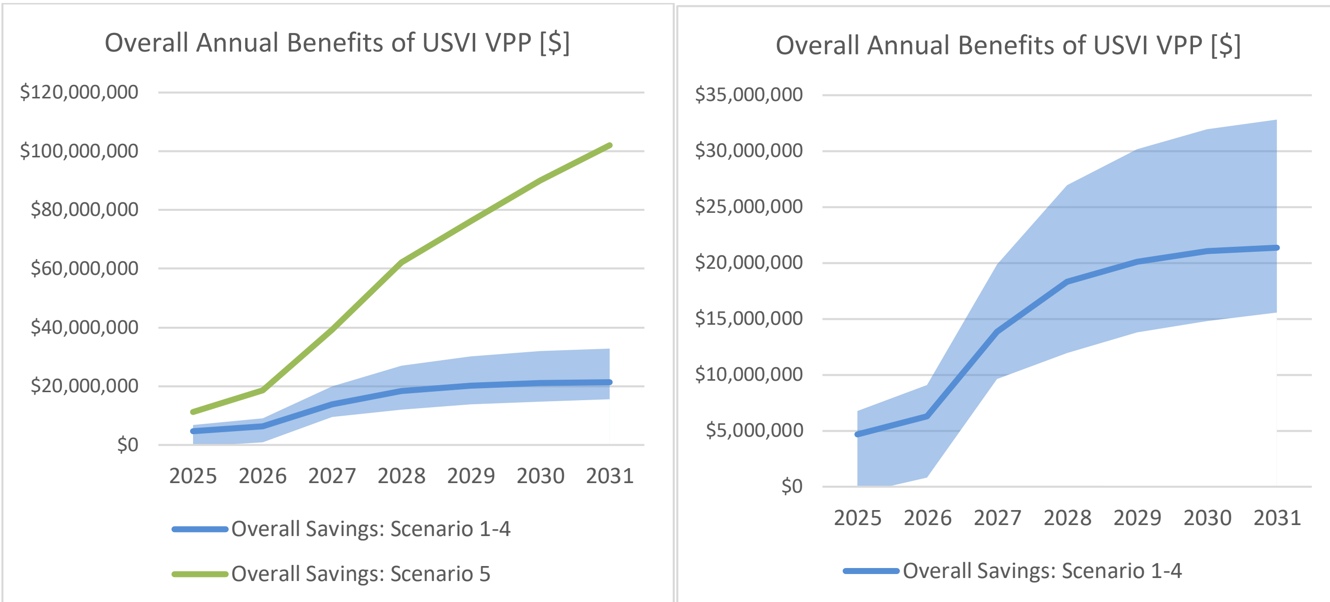


Figure 27 - Annual net benefits of a battery-based VPP in the USVI over a seven-year period

In addition to the savings from the reduction in annual total system costs, the VPP provides other financial benefits that were not captured in this analysis. One significant cost-saving opportunity is the reduction of spinning reserve costs. Spinning reserves, which are kept online to ensure grid stability and respond to demand fluctuations, often require costly fuel and maintenance to operate continuously. By leveraging distributed energy resources (DERs) within a VPP, the grid can rely on these assets for rapid response, reducing the need for traditional spinning reserves. This means lower fuel costs, fewer wear-and-tear expenses on utility generators, and overall reduced reserve capacity requirements—resulting in financial benefits that extend beyond the primary cost reductions analyzed.

4.4 Summary of VPP Benefits in USVI Context

The results from the long-term analysis demonstrate that, across all levels of DER penetration in a distributed, battery-based VPP, the net benefits are substantial. The costs associated with compensating participating assets in the VPP are significantly outweighed by the financial and operational gains.

One of the primary financial benefits of the VPP is its ability to reduce utility fuel consumption and reliance on traditional generators, which have significantly higher operational and maintenance costs. By offsetting both fixed and variable generation expenses, the VPP drives down overall electricity production costs, leading to potential savings for both utilities and consumers. These cost reductions become especially pronounced as the penetration of DERs increases over time.

The key results can be summarized in Table 23 for the Base Scenario, the Low DER penetration scenario, the Medium DER penetration scenario and the High DER penetration Scenario. For each scenario, the 2031 DER capacity is provided for both solar and BESS, with an indication of how many hours this BESS capacity could match the output of the largest generator. Next, the annual savings with the percentage reduction and the annual costs are provided for each of the scenarios. Finally, the overall benefits of the VPP are shown for each scenario in addition to the ancillary services that are provided by the interconnected DER systems.

	Base (2024/2025)	Low DER penetration	Medium DER penetration	High DER penetration
Description	Business-as-usual: Existing DERs are not aggregated into a VPP.	Existing DERs are aggregated into a VPP but there is no new buildout of distributed capacity.	DER solar PV allowed to expand to **50%** of remaining feeder capacity.	DER solar PV allowed to expand to **100%** of remaining feeder capacity.
2031 DER PV Capacity *[MW]*	0	31.5	43.9	56.5
2031 DER BESS Capacity *[MW/MWh]*	0	19.8/52.5 (can match largest gensets for 1.6 hours)	32.4/84.1 (can match largest gensets for 1.6 hours)	45.0/115.5 (can match largest gensets for 1.6 hours)
Annual Savings = total system cost reduction from base scenario		$15.4M (9.5% reduction)	$20.8M (12.8% reduction)	$26.1M (16.1% reduction)
Annual Costs = compensation to VPP participants for BESS provision at 20 cents/kWh		$2.3M	$3.0M	$3.6M
Overall Benefits = difference between savings and costs		**$13.0M (~$260 per household on USVI)**	**$17.8M (~$356 per household on USVI)**	**$22.5M (~$450 per household on USVI)**
Additional Ancillary Service		**$130k**	**$208k**	**$286k**

Table 23 - Summary of Key Findings for the long-term VPP analysis

In addition to the direct financial savings, the VPP also provides critical **non-financial benefits** that contribute to a more resilient, efficient, and sustainable grid. These benefits, though not always captured in standard cost-benefit analyses, have far-reaching implications for the long-term reliability and stability of the power system, including:

- **Enhanced Grid Reliability and Resiliency**: The distributed nature of VPPs, combined with the ability of DER assets to respond in real time, allows for more flexible grid operations. In the event of outages or extreme weather events, VPPs can help maintain critical power supply, making the grid more resilient to disruptions.
- **Frequency and Voltage Regulation**: Battery-based VPPs can provide essential grid services such as frequency regulation and voltage support, helping to stabilize the grid and prevent blackouts or brownouts, especially during periods of peak demand or grid stress.
- **Reduced Line Loading and Lower T&D Infrastructure Costs**: By generating power closer to where it is consumed, VPPs reduce the load on transmission and distribution (T&D) infrastructure. This can lower the need for expensive upgrades or maintenance to existing grid infrastructure, further enhancing the financial case for VPP integration.
- **Discouraging Load Defection**: A well-structured VPP can encourage customers to remain connected to the grid by offering compensation for their participation in grid services, reducing the incentive for load defection. This helps utilities maintain a stable customer base and ensures better overall grid management.
- **Environmental Benefits**: VPPs promote the integration of cleaner, distributed energy resources such as solar and wind, contributing to decarbonization goals and reducing overall emissions. This environmental impact, though often difficult to quantify financially, aligns with broader sustainability objectives and reduces the region's dependence on imported fossil fuels.

In conclusion, while the financial benefits of a distributed battery-based VPP—such as reduced fuel costs, generation savings, and deferred infrastructure upgrades—are significant, the non-financial advantages such as improved grid stability, reliability, and the potential for reduced emissions make VPPs an even more compelling solution. Together, these factors highlight the transformative potential of VPPs in modernizing the grid and enhancing energy security for the USVI and other regions considering similar deployments.

4.5 Other Results

Table 24 shows other results that were analyzed from the long-term model.

2031 Values	Low DER penetration	Medium DER penetration	High DER penetration	STX VPP	STT/STJ VPP	DER Overload
DER Solar Installed Capacity	31.5 MW	43.9 MW	56.5 MW	17.8 MW	33.6 MW	187.3 MW
DER BESS Installed Capacity	19.75 MW/52.5 MWh	32.4 MW/84.1 MWh	45.0 MW/115.5 MWh	19.5 MW/50.1 MWh	25.4 MW/65.4 MWh	64.6 MW/164.5 MWh
RE penetration level [% of *generation]*	6.7%	8.5%	10.2%	5.6%	7.1%	25.4%
Total DER generation [GWh]	52.8 GWh	73.7 GWh	94.5 GWh	39.1 GWh	56.5 GWh	257.3 GWh
Reduction in Fossil fuel generation [GWh]	38.9 GWh	54.9 GWh	70.9 GWh	28.9 GWh	39.6 GWh	209.7 GWh
Total DER New Build [MW]	0 MW	22.9 MW	45.8 MW	19.0 MW	22.6 MW	170.8 MW
Avoided Fuel Costs [$]	$12,008,280	$17,608,450	$23,195,470	$11,801,680	$10,668,900	$69,107,590
Emission Reductions [%]	5.4%	7.9%	10.5%	5.3%	4.9%	31.1%
Levelized cost of electricity reduction STX [$/kWh]	$1.4	$2.5	$3.7	$3.8	-$0.3	$10.9
Levelized cost of electricity reduction STT/STJ [$/kWh]	$1.7	$2.0	$2.4	$0.0	$2.4	$6.4
Line Losses Reduction [%]	10.3%	13.2%	15.8%	4.6%	11.5%	37.4%

Table 24 - Summary of other results for the long-term VPP analysis

Details of these additional results can be found in Appendix C and include the following:

- Total costs [$]
- Fuel costs [$]
- Levelized costs [$/MWh]
- Emissions [tonnes]
- Installed capacity by resource [MW]
- Generation by resource [GWh]
- Total new build capacity by resource [MW]
- RE penetration [%]
    - By installed capacity
    - By generation

- Fuel Offtake [TJ]
- Line loading [%]
- Line losses [GWh]
- Generation by feeder [GWh]
- Scenario-by-scenario look

5 Exploring VPP Benefits Over Short Timeframes

5.1 Goal of Study

The goal of the short-term analysis was to explore how a Virtual Power Plant (VPP) could enhance grid resiliency and reliability during specific use cases over a condensed time frame. This analysis aimed to assess the VPP's ability to bolster grid reliability in the face of generator outages or normal day-to-day operations, focusing on critical aspects such as load management, frequency regulation, and overall system flexibility. Specifically, two key use cases were analyzed: the loss of major generators in each system and the daily impact on generator dispatch.

5.2 Loss of Largest generators

This analysis simulated the loss of the two most impactful generating units on each island, rendering them unavailable for a designated period. The most impactful generators were identified based on their contribution to system generation during high-demand periods, as observed in the long-term scenarios. It's important to note that these may not necessarily be the physically largest generators, but rather those with the greatest impact on meeting grid demand. This analysis, commonly referred to as an **N-2 analysis**, is a standard reliability test for understanding the grid's ability to maintain stability following the loss of multiple generators.

Historically, during generator outages, the Virgin Islands Energy Office (VIEO) has had to implement rotational blackouts across grid feeders, sometimes lasting for weeks. These rotating blackouts are intended to distribute the impact of the generation shortfall, minimizing unscheduled or abrupt interruptions. The objective of this analysis was to determine whether the VPP could mitigate these rotational outages by dispatching interconnected DERs. By optimizing the use of DER assets, the VPP aggregator could reduce unserved energy and potentially eliminate the need for rotational blackouts altogether, thereby enhancing regional grid stability and minimizing disruptions to consumers.

In essence, the VPP's ability to mobilize a fleet of distributed energy resources in real-time could significantly reduce the extent and duration of outages, allowing for a more resilient grid during critical periods of generator loss.

5.2.1 N-2 Model Setup

There are two sets of scenarios in this short-term analysis—one for 2025 and one for 2031—designed to compare the performance of the VPP in its early stages versus at the end of the seven-year horizon. For each year, three distinct scenarios were run to assess grid performance and resiliency:

1. **Benchmark Scenario** (no loss of generators)
2. High DER Penetration Scenario
3. DER Overload Scenario

Each scenario was modeled over a two-week horizon, with the generator outages simulated to occur in the middle of the period, as illustrated in Figure 28. This allowed for a detailed comparison of grid dynamics during normal operations versus during periods of generator loss.

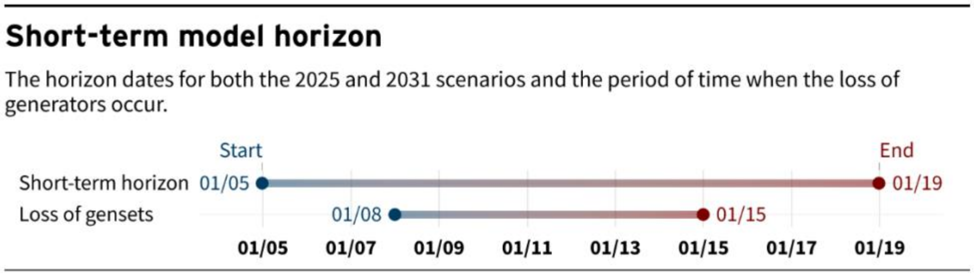


Figure 28 – Short-term model horizon

Overall, the scenarios that are run for this model are summarized in Table 25.

Scenario	Description	Horizon
Benchmark 2025	Model run over 2-week horizon but with no generator outages.	2 weeks: Jan 5 – Jan 19 (2025)
High DER Outage 2025	Model run with high DER penetration (See section 3.3.4)	2 weeks: Jan 5 – Jan 19 (2025) Outages Jan 8 – 15
DER Overload Outage 2025	Model run with DER overload penetration (See section 3.3.6)	2 weeks: Jan 5 – Jan 19 (2025) Outages Jan 8 – 15
Benchmark 2031	Model run over 2-week horizon but with no generator outages.	2 weeks: Jan 5 – Jan 19 (2031)
High DER Outage 2031	Model run with high DER penetration (See section 3.3.4)	2 weeks: Jan 5 – Jan 19 (2031) Outages Jan 8 – 15
DER Overload Outage 2031	Model run with DER overload penetration (See section 3.3.6)	2 weeks: Jan 5 – Jan 19 (2031) Outages Jan 8 – 15

Table 25 - Scenarios run for the short-term model in PLEXOS

To simulate the loss of the most impactful generators, capacity factor limits were applied to the utility generators, overriding the capacity limits established in previous sections. To determine these new capacity factor limits, outputs from the long-term VPP model were used as inputs for the short-term analysis. Specifically, hourly capacity factors for each generator were taken from the long-term results for both 2025 and 2031. Using the maximum capacity of each generator, the average capacity factor was calculated for each year. These averages served as the new capacity factor limits for normal grid operations in the short-term model.

During the simulated generator outages, the capacity factor limits for the affected generators were reduced to **0%**, while the remaining generators operated based on their respective average capacity factors from the long-term results. For instance, in St. Thomas/St. John, as shown in Table 26, **STT 23** and **STT 26** were identified as the most impactful generators (those with the highest generation output during the simulation period) and were set to 0% capacity in the 2025 scenario. For the 2031 scenario, the **Wärtsilä 1** and **Wärtsilä 2** generators were identified as the most impactful and were similarly disabled for the outage period.

STT/STJ	Max Capacity Factor [%] during 2025 outage	Max Capacity Factor [%] during 2031 outage
STT 15	26.7%	20%
STT 23	0	20%
STT 25	86.24%	68.44%
STT 26	86.24%	42.61%
STT 27	0	51.13%
Wärtsilä 1	39.95%	0
Wärtsilä 2	50.47%	0
Wärtsilä 3	43.52%	73.20
Wärtsilä 4	45.54%	78.00
Wärtsilä 5	62.84%	78.00
Wärtsilä 6	57.14%	78.00
Wärtsilä 7	62.82%	78.00
Donoe Solar	-	-

Table 26 - Capacity factor limits placed on generators in St. Thomas/St. John in short-term analysis

On St. Croix, as shown in Table 27, the generators **Aggreko** and **STX17** were identified as the most impactful units and were taken offline in both the 2025 and 2031 simulations. These selections were based on the generators' output and their critical role in grid stability during normal operations.

STX	Max Capacity Factor [%] during outage	Max Capacity Factor [%] during outage
STX 17	0	0
STX 19	85%	85%
STX 20	85%	85%
Aggreko	0	0
Future Solar (2026)	-	-

Table 27 - Capacity factor limits placed on generators in St. Croix in short-term analysis

Additionally, in order to ensure that the correct amount of DERs were on the grid during the short-term model, the DER values were fixed to the long-term result values for the period of interest. As an example, if in the long-term scenario 4 MW of solar had been built at Feeder 7A by January, 2031, this capacity was set as the fixed capacity in the short-term scenario. The capacities that were used for each of the short-term analyses can be found in Appendix D.

5.2.2 N-2 Analysis Results

The N-2 analysis simulated the loss of the two most impactful generators on the grid, and its impact on unserved energy (rotating blackouts) and system costs in the USVI. The results reveal the significant potential of a VPP to mitigate the negative effects of such outages.

The graph in Figure 29 illustrates the amount of unserved energy—essentially, the energy that would go unmet, leading to rotating blackouts—across all scenarios. The **base case** (orange area) shows a large amount of unserved energy, which is able to be significantly reduced in the **high DER penetration** scenario (dotted blue line) and the **DER overload** scenario (dotted yellow line). This highlights the VPP's ability to displace reduce unserved energy and alleviate strained grid operations during generator shutdowns.

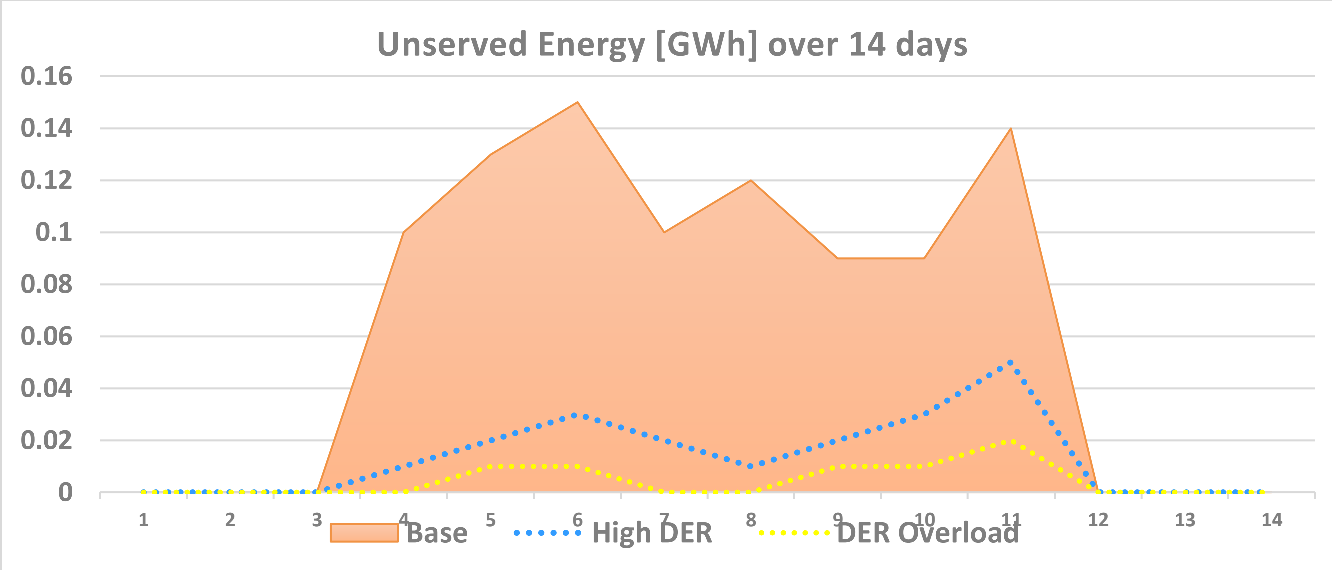


Figure 29 - Unserved energy in PLEXOS short-term scenarios

A summary of the two-week period in Table 28 further emphasizes the operational benefits of the VPP during loss of generators. In the **base case** (no VPP), there is 0.9 GWh of unserved energy during the generator outages. By contrast, the **high DER penetration** scenario reduces unserved energy by 79%, and the **DER overload** scenario nearly eliminates unserved energy altogether, showcasing the effectiveness of the VPP in maintaining grid reliability during major outages.

From a cost perspective, the base case with an outage results in a 15% increase in total system costs to the utility during the generator outages, compared to normal operations in the base case without any generator losses. However, in the high DER penetration scenario, this increase is significantly lower, at just 5.7%, and the DER overload scenario reduces the cost, even compared to the base case without any outage.

	Base (No outage)	Base	High DER penetration	DER Overload
Unserved Energy [GWh]	0	0.92	0.19 (79% reduction)	0.06 (93% reduction)
Fossil Fuel Generation per day [GWh]	2.31	2.24	2.12	1.83
Fossil Fuel operating hours per day	18.74	19.13	18.13	16.31
RE generation per day [GWh]	0.00	0.00	0.26	1.87
Total Cost per day	$ 483,297	$ 555,836 (15% increase)	$ 510,740 (5.7% increase)	$ 414,932 (14% decrease)
Fuel Cost per day	$ 459,113	$ 534,227	$ 489,682	$ 394,932
Savings Per Day	-	-	$ 45,096	$ 140,904

Table 28 - Results During a 2031 2-Week Period with Generator Shutdowns

5.3 Impact on Generator Dispatch

5.3.1 Model Set-up

The goal of this analysis is to assess how the Virtual Power Plant (VPP) can offset fossil fuel generation and optimize the dispatch order of generation resources on a day-to-day basis under normal grid operations (i.e., without any generator outages). This analysis is designed to explore the operational benefits of the VPP in terms of reducing fossil fuel reliance, increasing the use of distributed energy resources (DERs), and improving overall system efficiency. By comparing the base case with scenarios involving varying levels of DER penetration, the aim is to quantify the VPP's impact on reducing daily fossil fuel generation and its ability to improve grid performance.

This analysis runs over the same two-week period as the N-2 analysis, but without any generator outages. The same four key scenarios are modeled:

1. Base Case
2. Low DER Penetration Scenario
3. High DER Penetration Scenario
4. DER Overload Scenario

For each scenario, the VPP's effect on daily fossil fuel generation, renewable energy dispatch, and battery energy storage system (BESS) dispatch is tracked. The objective is to analyze how the VPP can shift dispatch away from traditional fossil fuel generators during peak and off-peak periods, particularly by utilizing solar and BESS assets during the day and storing excess energy for use during evening peaks.

The analysis provides insights into how the VPP can help reduce overall fossil fuel consumption, lower system costs, and enhance the efficiency of the grid during typical daily operations, demonstrating the potential for the VPP to play a key role in long-term energy transitions for the USVI.

5.3.2 Results

The results indicate that the VPP can deliver significant positive impacts on current generation operations, particularly in reducing reliance on fossil fuels. The graph in Figure 30 illustrates fossil fuel generation over a four-day period across the base case, the high DER penetration scenario and the DER overload scenario. The **base case** (orange area) shows consistently higher fossil fuel generation compared to the **high DER penetration** scenario (dotted blue line) and the **DER overload** scenario (dotted yellow line). This highlights the VPP's ability to displace fossil fuel generation by effectively integrating renewable energy sources and battery storage.

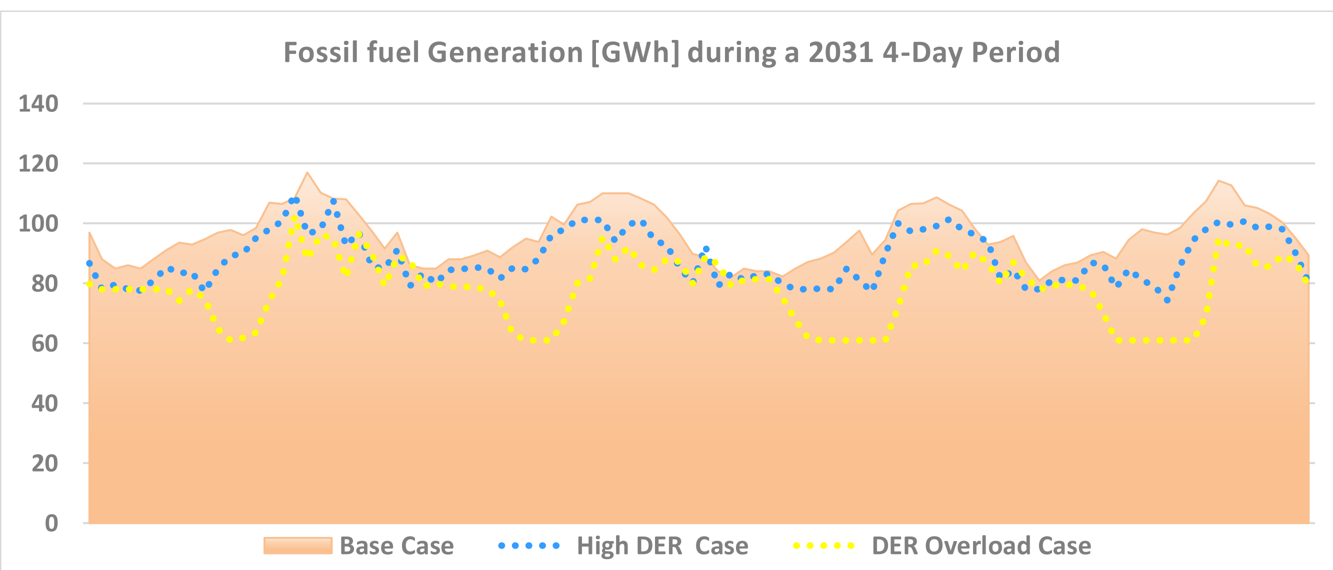


Figure 30 - Fossil fuel generation [GWh] during a 2031 4-day period for base case, high DER case and DER overload

The next graph in Figure 31 presents solar and battery energy storage system (BESS) generation during the same four-day period. During daylight hours, the interconnected DERs provide substantial excess generation to the grid, reducing the need for fossil fuel generation and creating the large dips seen in Figure 30. During the evening peak hours, the interconnected battery systems are dispatched to manage peak loads, further offsetting the need for fossil fuel-based generation and enhancing grid flexibility.

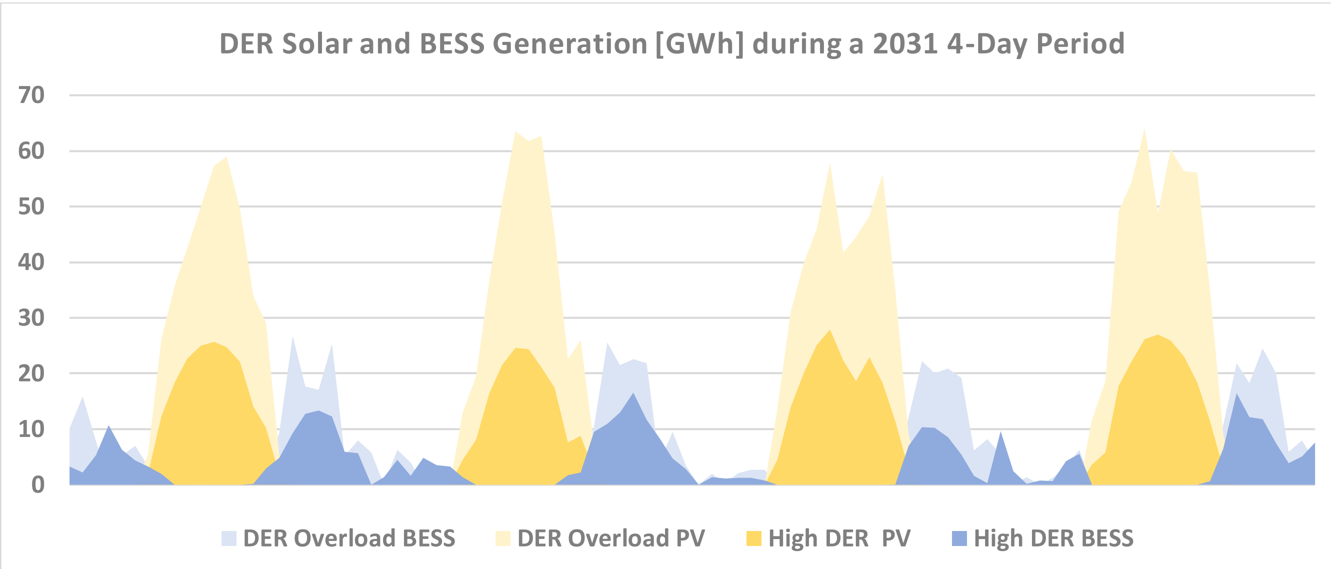


Figure 31 - DER generation [GWh] during a 2031 4-day period for base case, high DER case and DER overload

A summary of the two-week period in Table 29 further emphasizes the operational benefits of the VPP:

- In the **high DER penetration** scenario, fossil fuel generation is reduced by **7.8%** compared to the base case.
- In the **DER overload** scenario, the reduction in fossil fuel generation is even more substantial, at **19%**.
- The VPP also leads to a notable reduction in the daily operating hours of fossil fuel generators. In the high DER scenario, fossil fuel plants operate for nearly **one hour less per day**, while in the DER overload scenario, this reduction exceeds **two hours per day**.

The cost savings associated with these operational improvements are equally impressive. Over the two-week period, the high DER penetration scenario reduces overall generation costs by **12.3%**, while the DER overload scenario yields a **30%** cost reduction. These savings are driven by reduced fuel consumption, lower generator wear-and-tear, and the efficient utilization of renewable resources.

	Base	High DER penetration	DER Overload
Fossil Fuel Generation per day [GWh]	2.31	2.13 (7.8% reduction)	1.87 (19% reduction)
Fossil Fuel operating hours per day	18.74	17.93	16.52
RE generation per day [GWh]	0.00	0.23	0.57
Total Cost per day	$ 483,297	$ 423,724 (12.3% reduction)	$ 339,023 (30% reduction)

Fuel Cost per day	$ 459,113	$ 400,211	$ 316,229
Savings Per Day	-	$ 58,902	$ 142,884

Table 29 - Results During a 2031 2-Week Period

More details of the short-term model results can be found in Appendix E.

6 Incentivizing VPPs in the USVI

6.1 Through Understanding VPP Practices in Other Jurisdictions

Practices from four jurisdictions were assessed to gain insight into their regulatory frameworks and operations. Brief descriptions of the programs reviewed are described in the following sections while a comparison of the electricity systems in each jurisdiction is provided in Table 30.

6.1.1 Hawaii

Program: Hawaiian Electric's Bring Your Own Device (BYOD) Tariff and Grid Service Purchase Agreements

In 2019, the Public Utilities Commission (PUC) ordered the commencement of Phase 3 of the Distributed Energy Resources Program Structure (DPS) and developed the frameworks for what would be Hawaii's two long-term DER programs, which would succeed the interim programs. These are the Smart DER Tariff and BYOD Tariff. The Smart DER Tariff would be the basic net metering program which allowed customers to install solar and storage in the homes or businesses and either export to the grid for compensation (Export Rider) or primarily self-consume with no compensation for grid exports (Non-Export Rider). The BYOD Tariff is an optional, additional scheme which allows customers to interact more directly with grid operations through grid services under three different tiers. The Tier 1 Rider allows customers to provide capacity load reduction via energy storage for a predetermined two-hour period every day. The Tier 2 Rider provides capacity load reduction in the form of grid exports when signaled by the utility with a 24-hr day ahead notice period, unless in the case of emergencies. Finally, the Tier 3 Rider allows customers to provide frequency management services which signals customers to provide or take energy as needed to or from the grid with a similar 24-hr notice period. The BYOD Tariff is managed on the utility's behalf by a Dispatch Agent.

Third party operators can also provide VPP functionality for the utility via a Grid Services Purchase Agreement (GSPA)[4]. When it determines that capacity is needed, the utility will issue a Request for Proposal for grid services following the procurement guidelines. Interested parties are required to explain, among other things, their technologies, and layout their expectations for certain fees that they will be paid by the utility. These are the Management Fee, Enablement Fee, Incentive Adder and Competitive Program Incentives.

6.1.2 Puerto Rico

Program: LUMA's Battery Emergency Demand Response Program

In 2019, the Puerto Rico Public Energy Policy Act amended the Puerto Rico Energy Transformation and RELIEF Act (Energy Reform Act) and established demand response (DR) programs. The Regulation for Demand Response was subsequently published by the Puerto Rico Energy Bureau in 2020 following which the company in charge of transmission and distribution, LUMA, established the Battery Emergency Demand Response Program (BEDRP) in 2023 on behalf of the utility. In this program, third party providers can be contracted as Emergency Demand Response Aggregators to incentivize customers to use their storage systems to assist in provision of grid services. As per the Regulation, LUMA compensates these Aggregators who in turn compensate their participants according to their own unique business models.

[4] Draft Model Grid Services Purchase Agreement

6.1.3 Western Australia

Program: Project Symphony VPP Pilot

The Western Australia Distributed Energy Resources Orchestration Pilot, aka Project Symphony, ran from July 2021 to February 2024. The project was a collaboration among two state-owned agencies, Western Power (T&D system management) and Synergy (retailer), the Australian Energy Market Operator (AEMO) and Energy Policy WA, and was funded by the Australian Renewable Energy Agency. Project Symphony aimed to combine DERs including rooftop solar, battery energy storage, air conditioning and pool pumps in the isolated South West Interconnected System grid network into a VPP and explored the implications for the regulatory framework, technical operations and customer experience. In this pilot, Synergy, acted as a Parent Aggregator under which third-party aggregators would be contracted.

6.1.4 Vermont

Program: Green Mountain Power's BYOD Program

One of Vermont's electricity retailers, Green Mountain Power (GMP), has established the Bring Your Own Device (BYOD) program which makes use of customer-owned battery storage systems to meet grid needs. Under this program, participants can choose between the Backup Only or Self-Consumption options. In the former, participants make their systems available to GMP for either three or four hours at a chosen capacity, while in the latter, they agree to use power only from their systems during peak events. An additional incentive is also provided to participants in grid constrained areas who charge their batteries via solar between the hours of 10 am to 2 pm daily.

Jurisdiction	System Operator	Transmission system ownership	Distribution system ownership	Electricity retailer	Grid Network
Hawaii	N/A	Sole utility (private)	Sole utility (private)	Sole utility (private)	Isolated
Puerto Rico	N/A	Sole utility (private)	Sole utility (private)	Sole utility (private)	Isolated
USVI	N/A	Sole utility (state-owned)	Sole utility (state-owned)	Sole utility (state-owned)	Isolated
Vermont	ISO New England (independent, non-profit)	Transmission company (for profit, owned by distribution utilities and public benefits corporation)	Multiple utilities	Multiple	Interconnected
Western Australia	Australia Energy Market Operator (60% government, 40% industry)	T&D system provider (state-owned)	T&D system provider (state-owned)	Multiple	Isolated

Table 30 - Comparison of Electricity Systems in the 4 Jurisdictions

Of these four, the relevant information on policy and regulatory framework was most readily available for the programs in Hawaii and Puerto Rico, and hence the analysis focuses mostly on these two jurisdictions, with mentions of the others where applicable. Using these two islands as the major comparators for this analysis is appropriate as they share multiple similarities with the USVI:

- US states or territories
- Small islands
- One major electric utility responsible for transmission, distribution and retail of electricity

6.2 Through Policy and Legislation

6.2.1 Best Practices for Policies that promote VPPs

The review of practices around the world revealed that demand response programs and VPPs are the most common ways of leveraging grid-connected solar and battery. Some programs also include controllable loads such as thermostats, water heaters or electric vehicles for provision of services to the grid. Bearing the USVI context in mind, the following practices were highlighted as the ones most necessary to allow the USVI to begin making use of its grid-connected assets in a manner that is strategic, scalable and sustainable.

I. Establish grid service needs

The technological requirements of VPP or demand response equipment and software will depend on the services that participating assets will provide. Common services required by utilities include capacity provision, load reduction (via energy storage or self-supply), and frequency regulation.

Examples from other jurisdictions
Hawaii: Hawaiian Electric publishes an Integrated Grid Plan which incorporates resource planning with assessment of grid needs for a holistic approach to electricity system planning. **Vermont:** The Department of Public Service publishes a Comprehensive Energy Plan every 5 years which describes the state's strategies toward meeting its energy goals, including details for grid modernization.

II. Develop long-term DER plans

Medium- to long-term strategic planning is often used to create a cohesive structure and vision for DERs and their role in demand side management. These plans are usually mandated by the regulator of the utility. The Public Utilities Commission (PUC) in Hawaii ordered Hawaiian Electric to publish an Integrated Demand Response Portfolio which brought all their demand response programs at the time under one structure.

Examples from other jurisdictions
Puerto Rico: The Energy Bureau of mandated in their Regulations for Demand Response that LUMA develop both a Two-Year Transition Period Plan which described how they would prepare themselves and the market for both demand response and energy efficiency initiatives, and a Three-Year DR plan detailing their objectives with respect to the creation of demand response programs. **Vermont:** The Comprehensive Energy Plan describes the state's strategies toward meeting its energy goals, including details for grid modernization and incorporation of DERs. **Western Australia:** A DER Roadmap was released by Energy Transformation taskforce which was established by the WA government. The roadmap came out of the taskforce's Energy Transition Strategy.

III. Establish an overarching Demand Response or DER program

These programs may be established by the regulator but owned by the utility. Various programs or tariff schemes that leverage the use of customer-owned DERs may then be implemented under the overarching program.

Examples from other jurisdictions
Hawaii: Hawaiian Electric's net metering and demand response schemes fall within the DER Program Structure. **Puerto Rico:** VPP providers apply through LUMA's Customer Battery Energy Sharing Program (CBES, also known as the Battery Emergency Demand Response Program).

IV. Develop competitive procurement processes for third-party providers or aggregators

Third parties who are aggregators or, if the framework allows, are interested in providing a demand response program to customers, should be able to bid competitively in utility solicitation for provision of grid services. This may require adjustment to procurement frameworks to incorporate aspects that are more specific to demand response and/or VPPs.

Examples from other jurisdictions
Hawaii: When Hawaiian Electric requires grid services, third parties are invited to submit proposals, and successful bidders enter into a Grid Services Purchase Agreement with the utility. **Puerto Rico:** LUMA executes Master Aggregation Agreements with eligible aggregators. **Western Australia:** Two third-party Aggregators were procured to provide the Parent Aggregator (Synergy) with access to a wider pool of DER resources. Early engagement of aggregators was recommended to allow time for overcoming technological integration issues and necessary regulatory reforms.

V. Implement fair and sustainable compensation/incentives that reflect the value that DERs bring to utilities

These can take the form of upfront incentives, monthly incentives and monthly credits, and may be applied to either the participants or the aggregators. This may be separate from any compensation received from net metering or net billing schemes that the participant may be enrolled in. Depending on program structure, compensation can flow in a few ways:

- From utility to customer enrolled in a utility DR program or VPP.
- From utility to third-party program provider or aggregator, and subsequently,
- From third-party program provider or aggregator to customer enrolled in their program or VPP.

Upfront incentives generally aid prospective participants to purchase a DER, while monthly and ongoing credits encourage continued participation and may allow for participants to obtain a satisfactory return on their investment.

Examples from other jurisdictions
Hawaii: In Hawaiian Electric's BYOD Tariff program, where the utility operates customers DERs, participants receive three types of compensation – credits for energy exports, an upfront incentive ($/kW of capacity committed), and a monthly capacity performance incentive ($/kW of capacity committed). These incentives are determined through average short-run marginal costs over different times of day, and long term avoided costs of capacity, generation and transmission modelling in PLEXOS and RESOLVE respectively. The value impacts considered are also guided by the National Standard Practice Manual for Benefit-Cost Analysis of DERs. For participants enrolled in programs by aggregators under a grid services purchase agreement (GSPA), the utility provides an upfront incentive ($850/kW) only for new battery energy storage systems and a monthly minimum export incentive credit where the latter is a fixed credit calculated based on, among other things, non-fuel energy charges, adjustments and surcharges, the net metering export rate and the participant's allocated capacity. **Puerto Rico:** VPP aggregators receive a $/kWh compensation from the utility which they can choose to pass on to their participants based on their own business models. The compensation of $1.25/kWh was determined by LUMA based on their review of practices in other jurisdictions and input from potential aggregators.

VI. Determine appropriate cost recovery mechanisms

Recovery of costs incurred to the utility by DR or VPP programs is usually discussed between the regulator and the utility, and at least some costs are passed through to all ratepayers via a surcharge Recovery of costs incurred to the utility by DR or VPP programs is usually discussed between the regulator and the utility, and at least some costs are passed through to all ratepayers via a surcharge.

Examples from other jurisdictions
Hawaii: Hawaiian Electric's one-time upfront incentive, monthly capacity incentive, grid services energy export rate and cost of Evaluation, Monitoring and Verification (EM&V) activities are recovered in the Demand Side Management (DSM) Surcharge. According to the regulator, these are incremental costs which do not currently have an alternative method of recovery and represent the costs that BYOD program operation should ultimately avoid for Hawaiian Electric's ratepayers. The compensation paid out for energy exports is recovered in the Energy Cost Recovery Clause, which is the same recovery mechanism used for NEM compensation. **Puerto Rico:** All CBES program costs are recovered through the Power Purchase Clause Adjustment (PPCA). This includes both administrative costs and payments to aggregators. Both the DSM and the PPCA are reconciled with actual costs and adjusted on a quarterly basis.

VII. Regularly evaluate cost-effectiveness of demand response/VPP programs

Program regulations often mandate cost-effectiveness testing of programs. This is important to ensure that customers are actually benefiting from the program and can allow for early identification of any discrepancies or areas of ineffectiveness. Cost effectiveness tests generally weigh the benefits of the program against the costs incurred by the program.

Examples from other jurisdictions
Hawaii: As part of its RFP process, Hawaiian Electric evaluates the cost-effectiveness of contracted services (such as Grid Services) via a Value of Service (VOS) methodology. The VOS methodology is defined as "an avoided cost value that is produced by the Company to reflect an annual $/kW for each service being procured by island" and weighs the benefits that customers experience as a result of the contract against the costs incurred to them. **Puerto Rico:** The Puerto Rico Test is used. The Puerto Rico Energy Bureau is in charge of developing the specific benefits and costs to be included in the Puerto Rico Test, informed by stakeholder input. Impacts considered include all relevant generation, transmission, and distribution impacts, reliability and resilience, other fuel impacts, and environmental impacts, and may include other non-energy impacts, water impacts, economic development impacts, and social equity impacts. The accrual of specific non-energy impacts to certain programs or technologies, such as income eligible programs or combined heat and power may also be considered.

VIII. Ensure cybersecurity and data protection protocols are in place

Cybersecurity and data protection requirements are provided to potential aggregators to ensure the privacy of all parties involved in the VPP including the utility and participants. The cybersecurity risk may be mitigated through the use of scheduled dispatch modes of operation that do not require assets to be managed in real time and therefore do not require connectivity. In such cases, the utility will simply be aware of when certain grid services (e.g. load reduction or capacity provision) are expected to take place.

Examples from other jurisdictions

Hawaii: Procurement documents for third parties through Grid Services Purchase Agreements detail cybersecurity needs. These include use of National Institute of Standards and Technology (NIST) standards for own, utility and participant data, establishment of a continuous cybersecurity program, cybersecurity liability insurance and the utility's own requirements.

Puerto Rico: Program providers are required to provide a data security policy to LUMA before they can receive certification. They may also be audited to ensure compliance with the policy.

6.2.2 Assessment of Local Environment

Act 7075 – USVI Renewable and Alternative Energy Act (2009)

This Act aimed to encourage the adoption of both utility-scale and small-scale, distributed renewable and alternative energy in the USVI. It sets a renewable capacity target of 30% of peak demand by 2025 for VIWAPA, establishes incentives for clean energy investments, and mandates energy efficiency standards. It supports research and development in the sector and also stresses the need for the USVI government to lead by example through renewable energy and energy efficiency initiatives in its buildings. This Act also introduced the net metering program with caps of 10 MW capacity for St Thomas, St John, Water Island and other territorial offshore keys and islands, and 5 MW for St. Croix. System sizes were capped at 10 kW, except for systems already in the program as at the effective date of the Act.

Act 7586 – Feed-in Tariff Act (2014)

This Act amended the Renewable and Alternative Energy Act to introduce the Feed-in Tariff (FiT). Establishment of this tariff would be carried out via a power purchase agreement (PPA) between the utility and a qualified owner of a renewable energy generation project. The tariff rate would be set by the Commission according to their ratemaking authority and be established at a percentage discount to the avoided cost of the utility in the year that the PPA is established. The Act also maintained the island-wide caps established in Act 7075 and only system sizes from 10 kW to 500 kW were eligible for the FiT.

Net Billing Arrangement (2020)

The USVI's Net Energy Billing (NEB) program was introduced in 2020 as the successor to the NEM program which was closed in 2017, after the total 15 MW territory-wide capacity limit of interconnected distributed generation was reached. The NEB program had 4 significant differences from the NEM program. Firstly, under NEM, customer-generators were compensated for their electricity exports at the retail rate; under the NEB, customer-generators would now receive an excess generation credit equal to 75% of the current Levelized Adjustment Clause (LEAC). Secondly, participants in the NEB program would now need to pay a non-bypassable Grid Access Charge which would promote equity among the customer base by ensuring that customer-generators still contributed to the fixed costs of grid infrastructure maintenance. This charge varies based on the size of the system installed. Thirdly, the NEB program introduced monthly reconciliation where participants credits are zeroed out at the end of the monthly billing period and do not roll over into future months. Previously, credits were only zeroed out at the end of the calendar year. This change was introduced to encourage participants to right-size their systems. The final change made under the NEB program was the streamlining of the permitting process under the VIEO to ensure rapid rollout of the program. The VIEO plays a central role in the process, managing the flow of documentation and data among the utility and the Department of Natural Planning and Resources (DPNR) which issues permits and performs inspections.

6.2.3 Gap Analysis and Recommendations

Lack of strategic DER planning

A major gap identified in the documents reviewed was the lack of DER focus in the territory's strategies for achievement of their energy goals. Strategies such as demand-side management which make use of grid-connected, controllable assets like solar PV, batteries, thermostats and even electric vehicles are not mentioned in any governing legislation or regulations. This lack of inclusion of DERs in energy system planning means that policies and frameworks may not be tailored in a way that creates an enabling environment for programs that leverage them for provision of grid services, i.e. demand response or VPP programs. For instance, one barrier to the propagation of VPP programs is a lack of capacity in both technical and administrative aspects. To be able to circumvent this issue in the near-term and rapidly deploy such programs, third-party, private companies are often procured. However, within the USVI's current regulatory environment, it is uncertain how these third parties can enter the market or operate effectively within it. Considering the role of DERs in all aspects of the electricity value chain allows for the development of policies, regulations and procedures that can effectively allow them to be used as a grid asset.

Lack of incentive for grid exports

The USVI's current compensation rate under the NEB program, is less than the grid retail rate. This incentivizes self-consumption and storage which is counter to the behavior required for leveraging grid-connected assets to support the electricity system. This highlights the need for an additional form of compensation and/or incentive, whether provided by the utility or a separate program provider, that will encourage participation in a DER program.

6.2.4 Recommendations

Table 31 below provides recommendations to enhance the USVI's current regulatory framework based on the practices described in section 6.21.

Best Practice	Current USVI Context	Recommendation
1. Establish grid service needs	USVI legislation mandates that the utility develop and carry out a 10-year implementation plan to increase the efficiency of energy generation and improve the use of renewable energy sources. VIWAPA's latest IRP, published in 2020, assesses pathways for expansion of generation resources but does not give a detailed analysis of demand side management programs due to limited data availability.	Highlight most critical grid service needs to be addressed by customer-sited DERs to inform program development Knowing the grid service needs that are required in both the short and long term will help to ensure that any program developed is fit for purpose
2. Develop long-term DER plans	No long-term DER plans currently exist, nor is the development of such mandated.	Include the need for long-term, strategic planning for DERs in regulatory framework. This planning can inform development of programs that leverage these assets and benefit both the utility and ratepayers.

3. Establish an overarching Demand Response program	No demand response programs currently exist in the USVI, however there is an active Net Billing program.	The PUC and utility should collaborate to develop an overarching Demand Response or DER program. An overarching program will provide flexibility for different types of sub-programs or tariffs that can be used to carry out demand side management activities.
4. Develop competitive procurement processes for third-party providers or aggregators	There is currently a process for procurement of IPPs to provide renewable energy from large scale projects.	Adapt procurement framework to allow for contracting of independent third-parties to provide programs or aggregate customer DERs for use in a VPP. Having the proper frameworks in place will allow for ease of participation and faster uptake of the program.
5. Implement fair and sustainable compensation/incentives that reflect the value that DERs bring to utilities	The Feed-in Tariff Act states that grid export rates must be established at a discount to the avoided cost of the utility in the given year of a power purchase agreement. The FiT rate through the current Net Billing program is calculated as 75% of the current Levelized Energy Adjustment Clause, which in lieu of more precise data, is used as a proxy for the value of excess production from DERs[5]. The VIEO currently has a Battery Energy Storage Program that provides rebates to residents who purchase eligible devices. A similar program can be useful for incentivizing program participation.	Consider compensation mechanisms based on quantifiable factors such as the cost of avoided generation. Consider use of upfront incentives to allow for equitable program participation. These mechanisms will encourage new and continued participation in programs. Premiums can also be applied to compensation for emergency grid events.
6. Determine appropriate cost recovery mechanisms	Currently, the Feed-in Tariff Act has a clause for cost recovery which only requires utilities to file their rate schedules with provisions for automatic adjustment of charges in direct relation to the cost of electricity purchased from renewable energy generators.	Collaborate with the relevant stakeholders (PSC, utility, general public) to determine how costs incurred by the utility can be recovered. Sufficient consultation can allow for development of solutions that are acceptable to all from the outset and

5 https://newenergyevents.com/islandenergy/wp-content/uploads/sites/37/2021/04/NEM-Alternatives-Net-Energy-Billing-USVI.pptx.pdf

	Rate changes must go to the PSC for approval before they take effect.	hence minimize the risk of regulatory delays later in the program.
7. Regularly evaluate effectiveness of demand response/VPP programs	No such tests are currently mandated in legislation or regulations.	Consider regular use of an analysis that weighs customer benefits against costs to ensure that programs are cost-effective for both the utility and customers. Regularly assessing the cost-effectiveness of programs can allow for early detection of disparities or areas for improvement within the program.
8. Ensure cybersecurity and data protection protocols are in place	The utility VIWAPA has cybersecurity practices, which will likely need to be expanded to include protection of other program participant's data – either through requirements for eligibility to be a program provider or aggregator, or through expansion of the utility's own protocols, or both.	Requirements for cybersecurity and data protection in a customer DER program should be developed collaboratively and enforced on aggregators and program providers. These requirements will assuage the privacy and security concerns of all stakeholders involved in the program. Alternatively, in the early stages, the program can avoid the cybersecurity risk through use of scheduled dispatch operation where devices do not need to be managed in real-time and therefore do not require internet connectivity.

Table 31 - Recommendations for Enhancement of the USVI Regulatory Framework to Enable VPPs

6.3 Creation of a DER Management System (DERMS)

A Distributed Energy Resource Management System (DERMS) is a software platform designed to monitor, control, and optimize the operations of distributed energy resources. For the VPP in the USVI, implementing a DERMS would provide the essential technological backbone needed to efficiently integrate, manage, and optimize a wide array of DERs as a coordinated, grid-supporting entity. This DERMS would need to be designed and controlled by the VPP aggregator, whether it be a third-party or the utility. Its key functions are outlined below.

Key Functions of a DERMS for VPP Operations

1. **Real-Time Monitoring and Control:** A DERMS would provide real-time visibility and control over the diverse portfolio of DERs, enabling the participants and/or aggregator to adjust dispatch levels, respond to demand fluctuations, and optimize grid stability. The amount of battery storage provided by each household could be determined individually through something as simple as the battery provider's app like Tesla's app. Then a separate DERMS software used by the aggregator would help monitor and manage assets in real time, allowing the VPP to support grid needs dynamically and ensuring that distributed resources contribute to the system exactly when they are needed most, such as during peak demand or outage events.
2. **Optimized Dispatch and Coordination:** The DERMS would enable the USVI VPP to coordinate DERs for optimal dispatch, maximizing their ability to offset fossil fuel generation, reduce peak loads, and maintain grid balance. Through predictive analytics and machine learning, the DERMS would forecast demand and generation, adjust dispatch schedules, and prioritize DER contributions based on economic and technical criteria. This optimized dispatch would help the VPP deliver maximum cost savings and grid support.

3. **Frequency and Voltage Regulation:** One of the major challenges in integrating a large number of DERs is maintaining stable frequency and voltage across the grid. A DERMS could manage the collective response of DERs to stabilize grid frequency and voltage by providing ancillary services, such as fast response load adjustments or coordinated battery discharge. This is particularly beneficial in islanded or low-inertia systems, like the USVI, where frequency stability is crucial.
4. **Enhanced Grid Resilience and Reliability:** By consolidating control over DERs, the DERMS could bolster grid resilience in the USVI, especially during extreme weather events or system disturbances. In the event of outages, the DERMS can autonomously prioritize critical loads, ensure efficient use of backup power, and prevent large-scale blackouts by dispatching DERs in a way that minimizes unserved energy. This capability aligns well with the USVI's need for a more resilient energy system.
5. **Data Collection and Analysis:** The DERMS could continuously collect performance data from all connected DERs, providing insights that improve system performance, support operational planning, and inform regulatory decisions. Data on load patterns, DER availability, battery state of charge, and power quality would be collected and analyzed to help contribute to the ongoing refinement of the VPP, helping it evolve in response to grid conditions, customer behaviors, and energy market dynamics.
6. **Customer Participation and Incentivization:** By integrating DERs owned by customers, a DERMS would support customer engagement by enabling visibility into individual contributions, potential savings, and compensation through the VPP. Customers can monitor the status of their DER assets and understand how their participation impacts the grid by integrating the VPP functioning into the battery provider's app that is already being used by the household. This helps provide a transparent framework for fair compensation and fosters community support for the VPP program.

Supporting the USVI VPP with a DERMS

For the USVI, a DERMS could be a game-changer in making the VPP feasible, scalable, and impactful. By integrating a diverse set of DERs across the islands, the DERMS enables the USVI's VPP aggregator to provide essential services like peak shaving, reserve capacity, and frequency regulation, contributing to a cleaner, more reliable, and more cost-effective energy system. If integrated into the apps that are already used by households, it would also provide transparency and simplicity when incentivizing homeowners to participate. Moreover, with a DERMS in place, the VPP can better address challenges unique to the territory, such as low grid inertia, high dependence on fossil fuels, and the logistical complexities of maintaining grid stability across islands.

In conclusion, a DERMS is essential for transforming the USVI VPP from a concept into a reliable grid asset. By providing the control, visibility, and optimization needed to effectively manage DERs, a DERMS equips the VPP to meet current and future grid demands, support environmental targets, and ultimately build a more resilient and sustainable energy future for the USVI.

7 Conclusion

This report demonstrates the significant advantages of implementing a distributed battery-based VPP in the USVI, providing not only cost reductions but also a range of operational and environmental benefits that strengthen the grid and support the territory's energy transition goals. The VPP, by integrating distributed energy resources into a unified, flexible system, shows a powerful potential to reduce reliance on fossil fuel generation and lower system costs. The analysis illustrates that the VPP can achieve substantial savings by offsetting peak loads, minimizing operating hours of conventional generators, and delivering consistent cost reductions. However, the benefits extend well beyond direct financial savings, positioning the VPP as a critical asset for a sustainable and resilient USVI energy future.

VPP short term and long-term benefits:

In addition to cost savings, the VPP enhances **grid reliability and resiliency**, particularly in the face of extreme weather events and unplanned outages. By coordinating distributed solar and battery resources, the VPP can support critical loads during emergencies, reducing or even eliminating the need for rotational blackouts and ensuring continuous energy supply to essential services, as seen during the short-term analysis. This increased resilience is vital for island communities vulnerable to hurricanes and other natural disasters.

The VPP also supports **frequency and voltage regulation**, a key aspect of maintaining grid stability. Distributed batteries can respond quickly to fluctuations in demand or generation, stabilizing frequency and voltage levels more effectively than traditional generators. This capacity to manage grid variability improves overall system reliability and supports a higher penetration of renewable energy without compromising grid performance.

Moreover, the VPP contributes to **reduced line loading and decreased transmission and distribution (T&D) infrastructure needs**. By generating and storing power closer to where it is consumed, the VPP reduces the strain on T&D networks, potentially delaying or avoiding costly upgrades to infrastructure. This distributed approach to power generation and storage is particularly beneficial for remote or hard-to-reach areas where grid expansion is challenging and costly.

The VPP also offers an opportunity to **reduce load defection and empower customers**. By enabling and incentivizing customers to participate in the energy market through their own solar and storage systems, the VPP provides a new level of energy independence and financial benefit, which can discourage load defection to off-grid solutions. This empowerment promotes customer engagement and creates a community-driven approach to energy management, fostering greater public support for renewable energy initiatives.

Finally, the VPP's contribution to **reduced carbon emissions** aligns with the USVI's commitment to clean energy. By offsetting fossil fuel generation with distributed renewables, the VPP reduces greenhouse gas emissions, helping the territory meet its climate goals. The reduction in emissions not only benefits local air quality but also positions the USVI as a leader in sustainable island energy solutions, contributing to global climate action efforts.

Policy best practices and recommendations:

For the successful implementation of a VPP in the USVI, several policy best practices and recommendations have been highlighted in this report. First, establishing clear **grid service requirements** is critical to identify the roles that DERs can play within the VPP, such as frequency regulation, load shifting, and capacity support, and ensure that the technological requirements of the VPP are defined appropriately. These service requirements help ensure that the VPP can meet specific grid needs while providing flexibility in its operation.

Second, the USVI should consider **developing a comprehensive DER and VPP roadmap** similar to an Integrated Resource Plan (IRP) but focused on distributed energy integration. This roadmap would outline future DER adoption goals, identify grid service needs, and provide a structured approach to scaling up VPP operations.

Implementing **competitive procurement processes** for third-party aggregators can also be beneficial. By enabling third-party providers to manage DER aggregation and VPP coordination, the USVI can leverage private sector expertise and resources, accelerating VPP deployment and reducing the administrative burden on local utilities.

Additionally, **incentives and fair compensation** mechanisms should be established to encourage participation in the VPP. Providing upfront payments for battery installations and/or compensation for energy or capacity contributions can motivate customers to invest in DERs and engage with the VPP program. Recovery of costs associated with these mechanisms as well as the rest of the VPP program is a critical point of discussion among key stakeholders including the regulator, and the resulting cost-effectiveness of the program should be assessed regularly to ensure that ratepayers are experiencing the desired benefits.

Finally, **cybersecurity and data** privacy protocols are essential to protect the VPP's integrity and participants' information. Ensuring robust security measures for DER assets connected to the VPP will build public trust and participation, and reduce the risk of disruptions.

Next Steps:

As the USVI moves forward with VPP planning, an initial step could be to pilot the VPP concept in a specific area, evaluating technical feasibility, customer engagement, and regulatory frameworks in a controlled setting. Insights gained from the pilot can inform the broader rollout of the VPP across the territory. Additionally, ongoing monitoring and evaluation will be crucial to adapt the VPP model based on performance data and evolving grid needs. Engaging stakeholders—utilities, customers, regulators, and DER providers—in this process will also help ensure the VPP's long-term success and alignment with community goals.

The analysis highlighted some key considerations for the location of a VPP pilot in the USVI:

- A VPP on St. Croix has the potential to save 61 thousand barrels of fuel annually and 427 barrels of fuel over a 7-year time period. Given that the generation mix on this island includes generators which are leased at high costs, a VPP here can potentially provide significant cost savings through displacement of fuel generation. Analysis of the feeder loading showed that that in the STX VPP scenario, the average line loading is 30% (see Figure C-17) while for all scenarios the line loading on the St. Croix is always below 60% (see Table C-14), indicating that the feeders can handle the loading effects of a VPP.
- A VPP on St. John can increase the island's resilience. The estimated 4 MW/10.6 MWh of battery storage installed behind-the-meter can be coordinated and used to support the island's distribution network, providing grid services and reducing outages. This storage, along with the estimated 5 MW of decentralized solar PV generation installed, can be valuable during recovery from severe weather events, especially considering that the island does not have its own central generation plant and is dependent on generation from St Thomas via a submarine cable. Analysis of the feeder loading showed that in the STT/STJ VPP scenario, the line loading of each of the two St. John feeders is around 30% and for all scenarios the line loading is less than 40% (see Table C-13), indicating again that these feeders can handle the loading effects of a VPP.
- Finally, a VPP on the St. Thomas/St. John network has the potential to save 49 thousand barrels of fuel annually and 343 gallons over a 7-year time-period. Such a VPP would incorporate DERs on both St. Thomas and St. John, and would spread the resilience benefits across the two interconnected islands. St. Thomas' feeders are also able to manage the line loading

In conclusion, a well-implemented VPP in the USVI has the potential to transform the energy landscape, providing economic, operational, and environmental benefits that extend beyond traditional grid solutions. By addressing both policy and technical requirements, the USVI can position itself as a model for resilient, renewable-based island energy systems, setting a benchmark for other island communities worldwide.

8 Appendices

8.1 Appendix A: Generator Operation Costs

STX 17	Units	2023	2024	2025	2026	2027	2028	2029	2030
Variable O&M Costs	US $/MWh	1.53	1.56	1.59	1.62	1.65	1.69	1.72	1.76
Fixed O&M Costs	$/kW/year	49.41	50.40	51.40	52.43	53.48	54.55	55.64	56.75
Startup Cost	USD/start	158.0	161.0	164.0	167.0	171.0	174.0	177.5	181.0
STX 19	Units	2023	2024	2025	2026	2027	2028	2029	2030
Variable O&M Costs	US $/MWh	5.00	5.10	5.20	5.31	5.41	5.52	5.63	5.74
Fixed O&M Costs	$/kW/year	45.52	46.43	47.36	48.31	49.27	50.26	51.27	52.29
Startup Cost	USD/start	448.0	457.0	466.0	475.0	484.0	494.0	503.9	514
STX 20	Units	2023	2024	2025	2026	2027	2028	2029	2030
Variable O&M Costs	US $/MWh	1.30	1.32	1.35	1.38	1.41	1.43	1.46	1.49
Fixed O&M Costs	$/kW/year	46.31	47.24	48.19	49.15	50.13	51.13	52.15	53.20
Startup Cost	USD/start	499.0	509.0	520.0	530.0	541.0	551.0	562.0	573.3
Aggreko	Units	2023	2024	2025	2026	2027	2028	2029	2030
Variable O&M Costs	US $/MWh	10.50	10.50	10.50	10.50	10.50	10.50	10.71	10.92
Fixed O&M Costs	$/kW/year	401.7	401.7	401.7	401.7	401.7	401.7	409.7	417.9
Startup Cost	USD/start	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Wartsila 1	Units	2023	2024	2025	2026	2027	2028	2029	2030
Variable O&M Costs	US $/MWh	14.37	14.66	14.96	15.25	15.56	15.87	16.19	16.51
Fixed O&M Costs	$/kW/year	11.91	12.14	12.39	12.64	12.89	13.15	13.41	13.68
Startup Cost	USD/start	37.00	38.00	38.00	39.00	40.00	41.00	41.82	42.66
Wartsila 2	Units	2023	2024	2025	2026	2027	2028	2029	2030
Variable O&M Costs	US $/MWh	14.37	14.66	14.96	15.25	15.56	15.87	16.19	16.51
Fixed O&M Costs	$/kW/year	11.91	12.14	12.39	12.64	12.89	13.15	13.41	13.68
Startup Cost	USD/start	37.00	38.00	38.00	39.00	40.00	41.00	41.82	42.66
Wartsila 3	Units	2023	2024	2025	2026	2027	2028	2029	2030
Variable O&M Costs	US $/MWh	14.37	14.66	14.96	15.25	15.56	15.87	16.19	16.51
Fixed O&M Costs	$/kW/year	11.91	12.14	12.39	12.64	12.89	13.15	13.41	13.68
Startup Cost	USD/start	37.00	38.00	38.00	39.00	40.00	41.00	41.82	42.66
Wartsila 4	Units	2023	2024	2025	2026	2027	2028	2029	2030
Variable O&M Costs	US $/MWh	14.37	14.66	14.96	15.25	15.56	15.87	16.19	16.51
Fixed O&M Costs	$/kW/year	11.91	12.14	12.39	12.64	12.89	13.15	13.41	13.68
Startup Cost	USD/start	37.00	38.00	38.00	39.00	40.00	41.00	41.82	42.66
Wartsila 5	Units	2023	2024	2025	2026	2027	2028	2029	2030
Variable O&M Costs	US $/MWh	14.37	14.66	14.96	15.25	15.56	15.87	16.19	16.51
Fixed O&M Costs	$/kW/year	11.91	12.14	12.39	12.64	12.89	13.15	13.41	13.68
Startup Cost	USD/start	37.00	38.00	38.00	39.00	40.00	41.00	41.82	42.66
Wartsila 6	Units	2023	2024	2025	2026	2027	2028	2029	2030
Variable O&M Costs	US $/MWh	14.37	14.66	14.96	15.25	15.56	15.87	16.19	16.51
Fixed O&M Costs	$/kW/year	11.91	12.14	12.39	12.64	12.89	13.15	13.41	13.68
Startup Cost	USD/start	37.00	38.00	38.00	39.00	40.00	41.00	41.82	42.66
Wartsila 7	Units	2023	2024	2025	2026	2027	2028	2029	2030
Variable O&M Costs	US $/MWh	14.37	14.66	14.96	15.25	15.56	15.87	16.19	16.51

Fixed O&M Costs	$/kW/year	11.91	12.14	12.39	12.64	12.89	13.15	13.41	13.68
Startup Cost	USD/start	37.00	38.00	38.00	39.00	40.00	41.00	41.82	42.66
STT 15	Units	2023	2024	2025	2026	2027	2028	2029	2030
Variable O&M Costs	US $/MWh	6.12	6.24	6.37	6.49	6.62	6.76	6.90	7.03
Fixed O&M Costs	$/kW/year	45.63	46.55	47.48	48.43	49.40	50.38	51.39	52.42
Startup Cost	USD/start	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
STT 23	Units	2023	2024	2025	2026	2027	2028	2029	2030
Variable O&M Costs	US $/MWh	3.87	3.94	4.02	4.10	4.18	4.27	4.36	4.44
Fixed O&M Costs	$/kW/year	18.70	19.07	19.45	19.84	20.24	20.64	21.05	21.47
Startup Cost	USD/start	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
STT 25	Units	2023	2024	2025	2026	2027	2028	2029	2030
Variable O&M Costs	US $/MWh	2.97	3.03	3.09	3.15	3.21	3.27	3.34	3.40
Fixed O&M Costs	$/kW/year	4.08	4.16	4.25	4.33	4.42	4.51	4.60	4.69
Startup Cost	USD/start	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
STT 26	Units	2023	2024	2025	2026	2027	2028	2029	2030
Variable O&M Costs	US $/MWh	2.97	3.03	3.09	3.15	3.21	3.27	3.34	3.40
Fixed O&M Costs	$/kW/year	3.73	3.80	3.88	3.96	4.04	4.12	4.20	4.29
Startup Cost	USD/start	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
STT 27	Units	2023	2024	2025	2026	2027	2028	2029	2030
Variable O&M Costs	US $/MWh	2.97	3.03	3.09	3.15	3.21	3.27	3.34	3.40
Fixed O&M Costs	$/kW/year	3.91	3.98	4.06	4.14	4.23	4.31	4.40	4.48
Startup Cost	USD/start	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

Table A.1-Variable operation and maintenance costs, fixed operation and maintenance costs, and startup costs for all fossil fuel generators on both St. Croix and St. Thomas/St.John.

8.2 Appendix B: Demand Forecast

This section provides the historical and projected monthly load forecast (2019-2031) and historical generation (2019-2024) for both St. Thomas/St. John and for St. Croix. Additionally, a daily load forecast is shown for a year's time for each system.

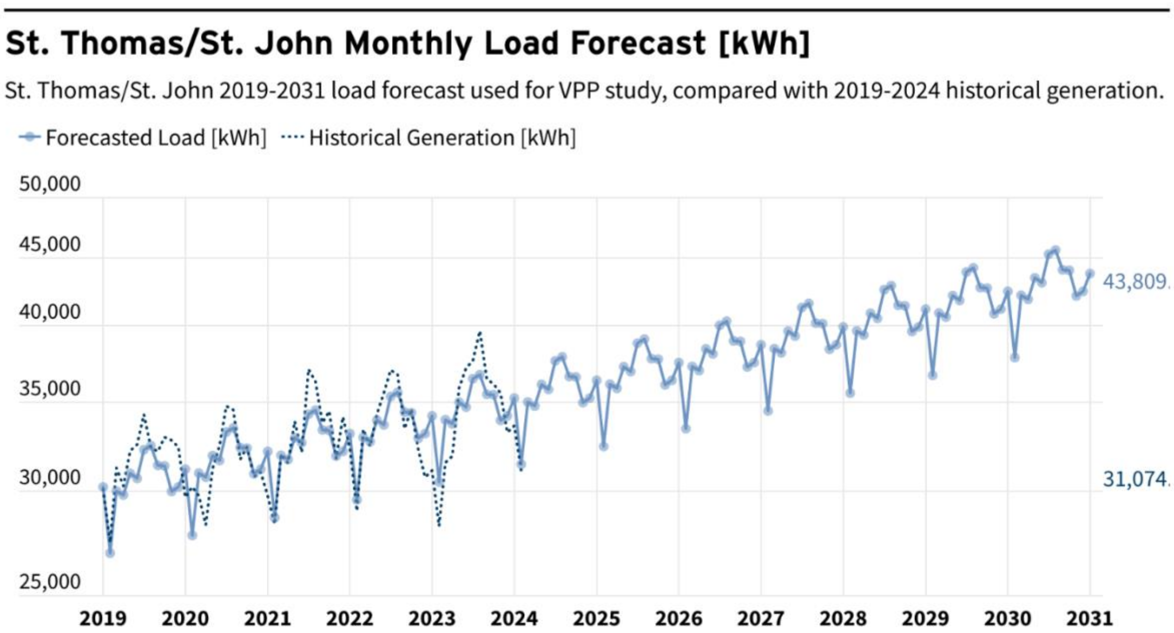


Figure B.1- St. Thomas/St. John monthly load forecast [kWh] 2019-2031 and historical generation 2019-2024 [kWh].

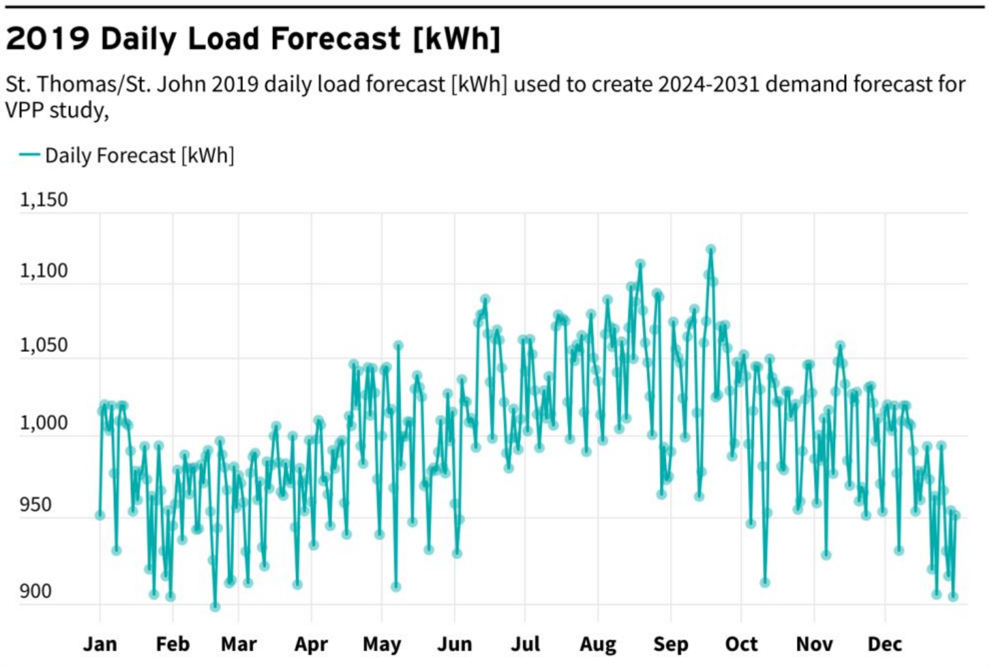


Figure B.2-St. Thomas/St. John 2019 daily load forecast [kWh].

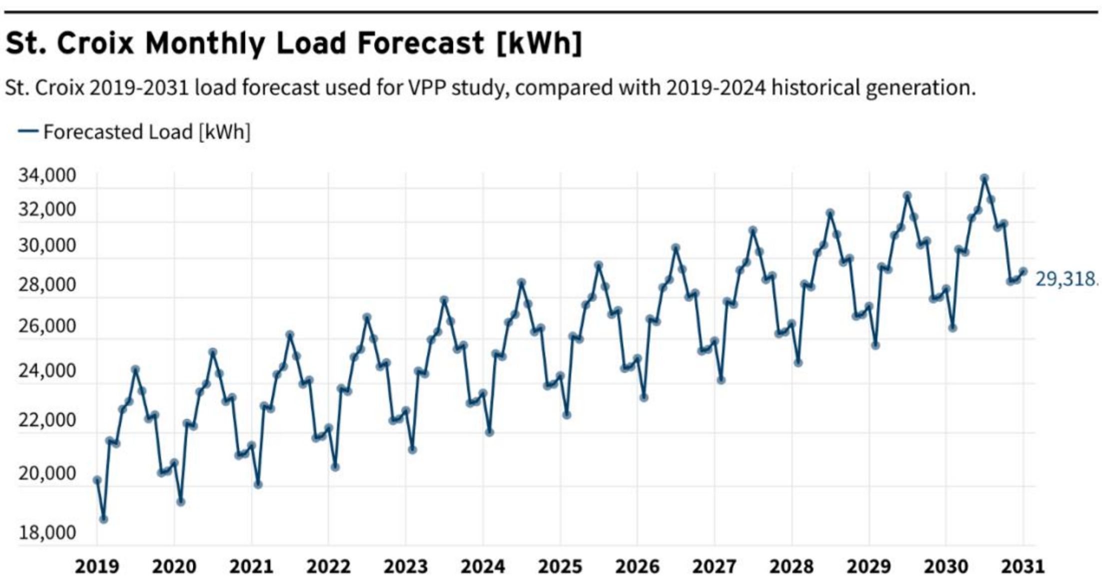


Figure B.3-St. Croix monthly load forecast [kWh] 2019-203.

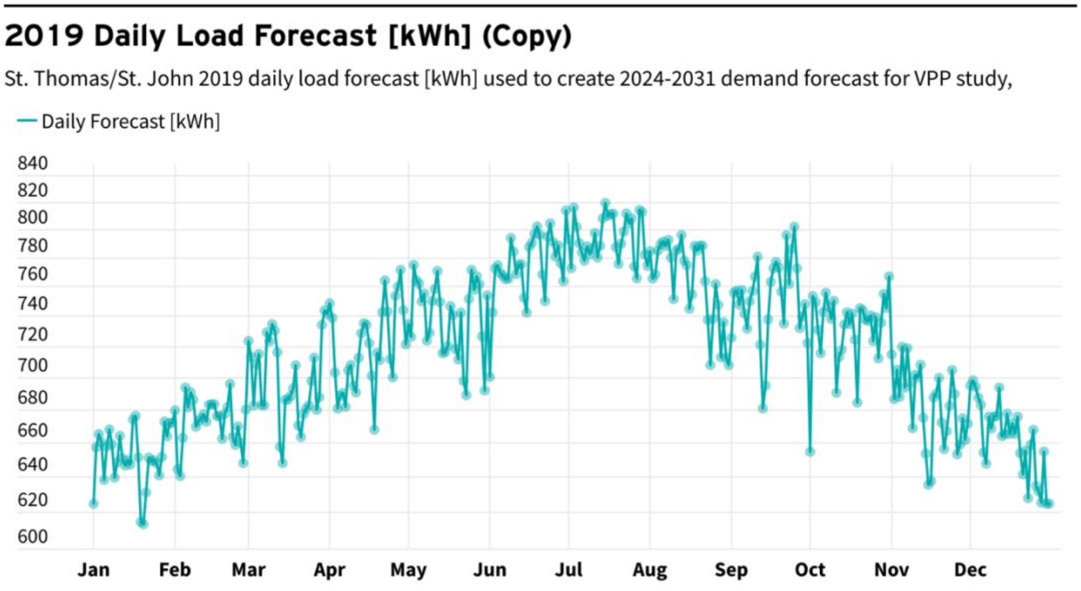


Figure B.4-St. Croix John 2019 daily load forecast [kWh].

8.3 Appendix C: Other Findings from Long-term PLEXOS Analysis

These are additional results from the long-term PLEXOS Analysis described in Section 3 and 4:

- Total costs [$]
- Fuel costs [$]
- Levelized costs [$/MWh]
- Emissions [tonnes]
- Installed capacity by resource [MW]
- Generation by resource [GWh]
- Total new build capacity by resource [MW]
- RE penetration [%]
    - By installed capacity
    - By generation
- Fuel Offtake [TJ]
- Line loading [%]
- Line losses [GWh]
- Generation by feeder [GWh]
- Scenario-by-scenario look

8.3.1 Total Costs [$]

The total cost is defined as the sum of all fixed and variable costs for all generators (incl. batteries) and physical contracts in the region and includes:

- The fixed charges include fixed O&M costs [$/kW] for installed capacity
- The variable charges include VO&M costs [$/kWh] for generation and fuel costs [$/kWh] (fuel offtake times the fuel price)
- Other generator costs include start and shutdown costs, emissions costs and abatement costs if they exists

The physical contracts represent the external generation (offer quantity) and costs to acquire this generation (offer price) **i.e. the VPP assets and their compensation are already factored into the total cost.**

The total cost analysis reveals that the VPP would reduce annual total costs on average by between $7.1M (scenario 4b) and $16.1M (scenario 3) compared to the base case. Scenario 5 has potential annual cost reductions of $39M compared to the base case. This analysis suggests that a VPP in STX has potential for larger cost reductions from the base case ($8.8M on average) than one in STT/STJ ($7.1M on average)

	Scenario 0: Base	Scenario 1: Low DER penetration	Scenario 2: Medium DER penetration	Scenario 3: High DER penetration	Scenario 4a: STX VPP	Scenario 4b. STT/STJ VPP	Scenario 5: DER overload
2025	$162,075,270	$158,450,840	$157,808,020	$157,172,030	$157,220,730	$162,692,880	$154,187,170
2026	$156,211,010	$151,716,990	$150,510,960	$149,307,340	$150,025,700	$155,479,350	$143,012,610
2027	$160,479,440	$150,915,230	$148,308,250	$145,830,490	$152,745,720	$153,523,670	$133,358,080
2028	$169,115,990	$157,903,230	$154,063,850	$150,264,520	$160,115,970	$159,260,530	$127,253,150
2029	$185,103,500	$173,367,490	$168,626,040	$163,912,730	$174,680,150	$174,333,940	$133,314,700
2030	$198,410,670	$186,331,140	$181,024,330	$175,738,630	$187,137,200	$187,015,700	$136,832,460
2031	$207,937,900	$195,817,230	$190,180,160	$184,556,080	$196,092,880	$197,105,730	$138,286,940

Table C.1-Total annual system costs [$] by year and scenario

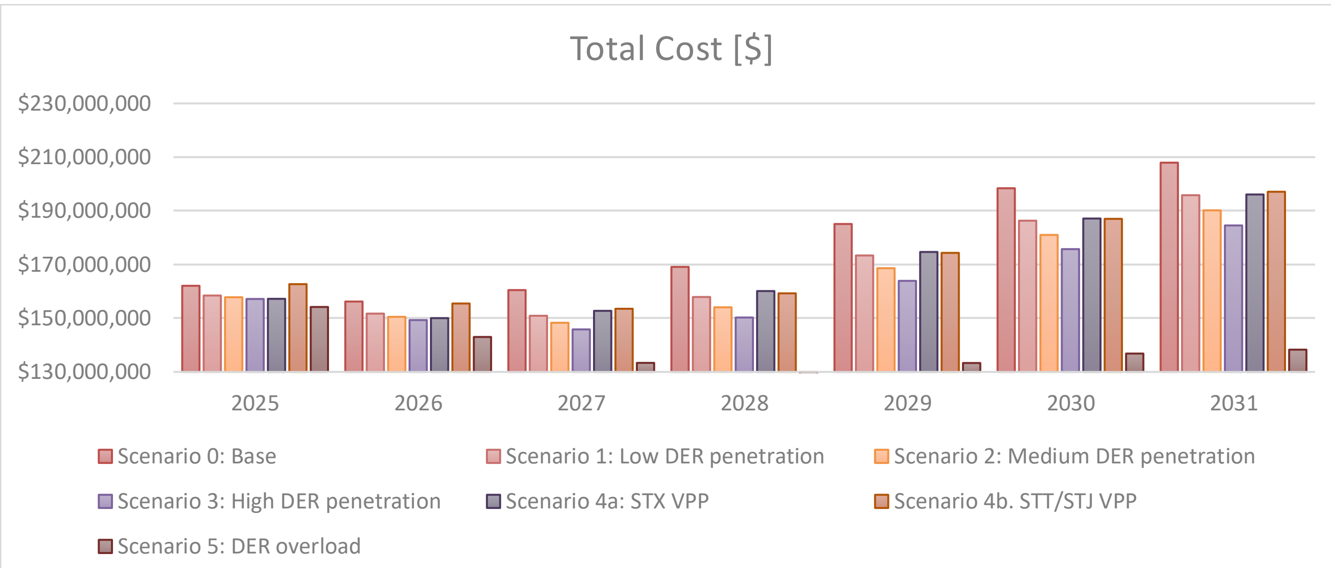


Figure C.1-Total annual system costs [$] by year and scenario

8.3.2 Fuel Costs [$]

Fuel costs are just one aspect that makes up the total cost. This analysis shows that the VPP would help alleviate fuel costs, which is the largest contributor to total costs in USVI. Annual fuel cost reductions on average when compared to the base case range from $7M (scenario 4b) to $16M (scenario 3) to $38.7M (scenario 5).

	Scenario 0: Base	Scenario 1: Low DER penetration	Scenario 2: Medium DER penetration	Scenario 3: High DER penetration	Scenario 4a: STX VPP	Scenario 4b. STT/STJ VPP	Scenario 5: DER overload
2025	$143,019,790	$139,410,560	$138,769,670	$138,136,120	$138,184,550	$143,659,450	$135,163,950
2026	$136,061,060	$131,592,710	$130,384,010	$129,180,460	$129,900,620	$135,327,010	$122,909,660
2027	$139,595,970	$130,120,290	$127,511,690	$125,042,490	$131,889,420	$132,705,200	$112,633,400
2028	$147,859,370	$136,754,470	$132,941,700	$129,169,130	$138,894,240	$138,130,220	$106,335,000
2029	$163,568,100	$151,942,330	$147,232,710	$142,551,330	$153,183,820	$152,933,480	$112,187,300

2030	$176,533,250	$164,566,230	$159,294,790	$154,044,500	$165,301,360	$165,279,990	$115,436,510
2031	$186,015,620	$174,007,340	$168,407,170	$162,820,150	$174,213,940	$175,346,720	$116,908,030

Table C.2- Annual fuel costs [$] by year and scenario

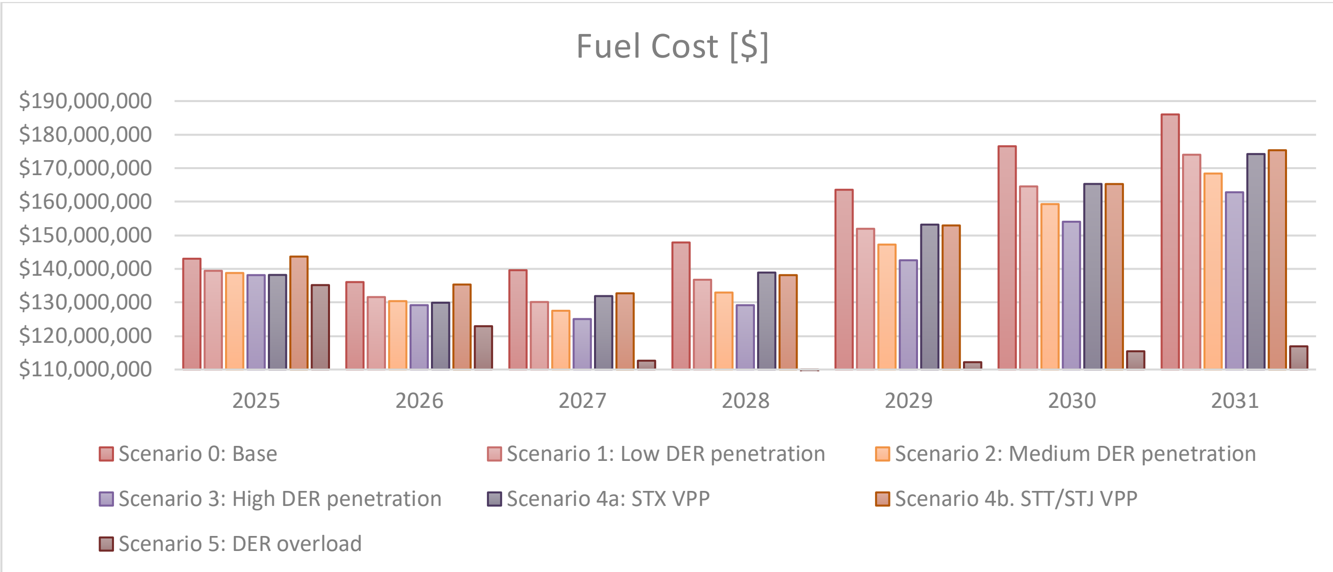


Figure C.2- Annual fuel costs [$] by year and scenario

8.3.3 Levelized Costs [$/MWh]

Levelized Cost in STT/STJ:

The levelized cost (LC) reflects the total cost of all system assets considering the total generation of these assets. It is defined as the Total Cost divided by Total Generation (see total cost explanation in section 9.3.1). The analysis reveals that the LC in STT/STJ is relatively constant across all scenarios in 2025 and 2026, as little DER has come online, and the utility generator dispatch order is heavily constrained during these years. To reflect historic generator dispatch trends from WAPA in STT, capacity factor ranges for certain generators were put in place and slowly phased out from 2024-2027. In 2027, all generation minimum limits were removed and the generation dramatically switched to the much cheaper, more efficient LPG Wartsila generators leading to a dramatic drop in price.

Overall, the VPP would reduce the LC in STT/STJ by the following amounts:

- Scenario 1 reduces the average LC by 1.18 cents/kWh
- Scenario 2 reduces the average LC by 1.39 cents/kWh
- Scenario 3 reduces the average LC by 1.63 cents/kWh
- Scenario 4b reduces the average LC by 1.62 cents/kWh
- Scenario 5 reduces the average LC by 3.46 cents/kWh

Scenario 4a, which only deploys a VPP on STX, actually increases the average LC in STT/STJ by ~0.06 cents/kWh.

	Scenario 0: Base	Scenario 1: Low DER penetration	Scenario 2: Medium DER penetration	Scenario 3: High DER penetration	Scenario 4a: STX VPP	Scenario 4b. STT/STJ VPP	Scenario 5: DER overload
2025	$179	$178	$179	$179	$179	$179	$179
2026	$157	$155	$155	$155	$158	$155	$155
2027	$146	$132	$130	$128	$146	$128	$123
2028	$147	$131	$127	$124	$148	$124	$104

2029	$157	$141	$138	$134	$158	$134	$106
2030	$164	$148	$144	$140	$165	$140	$106
2031	$168	$152	$148	$144	$169	$144	$104

Table C.3- Levelized costs in STT/STJ [$/MWh] by year and scenario

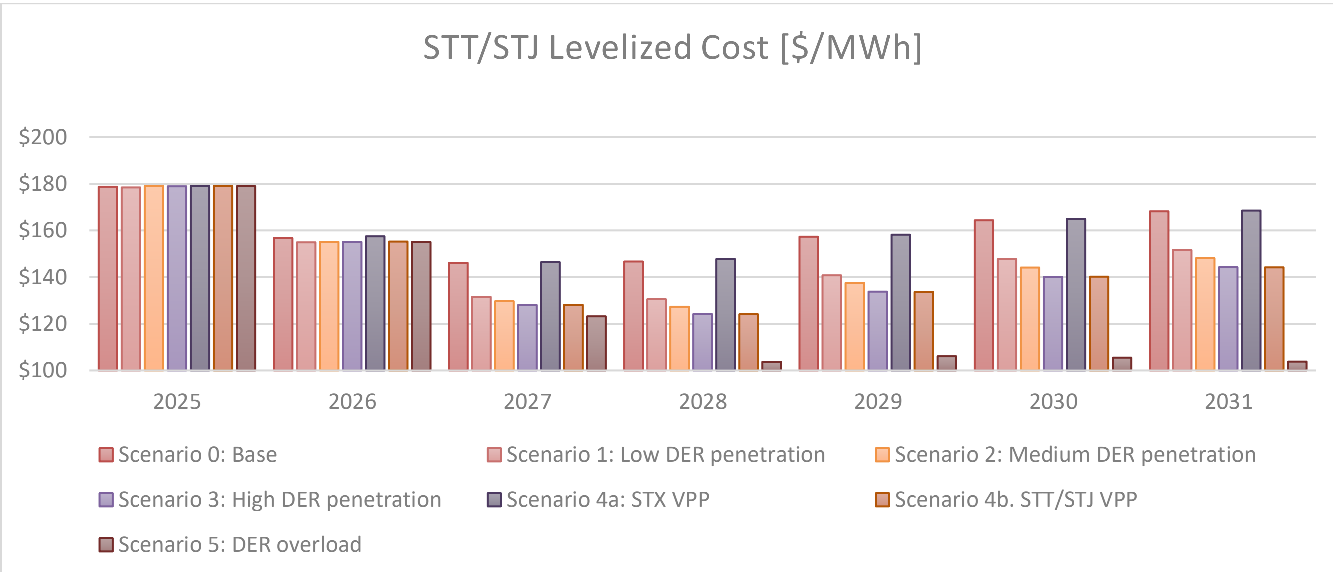


Figure C.3- Levelized costs in STT/STJ [$/MWh] by year and scenario

Levelized Cost in STX:
The VPP has an immediate impact on the LC in STX because there is no constraint on dispatch order other than the Aggreko PPA contract limits. Overall, the VPP would reduce the LC in STX by the following:

- Scenario 1 reduces the average LC by 1.48 cents/kWh
- Scenario 2 reduces the average LC by 2.21 cents/kWh
- Scenario 3 reduces the average LC by 2.99 cents/kWh
- Scenario 4a reduces the average LC by 3.02 cents/kWh
- Scenario 5 reduces the average LC by 7.12 cents/kWh
- Scenario 4b, which only deploys a VPP on STT.STJ, actually increases the LC in STX by ~0.11 cents/kWh

The impact of the VPP in STX is quite a bit higher than the VPP in STT/STJ based on the LC analysis. This is partly because the LC in STX is ~1.76X larger than in STT/STJ meaning there is a larger margin for improvement/cost reduction, which a VPP can help provide. However, based on the RE penetration level analysis, one could argue that a VPP in STT/STJ has more impact.

	Scenario 0: Base	Scenario 1: Low DER penetration	Scenario 2: Medium DER penetration	Scenario 3: High DER penetration	Scenario 4a: STX VPP	Scenario 4b. STT/STJ VPP	Scenario 5: DER overload
2025	$261	$246	$244	$241	$241	$263	$231
2026	$255	$240	$236	$232	$232	$255	$212
2027	$268	$253	$247	$241	$240	$269	$210
2028	$278	$263	$255	$247	$246	$278	$205
2029	$293	$278	$268	$258	$258	$293	$206
2030	$303	$288	$278	$267	$266	$304	$204
2031	$306	$293	$281	$269	$269	$310	$198

Table C.4- Levelized costs in STX [$/MWh] by year and scenario

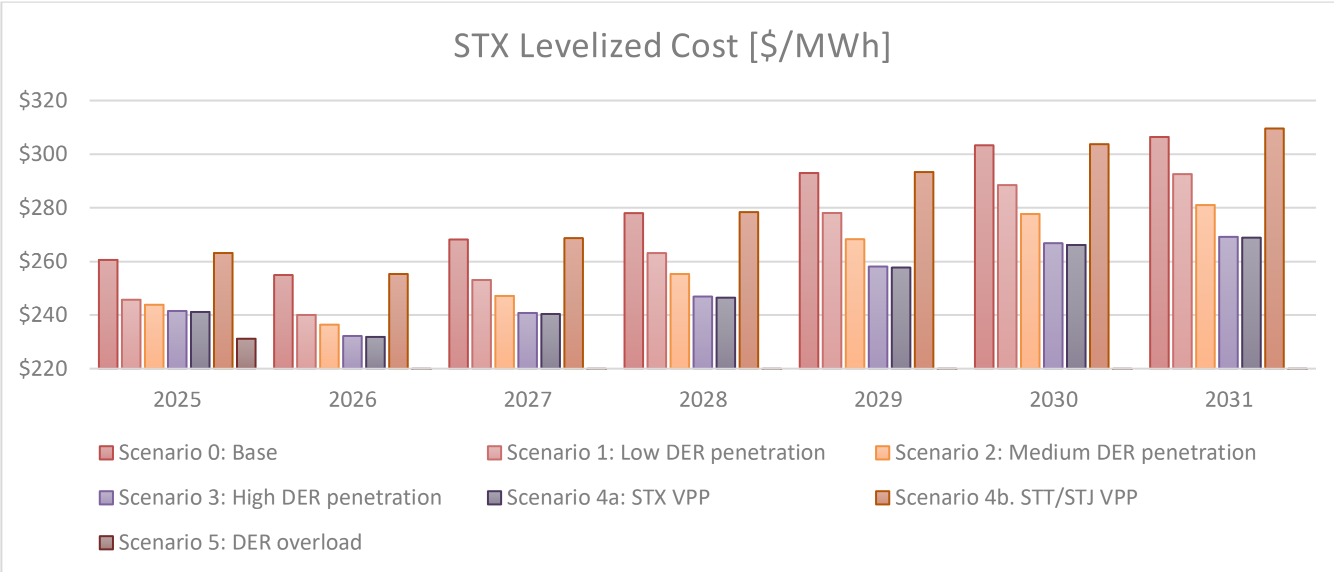


Figure C.4- Levelized costs in STX [$/MWh] by year and scenario

8.3.4 Emissions [tonnes]

The emissions are relatively straightforward

Scenario 5 has a very dramatic reduction compared to the other scenarios as it has reached DER capacity levels that impact the dispatch of oil generators and therefore, achieving annual emission reductions of ~19.5% compared to the base case

The other scenarios also reduce annual emissions compared to the base case but only by an average of around 5.5%

	Scenario 0: Base	Scenario 1: Low DER penetration	Scenario 2: Medium DER penetration	Scenario 3: High DER penetration	Scenario 4a: STX VPP	Scenario 4b. STT/STJ VPP	Scenario 5: DER overload
2025	598,398	585,375	583,072	580,788	580,957	600,020	570,068
2026	570,134	554,635	550,545	546,439	548,773	567,758	524,745
2027	571,325	539,980	531,611	523,539	545,885	548,887	482,656
2028	587,155	551,361	539,071	526,911	558,258	555,796	453,310
2029	613,171	577,270	562,727	548,270	581,104	580,331	454,504
2030	639,888	603,875	588,012	572,212	606,087	606,023	456,029
2031	668,007	631,870	615,018	598,205	632,492	635,201	460,041

Table C.5- Annual emissions [tonnes] by year and scenario

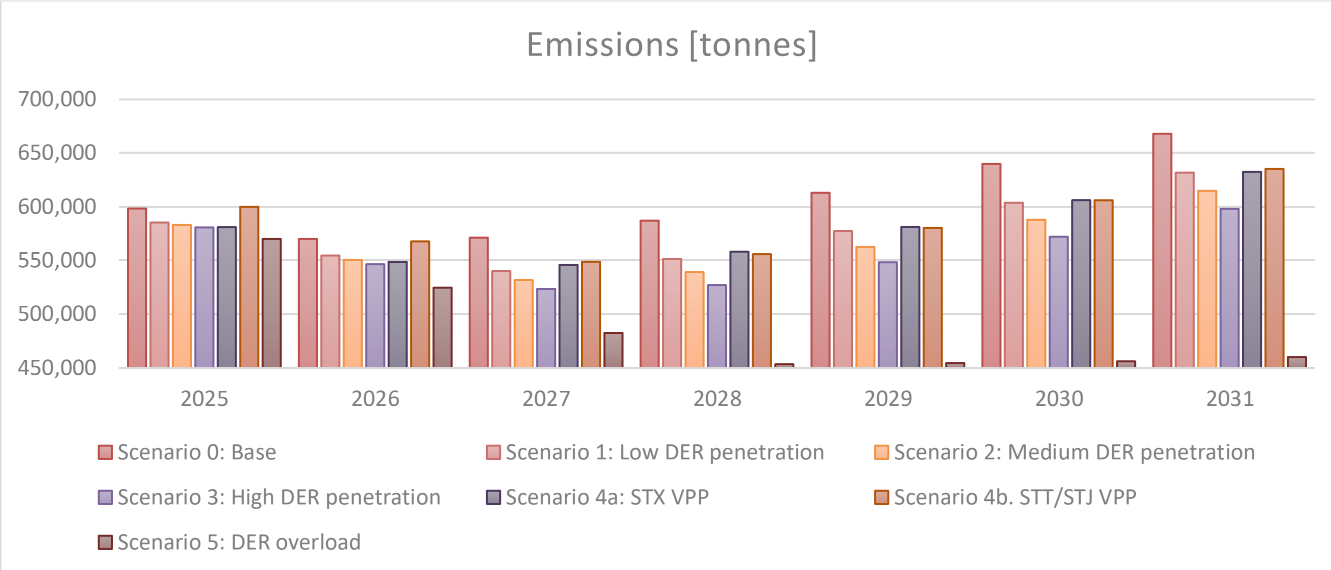


Figure C.5- Annual emissions [tonnes] by year and scenario

8.3.5 Installed capacity by resource [MW]

DER scenarios have a much more diversified energy mix in terms of installed capacity compared to the Base Case:

- Scenario 5 sees a 6.0X increase in DER solar and a 3.3X increase in DER BESS by 2031 compared to Scenario 1
- Scenario 3 sees a 1.8X increase in DER solar and a 2.3X increase in DER BESS by 2031 compared to Scenario 1

	Distributed Solar	Utility Solar	Oil	LPG	Distributed BESS	Utility BESS
Scenario 0: Base	0	13.97	184.1	76.89	0	12.2
Scenario 1: Low DER penetration	31.1658	13.97	184.1	76.89	19.75	12.2
Scenario 2: Medium DER penetration	43.8658	13.97	184.1	76.89	32.35	12.2
Scenario 3: High DER penetration	56.5277	13.97	184.1	76.89	44.95	12.2
Scenario 4a: STX VPP	17.7673	13.97	184.1	76.89	19.52	12.2
Scenario 4b. STT/STJ VPP	33.5534	13.97	184.1	76.89	25.43	12.2
Scenario 5: DER overload	187.2996	13.97	184.1	76.89	64.55	12.2

Table C.6- Installed capacity [MW] by resource and scenario

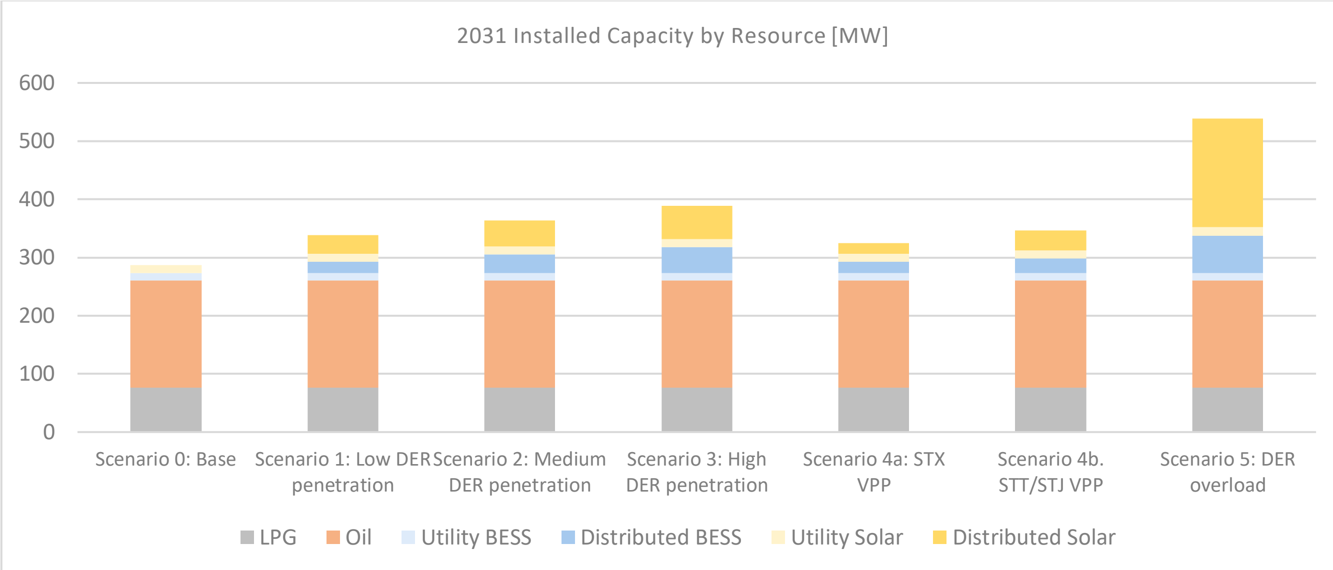


Figure C.6- Installed capacity [MW] by resource and scenario

This section also presents installed capacity can separated for STT/STJ and for STX and just installed DER capacity, aggregated and separated between the two systems.

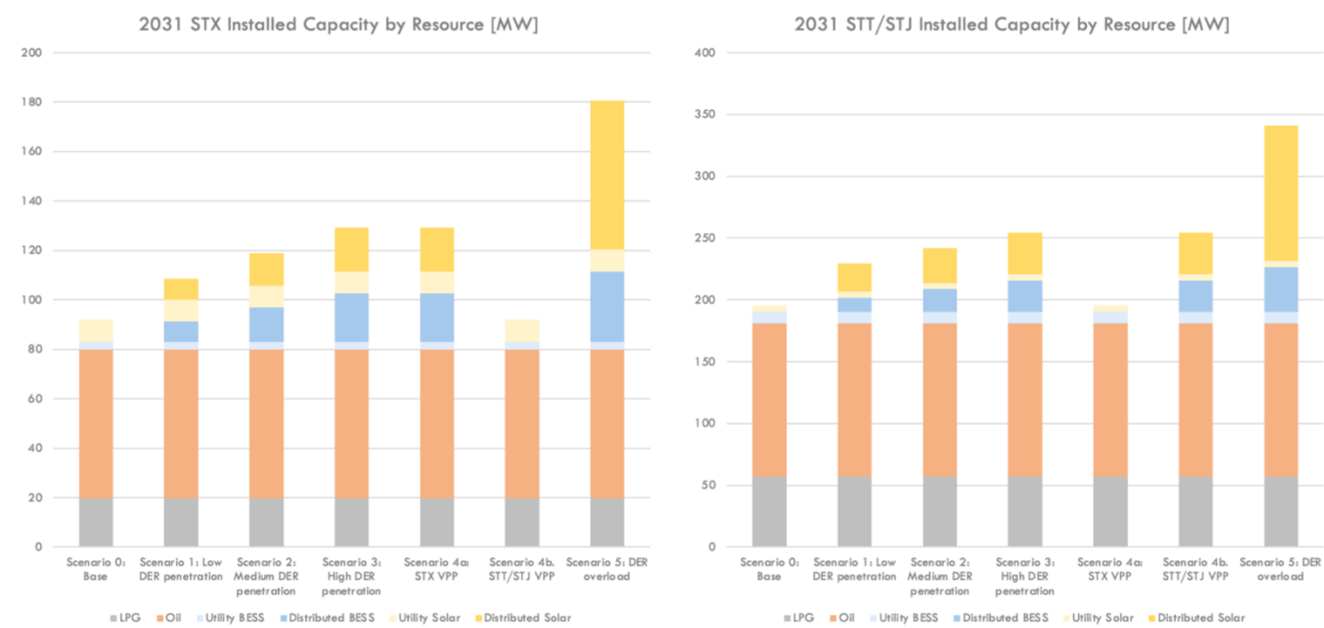


Figure C.7- Installed capacity [MW] by resource and scenario divided by system.

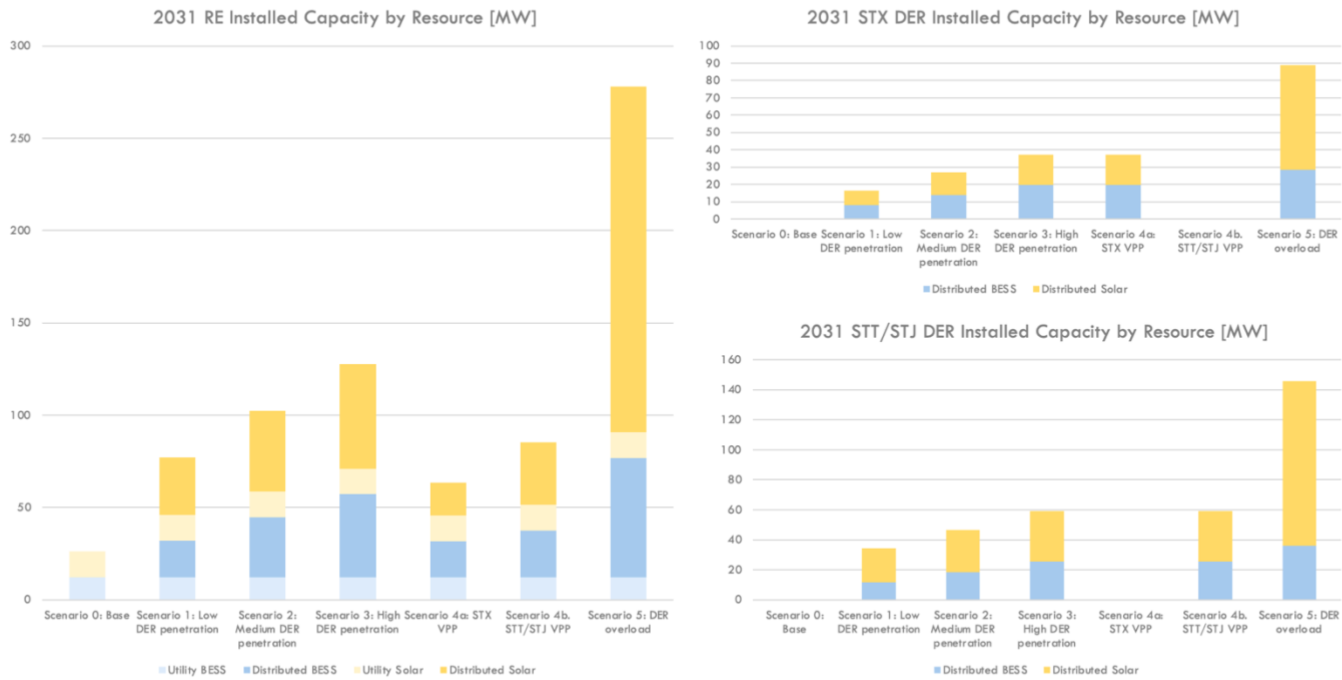


Figure C.8- RE Installed capacity [MW] by resource and scenario, further divided by system

8.3.6 Generation by resource [GWh]

When looking at the thermal generation from oil and LPG, it is still clear that the majority of generation comes from these assets, however all scenarios demonstrate meaningful reduction of oil generation.

By 2031, oil generation is reduced relative to the base case as follows:

- Scenario 1 reduces oil generation by ~39 GWh
- Scenario 2 reduces oil generation by ~55 GWh
- Scenario 3 reduces oil generation by ~71 GWh
- Scenario 4a reduces oil generation by ~29 GWh
- Scenario 4b reduces oil generation by ~40 GWh
- Scenario 5 reduces oil generation by ~210 GWh, which is by far the largest impact on dispatch order

It is also worth noting that no scenario impacts the dispatch of LPG generators. This is because diesel oil is the more expensive fuel and therefore, is the first fuel to be offset by a VPP from a cost-benefit analysis. The DER scenarios have a much more diversified energy mix in terms of generation compared to the Base case. Furthermore, all cases increase DER generation compared to the Base case at varying levels.

	Distributed Solar	Utility Solar	Oil	LPG	Distributed BESS	Utility BESS
Scenario 0: Base	0	22.32	358.05	532.11	0	8.46
Scenario 1: Low DER penetration	38.89	22.32	319.15	532.11	13.87	5.32
Scenario 2: Medium DER penetration	54.88	22.32	303.16	532.11	18.85	3.16
Scenario 3: High DER penetration	70.86	22.32	287.14	532.11	23.68	3.21
Scenario 4a: STX VPP	28.84	22.32	329.17	532.11	10.22	6.77
Scenario 4b. STT/STJ VPP	42.02	22.32	318.43	528.88	14.43	2.77

Scenario 5: DER overload	209.63	22.32	148.32	532.11	47.66	7.4

Table C.7-Annual generation [MWh] by resource and scenario

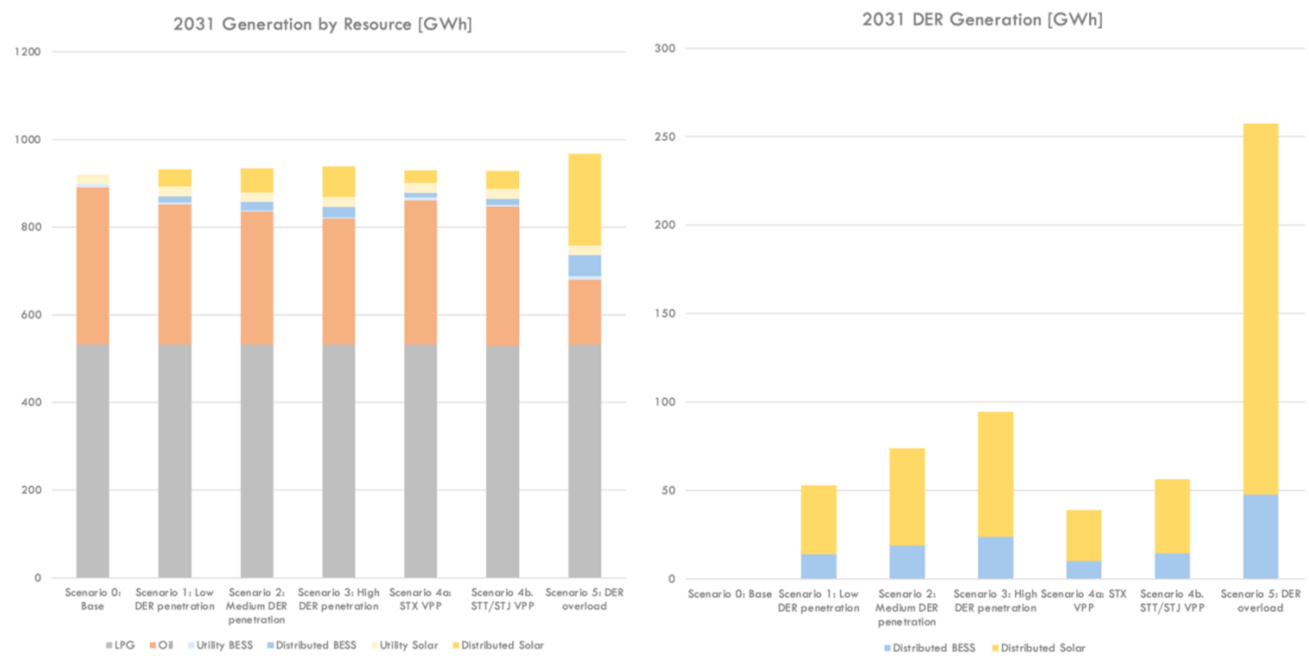


Figure C.9-Annual generation [MWh] (left) and annual DER generation [MWh] (right) by resource and scenario

Figure C.10-Annual STX generation [MWh] (upper left), annual STX DER generation [MWh] (upper right), annual STT/STJ generation [MWh] (lower left), annual STT/STJ DER generation [MWh] (lower right) by resource and scenario

8.3.7 Total new build capacity by resource [MW]

New build is defined uniquely for all scenarios are there are limits for both Maximum units built in a year and Maximum units built overall. Overall, the build it is as expected:

- The base case and Scenario 1 have no new DER buildout
- Scenario 5 sees the most dramatic increase followed by Scenario 3.
- Scenario 4a limits new DER buildout to occur only on STX
- Scenario 4b limits new DER buildout to occur only on STT/STJ

	STT/STJ Distributed Solar	STX Distributed Solar	STT/STJ DER BESS	STX DER BESS	STT/STJ DER BESS (MWh)	STX DER BESS (MWh)
Scenario 0: Base	0	0	0	0	0	0
Scenario 1: Low DER penetration	0	0	0	0	0	0
Scenario 2: Medium DER penetration	4.36	5.92	6.93	5.67	17.71	14.49
Scenario 3: High DER penetration	8.73	11.83	13.86	11.34	34.65	28.35
Scenario 4a: STX VPP	0	7.63	0	11.34	0	28.35
Scenario 4b. STT/STJ VPP	8.73	0	13.86	0	34.65	0
Scenario 5: DER overload	70	56	24.64	20.16	61.6	50.4

Table C.8-Annual new build capacity [MW] by resource and scenario and divided by system

	Distributed Solar	DER BESS (MW)	DER BESS (MWh)
Scenario 0: Base	0	0	0
Scenario 1: Low DER penetration	0	0	0
Scenario 2: Medium DER penetration	10.28	12.6	32.2
Scenario 3: High DER penetration	20.56	25.2	63
Scenario 4a: STX VPP	7.63	11.34	28.35
Scenario 4b. STT/STJ VPP	8.73	13.86	34.65
Scenario 5: DER overload	126	44.8	112

Table C.9-Annual new build capacity [MW] by resource and scenario

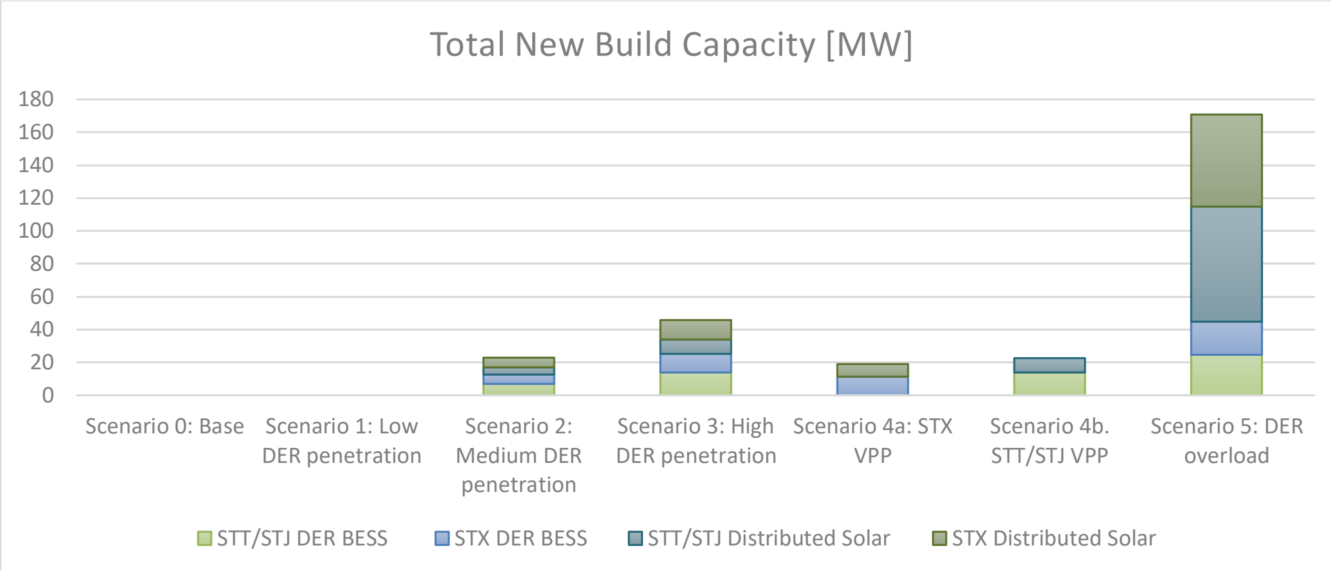


Figure C.11-Annual new build capacity [MW] by resource and scenario

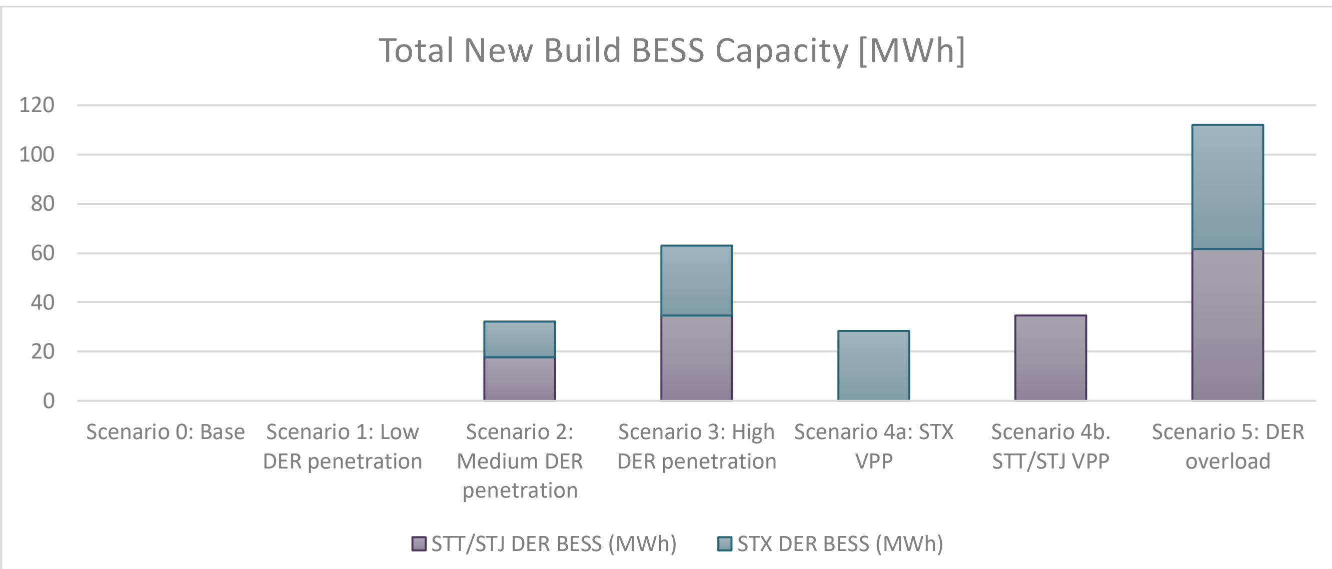


Figure C.12-Annual new build BESS capacity [MWh] by system and scenario

8.3.8 RE penetration [%]

8.3.8.1 By installed capacity

The RE penetration levels directly reflect the installed capacity results. The maximum penetration reached by 2031 is nearly 46% in Scenario 5. Scenario 1 and 4a see the lowest penetration compared to the base case in 2031, but still increases RE penetration by ~10-12.5% from the base case. The big jump in RE penetration in 2026 in the base case occurs in part due to the addition of the STX future utility solar plant coming online.

	Scenario 0: Base	Scenario 1: Low DER penetration	Scenario 2: Medium DER penetration	Scenario 3: High DER penetration	Scenario 4a: STX VPP	Scenario 4b. STT/STJ VPP	Scenario 5: DER overload
2025	1.81%	15.44%	16.40%	17.34%	7.90%	12.30%	21.44%

2026	5.98%	18.54%	20.35%	22.08%	12.47%	16.67%	28.96%
2027	5.98%	18.55%	21.25%	23.76%	13.32%	17.70%	33.19%
2028	5.95%	18.48%	21.91%	25.07%	14.04%	18.42%	36.87%
2029	5.98%	18.55%	22.67%	26.39%	14.81%	19.19%	40.25%
2030	5.98%	18.54%	23.24%	27.41%	15.31%	19.83%	43.22%
2031	5.98%	18.54%	23.74%	28.31%	15.80%	20.36%	45.91%

Table C.10-RE penetration [%] based on installed capacity by year and scenario

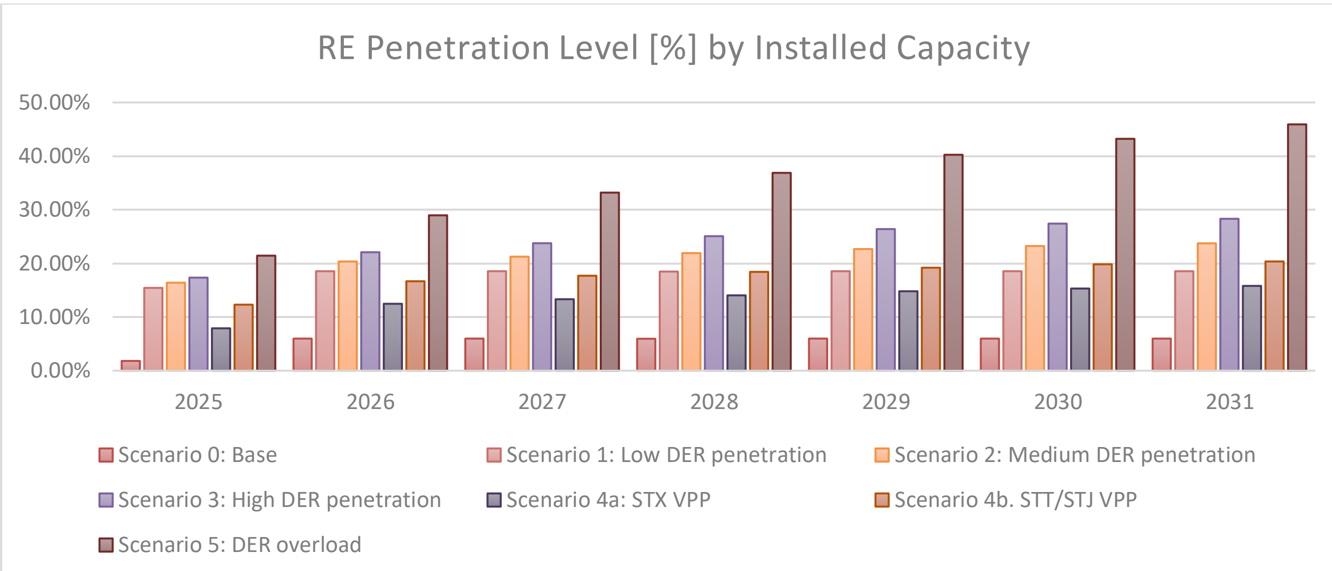


Figure C.13-RE penetration [%] based on installed capacity by year and scenario

8.3.8.2 By generation

The RE penetration levels directly reflect the generation results. The maximum penetration reached by 2031 is nearly 26% in Scenario 5. Scenario 4a sees the lowest penetration compared to the base case in 2031, increasing RE penetration by only about 3.2% compared to the base case. Overall, the amount of generation coming from DER renewables is quite low in USVI due to the over capacity of thermal generators and the addition of efficient Wartsila generators that have a high preference in the dispatch order.

	Scenario 0: Base	Scenario 1: Low DER penetration	Scenario 2: Medium DER penetration	Scenario 3: High DER penetration	Scenario 4a: STX VPP	Scenario 4b. STT/STJ VPP	Scenario 5: DER overload
2025	1.05%	2.46%	2.71%	2.96%	2.93%	1.07%	4.12%
2026	2.86%	4.63%	5.03%	5.44%	5.10%	3.19%	7.74%
2027	2.77%	6.90%	7.80%	8.70%	5.35%	6.12%	13.29%
2028	2.67%	7.33%	8.75%	10.15%	5.50%	7.32%	18.94%
2029	2.60%	7.13%	8.75%	10.37%	5.65%	7.32%	21.30%
2030	2.52%	6.92%	8.63%	10.34%	5.63%	7.23%	23.51%
2031	2.45%	6.71%	8.46%	10.21%	5.61%	7.06%	25.42%

Table C.11-RE penetration [%] based on generation by year and scenario

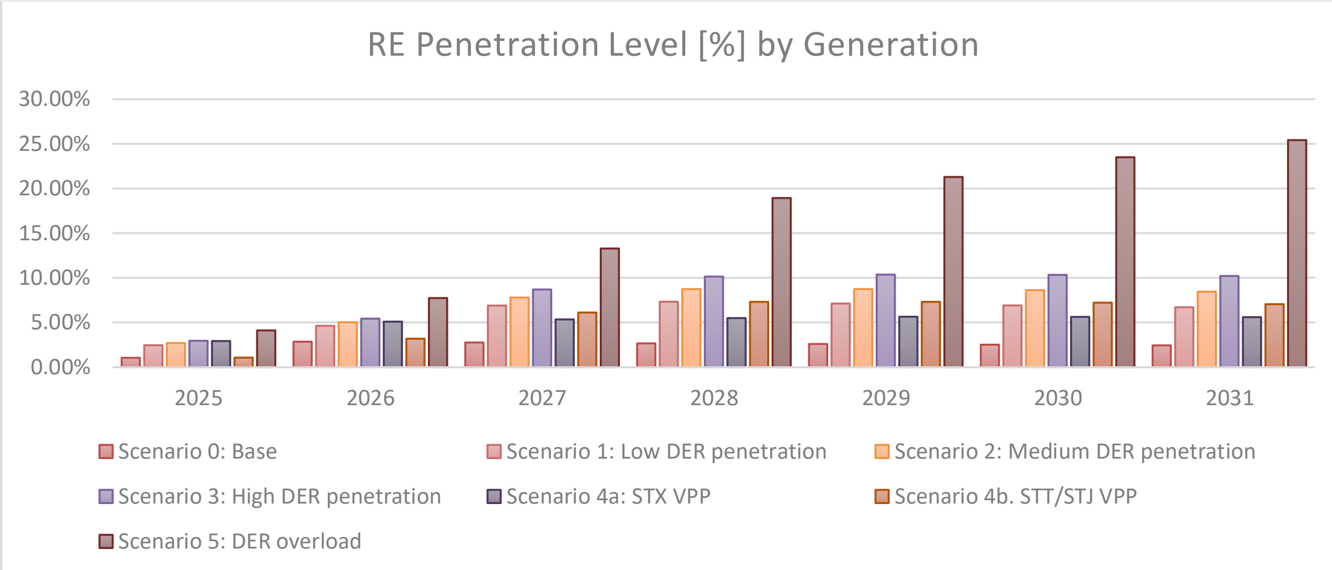


Figure C.14-RE penetration [%] based on generation by year and scenario

8.3.9 Fuel Offtake [TJ]

Fuel Offtake is the total amount of all fuel consumed by generators using the fuel either for generation or for starting. The analysis shows the possibility of the VPP to reduce the amount of fuel used by the generators and is directly tied to the fuel cost reductions seen in Section 8.3.2.

	Scenario 0: Base	Scenario 1: Low DER penetration	Scenario 2: Medium DER penetration	Scenario 3: High DER	Scenario 4a: STX VPP	Scenario 4b. STT/STJ VPP	Scenario 5: DER overload
2025	8,793	8,618	8,587	8,556	8,559	8,809	8,412
2026	8,556	8,347	8,293	8,239	8,269	8,525	7,947
2027	8,651	8,230	8,119	8,012	8,310	8,353	7,463
2028	8,880	8,398	8,233	8,069	8,491	8,458	7,079
2029	9,227	8,744	8,548	8,354	8,796	8,785	7,092
2030	9,587	9,102	8,889	8,676	9,132	9,131	7,113
2031	9,961	9,475	9,248	9,022	9,483	9,513	7,163

Table C.12-Fuel offtake [Tj] by year and scenario

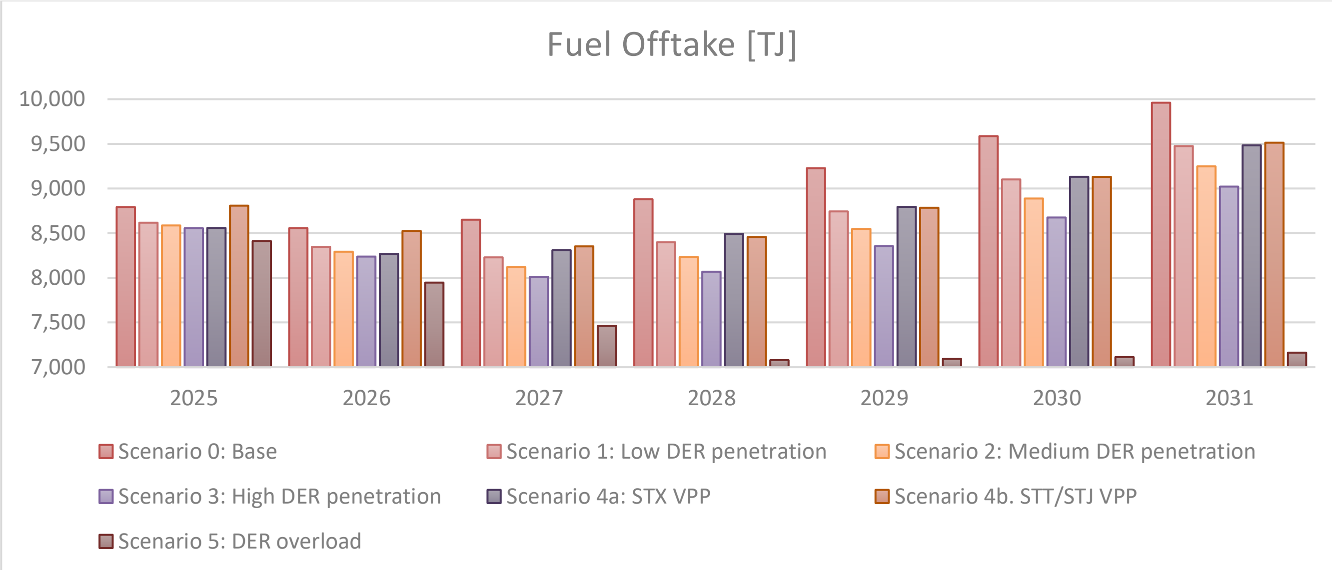


Figure C.15-Fuel offtake [Tj] by year and scenario

8.3.10 Line loading [%]

Another interesting analysis is to explore how the VPP impacts the amount of line loading that occurs on the transmission and distribution lines. This is analysis is done for the two systems separately.

<u>2031 STT/STJ Line Loading:</u>

This table shows every line that is on the STT/STJ system and how much of maximum the line load is being reached in 2031 for each line and for each scenario. The table reveals that as the amount of DER penetration is increased and connected as a VPP, the amount of line loading tends to decrease, particularly for the larger lines. The chart below the table shows the average line loading across all lines for each scenario.

	DF-10B	DF-6B	DF-7B	DF-8B	DF-9B	DF-EE	DF-YH	EE-9D	EE-STJ1	EE-STJ2	EE-T	RH-5A	RH-6A	RH-7A	RH-8A	RH-9A	RH-DF	RH-T	STJ-7E	STJ-9E	STJ-EE	T-7C	T-9C	T-Mall
Scenario 0	58.88	46.36	21.82	15.81	37.07	5.99	7.98	8.99	24.75	24.75	0.00	29.49	46.16	30.15	18.53	28.18	81.16	59.84	35.91	38.33	0.00	38.48	31.87	11.01
Scenario 1	56.32	45.52	19.15	12.48	37.07	4.96	7.98	8.99	22.23	22.23	0.00	29.25	43.58	28.16	17.84	28.18	76.37	56.01	33.62	33.08	0.00	36.69	29.05	11.01
Scenario 2	55.75	43.96	19.15	12.49	37.07	5.05	7.98	8.99	22.23	22.23	0.00	27.91	43.13	27.79	16.88	28.18	75.61	55.43	33.62	33.08	0.00	35.47	29.05	11.01
Scenario 3	55.18	42.40	19.15	12.49	37.07	5.14	7.98	8.99	22.23	22.23	0.00	26.58	42.70	27.43	15.91	28.18	74.84	54.85	33.62	33.07	0.00	34.24	29.04	11.01
Scenario 4a	58.89	46.36	21.82	15.81	37.07	5.99	7.98	8.99	24.75	24.75	0.00	29.49	46.16	30.15	18.53	28.18	81.16	59.84	35.91	38.33	0.00	38.48	31.87	11.01
Scenario 4b	55.18	42.40	19.15	12.48	37.07	5.14	7.98	8.99	22.23	22.23	0.00	26.58	42.70	27.43	15.91	28.18	74.84	54.85	33.62	33.07	0.00	34.24	29.05	11.01
Scenario 5	46.71	35.87	10.40	12.54	37.07	5.29	7.98	8.99	20.51	20.51	0.00	21.83	34.62	19.55	9.32	28.18	65.09	47.40	27.51	34.02	0.00	28.59	21.53	11.01

Table C.13-2031 STT/STJ Line loading [%] by line and scenario

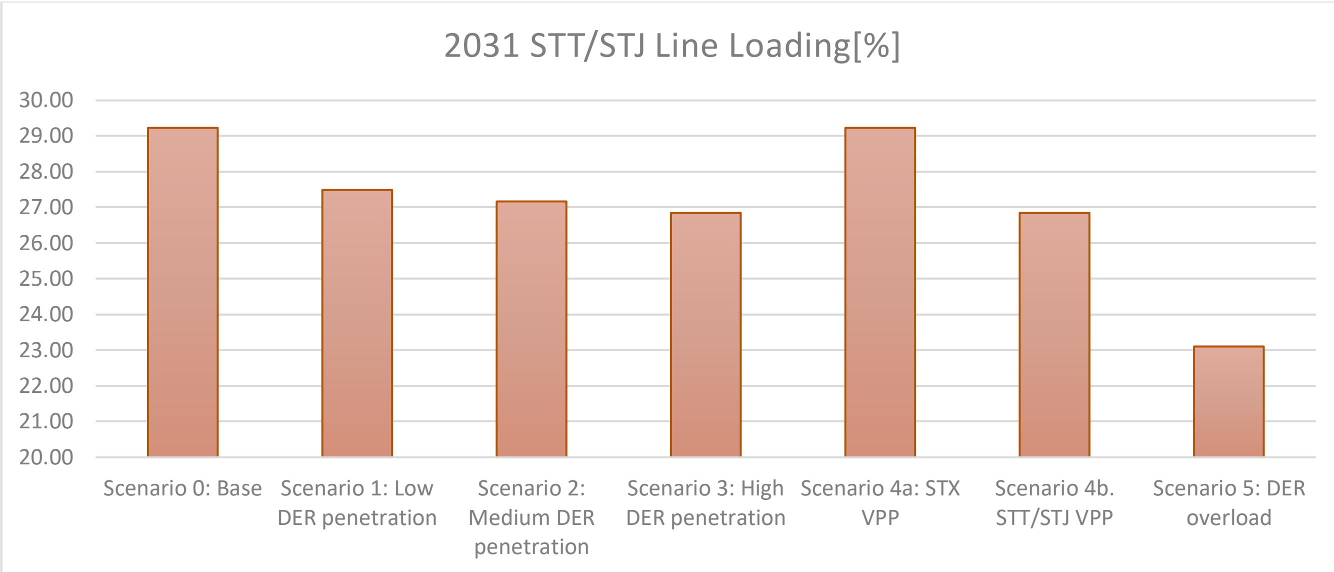


Figure C.16-2031 STT/STJ Line loading [%] by scenario

<u>2031 STX Line Loading:</u>

This table shows every line that is on the STX system and how much of maximum the line load is being reached in 2031 for each line and for each scenario. Similar to the STT/STJ analysis, the amount of line load is reduced as DER penetration is increased. The chart below the table shows the average line loading across all lines in STX for each scenario.

	M-10A	M-10B	M-8B	M-9B	R-2A	R-3A	R-4A	R-5A	R-6A	R-6B	R-9D	R-M
Scenario 0: Base	41.46	21.16	38.95	46.57	40.62	15.97	56.34	59.86	26.94	9.69	5.45	26.90
Scenario 1: Low DER penetration	41.18	20.89	35.39	45.84	38.98	15.49	55.91	58.02	26.23	9.69	5.45	25.93
Scenario 2: Medium DER penetration	39.62	19.33	35.18	44.28	38.98	14.37	54.80	57.40	25.21	9.69	5.45	24.95
Scenario 3: High DER penetration	38.06	17.77	34.98	42.72	38.98	13.25	53.70	56.77	24.19	9.69	5.45	23.97
Scenario 4a: STX VPP	38.05	17.77	34.98	42.72	38.98	13.25	53.70	56.77	24.19	9.69	5.45	23.97
Scenario 4b. STT/STJ VPP	40.93	21.16	38.87	46.55	40.59	15.95	56.33	59.81	26.93	9.68	5.45	26.77
Scenario 5: DER overload	32.02	11.99	25.49	35.73	38.98	6.44	45.88	47.97	16.81	9.69	5.45	18.10

Table C.14-2031 STX Line loading [%] by line and scenario

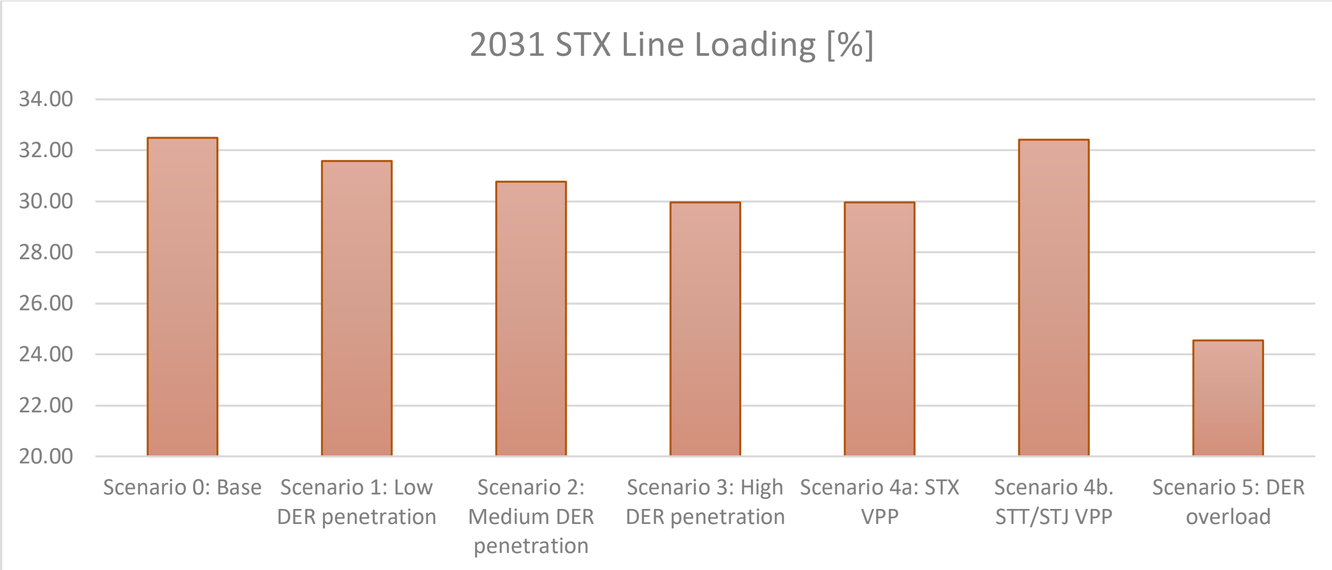


Figure C.17-2031 STX Line loading [%] by scenario

8.3.11 Line losses [GWh]

The VPP has a large potential to reduce line losses. Scenario 5 has a very dramatic reduction compared to the other scenarios as achieves reductions of ~37.4% or 19.57 GWh compared to the base case. The other scenarios also reduce annual line losses compared to the base case by an average of around 11.1% or 27.8 GWh.

	Scenario 0: Base	Scenario 1: Low DER penetration	Scenario 2: Medium DER penetration	Scenario 3: High DER penetration	Scenario 4a: STX VPP	Scenario 4b. STT/STJ VPP	Scenario 5: DER overload
2024	22.20	21.71	21.62	21.54	21.55	22.17	21.17
2025	22.84	22.06	21.94	21.86	22.10	22.55	21.24
2026	24.28	21.88	21.52	21.25	23.42	22.08	19.72
2027	25.82	22.96	22.38	21.88	24.81	22.86	18.40
2028	27.60	24.58	23.88	23.25	26.40	24.39	18.79
2029	29.36	26.27	25.47	24.74	28.05	26.01	19.09
2030	31.28	28.06	27.16	26.35	29.84	27.69	19.57

Table C.15- Line losses [GWh] by year and scenario

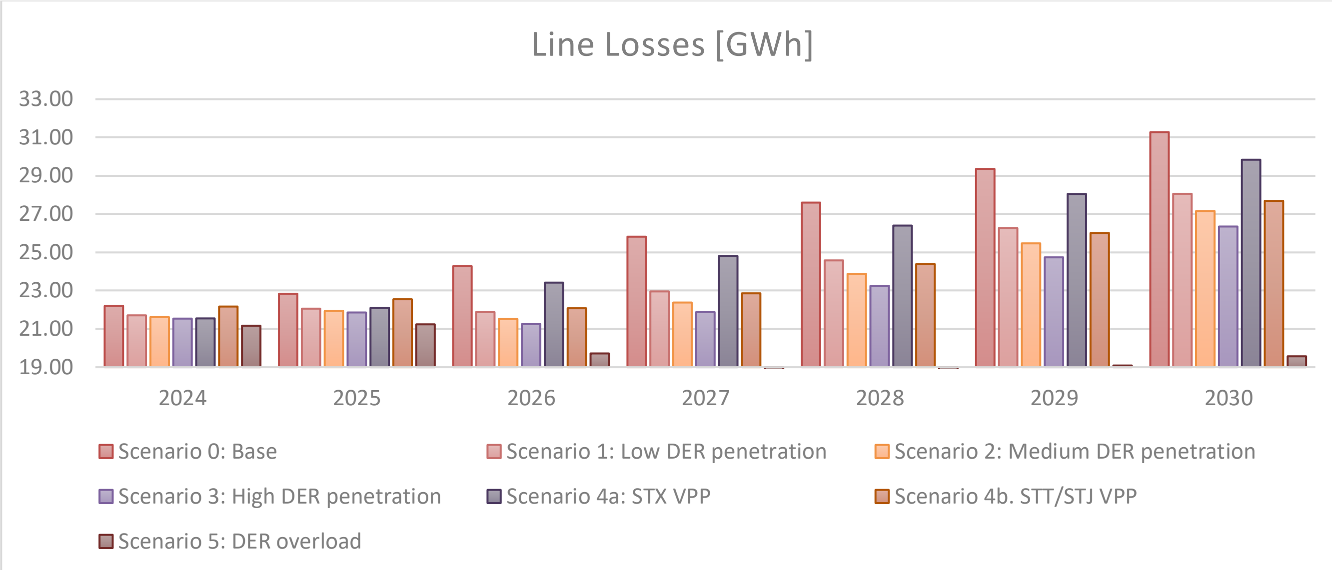


Figure C.18- Line losses [GWh] by year and scenario

8.3.12 Generation by feeder [GWh]

The VPP also impacts the amount of generation that occurs at each feeder. This is analysis is done for the two systems separately.

2031 STT/STJ generation by feeder [GWh]:

This table shows the amount of 2031 generation [GWh] at all substations and feeders on STT/STJ. The results reveal that as the DER penetration and VPP levels increase, there is a shift of generation happening at the larger substations, particularly Randolph Harley, towards generation at the feeder level. This means that, moving forward, more efforts will need to be put into upgrader feeder-level infrastructure. This trend can be clearly observed in the two figures.

	Donald Francois (B)	East End (D)	Fdr 05A	Fdr 06A	Fdr 06B	Fdr 07A	Fdr 07B	Fdr 07C	Fdr 07E (St. John's)	Fdr 08A	Fdr 08B	Fdr 09A	Fdr 09B	Fdr 09C	Fdr 09D	Fdr 09E (St. John's)	Fdr 10B	Fdr Mall	Fdr YH	Randolph Harley (A)	St John (E)	Tutu (C)
Scenario 0: Base	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0	0	0.00	0	0.00	0.00	0	0	537.35	0	0
Scenario 1: Low DER penetration	0.00	0.00	0.26	3.96	0.90	2.25	3.85	2.23	3.72	1.11	4.79	0	0	3.39	0	8.35	3.20	0	0	506.49	0	0
Scenario 2: Medium DER penetration	0.00	0.00	1.66	4.86	2.77	2.75	4.31	3.64	3.92	2.79	5.33	0	0	3.43	0	7.92	3.83	0	0	497.70	0	0
Scenario 3: High DER penetration	0.00	0.00	3.06	5.55	4.53	3.29	4.44	5.03	4.00	4.29	5.45	0	0	3.50	0	8.05	4.73	0	0	490.72	0	0
Scenario 4a: STX VPP	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0	0	0.00	0	0.00	0.00	0	0	536.28	0	0
Scenario 4b. STT/STJ VPP	0.00	0.00	3.06	5.61	4.60	3.30	4.18	5.10	3.89	4.52	5.20	0	0	3.62	0	8.75	4.61	0	0	490.39	0	0
Scenario 5: DER overload	0.00	0.00	8.11	14.90	12.43	12.96	15.65	12.55	11.67	12.58	6.67	0	0	13.17	0	8.73	15.40	0	0	419.48	0	0

Table C.16- 2031 STT/STJ generation [GWh] by feeder and scenario

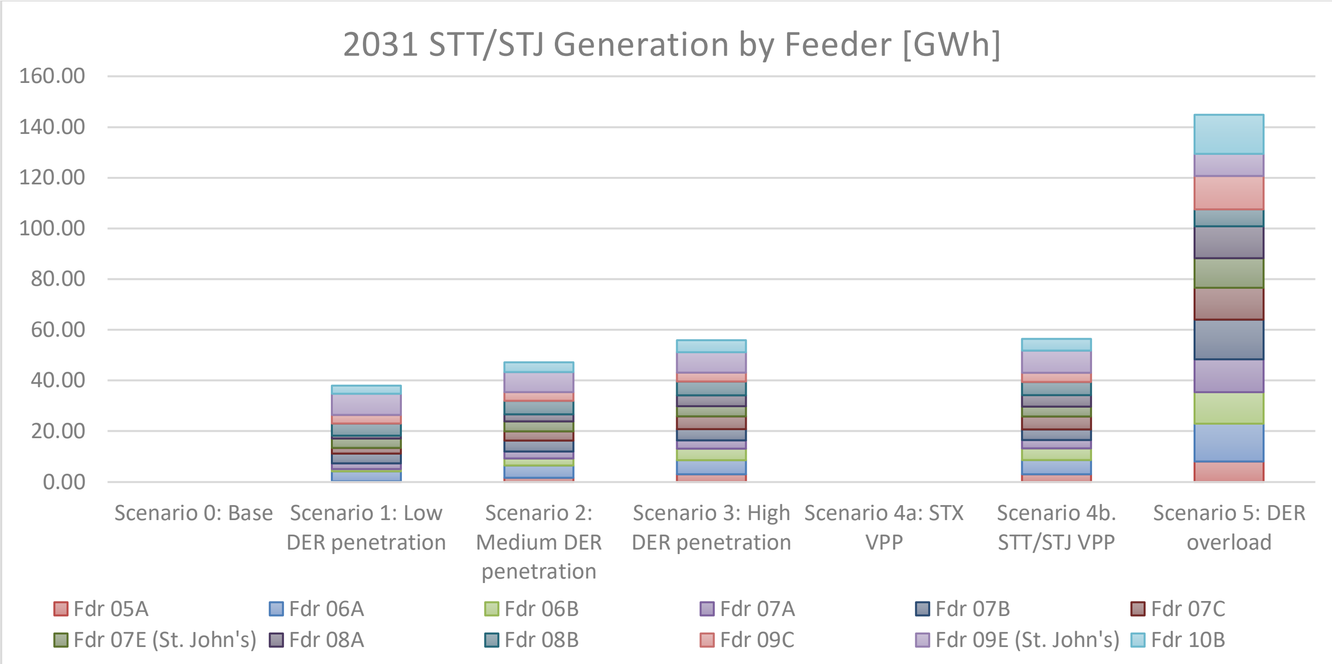


Figure C.19- 2031 STT/STJ generation [GWh] by feeder and scenario

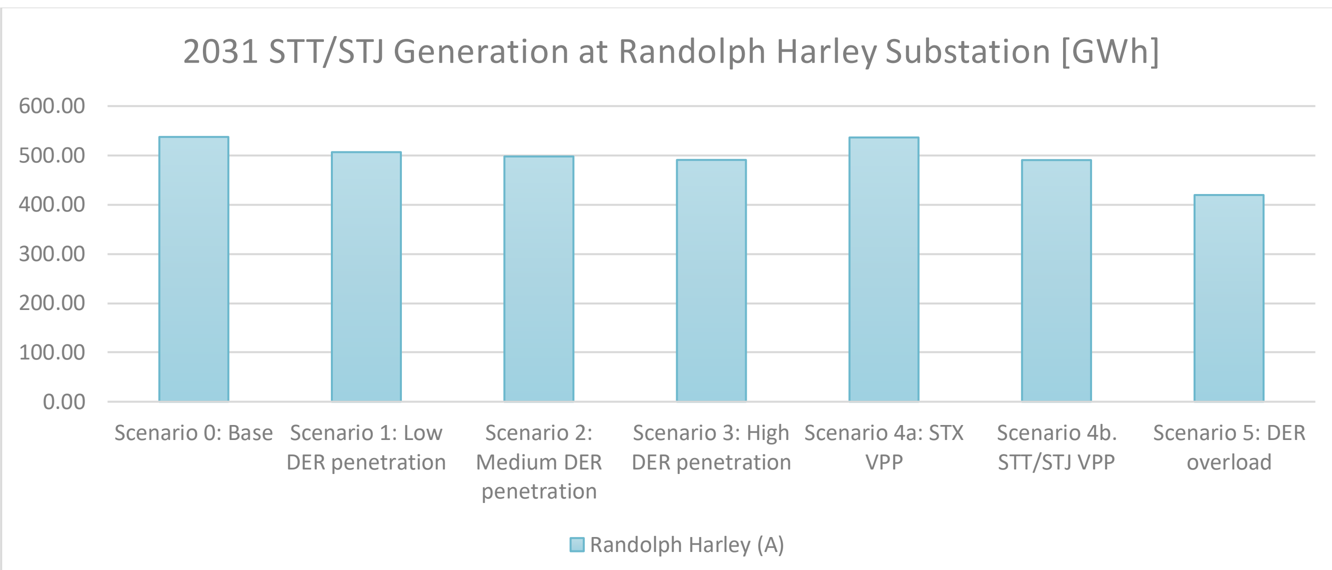


Figure C.20- 2031 STT/STJ generation [GWh] at Randolph Harley substation by scenario

2031 STX generation by feeder [GWh]:
This table shows the amount of 2031 generation [GWh] at all substations and feeders on STX. The results are similar to the STT/STJ system. The larger the amount of DER penetration, the more generation coming from feeders and less from the larger substations, Richmond and Midland.

	Midland	Richmond	STX Fdr 02A	STX Fdr 03A	STX Fdr 04A	STX Fdr 05A	STX Fdr 06A	STX Fdr 06B	STX Fdr 08B	STX Fdr 09B	STX Fdr 09D	STX Fdr 10A	STX Fdr 10B
Scenario 0:	16.34	367.24	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Scenario 1:	15.60	356.79	2.65	0.76	0.61	3.03	1.08	0.00	4.68	1.10	0.00	0.44	0.38

Scenario 2:	15.45	347.57	2.80	2.34	2.08	4.09	2.55	0.00	5.16	3.17	0.00	2.18	2.14
Scenario 3:	15.68	338.38	3.12	3.94	3.59	5.39	4.10	0.00	5.68	5.15	0.00	3.85	3.80
Scenario 4a:	15.72	338.36	3.15	3.90	3.59	5.62	4.06	0.00	5.92	5.15	0.00	3.86	3.80
Scenario 4b.	15.57	366.43	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Scenario 5:	16.83	273.83	3.93	13.40	12.91	16.89	13.12	0.00	16.96	13.63	0.00	10.39	11.25

Table C.17- 2031 STX generation [GWh] by feeder and scenario

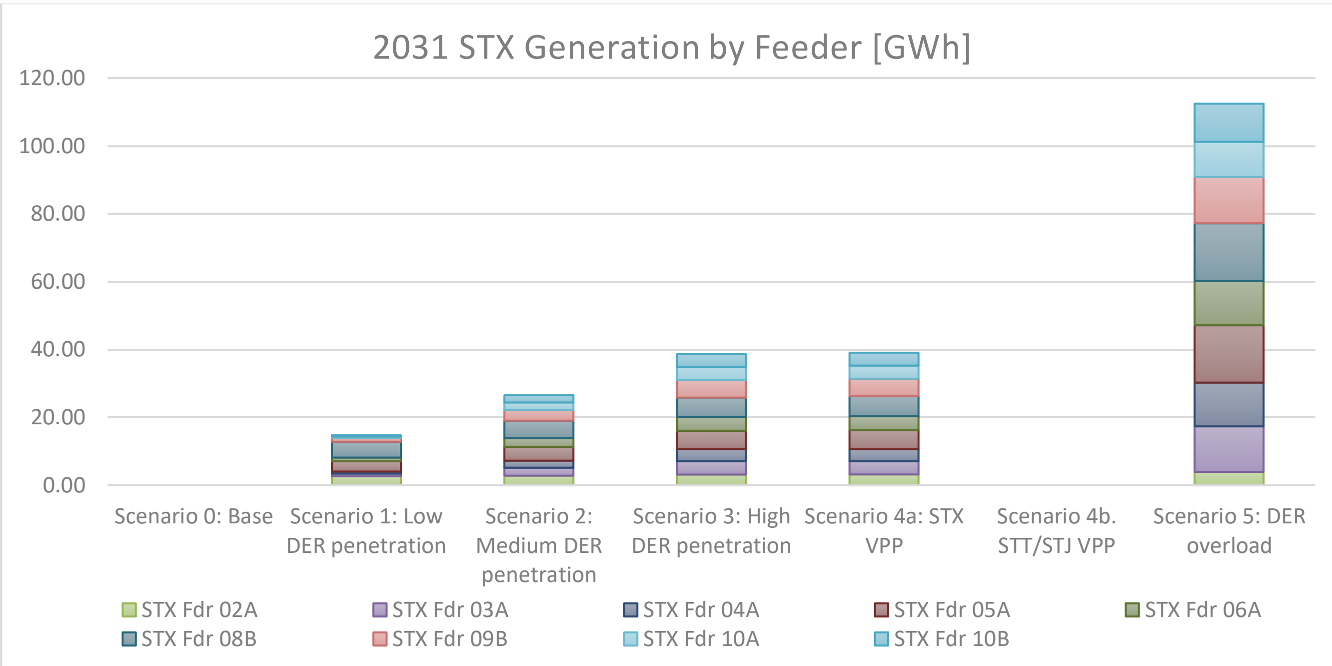


Figure C.21- 2031 STX generation [GWh] by feeder and scenario

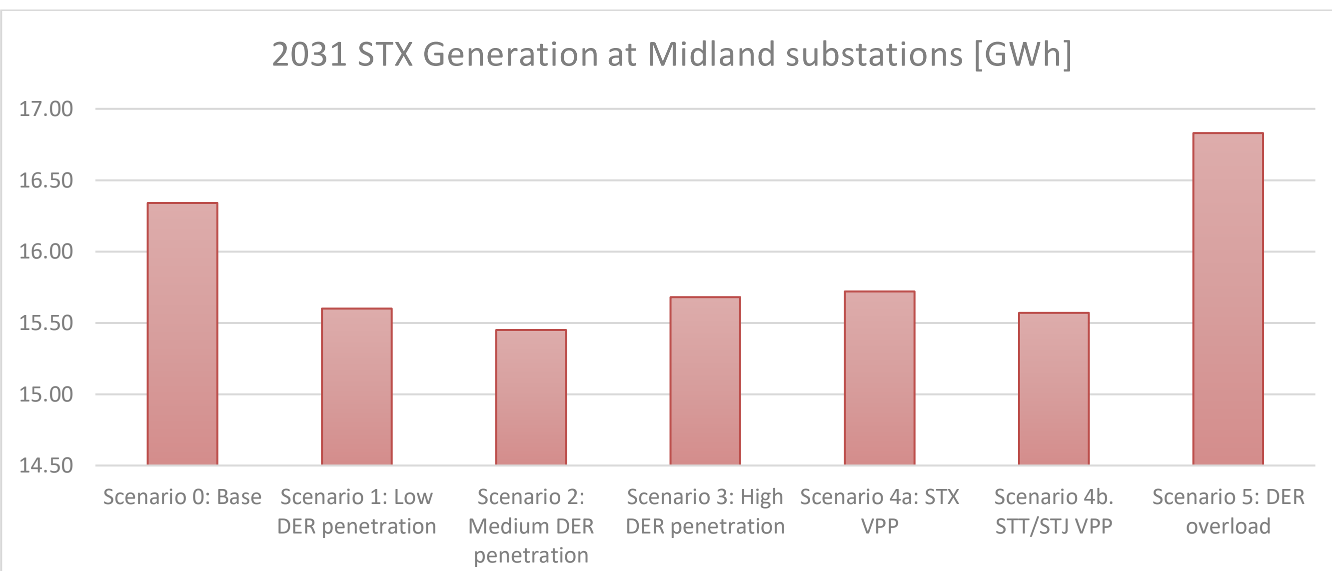


Figure C.22- 2031 STX generation [GWh] at Midland substation by scenario

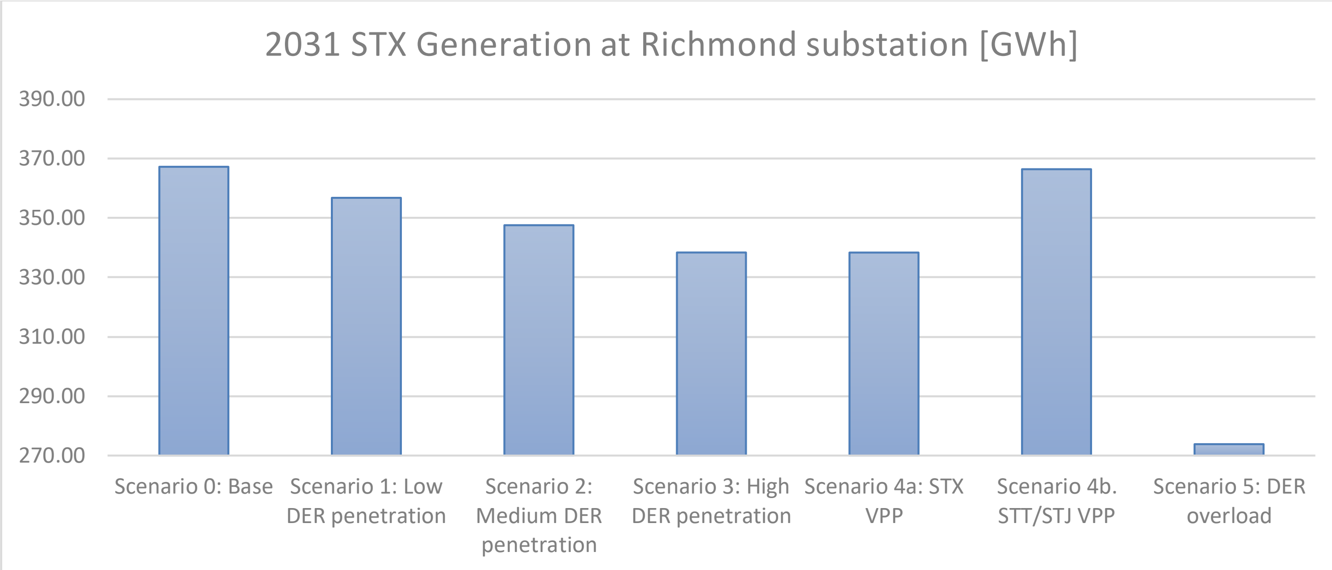


Figure C.23- 2031 STX generation [GWh] at Richmond substation by scenario

8.3.13 Scenario 0 Highlights

Overall, Scenario 0 represents the true base scenario with generation being dominated by LPG and oil and no interconnected distribution generation. This scenario sees the highest fuel costs, total costs, and region prices of any scenario. This is used as a comparison case to see the benefits of all other scenarios

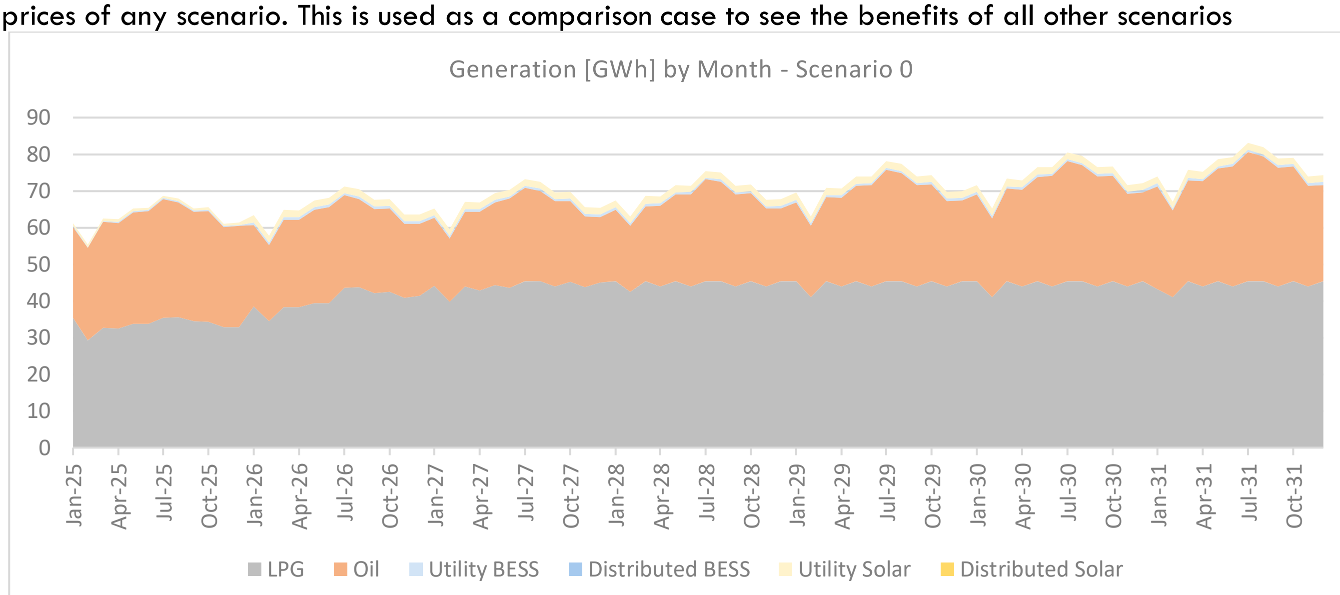


Figure C.24- Scenario 0 generation [GWh] by month

8.3.14 Scenario 1 Highlights

Scenario 1 is essentially the low DER scenario, assuming that the existing DER resources form part of the VPP but no further buildout of DERs occurs. The DER generation is a bit stunted in 2025-2026 as oil generators are intentionally given dispatch priority for this time-period in STT/STJ.

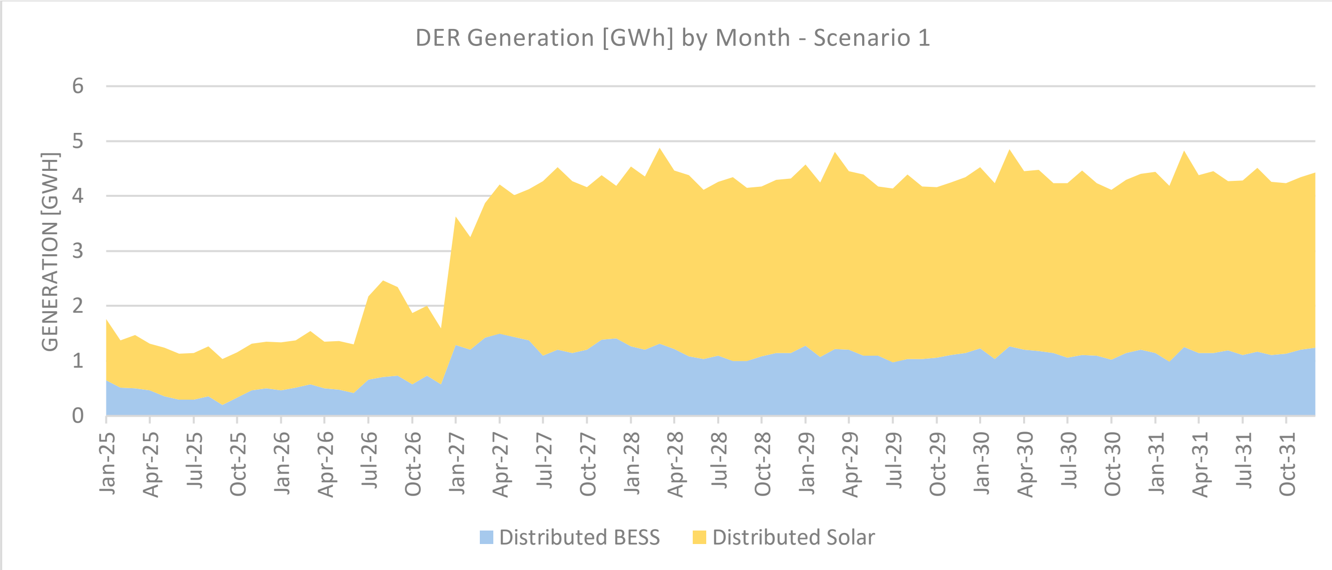


Figure C.25- Scenario 1 DER generation [GWh] by month

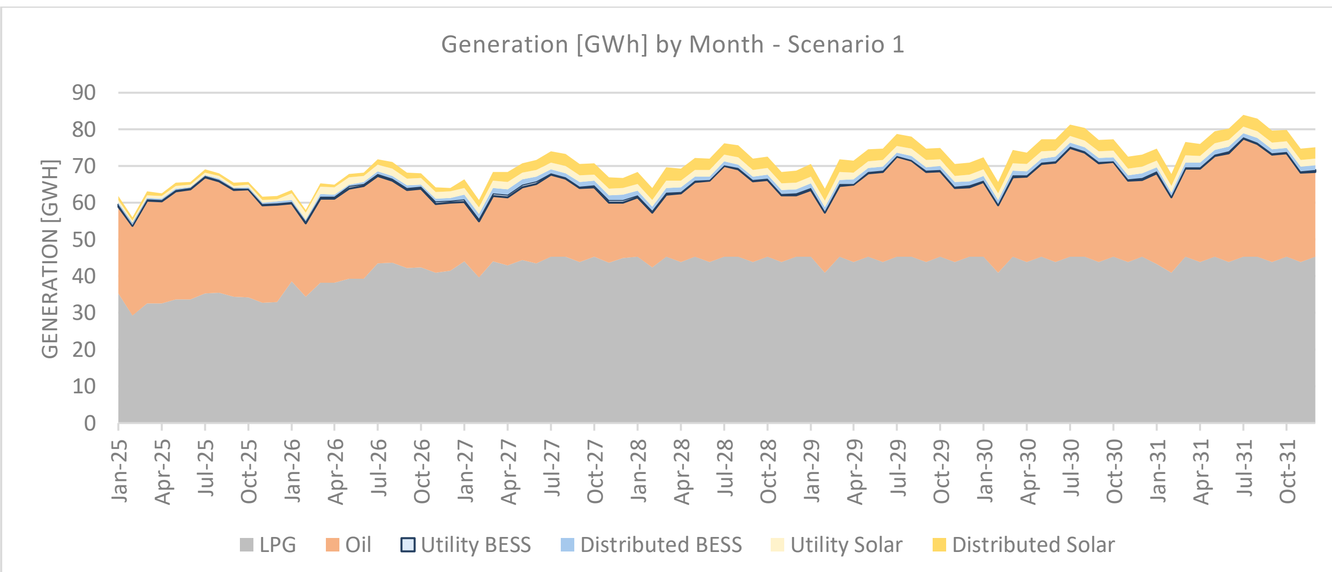


Figure C.26- Scenario 1 generation [GWh] by month

8.3.15 Scenario 2 Highlights

Scenario 2 is the first scenario that sees new buildout for DERs. Rapid buildout occurs at an increasing rate during the first years and then begins to teeter out as build limits are reached. DER generation is about 1.4x that of Scenario 1.

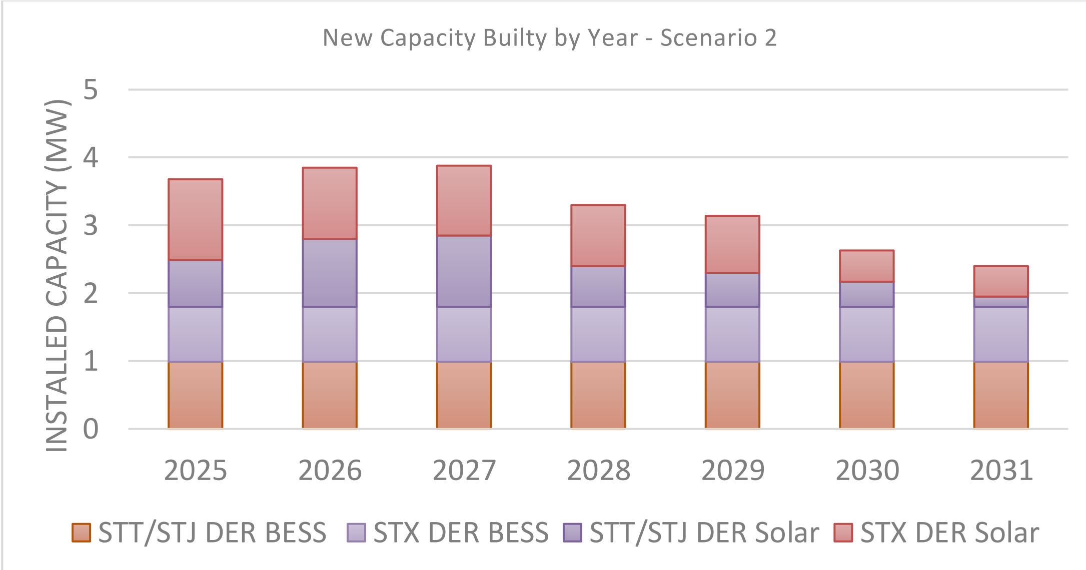


Figure C.27- Scenario 2 new build capacity [MW] by year, resource, and system

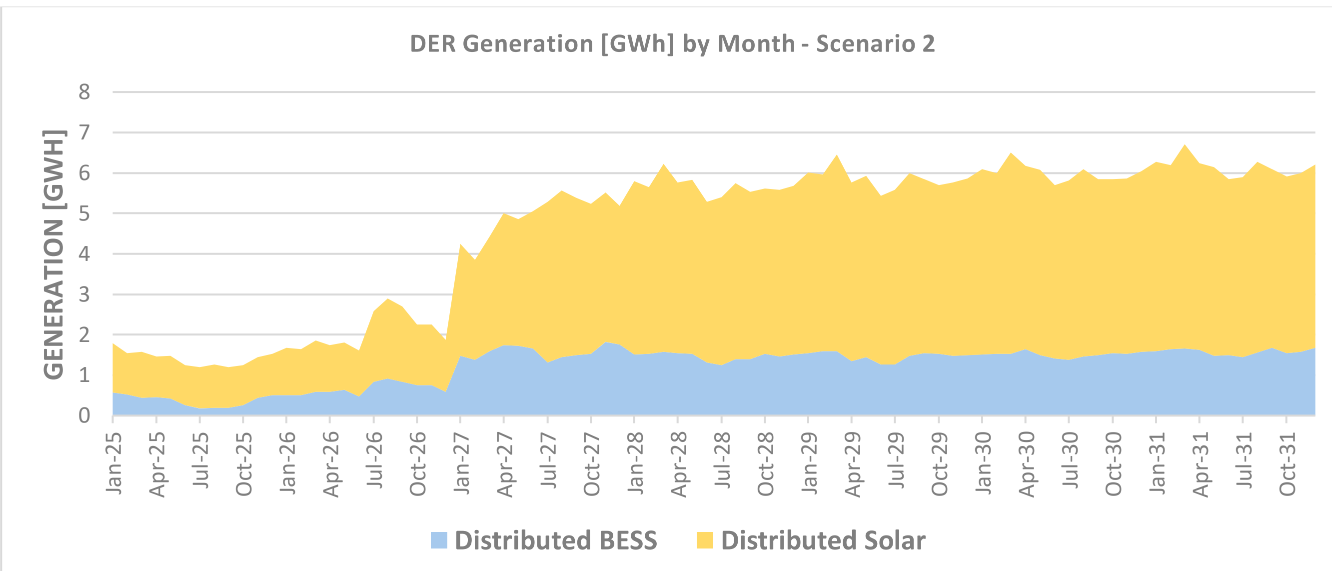


Figure C.28- Scenario 2 DER generation [GWh] by month

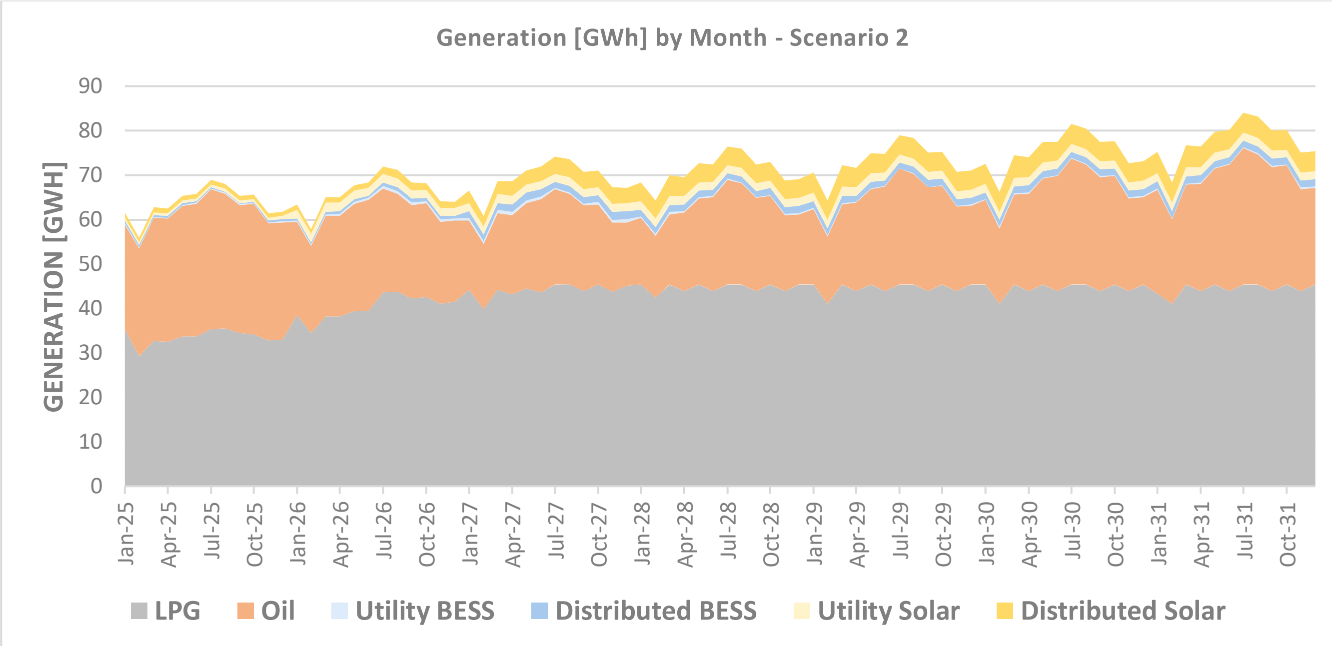


Figure C.29- Scenario 2 generation [GWh] by month

8.3.16 Scenario 3 Highlights

Scenario 3 sees new buildout for DERs up to the feeder limits. Again, rapid buildout occurs at an increasing rate during the first years and then begins to teeter out as feeder limits are reached. DER generation is about 1.8x that of Scenario 1

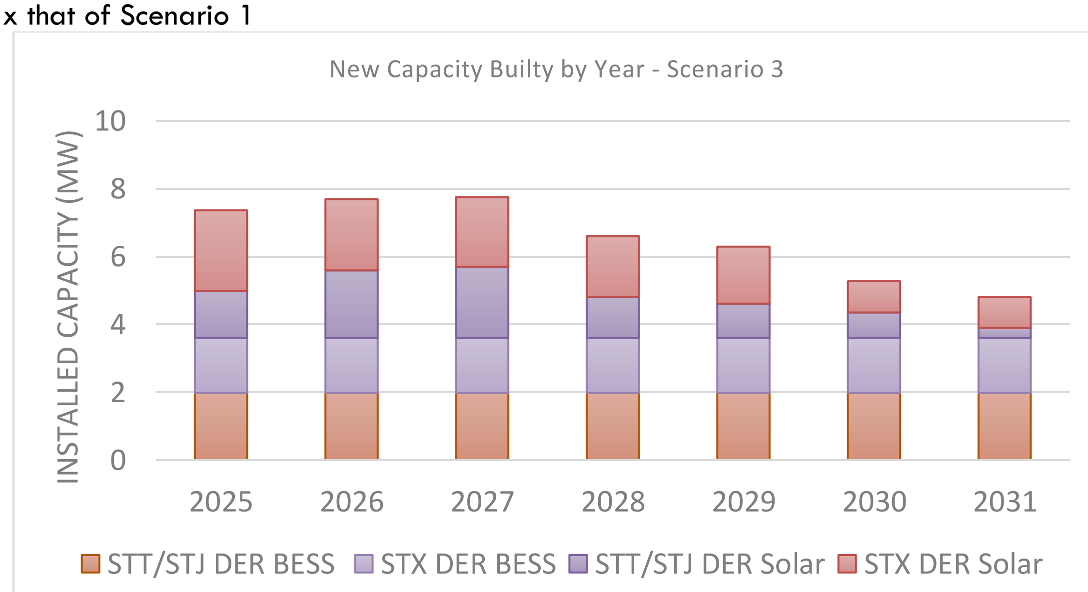


Figure C.30- Scenario 3 new build capacity [MW] by year, resource, and system

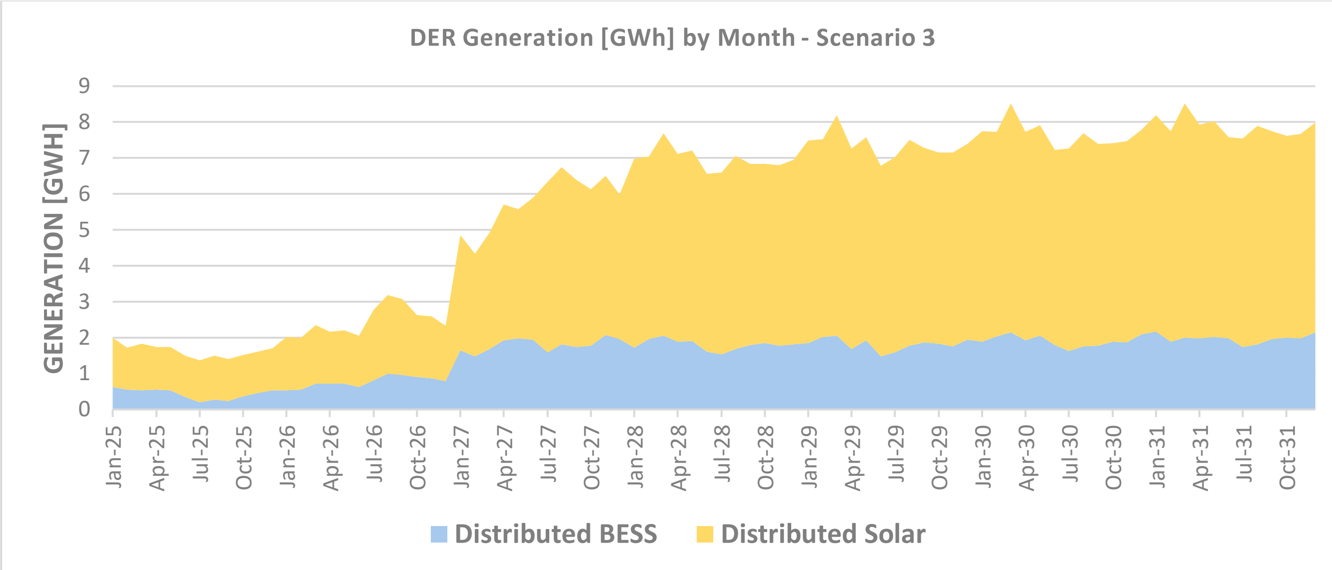


Figure C.31- Scenario 3 DER generation [GWh] by month

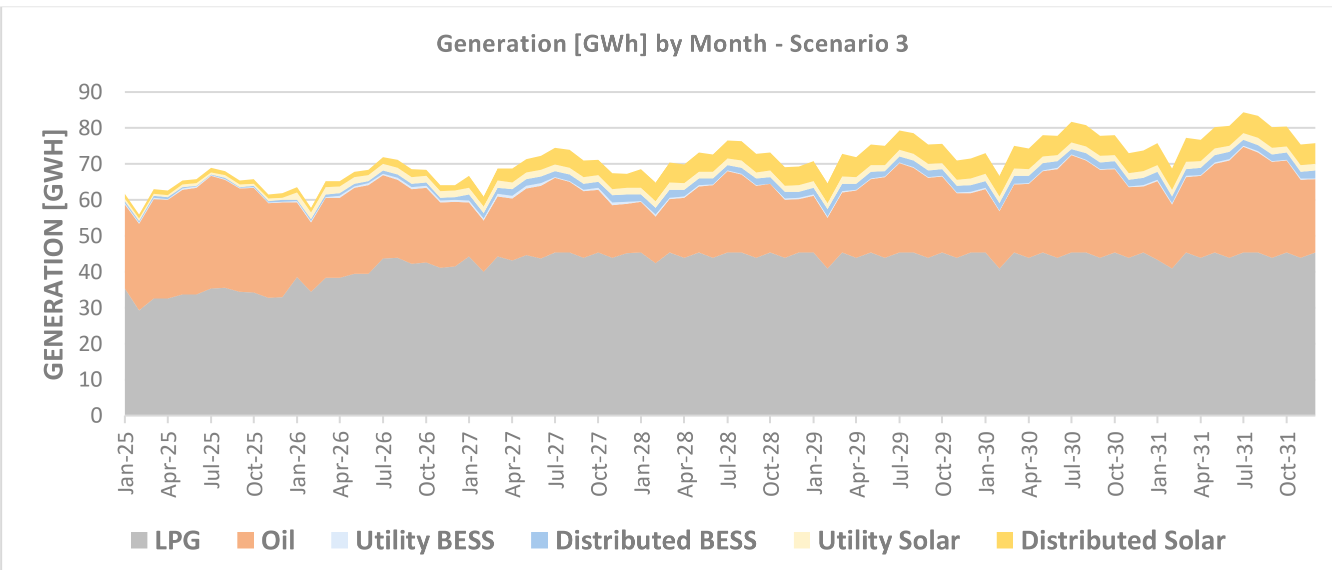


Figure C.32- Scenario 3 generation [GWh] by month

8.3.17 Scenario 4a Highlights

Scenario 4a sees new buildout for DERs only in STX. Unlike Scenario 2 and 3, maximum DER buildout occurs in Year 1 and then each consecutive year sees DER buildout at a decreasing rate. All newbuild DER solar is installed in the first 5 years. DER generation is about a bit lower than that of Scenario 1 because buildout is limited to STX. The DER generation profile is not impacted by the dispatch requirements in STT in the first 2 year, so its growth is more gradual

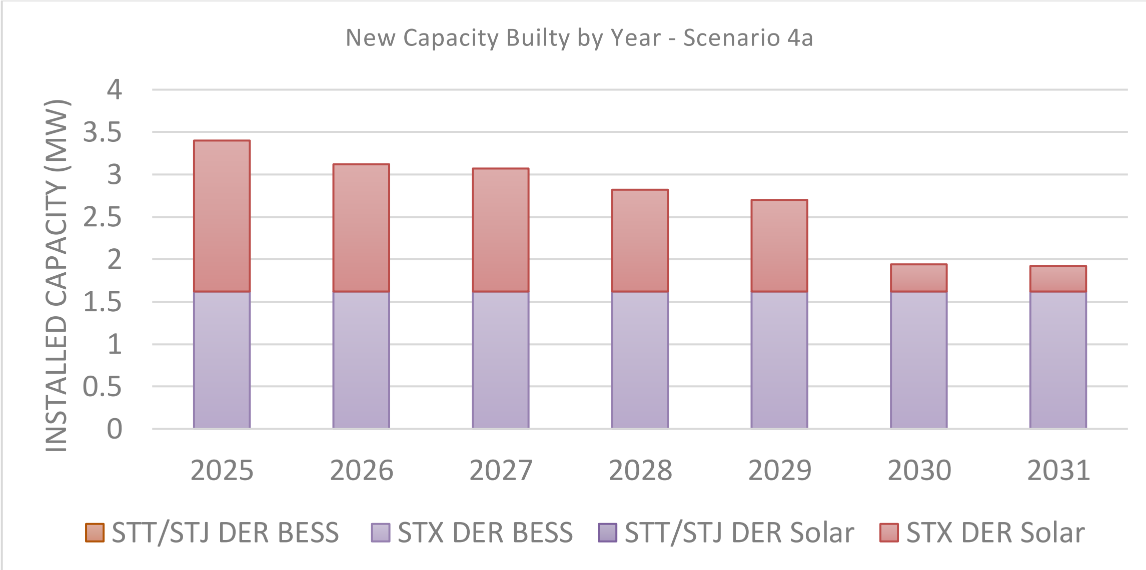


Figure C.33- Scenario 4a new build capacity [MW] by year, resource, and system

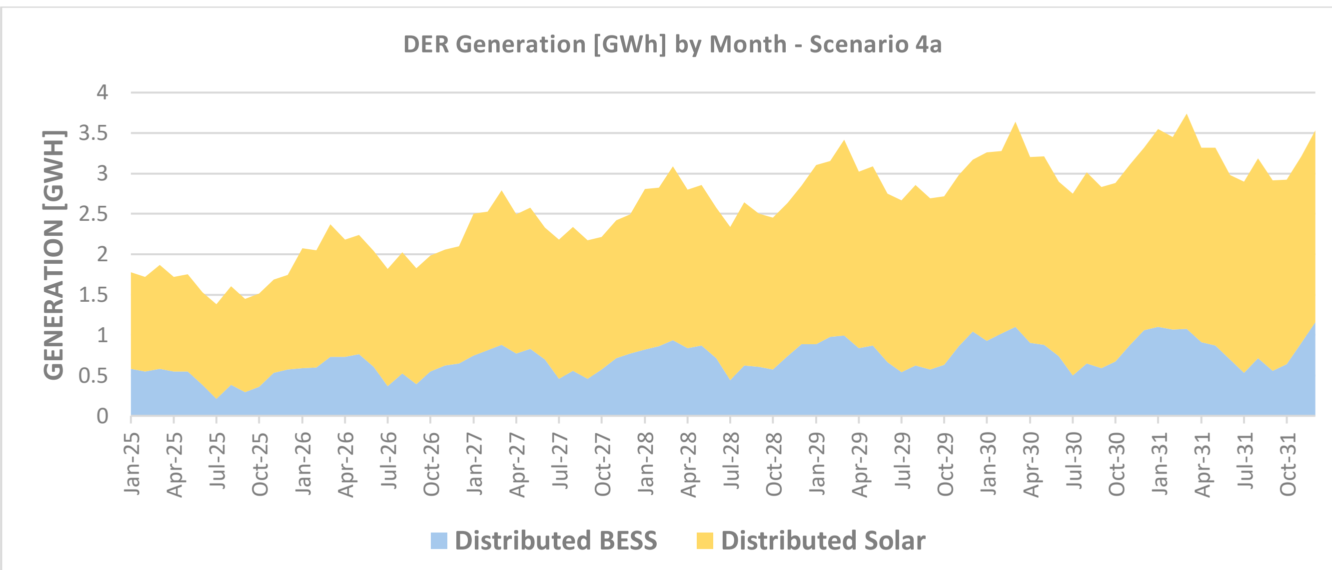


Figure C.34- Scenario 4a DER generation [GWh] by month

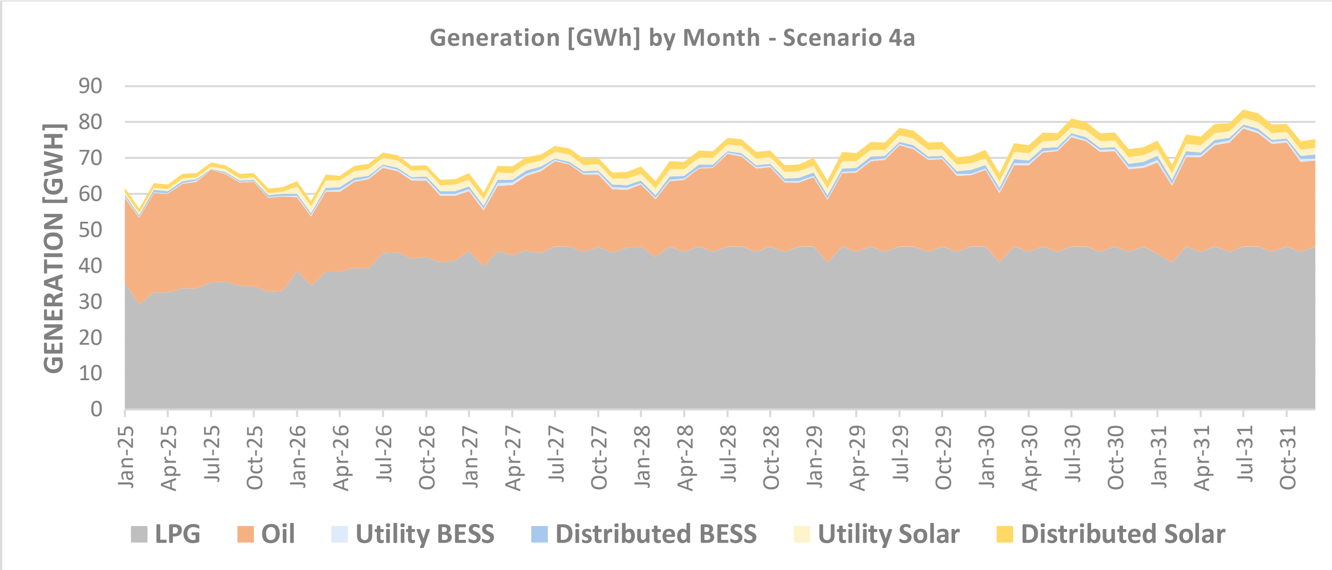


Figure C.35- Scenario 4a generation [GWh] by month

8.3.18 Scenario 4b Highlights

Scenario 4b sees new buildout for DERs only in STT/STJ. Similar to Scenario 2 and 3, rapid buildout occurs at an increasing rate during the first years and then begins to teeter out as build limits are reached. All new-build DER solar is installed in the first 5 years. DER generation is about 1.1x that of Scenario 1, even though only STT/STJ is considered for the VPP in this scenario. Interestingly, no DER generation occurs during the first 18 months, since minimum dispatch limits are put in place for several oil generators in STT, dampening DER generation.

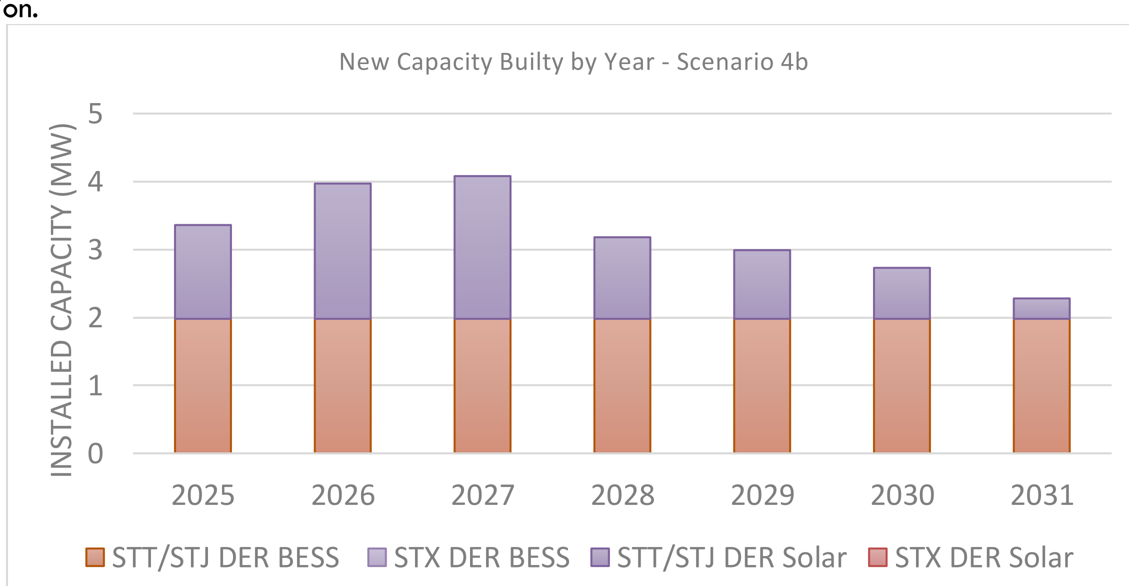


Figure C.36- Scenario 4b new build capacity [MW] by year, resource, and system

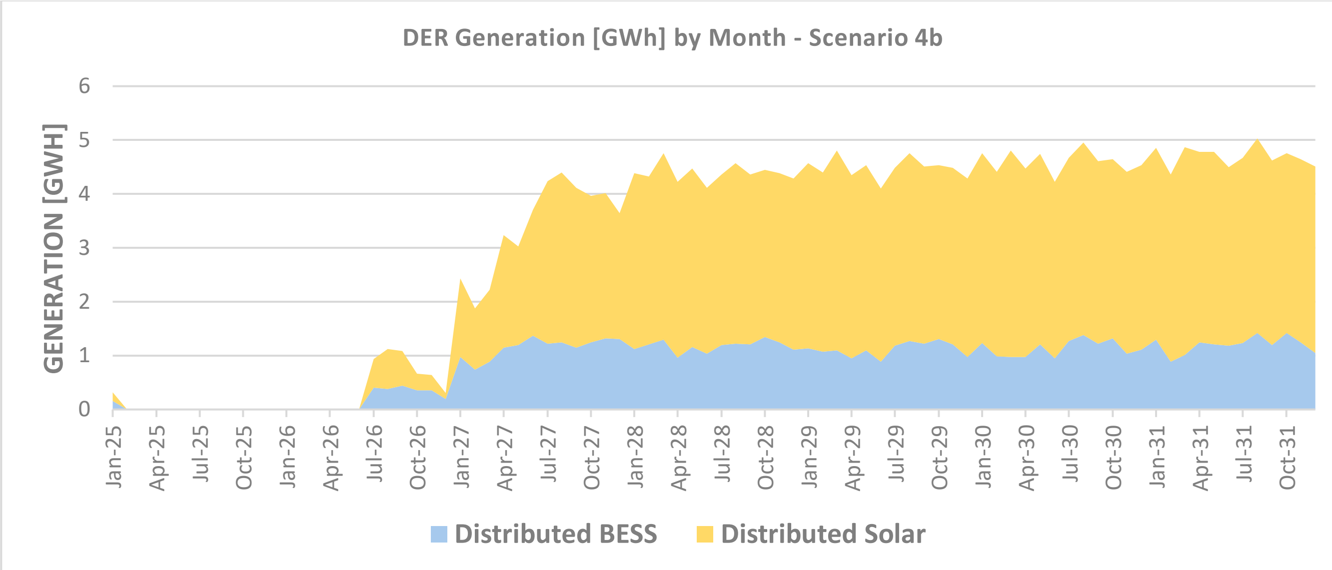


Figure C.37- Scenario 4b DER generation [GWh] by month

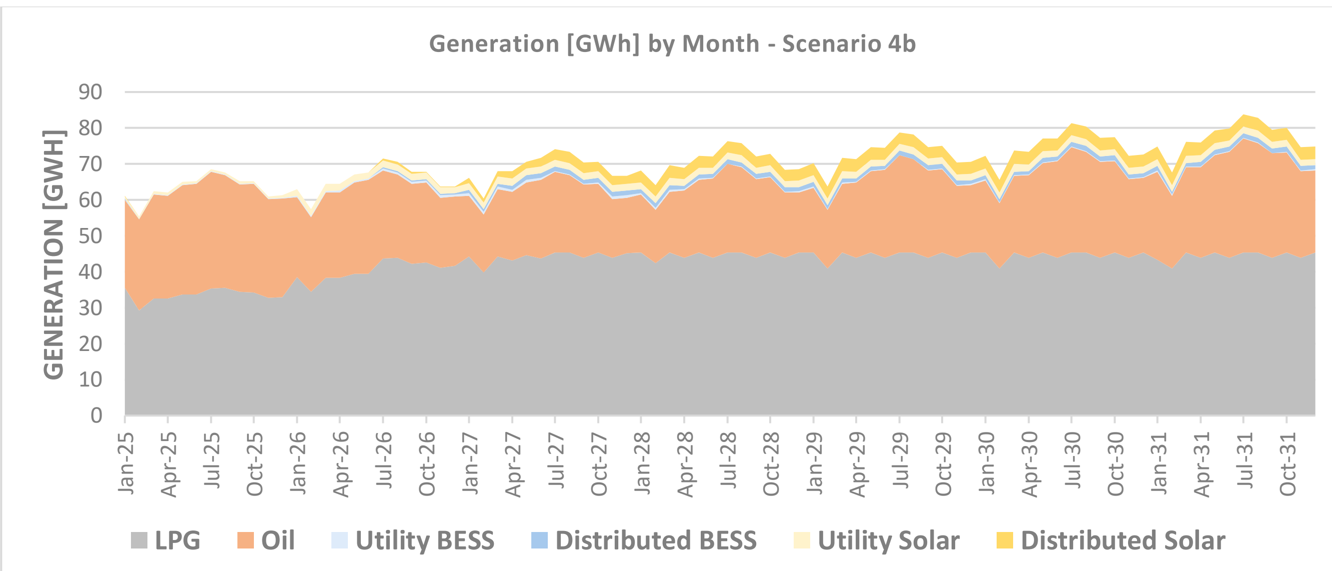


Figure C.38- Scenario 4b generation [GWh] by month

8.3.19 Scenario 5 Highlights

Scenario 5 sees new buildout for DERs with NO feeder limits. This means that buildout occurs at the maximum rate each year. A separate analysis is needed to estimate the additional cost for feeder upgrades and T&D infrastructure upgrades. DER generation is about 5.4x that of Scenario 1 and even 3x that of Scenario 3, which represents the feasible new build scenario given current feeder limits. The generation increases rapidly beginning in the second half of 2026. Further, this scenario really enables DERs to replace oil generation.

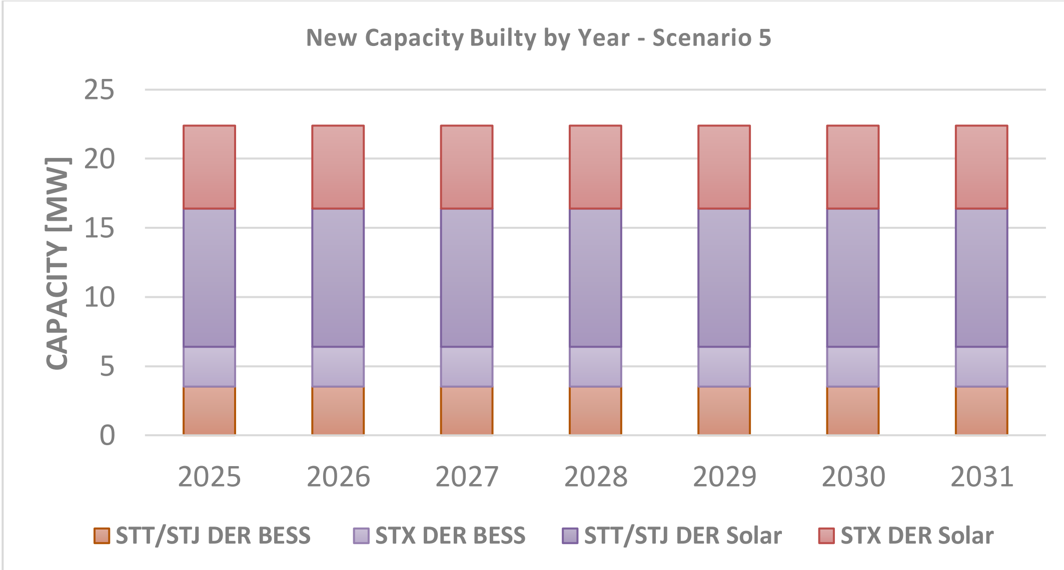


Figure C.39- Scenario 5 new build capacity [MW] by year, resource, and system

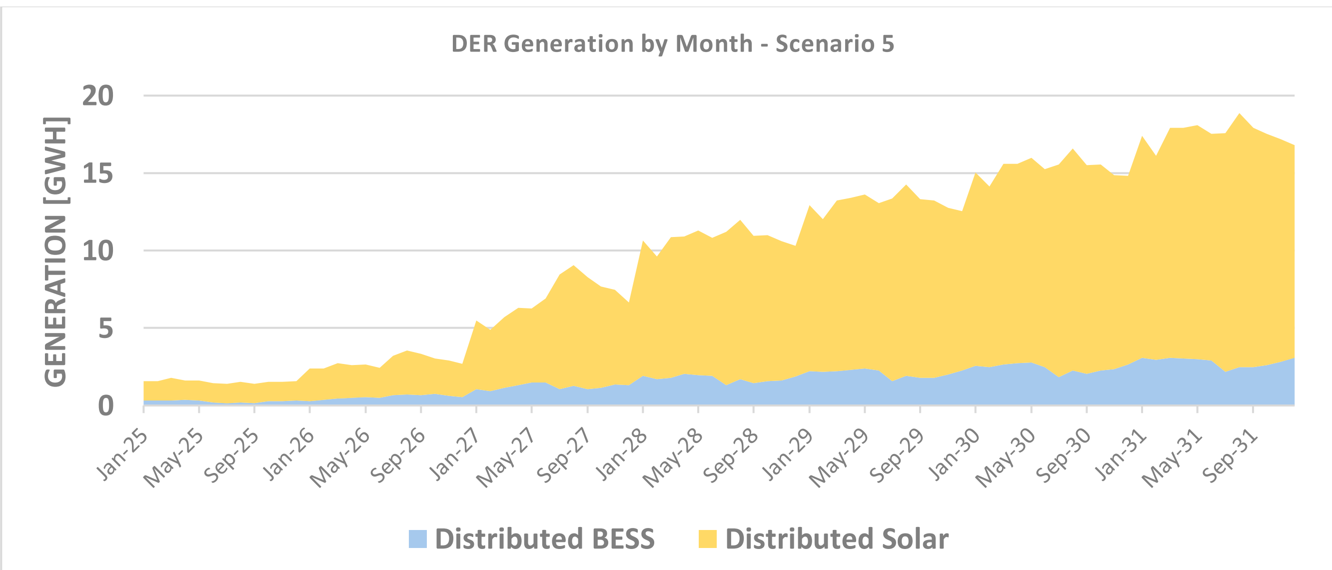


Figure C.40- Scenario 5 DER generation [GWh] by month

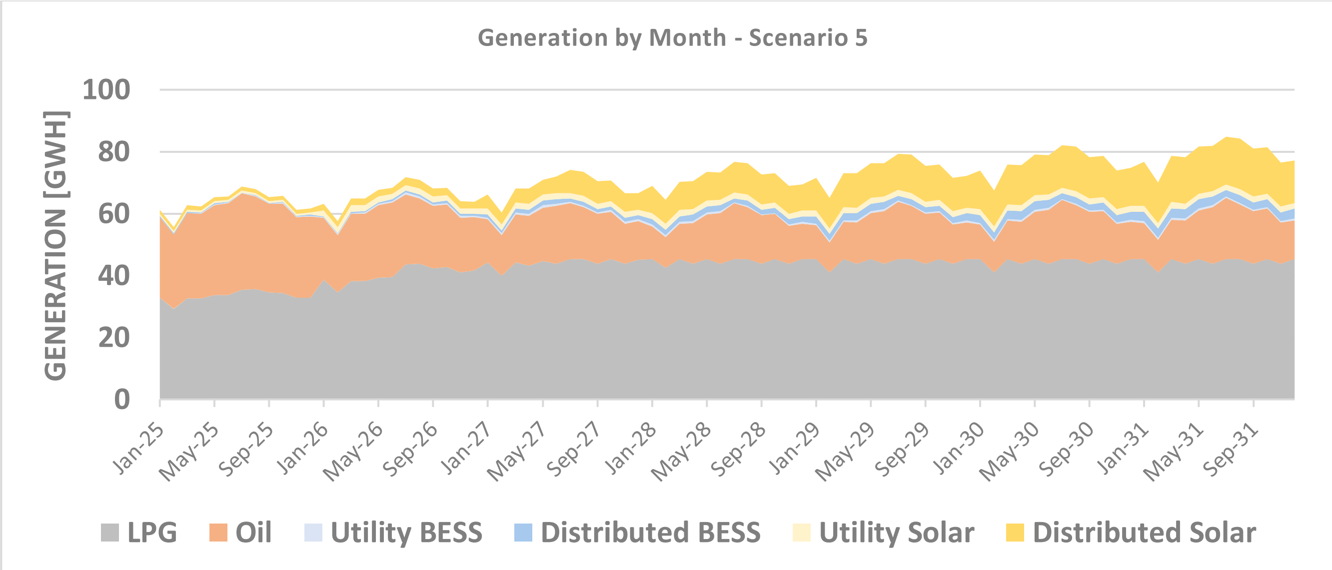


Figure C.41- Scenario 5 generation [GWh] by month

8.4 Appendix D: DER Capacities for Short-term Analyses

This section shows the DER capacities that were used for the 2-week short term analyses in 2025 and 2031 for both the high DER penetration scenario and the DER overload scenario. The tables show the capacities, including solar capacity [MW], solar offer quantity [MW], BESS power capacity [MW], BESS energy capacity [MWh], and BESS offer quantity [MW] for each of the two years and for each scenario modeled.

Feeder	Solar PV Capacity (MWac)	Solar PV Offer Quantity (MWac)	BESS Power Capacity (MW)	BESS Energy Capacity (MWh)	BESS Offer Quantity (MW)
ST. CROIX					
STX Feeder 02A	1.09	0.98	1.27	3.36	0.76
STX Feeder 03A	0.62	0.56	0.82	2.14	0.49
STX Feeder 04A	0.59	0.53	0.44	1.13	0.26
STX Feeder 05A	1.52	1.37	2.87	7.60	1.72
STX Feeder 06A	0.76	0.68	1.15	3.02	0.69
STX Feeder 06B	0.00	0	0	0.00	0.00
STX Feeder 08B	2.64	2.38	1.36	3.58	0.82
STX Feeder 09B	0.79	0.71	0.91	2.39	0.55
STX Feeder 09D	0.00	0	0	0.00	0.00
STX Feeder 10A	0.48	0.43	0.64	1.67	0.38
STX Feeder 10B	0.48	0.43	0.34	0.88	0.20
STX Total	8.97	8.07	9.80	25.77	5.88
ST. THOMAS					
STT Feeder 05A	0.46	0.41	0	0.00	0.00
STT Feeder 06A	1.71	1.54	1.46	3.86	0.88
STT Feeder 06B	0.86	0.77	0.2	0.52	0.12
STT Feeder 07A	1.32	1.19	0.44	1.14	0.26
STT Feeder 07B	1.77	1.59	1.21	3.19	0.73
STT Feeder 07C	1.49	1.34	0.97	2.56	0.58

STT Feeder 08A	0.76	0.68	1.32	3.47	0.79
STT Feeder 08B	2.21	1.99	1.33	3.50	0.80
STT Feeder 09C	1.87	1.68	1.17	3.08	0.70
STT Feeder 10B	1.88	1.69	1.09	2.87	0.65
STT Total	14.33	12.9	9.19	24.19	5.51
ST. JOHN					
STJ Feeder 07E	1.51	1.36	1.51	3.98	0.91
STJ Feeder 09E	3.49	3.14	2.85	7.54	1.71
STJ Total	5	5	4.36	11.52	2.62
GRAND TOTAL	28.3	25.47	23.35	61.48	14.01

Table D.1- 2025 DER capacities used for short-term analysis for high DER penetration scenario

Feeder	Solar PV Capacity (MWac)	Solar PV Offer Quantity (MWac)	BESS Power Capacity (MW)	BESS Energy Capacity (MWh)	BESS Offer Quantity (MW)
ST. CROIX					
STX Feeder 02A	1.09	0.98	1.41	3.71	0.85
STX Feeder 03A	1.32	1.19	0.96	2.49	0.58
STX Feeder 04A	1.29	1.16	0.58	1.48	0.35
STX Feeder 05A	2.22	2.00	3.01	7.95	1.81
STX Feeder 06A	1.46	1.31	1.29	3.37	0.77
STX Feeder 06B	0.00	0.00	0	0	0.00
STX Feeder 08B	3.36	3.02	1.5	3.93	0.90
STX Feeder 09B	1.49	1.34	1.05	2.74	0.63
STX Feeder 09D	0.00	0.00	0	0	0.00
STX Feeder 10A	0.18	0.16	0.78	2.02	0.47
STX Feeder 10B	0.18	0.16	0.48	1.23	0.29
STX Total	12.59	11.33	11.06	28.92	6.64
ST. THOMAS					
STT Feeder 05A	1.160	1.04	0	0	0.00
STT Feeder 06A	2.710	2.44	1.6	4.21	0.96
STT Feeder 06B	1.560	1.40	0.34	0.87	0.20
STT Feeder 07A	2.320	2.09	0.58	1.49	0.35
STT Feeder 07B	2.770	2.49	1.35	3.54	0.81
STT Feeder 07C	2.190	1.97	1.11	2.91	0.67
STT Feeder 08A	1.460	1.31	1.46	3.82	0.88
STT Feeder 08B	2.210	1.99	1.47	3.85	0.88
STT Feeder 09C	2.870	2.58	1.31	3.43	0.79
STT Feeder 10B	2.700	2.43	1.23	3.22	0.74
STT Total	21.95	19.76	10.45	27.34	6.27
ST. JOHN					
STJ Feeder 07E	2.510	2.26	1.65	4.33	0.99
STJ Feeder 09E	3.490	3.14	2.99	7.89	1.79
STJ Total	6.00	5.40	4.64	12.22	2.78
GRAND TOTAL	40.54	36.49	26.15	68.48	15.69

Table D.2- 2025 DER capacities used for short-term analysis for DER Overload scenario

Feeder	Solar PV Capacity (MWac)	Solar PV Offer Quantity (MWac)	BESS Power Capacity (MW)	BESS Energy Capacity (MWh)	BESS Offer Quantity (MW)
ST. CROIX					
STX Feeder 02A	1.09	0.98	2.35	6.06	1.41
STX Feeder 03A	1.79	1.61	1.9	4.84	1.14
STX Feeder 04A	1.74	1.57	1.52	3.83	0.91
STX Feeder 05A	2.04	1.84	3.95	10.3	2.37
STX Feeder 06A	1.80	1.62	2.23	5.72	1.34
STX Feeder 06B	0.00	0.00	0	0	0.00
STX Feeder 08B	2.63	2.37	2.44	6.28	1.46
STX Feeder 09B	2.54	2.29	1.99	5.09	1.19
STX Feeder 09D	0.00	0.00	0	0	0.00
STX Feeder 10A	2.23	2.01	1.72	4.37	1.03
STX Feeder 10B	2.23	2.01	1.42	3.58	0.85
STX Total	18.09	16.28	19.52	50.07	11.71
ST. THOMAS					
STT Feeder 05A	1.910	1.72	0	0	0.00
STT Feeder 06A	2.290	2.06	2.54	6.56	1.52
STT Feeder 06B	2.610	2.35	1.28	3.22	0.77
STT Feeder 07A	1.790	1.61	1.52	3.84	0.91
STT Feeder 07B	1.770	1.59	2.29	5.89	1.37
STT Feeder 07C	2.790	2.51	2.05	5.26	1.23
STT Feeder 08A	1.730	1.56	2.4	6.17	1.44
STT Feeder 08B	2.210	1.99	2.41	6.2	1.45
STT Feeder 09C	1.870	1.68	2.25	5.78	1.35
STT Feeder 10B	2.450	2.21	2.17	5.57	1.30
STT Total	21.42	19.28	18.91	48.49	11.35
ST. JOHN					
STJ Feeder 07E	1.510	1.36	2.59	6.68	1.55
STJ Feeder 09E	3.490	3.14	3.93	10.24	2.36
STJ Total	5.0	4.5	6.52	16.92	3.91
GRAND TOTAL	44.51	40.06	44.95	115.48	26.97

Table D.3- 2031 DER capacities used for short-term analysis for high DER penetration scenario

Feeder	Solar PV Capacity (MWac)	Solar PV Offer Quantity (MWac)	BESS Power Capacity (MW)	BESS Energy Capacity (MWh)	BESS Offer Quantity (MW)
ST. CROIX					
STX Feeder 02A	1.09	0.98	3.33	8.51	2.00
STX Feeder 03A	7.15	6.44	2.88	7.29	1.73
STX Feeder 04A	7.12	6.41	2.5	6.28	1.50
STX Feeder 05A	8.05	7.25	4.93	12.75	2.96
STX Feeder 06A	7.29	6.56	3.21	8.17	1.93
STX Feeder 06B	0.00	0.00	0	0	0.00

STX Feeder 08B	9.19	8.27	3.42	8.73	2.05
STX Feeder 09B	7.32	6.59	2.97	7.54	1.78
STX Feeder 09D	0.00	0.00	0	0	0.00
STX Feeder 10A	0.18	0.16	2.7	6.82	1.62
STX Feeder 10B	0.18	0.16	2.4	6.03	1.44
STX Total	47.57	42.81	28.34	72.12	17.00
ST. THOMAS					
STT Feeder 05A	6.990	6.29	0	0	0.00
STT Feeder 06A	8.540	7.69	3.52	9.01	2.11
STT Feeder 06B	7.390	6.65	2.26	5.67	1.36
STT Feeder 07A	8.150	7.34	2.5	6.29	1.50
STT Feeder 07B	8.600	7.74	3.27	8.34	1.96
STT Feeder 07C	8.020	7.22	3.03	7.71	1.82
STT Feeder 08A	7.290	6.56	3.38	8.62	2.03
STT Feeder 08B	2.210	1.99	3.39	8.65	2.03
STT Feeder 09C	8.700	7.83	3.23	8.23	1.94
STT Feeder 10B	8.530	7.68	3.15	8.02	1.89
STT Total	74.42	66.98	27.73	70.54	16.64
ST. JOHN					
STJ Feeder 07E	8.340	7.51	3.57	9.13	2.14
STJ Feeder 09E	3.490	3.14	4.91	12.69	2.95
STJ Total	11.83	10.65	8.48	21.82	5.09
GRAND TOTAL	133.82	120.44	64.55	164.48	38.73

Table D.4- 2031 DER capacities used for short-term analysis for DER Overload scenario

8.5 Appendix E: Details of Short-term model results

These are additional results from the short-term PLEXOS Analysis described in Section 5 and only for the 2031 analysis:

- 2031 Results with **NO** outage
  - Total costs [$]
  - Fuel costs [$]
  - Fossil fuel operating hours [hrs.]
  - Fossil fuel generation [GWh]
  - RE generation [GWh]
  - Hourly generation [GWh]
- 2031 Results **WITH** outage
  - Unserved energy [GWh]
  - Total costs [$]
  - Fuel costs [$]
  - Fossil fuel operating hours [hrs.]
  - Fossil fuel generation [GWh]
  - RE generation [GWh]
  - Hourly generation [GWh]

8.5.1 2031 Results with **NO** outage

8.5.1.1 Total costs [$]

The total cost is defined as the sum of all fixed and variable costs for all generators (incl. batteries) and physical contracts in the region. The fixed charges include fixed O&M costs [$/kW] for installed capacity.

The variable charges include VO&M costs [$/kWh] for generation and fuel costs [$/kWh] (fuel offtake times the fuel price). Other generator costs include start and shutdown costs, emissions costs and abatement costs if they exists.

The total cost analysis reveals that the average daily cost is as follows:

- Base case with NO outage - $483,297
- High DER penetration VPP with NO outage - $423,724, representing only a 12.3% increase from normal operations
- DER Overload VPP with NO outage - $339,023, representing a 30% decrease from normal operations even with an outage

	Base No Outage 2031	High DER NO outage 2031	DER Overload NO outage 2031
1/5/31 0:00	$ 494,000.00	$ 427,250.00	$ 356,330.00
1/6/31 0:00	$ 492,050.00	$ 436,050.00	$ 351,730.00
1/7/31 0:00	$ 464,990.00	$ 415,620.00	$ 327,270.00
1/8/31 0:00	$ 480,320.00	$ 412,120.00	$ 325,670.00
1/9/31 0:00	$ 494,730.00	$ 424,530.00	$ 338,510.00
1/10/31 0:00	$ 498,670.00	$ 437,360.00	$ 349,260.00
1/11/31 0:00	$ 487,750.00	$ 437,710.00	$ 335,150.00
1/12/31 0:00	$ 488,330.00	$ 428,330.00	$ 327,050.00
1/13/31 0:00	$ 479,320.00	$ 414,920.00	$ 326,860.00
1/14/31 0:00	$ 462,040.00	$ 396,580.00	$ 337,780.00
1/15/31 0:00	$ 497,800.00	$ 446,820.00	$ 354,010.00
1/16/31 0:00	$ 494,360.00	$ 454,970.00	$ 374,590.00
1/17/31 0:00	$ 476,380.00	$ 412,410.00	$ 338,090.00
1/18/31 0:00	$ 455,420.00	$ 387,460.00	$ 304,020.00

Table E.1- 2031 Total System Cost [GWh] with NO outage by day and scenario

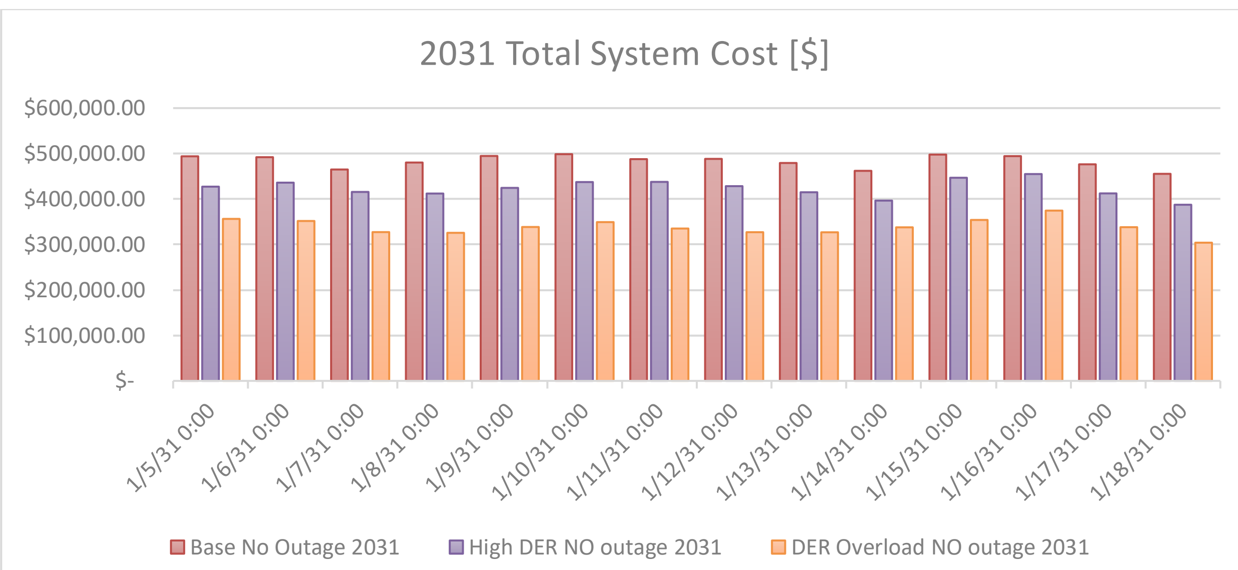


Figure E.1- 2031 Total System Cost [GWh] with NO outage by day and scenario

8.5.1.2 Fuel costs [$]

Fuel costs are just one aspect that makes up the total cost. The fuel cost analysis reveals that the average daily fuel cost is as follows:

- Base case with NO outage - $459,113

- High DER penetration VPP with NO outage - $400,211, representing only a 12.8% decrease from normal operations
- DER Overload VPP with NO outage - $316,229, representing a 31% decrease from normal operations even with an outage

	Base No Outage 2031	High DER NO outage 2031	DER Overload NO outage 2031
1/5/31 0:00	$ 469,920.00	$ 403,740.00	$ 333,490.00
1/6/31 0:00	$ 467,780.00	$ 412,520.00	$ 328,890.00
1/7/31 0:00	$ 440,980.00	$ 392,260.00	$ 304,550.00
1/8/31 0:00	$ 456,040.00	$ 388,680.00	$ 302,950.00
1/9/31 0:00	$ 470,380.00	$ 400,960.00	$ 315,650.00
1/10/31 0:00	$ 474,310.00	$ 413,690.00	$ 326,340.00
1/11/31 0:00	$ 463,430.00	$ 413,990.00	$ 312,300.00
1/12/31 0:00	$ 464,040.00	$ 404,770.00	$ 304,350.00
1/13/31 0:00	$ 455,370.00	$ 391,480.00	$ 304,130.00
1/14/31 0:00	$ 437,970.00	$ 373,290.00	$ 314,970.00
1/15/31 0:00	$ 473,510.00	$ 423,150.00	$ 331,190.00
1/16/31 0:00	$ 470,140.00	$ 431,260.00	$ 351,620.00
1/17/31 0:00	$ 452,260.00	$ 388,950.00	$ 315,310.00
1/18/31 0:00	$ 431,450.00	$ 364,210.00	$ 281,470.00

Table E.2- 2031 Fuel Cost [GWh] with NO outage by day and scenario

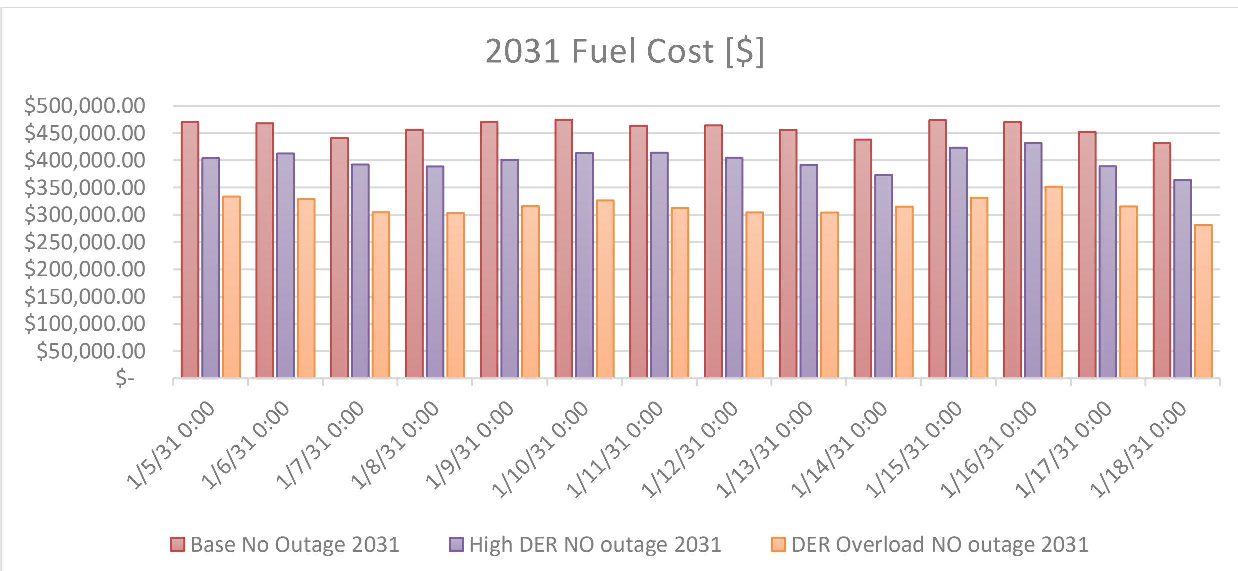


Figure E.2- 2031 Fuel Cost [GWh] with NO outage by day and scenario

8.5.1.3 Fossil fuel operating hours [hrs.]

This analysis shows how the VPP can reduce the amount of fossil fuel generating hours during normal operations. The average daily operating hours for the fossil fuel gensets are as follows:

- Base case with NO outage – 18.74
- High DER penetration VPP with NO outage -17.93, representing only a 0.82 hour decrease from normal operations
- DER Overload VPP with NO outage – 16.52, representing a 2.22 hour decrease from normal operations even with an outage

Base No Outage 2031	High DER NO outage 2031	DER Overload NO outage 2031

1/5/31 0:00	18.79	17.43	16.57
1/6/31 0:00	18.64	18.21	17.07
1/7/31 0:00	18.71	17.86	16.43
1/8/31 0:00	18.64	17.79	16.07
1/9/31 0:00	19.14	17.86	16.43
1/10/31 0:00	19.21	18.29	16.57
1/11/31 0:00	19.00	18.21	16.21
1/12/31 0:00	18.93	18.14	16.57
1/13/31 0:00	18.29	17.93	16.00
1/14/31 0:00	18.36	17.43	16.71
1/15/31 0:00	18.79	18.36	17.00
1/16/31 0:00	18.86	18.79	17.43
1/17/31 0:00	18.79	17.71	16.64
1/18/31 0:00	18.29	17.00	15.57

Table E.3- 2031 Fossil fuel operating hours [hrs.] with NO outage by day and scenario

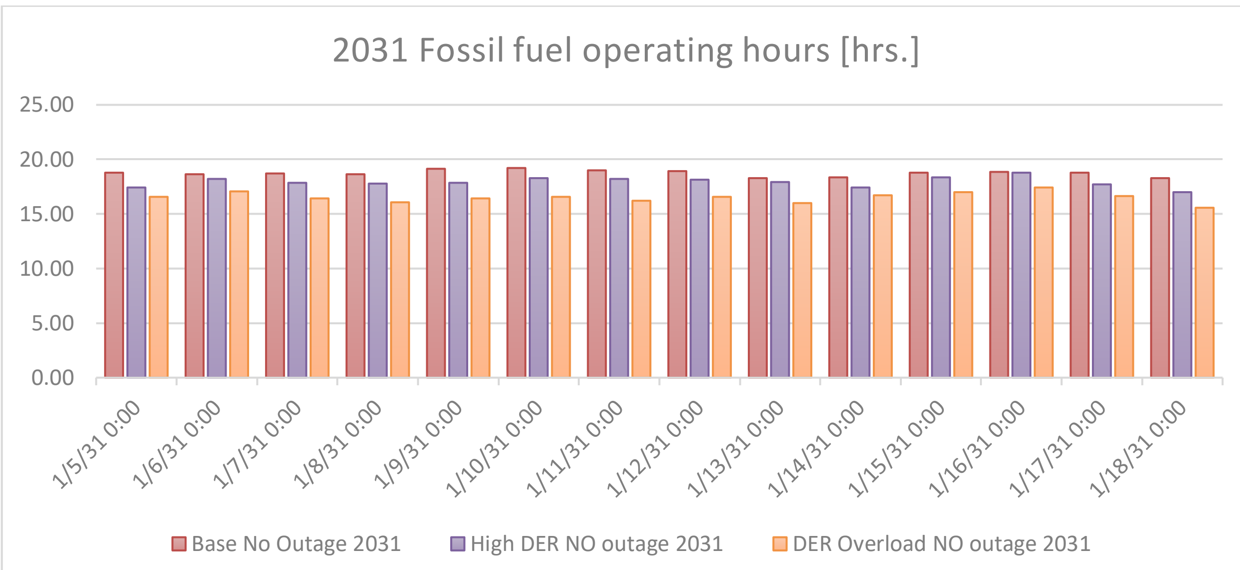


Figure E.3- 2031 Fossil fuel operating hours [hrs.] with NO outage by day and scenario

8.5.1.4 Fossil fuel generation [GWh]

When looking at the thermal generation from oil and LPG, it is clear that the VPP results in a lower amount of fossil fuel generation, which is directly due to the dispatchable distributed resources. The average 2031 daily fossil generation in GWh is as follows:

- Base case with NO outage – 2.31
- High DER penetration VPP with NO outage – 2.13
- DER Overload VPP with NO outage – 1.87

	Base No Outage 2031	High DER NO outage 2031	DER Overload NO outage 2031
1/5/31 0:00	2.34	2.14	1.91
1/6/31 0:00	2.33	2.16	1.90
1/7/31 0:00	2.24	2.08	1.83
1/8/31 0:00	2.30	2.09	1.83
1/9/31 0:00	2.35	2.14	1.87

1/10/31 0:00	2.36	2.17	1.91
1/11/31 0:00	2.33	2.19	1.87
1/12/31 0:00	2.33	2.14	1.83
1/13/31 0:00	2.31	2.11	1.84
1/14/31 0:00	2.24	2.03	1.87
1/15/31 0:00	2.34	2.19	1.90
1/16/31 0:00	2.33	2.22	1.95
1/17/31 0:00	2.29	2.08	1.87
1/18/31 0:00	2.23	2.02	1.77

Table E.4- 2031 Fossil fuel generation [GWh] with NO outage by day and scenario

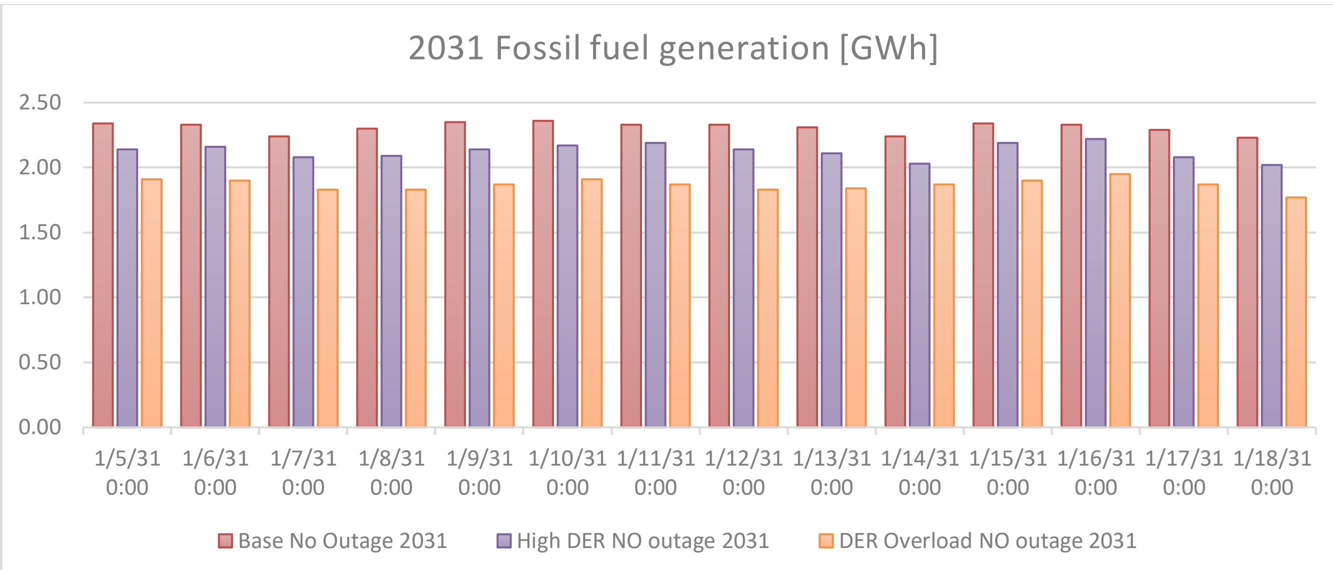


Figure E.4- 2031 Fossil fuel generation [GWh] with NO outage by day and scenario

8.5.1.5 RE generation [GWh]

This analysis shows that the VPP and its ability to dispatch DERs allows thermal generation, normally required on a day-to-day basis, to be met by distributed solar and battery generation. The high DER penetration VPP is able to generate 0.23 GWh . The DER Overload VPP is able to generate 0.57 GWh.

	Base No Outage 2031	High DER NO outage 2031	DER Overload NO outage 2031
1/5/31 0:00	0.00	0.26	0.55
1/6/31 0:00	0.00	0.28	0.58
1/7/31 0:00	0.00	0.24	0.54
1/8/31 0:00	0.00	0.24	0.61
1/9/31 0:00	0.00	0.24	0.61
1/10/31 0:00	0.00	0.22	0.60
1/11/31 0:00	0.00	0.18	0.57
1/12/31 0:00	0.00	0.21	0.64
1/13/31 0:00	0.00	0.25	0.60
1/14/31 0:00	0.00	0.22	0.50
1/15/31 0:00	0.00	0.24	0.60
1/16/31 0:00	0.00	0.23	0.50

1/17/31 0:00	0.00	0.20	0.54
1/18/31 0:00	0.00	0.24	0.57

Table E.5- 2031 RE generation [GWh] with NO outage by day and scenario

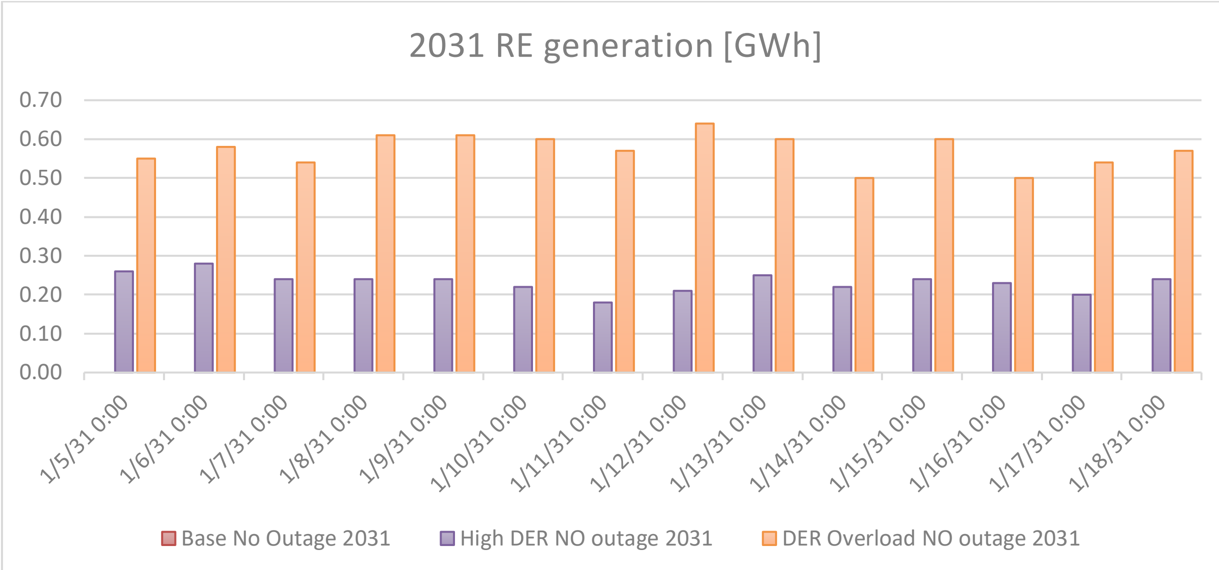


Figure E.5- 2031 RE generation [GWh] with NO outage by day and scenario

8.5.1.6 Hourly generation [GWh]

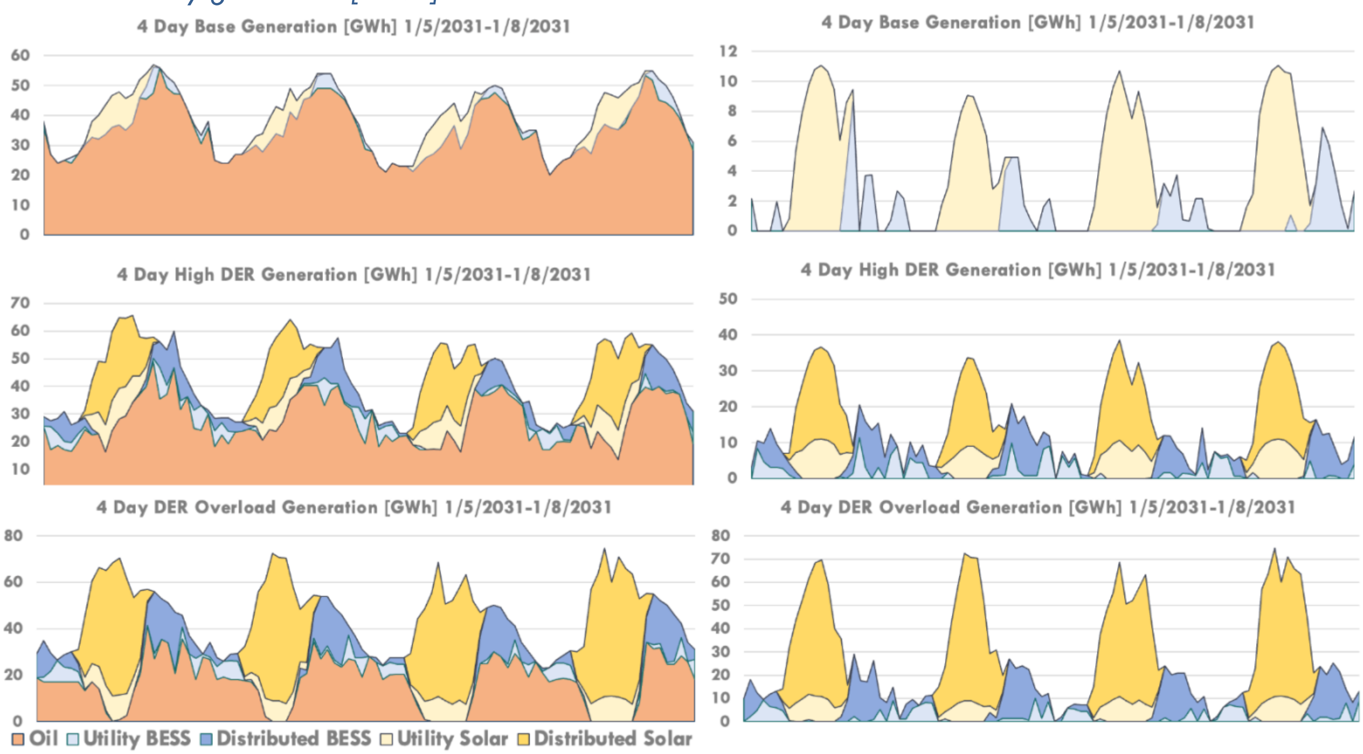


Figure E.6- 2031 Generation [GWh] by resource (left) and RE generation [GWh] (right) for the base scenario (top), high DER penetration VPP (middle) and DER overload VPP (bottom) with NO outage during a 4 day period

8.5.2 2031 Results **WITH** outage

8.5.2.1 Unserved energy [GWh]

The VPP has a huge potential to reduce the unserved energy during the loss of generators. In the base case, the loss of the generators causes a total of 0.92 GWh of unserved energy during the 9-day outage. The high DER penetration VPP is able to reduce this to 0.19 GWh, which is a 79% reduction. The DER Overload VPP is able to reduce this to 0.06 GWh, which is a 93% reduction. It is important to note that these reductions are the results from when there this is the loss of the two largest gensets from each system, and potentially with just the loss of the largest genset, the VPP would be able to eliminate the unserved energy and need for rotating blackouts entirely.

	Base No Outage 2031	Base Outage 2031	High DER outage 2031	DER Overload outage 2031
1/5/31 0:00	0.00	0.00	0.00	0.00
1/6/31 0:00	0.00	0.00	0.00	0.00
1/7/31 0:00	0.00	0.00	0.00	0.00
1/8/31 0:00	0.00	0.10	0.01	0.00
1/9/31 0:00	0.00	0.13	0.02	0.01
1/10/31 0:00	0.00	0.15	0.03	0.01
1/11/31 0:00	0.00	0.10	0.02	0.00
1/12/31 0:00	0.00	0.12	0.01	0.00
1/13/31 0:00	0.00	0.09	0.02	0.01
1/14/31 0:00	0.00	0.09	0.03	0.01
1/15/31 0:00	0.00	0.14	0.05	0.02
1/16/31 0:00	0.00	0.00	0.00	0.00
1/17/31 0:00	0.00	0.00	0.00	0.00
1/18/31 0:00	0.00	0.00	0.00	0.00
Total	0.00	0.92	0.19	0.06

Table E.6- 2031 Unserved Energy [GWh] WITH outage by day and scenario

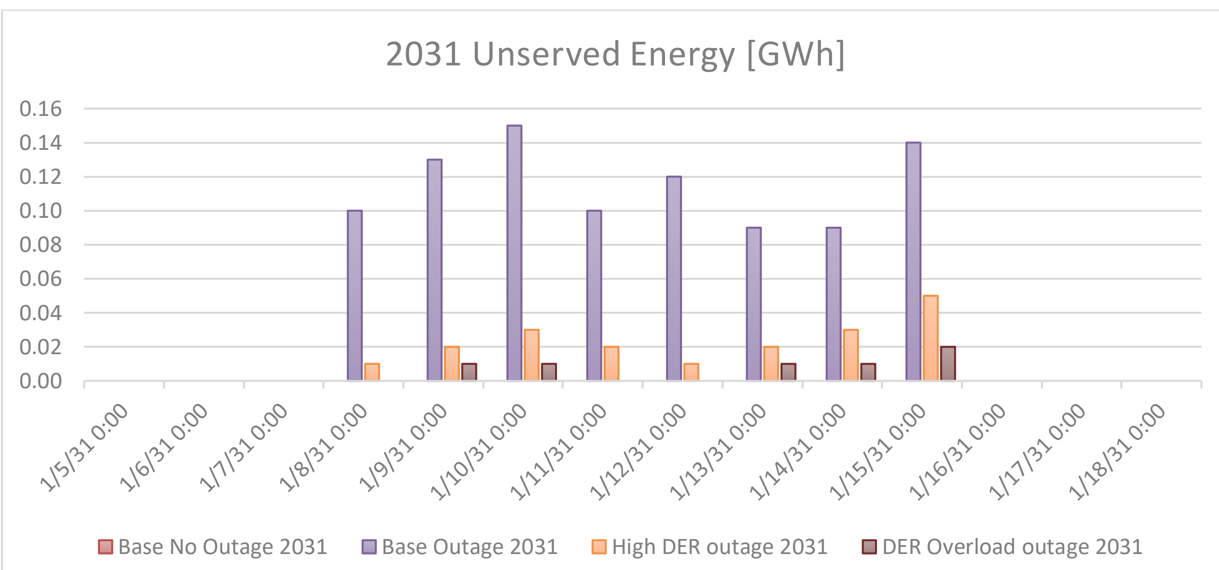


Figure E.7- 2031 Unserved Energy [GWh] WITH outage by day and scenario

8.5.2.2 Total costs [$]

The total cost is defined as the sum of all fixed and variable costs for all generators (incl. batteries) and physical contracts in the region. The fixed charges include fixed O&M costs [$/kW] for installed capacity. The variable charges include VO&M costs [$/kWh] for generation and fuel costs [$/kWh] (fuel offtake times the fuel price). Other generator costs include start and shutdown costs, emissions costs and abatement costs if they exists.

The total cost analysis reveals that the average daily cost is as follows:

- Base case with NO outage - $483,297
- Base case WITH outage - $555,836, representing a 15% increase from normal operations
- High DER penetration VPP WITH outage - $510,740, representing only a 5.7% increase from normal operations
- DER Overload VPP WITH outage - $414,932, representing a 14% decrease from normal operations even with an outage

	Base No Outage 2031	Base Outage 2031	High DER outage 2031	DER Overload outage 2031
1/5/31 0:00	$ 494,000.00	$ 493,030.00	$ 428,070.00	$ 353,730.00
1/6/31 0:00	$ 492,050.00	$ 492,970.00	$ 436,790.00	$ 363,300.00
1/7/31 0:00	$ 464,990.00	$ 471,690.00	$ 442,570.00	$ 364,720.00
1/8/31 0:00	$ 480,320.00	$ 608,600.00	$ 538,520.00	$ 411,280.00
1/9/31 0:00	$ 494,730.00	$ 618,140.00	$ 580,830.00	$ 465,810.00
1/10/31 0:00	$ 498,670.00	$ 615,960.00	$ 595,430.00	$ 480,500.00
1/11/31 0:00	$ 487,750.00	$ 618,270.00	$ 586,560.00	$ 473,960.00
1/12/31 0:00	$ 488,330.00	$ 616,700.00	$ 587,140.00	$ 475,530.00
1/13/31 0:00	$ 479,320.00	$ 614,940.00	$ 568,290.00	$ 454,940.00
1/14/31 0:00	$ 462,040.00	$ 594,570.00	$ 545,500.00	$ 451,150.00
1/15/31 0:00	$ 497,800.00	$ 610,230.00	$ 578,500.00	$ 489,430.00
1/16/31 0:00	$ 494,360.00	$ 498,130.00	$ 452,870.00	$ 383,610.00
1/17/31 0:00	$ 476,380.00	$ 473,230.00	$ 428,830.00	$ 331,460.00
1/18/31 0:00	$ 455,420.00	$ 455,250.00	$ 380,460.00	$ 309,630.00

Table E.7- 2031 Total cost [$] WITH outage by day and scenario

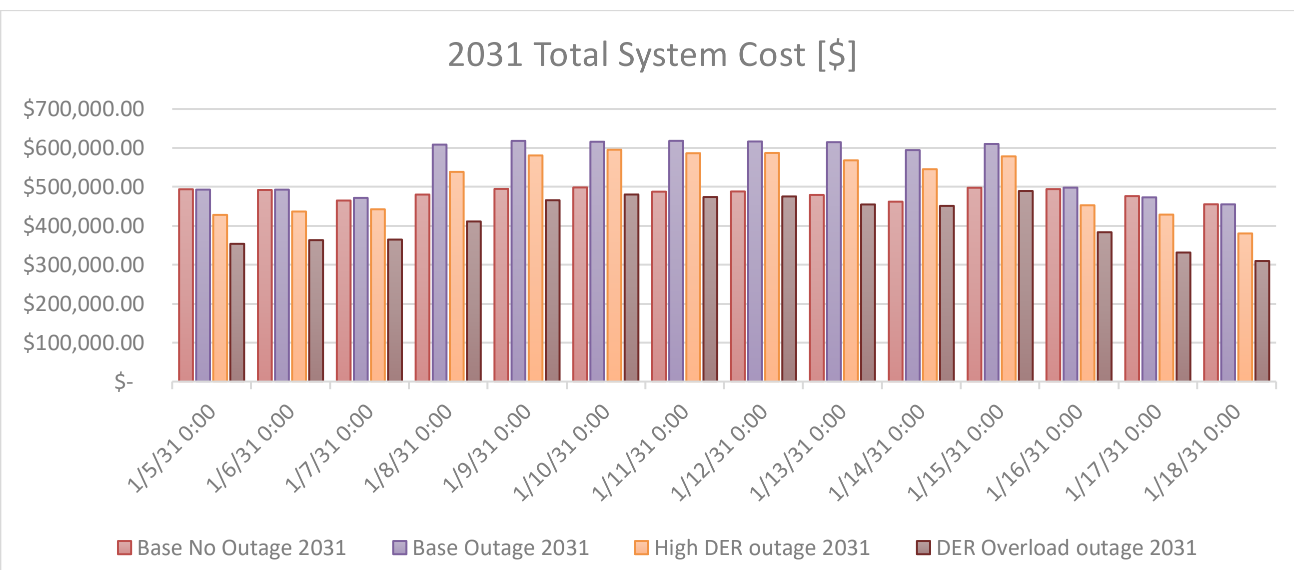


Figure E.8- 2031 Total cost [$] WITH outage by day and scenario

8.5.2.3 Fuel costs [$]

Fuel costs are just one aspect that makes up the total cost. The fuel cost analysis reveals that the average daily fuel cost is as follows:

- Base case with NO outage - $459,113
- Base case WITH outage - $534,227, representing a 16.3% increase from normal operations
- High DER penetration VPP WITH outage - $489,682, representing only a 6.7% increase from normal operations
- DER Overload VPP WITH outage - $394,932, representing a 14% decrease from normal operations even with an outage

	Base No Outage 2031	Base Outage 2031	High DER outage 2031	DER Overload outage 2031
1/5/31 0:00	$ 469,920.00	$ 468,970.00	$ 404,550.00	$ 330,910.00
1/6/31 0:00	$ 467,780.00	$ 468,740.00	$ 413,270.00	$ 340,320.00
1/7/31 0:00	$ 440,980.00	$ 447,710.00	$ 418,760.00	$ 341,380.00
1/8/31 0:00	$ 456,040.00	$ 587,950.00	$ 518,960.00	$ 393,210.00
1/9/31 0:00	$ 470,380.00	$ 598,360.00	$ 561,640.00	$ 448,090.00
1/10/31 0:00	$ 474,310.00	$ 596,220.00	$ 576,030.00	$ 462,640.00
1/11/31 0:00	$ 463,430.00	$ 598,490.00	$ 567,300.00	$ 456,140.00
1/12/31 0:00	$ 464,040.00	$ 596,950.00	$ 567,860.00	$ 457,740.00
1/13/31 0:00	$ 455,370.00	$ 595,230.00	$ 549,290.00	$ 437,360.00
1/14/31 0:00	$ 437,970.00	$ 575,160.00	$ 526,820.00	$ 433,620.00
1/15/31 0:00	$ 473,510.00	$ 590,580.00	$ 559,370.00	$ 471,460.00
1/16/31 0:00	$ 470,140.00	$ 474,000.00	$ 429,090.00	$ 360,430.00
1/17/31 0:00	$ 452,260.00	$ 449,370.00	$ 405,310.00	$ 308,740.00
1/18/31 0:00	$ 431,450.00	$ 431,450.00	$ 357,300.00	$ 287,020.00

Table E.8- 2031 Fuel cost [$] WITH outage by day and scenario

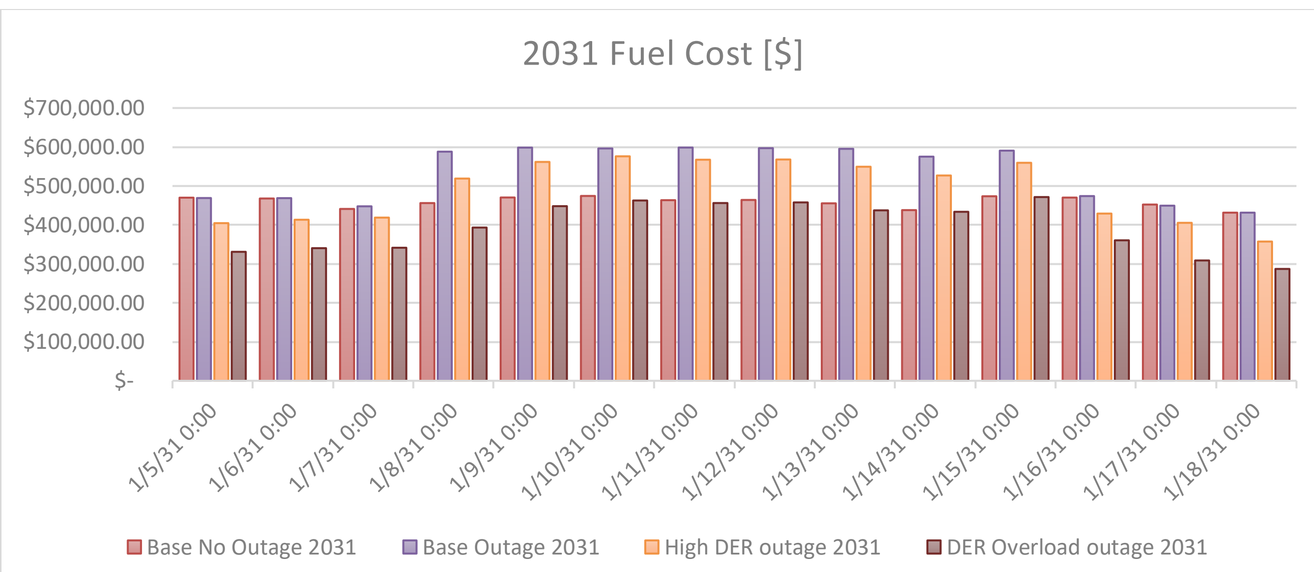


Figure E.9- 2031 Fuel cost [$] WITH outage by day and scenario

8.5.2.4 Fossil fuel operating hours [hrs.]

This analysis shows how the VPP can reduce the amount of fossil fuel generating hours even during an outage. The average daily operating hours for the fossil fuel gensets are as follows:

- Base case with NO outage – 18.74
- Base case WITH outage – 19.13, representing a 0.39 hour increase from normal operations
- High DER penetration VPP WITH outage -18.13, representing only a 0.61 hour decrease from normal operations
- DER Overload VPP WITH outage – 16.31, representing a 2.43 hour decrease from normal operations even with an outage

This analysis shows that even though the VPP is able to decrease the fossil fuel operating hours during an outage due to the dispatchable DERs, the type of fossil fuels operating during the outage are the more expensive and less efficient ones, which explains why the fossil fuel cost analysis varies slightly.

	Base No Outage 2031	Base Outage 2031	High DER outage 2031	DER Overload outage 2031
1/5/31 0:00	18.79	18.71	17.43	16.50
1/6/31 0:00	18.64	18.79	18.21	17.14
1/7/31 0:00	18.71	18.86	17.93	16.86
1/8/31 0:00	18.64	19.43	17.93	15.14
1/9/31 0:00	19.14	19.64	18.79	16.07
1/10/31 0:00	19.21	19.64	18.93	16.29
1/11/31 0:00	19.00	19.71	18.71	16.50
1/12/31 0:00	18.93	19.50	18.71	16.36
1/13/31 0:00	18.29	19.57	18.21	15.71
1/14/31 0:00	18.36	19.14	17.71	15.50
1/15/31 0:00	18.79	19.36	18.21	16.14
1/16/31 0:00	18.86	18.79	18.29	17.57
1/17/31 0:00	18.79	18.57	18.00	16.86
1/18/31 0:00	18.29	18.14	16.71	15.64

Table E.9- 2031 Fossil fuel operating hours [hrs.] WITH outage by day and scenario

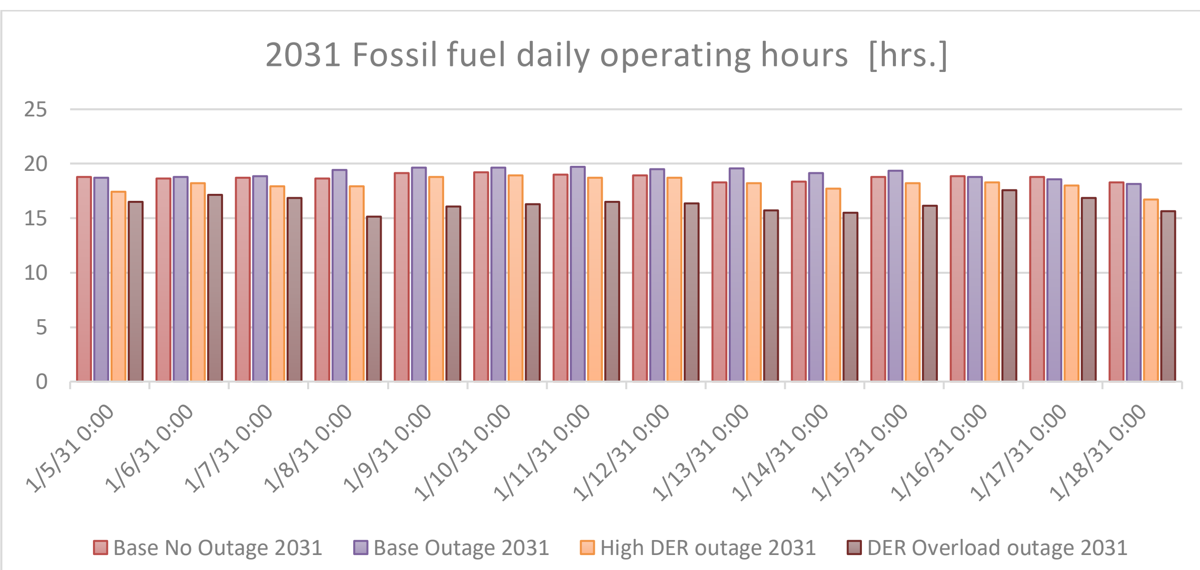


Figure E.10- 2031 Fossil fuel operating hours [hrs.] WITH outage by day and scenario

8.5.2.5 Fossil fuel generation [GWh]

When looking at the thermal generation from oil and LPG, it is clear that the outage results in a lower amount of fossil fuel generation in all cases, which is either able to be met be DERs in the case of the VPPs or results in unserved energy and ramping up of inefficient thermal generators. The average 2031 daily fossil generation in GWh is as follows:

- Base case with NO outage – 2.31
- Base case WITH outage – 2.24
- High DER penetration VPP WITH outage – 2.12
- DER Overload VPP WITH outage – 1.83

	Base No Outage 2031	Base Outage 2031	High DER outage 2031	DER Overload outage 2031
1/5/31 0:00	2.34	2.34	2.14	1.90
1/6/31 0:00	2.33	2.33	2.15	1.93
1/7/31 0:00	2.24	2.26	2.16	1.94
1/8/31 0:00	2.30	2.19	2.02	1.63
1/9/31 0:00	2.35	2.23	2.13	1.80
1/10/31 0:00	2.36	2.21	2.17	1.83
1/11/31 0:00	2.33	2.22	2.15	1.83
1/12/31 0:00	2.33	2.22	2.14	1.82
1/13/31 0:00	2.31	2.22	2.08	1.76
1/14/31 0:00	2.24	2.16	2.02	1.74
1/15/31 0:00	2.34	2.20	2.12	1.84
1/16/31 0:00	2.33	2.34	2.20	1.98
1/17/31 0:00	2.29	2.27	2.14	1.85
1/18/31 0:00	2.23	2.23	2.00	1.79

Table E.10- 2031 Fossil fuel generation [GWh] WITH outage by day and scenario

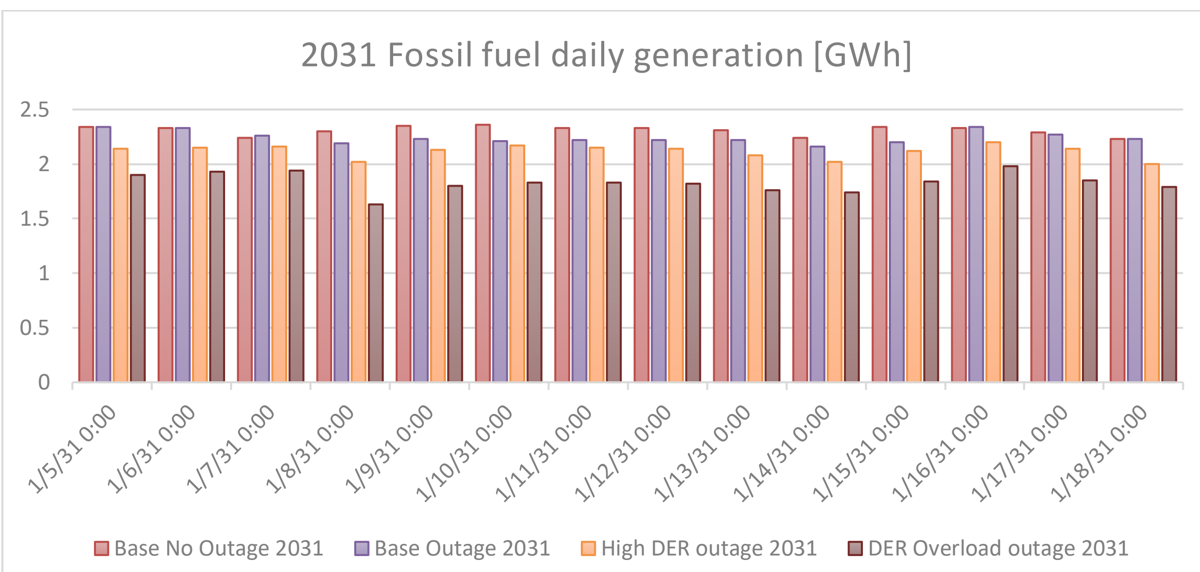


Figure E.11- 2031 Fossil fuel generation [GWh] WITH outage by day and scenario

8.5.2.6 RE generation [GWh]

This analysis shows that the VPP and its ability to dispatch DERs allows some of the lost thermal generation to be met by distributed solar and battery generation, rather than by inefficient, expensive gensets that were offline or as directly as unserved energy compared to the Base case. The high DER penetration VPP is able to generate 0.26 GWh. The DER Overload VPP is able to generate 1.87 GWh

	Base No Outage 2031	Base Outage 2031	High DER outage 2031	DER Overload outage 2031
1/5/31 0:00	0.00	0.00	0.31	1.91
1/6/31 0:00	0.00	0.00	0.29	1.90
1/7/31 0:00	0.00	0.00	0.19	1.83
1/8/31 0:00	0.00	0.00	0.33	1.83
1/9/31 0:00	0.00	0.00	0.34	1.87
1/10/31 0:00	0.00	0.00	0.28	1.91
1/11/31 0:00	0.00	0.00	0.21	1.87
1/12/31 0:00	0.00	0.00	0.28	1.83
1/13/31 0:00	0.00	0.00	0.26	1.84
1/14/31 0:00	0.00	0.00	0.27	1.87
1/15/31 0:00	0.00	0.00	0.27	1.90
1/16/31 0:00	0.00	0.00	0.19	1.95
1/17/31 0:00	0.00	0.00	0.19	1.87
1/18/31 0:00	0.00	0.00	0.26	1.77

Table E.11- 2031 RE generation [GWh] WITH outage by day and scenario

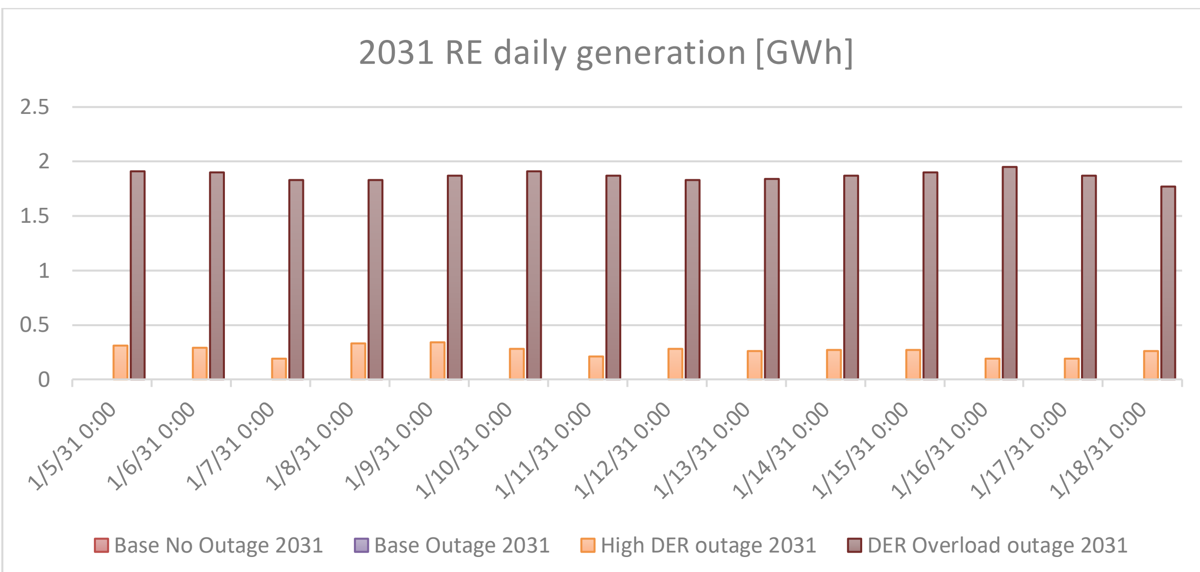


Figure E.12- 2031 RE generation [GWh] WITH outage by day and scenario

8.5.2.7 Hourly generation [GWh]

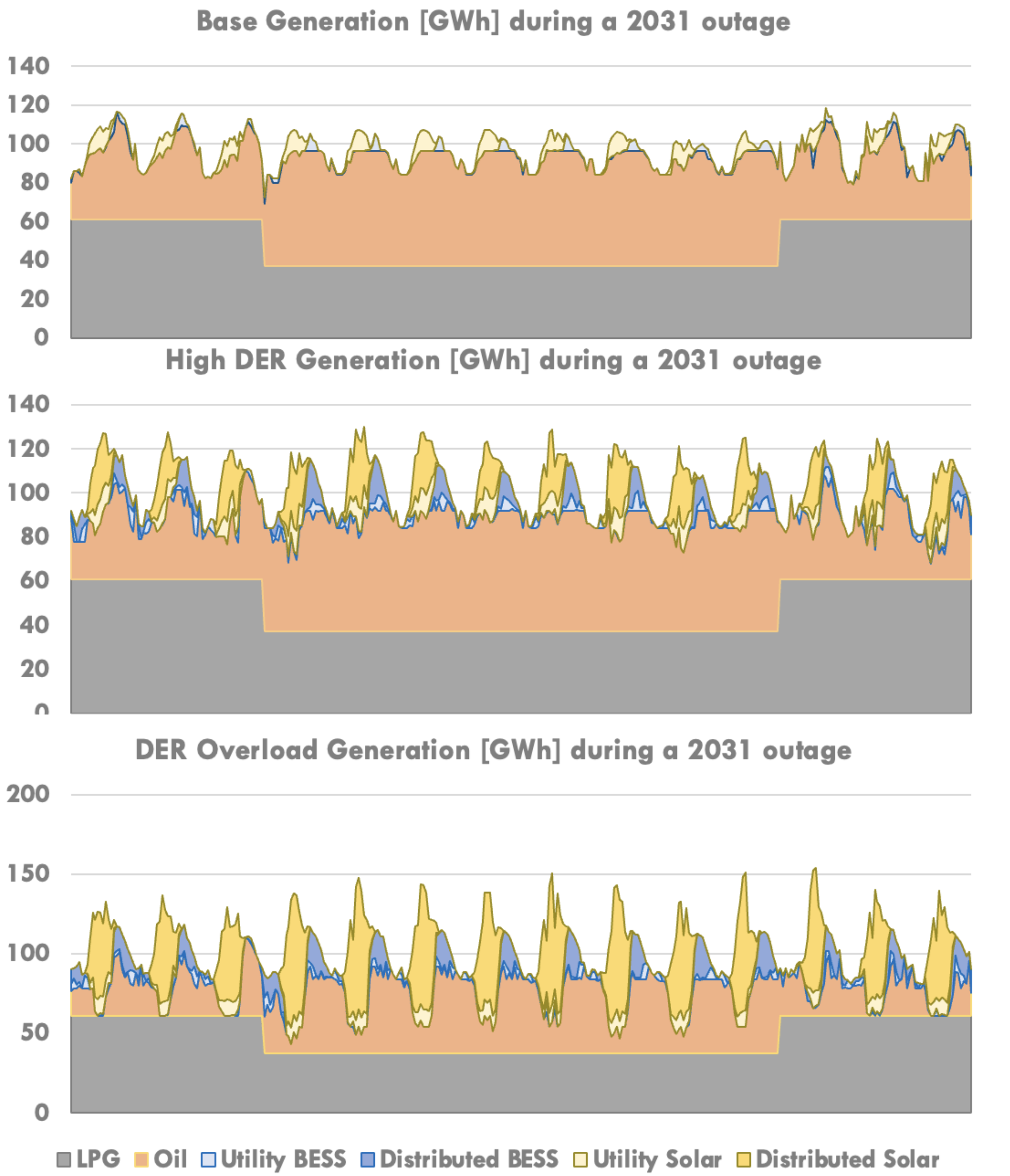
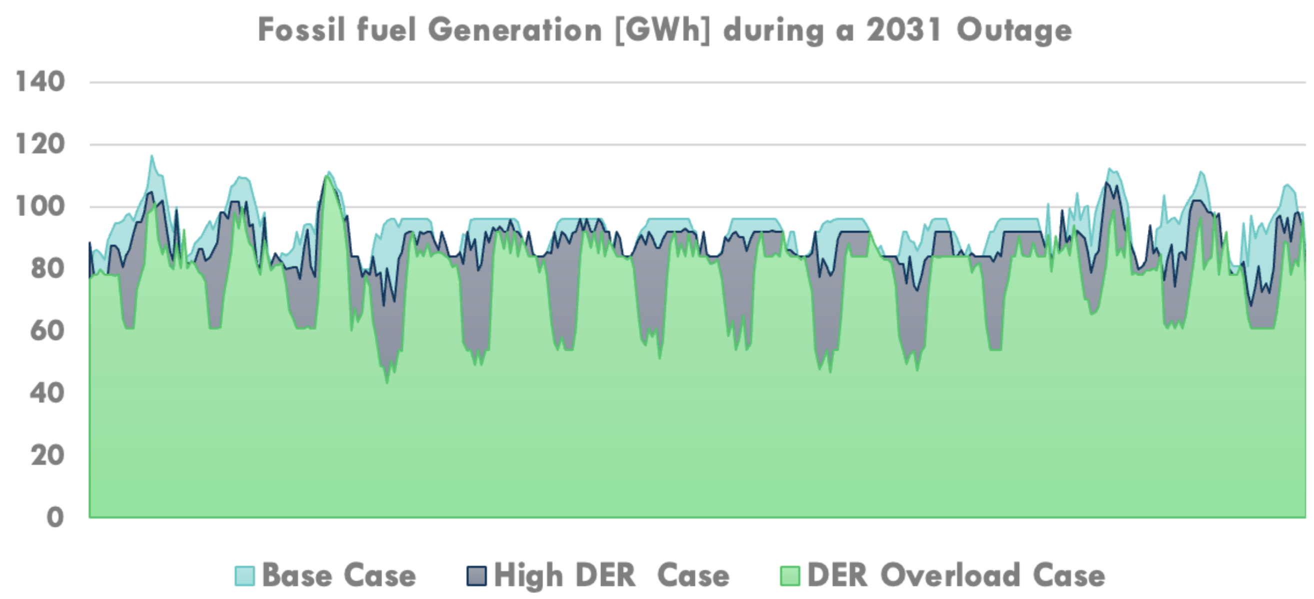


Figure E.13- 2031 Generation [GWh] by resource for the base scenario (top), high DER penetration VPP (middle) and DER overload VPP (bottom) WITH outage during a 14 day period.



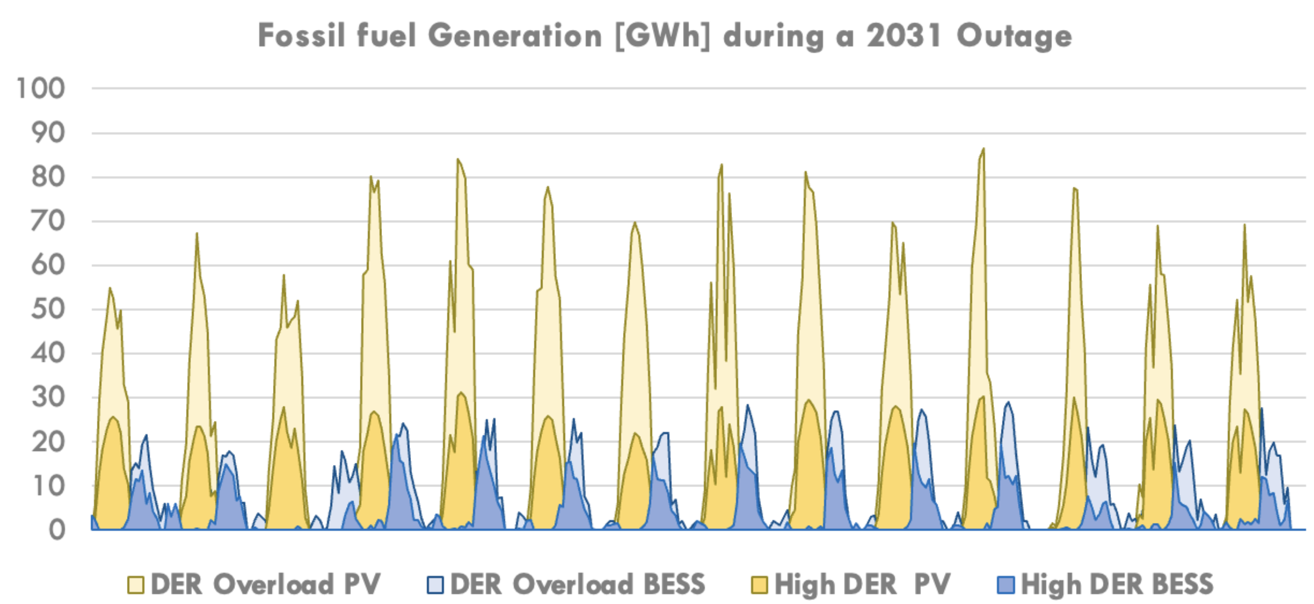


Figure E.14- 2031 Fossil Generation [GWh] for the base scenario, high DER penetration VPP and DER overload VPP (top) and RE Generation [GWh] for the high DER penetration VPP and DER overload VPP (bottom) WITH outage during a 14 day period. Fossil fuel generation [GWh] during the