Integrating Renewable Energy into the Transmission and Distribution System of the U.S. Virgin Islands

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Technical Report
NREL/TP-7A20-51294
September 2011

Contract No. DE-AC36-08GO28308

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Executive Summary

Like many island communities, the U.S. Virgin Islands (USVI) is almost 100% dependent on fossil fuels for electricity and transportation. This total reliance on oil leaves the territory vulnerable to global oil price fluctuations that can have devastating economic effects on individuals and businesses. USVI electricity costs are over four times the U.S. average, making energy price spikes extremely difficult for ratepayers to absorb. And like other island communities around the world, the U.S. Virgin Islands are among the first to feel the impact of the environmental threats associated with fossil fuel-based energy sources—rising sea levels, intense hurricanes, and widespread loss of coral reefs due to ocean acidification.

Such risks and hardships incurred by islands offer mounting evidence that the status quo is unsustainable. In the USVI and other island communities, this has created a sense of urgency around the need to dramatically transform the way energy is sourced, generated, and used. In response, islands around the globe have adopted some of the most aggressive clean energy goals. The USVI's goal is to reduce fossil fuel use 60% from business as usual by 2025.

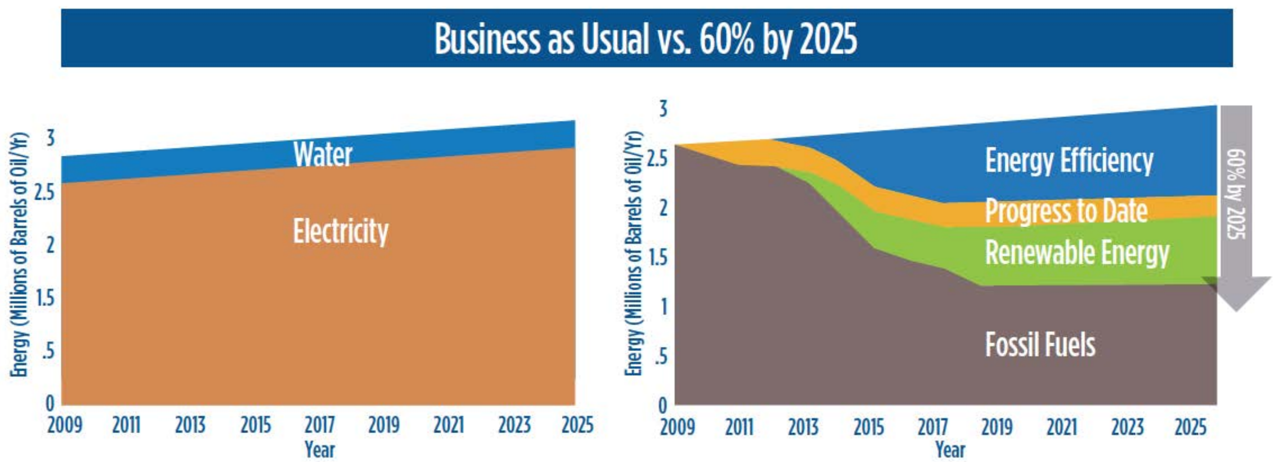

Figure ES-1-1. Comparison of two possible courses for the USVI: the status quo vs. a 60% reduction in fossil fuel use by 2025.

Source: NREL

As islands reduce their fossil fuel usage, they have an opportunity to lead the rest of the world in transforming our shared energy future. This report describes one area in which islands may lead: *integrating a high percentage of renewable energy resources into an isolated grid.* In addition, it explores the challenges, feasibility, and potential benefits of interconnecting the USVI grids with the much larger Puerto Rican grid.

The overall objective of the interconnection study is to explore the most economical mix of fossil fuel-based and renewable power generation technologies that can be deployed to enable the USVI to reach its goal. This report focuses on the economic and technical feasibility of integrating renewable energy technologies into the USVI transmission and distribution systems. The report includes three main areas of analysis:

- The first area of analysis (Sections 3 and 4 of the report) examines the economics of deploying utility-scale renewable energy technologies, such as photovoltaics (PV) and wind turbines, on the islands of St. Thomas and St. Croix.
- The second (Sections 5, 6, and 7) focuses on the potential sites for installing roof- and ground-mount PV systems and wind turbines and investigates the impact renewable generation will have on the electrical subtransmission and distribution infrastructure.
- The third (Section 8) summarizes the results of a study to determine the feasibility of a 100–200 megawatt (MW) power interconnection of the Puerto Rico, USVI, and British Virgin Islands (BVI) utility grids via a submarine cable system.

Economic Analysis

The National Renewable Energy Laboratory (NREL), in partnership with HOMER Energy LLC, developed two models using the Hybrid Optimization Model for Renewable Energy (HOMER) software tool to analyze the electrical generation on St. Thomas/St. John and St. Croix. The models were used to determine the optimal hybrid mix of conventional generation and renewables and the most cost-effective way to meet the island demand loads. The models used solar and wind resource data specific to the region along with 2009–2010 generation and fuel use data provided by the Virgin Islands Water and Power Authority (WAPA) for St. Thomas and St. Croix. The models examined the economic impact of putting 5.5 MW of PV and 15 MW of wind on each island. The model for St. Croix also included a 16.5 MW waste-to-energy (WTE) plant planned for 2012.

The results of the analysis demonstrate the following:

- Wind is cost effective at fuel prices as low as 58.66/barrel.
- 15 MW of wind can reduce fuel usage by 9% on St. Thomas and 14% on St. Croix.
- PV becomes cost effective when installed costs drop below $5.50/watt (W) on St. Thomas and below $5.00/W on St. Croix, or when fuel prices exceed $99/barrel.
- Under the proposed power purchase agreement (PPA), modeling indicates the 16.5 MW WTE plant is cost effective. WTE is also cost effective when combined with PV and wind.

The high-level economic results suggest that the recently released solar request for proposals (RFPs) will garner acceptable responses. More detailed financial models are currently under way to understand the variables that affect PV costs in the USVI. Overall, wind turbines appear to be the most economically feasible alternative energy technology, even with very conservative assumptions. Further detailed studies should be done to obtain quality wind resource data at identified sites.

Site Selection and Impacts on the Electrical Power System

In preparation for WAPA to release an RFP for PV, NREL worked with WAPA personnel to identify rooftops and/or cleared areas that were suitable for PV deployment. A number of criteria were included in this analysis, including potential site shading, geography, proximity to the feeders, and site ownership.

An analysis was conducted to determine the capacity of the distribution feeders to accept PV. When considering variable generation sources such as PV, both the maximum and the minimum loads on the distribution feeder must be considered. The maximum loads are used in determining feeder penetration and calculations for voltage regulation limits. Conditions may exist where PV generation is high and the local feeder loads are low (i.e., on weekends), resulting in high voltage conditions. Of course, daytime minimum loads must be considered as opposed to overall minimums, since PV generation only occurs during daylight hours.

On a distribution feeder, penetration level is defined as the ratio of PV system power rating to the feeder's peak load. In accordance with IEEE 1547.2, the 10% penetration limit was applied to the peak loads on the feeders for total aggregate system size that can be installed without concern of negatively impacting feeder voltage regulation. With this constraint applied, the analysis determined that a maximum of 7.6 MW of PV generation can be readily added on St. Thomas, and 4.9 MW can be added on St. Croix. Additional PV may be installed after interconnection engineering studies verify that system operation is not compromised.

PREPA-WAPA Interconnection Study

Under the oversight of NREL, WAPA, and the Puerto Rico Electric Power Authority (PREPA), Siemens PTI performed a feasibility study focused on the proposed interconnection of the PREPA, WAPA, and British Virgin Islands Electricity Corporation power grids. The system study was designed to examine means of decreasing the cost of energy for the USVI, increasing WAPA system reliability, reducing WAPA spinning reserve requirements, and increasing the potential for high-penetration renewable energy in the USVI.

The feasibility study reviewed existing transmission and generation development plans and select study scenarios, performed WAPA system steady state and stability assessments, and conducted short circuit analysis. The resulting power system report was completed in April and determined that the proposed submarine cable interconnecting the Puerto Rico, USVI, and BVI power grids is feasible with a few recommended upgrades to all three systems.

One of the major purposes of this interconnection study was to demonstrate the benefits of the interconnections for WAPA. The final report on the interconnection study will address such benefits as reduced generation costs, increased system reliability, and potential for higher levels of variable renewable generation in the USVI. The report on the impact of interconnection will be released in September 2011.

List of Acronyms

AGC	automatic generating control
ARRA	American Recovery and Reinvestment Act
Btu	British thermal unit
BVI	British Virgin Islands
CAES	compressed air energy storage
CICC	cable-in-conduit conductor
CSP	concentrating solar power
CTG	combustion turbine generator
DER	distributed energy resource
DFIG	double-fed induction generator
DG	distributed generation
DOE	U.S. Department of Energy
DPR	Dynamic Power Resource
DS	distributed storage
DSM	demand side management
D-SMES	distributed superconducting magnetic energy storage
EC	electrochemical capacitors
EDIN	Energy Development in Island Nations
EIA	Energy Information Administration
EO	Energy Office
EPR	ethylene propylene rubber
EPS	electrical power system
ETM	Engineering Test Model
FACTS	flexible AC transmission
GTO	gate turn-off thyristor
GVEA	Golden Valley Electric Association
GVI	government of the U.S. Virgin Islands
GW	gigawatt
H_2-Br_2	hydrogen-bromine
HOMER	Hybrid Optimization Model for Electric Renewables
HRSG	heat recovery steam generator
HVAC	high-voltage alternating current
HVDC	high-voltage direct current
HVRT	high-voltage ride through
IEEE	Institute of Electrical and Electronics Engineers
IGBT	insulated gate bipolar transistor
IGCT	integrated gate commutated thyristor
IREC	Interstate Renewable Energy Council
IPP	independent power producers
IRC	integral return conductor
IREC	Interstate Renewable Energy Council
kW	kilowatt
kWh	kilowatt-hour
LCC	line-commutated converter

LCOE	levelized cost of energy
LEAC	Levelized Energy Adjustment Clause
Li-ion	lithium-ion
LL	long life
LV	low voltage
LVRT	low-voltage ride through
MED	multi-effect desalinization
MMBtu	million Btu
MV	medium voltage
MW	megawatt
MWh	megawatt-hour
NCAA	Na+/Cu2+ associated anion
NERC	North American Electric Reliability Corporation
Ni Cd	nickel-cadmium
Ni MH	nickel-metal hydride
NLTO	lithium titanate
NREL	National Renewable Energy Laboratory
OR	operating reserve
PB/c	lead/carbon
PCC	point of common coupling
PFC	power factor correction
PHS	pumped hydro storage
PMSG	permanent magnet synchronous generator
PREPA	Puerto Rico Electric Power Authority
PPA	power purchase agreement
PSC	Public Service Commission
PV	photovoltaic
PWM	pulse-width modulation
RFP	request for proposals
RO	reverse osmosis
SC	short circuit
SCFF	self-contained fluid-filled cables
SMES	superconducting magnetic energy storage
SOC	state of charge
STATCOM	static synchronous compensator
STG	steam turbine generator
STT	St. Thomas
STX	St. Croix
SVC	static VAR compensator
TES	thermal energy storage
TLCC	total life-cycle cost
USVI	U.S. Virgin Islands
UVI	University of the Virgin Islands
VIEO	Virgin Islands Energy Office
VRB	vanadium redox battery
VSC	voltage source converter

WAPA	[Virgin Islands] Water and Power Authority
W	watt
WPP	wind power plant
WTE	waste-to-energy
WTG	wind turbine generator
XLDC	cross-linked DC polymer
XLPE	cross-linked polyethylene
ZVRT	zero-voltage ride through

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1 Introduction

The National Renewable Energy Laboratory (NREL) partnered with the Virgin Islands Water and Power Authority (WAPA) and the Virgin Islands Energy Office (VIEO) to examine the technical and economical feasibility of adding renewable energy to the islands of St. Thomas, St. John, and St. Croix. Like many island communities, the U.S. Virgin Islands (USVI) territory is almost wholly dependent on fossil fuels for electricity and transportation. The USVI's goal is to reduce its dependency on fossil fuel by 60% by 2025. NREL is supporting the territory's efforts to reduce fossil-fuel use in its power generation and transportation sectors.

In 2008, Iceland, New Zealand, and the United States entered into a partnership to address the unique energy challenges islands face by advancing the adoption of energy efficiency and renewable energy technologies in island nations and territories. Under the Energy Development in Island Nations (EDIN) initiative, each nation selected a pilot project aimed at identifying and overcoming barriers to clean energy deployment. The U.S. Department of Energy (DOE) selected the USVI as the U.S. pilot project for the EDIN initiative. The EDIN-USVI project is a collaborative effort comprising many public and private groups, including DOE, the Department of Interior (DOI), WAPA, VIEO, the University of the Virgin Islands (UVI), and local community activists, environmentalists, and businesses.

In June 2010, NREL announced the formation of five working groups focused on the following areas: (1) Energy Efficiency, (2) Renewable Energy, (3) Transportation, (4) Education and Outreach, and (5) Policy and Analysis. The Renewable Energy group is investigating various technologies to determine the best mix of renewable energy on the islands. This report focuses on the electrical generation and the cost-effective deployment of renewable energy on the islands.

Integrating renewable energy into an island grid results in a renewable/diesel hybrid system architecture. These systems have special planning and control requirements. Many technical decisions factor into such systems, and this report examines some of the important considerations in their design. Figure 1-1 shows the general high-level approach to introducing renewable energy systems into islanded electrical power systems (EPS) and provides an outline of this report.

First, a baseline model of the existing generation and distribution system is developed, including annual loads, inventory of power station generation units, distribution system characteristics, loads by feeder, and fuel consumption and costs.

After the baseline EPS is understood, wind and photovoltaic (PV) renewable energy systems are evaluated from an economic perspective. Renewable energy generally requires a large capital expenditure compared with the standard diesel generators but decreases spending on fuel and maintenance. The cost-benefit analysis of the interplay of wind and PV with the existing generators is presented.

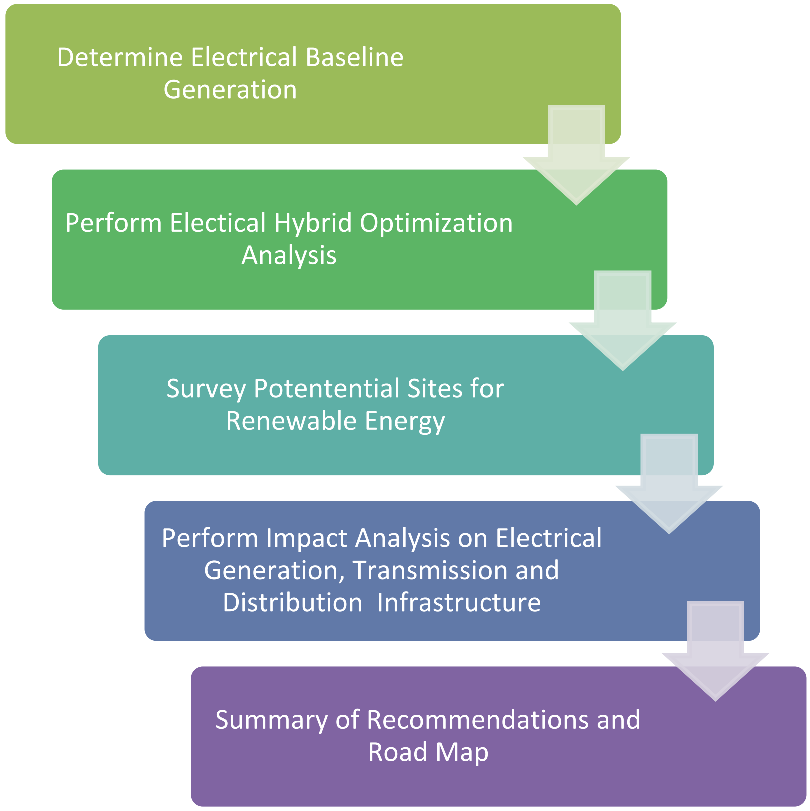


Figure 1-1. Approach to analysis of integrating renewables
Source: NREL

Because intermittent generation from wind and PV systems is more challenging to incorporate into small island systems than conventional, dispatchable generation, the economic analysis is followed by a discussion of the practical issues involved in achieving a high penetration of renewable energy. These include better characterization of the USVI solar and wind resources, identification of sites for large systems, and impact on WAPA's distribution system and generation stations.

One proposed solution for addressing the USVI's energy challenges is an interconnection of the Puerto Rico Electric Power Authority (PREPA), WAPA, and British Virgin Islands Electricity Corporation power grids. Lastly, this report discusses the study that is under way to determine whether the proposed submarine cable will reduce the cost of energy for the USVI, increase WAPA's system reliability (reducing the operating reserve of the generators), and increase the potential for high penetration of renewables.

2 U.S. Virgin Islands Electrical Power System

This section of the report gives an overview of the USVI utility structure, the general loads on the islands, and the cost of fuel and electricity.

2.1 Water and Power Authority

WAPA provides the electrical service to the islands and operates and maintains potable water production and storage facilities. WAPA was created by the USVI government in 1964 to provide an adequate electric and water supply to the Virgin Islands. WAPA operates as a semiautonomous government agency governed by a nine-member board of public and private sector members. All board members are appointed by the governor, with the six private sector members also requiring confirmation by the legislature. The other three members of the board are appointed from among the heads of cabinet-level executive departments or agencies. The WAPA Governing Board is responsible for establishing policy for all facets of WAPA's operations, including budgeting, purchasing, and system development. The Public Service Commission (PSC), also established by the legislature, oversees and regulates the utility rates for services.

WAPA has electric power generation plants on St. Thomas and St. Croix. St. Thomas provides power to St. John and to two nearby islands—Hassel Island and Water Island—by way of submarine cables.

WAPA also owns and operates eight multi-effect desalinization (MED) units (four on St. Thomas and four on St. Croix) to produce potable water for the islands. These MED units are being replaced by reverse osmosis (RO) systems, which are expected to consume less energy. For the purpose of this analysis, the desalination process is not modeled.

2.2 Electrical Generation

The power plants on St. Thomas and St. Croix operate a combination of combustion turbine generators (CTGs) and steam turbine generators (STGs). A 2.5 megawatt (MW) diesel generator system is located on St. John and is used in emergency situations. The steam turbines are fueled with #6 fuel oil, and the combustion turbine generators use # 2 diesel oil. The two WAPA transmission and distribution systems are not interconnected and are separated by a distance of about 64 kilometers, with an ocean depth ranging from two to six kilometers between them. The installed electrical generation capacity on St. Thomas is approximately 191 MW, with peak load presently at 78 MW to 88 MW and average load of 65 MW. The installed capacity on St. Croix is 117 MW, with peak loads of 50 MW to 55 MW and average load around 40 MW.[1]

To improve plant efficiency, WAPA installed a waste heat recovery steam generator (HRSG) on St. Thomas in 1997 and on St. Croix in 2010. (Note that HRSGs also are referred to as waste heat boilers.) The HRSGs use the waste heat from two of the CTGs to produce steam for electric generation and water desalination. Presently, the desalination process requires steam that is extracted from the STG units or supplied in part by the steam from the waste heat boilers. There

[1]Beck, R.W. (2008). *Power Supply Evaluation, Virgin Islands Water and Power Authority Report*. St. Thomas, U.S. Virgin Islands: WAPA.

also are supplemental boilers that use #6 fuel oil to produce additional steam as necessary. Approximately 10% of the heat energy produced from the boilers is used for the desalination plants.[2]

The following data are from the report by R.W. Beck.[3]

Table 2-1. Power Generating Station for St. Thomas, St. John, and St. Croix

Summary of Existing Oil-Fueled Production Facilities

St. Thomas/St. John – Randolph E. Harley Generating Station

Generator Unit No.	Technology	Fuel Type	Rated Capacity (MW)	In Service Date
7 (St. John)	Reciprocating Engine Generator	No. 2 Oil	2.5	1985
11	Fired Boiler/STG [1]	No. 6 Oil	18.5	1968
12	Simple Cycle CTG	No. 2 Oil	12.5	1970
14	Simple Cycle CTG	No. 2 Oil	12.5	1972
13	Fired Boiler/STG [1]	No. 6Oil	36.9	1973
15	Combined Cycle CTG/HRSG [1]	No. 2 Oil	20.9 [2]	1981
18	Combined Cycle CTG/HRSG [1]	No. 2 Oil	23.5 [2]	1993
22	Simple Cycle CTG	No. 2 Oil	24	2001
23	Simple Cycle CTG	No. 2 Oil	39.5	2004
Total			**190.8**	

St. Croix – Estate Richmond Generating Station

Generator Unit No.	Technology	Fuel Type	Rated Capacity (MW)	In Service Date
10	Fired Boiler/STG [3]	No. 6 Oil	10	1967
11	Fired Boiler/STG [3]	No. 6 Oil	19.1	1970
16	Combined Cycle CTG/HRSG [3]	No. 2 Oil	20.9	1981
17	Combined Cycle CTG/HRSG [3]	No. 2 Oil	21.9	1988
19	Simple Cycle CTG	No. 2 Oil	22.5	1994
20	Simple Cycle CTG	No. 2 Oil	22.5	1994
Total			**116.9**	

[1] Fired boilers and HRSGs deliver steam to steam headers to supply STGs No. 11 and No. 12 and four MED water production units.
[2] Capacity shows CTG output only.
[3] Fired boilers and HRSGs deliver steam to steam headers to supply STGs No. 10 and No. 11 and four MED water production units.

Table 2-2. Water Production Facilities for St. Thomas, St. Croix, and St. John

Facility Unit No.	Location	Status	Commercial In Service Date	Planned Retirement Date	Design Capability (Million gallons/day)	Capa bility [2] MGD	Low Pressure Steam Requirements (lb/hr)	High Pressure Steam Requirements [4] (lb/hr)
Unit No. 1	Krum Bay	In Service	May 1981	Apr 2011	1.25	1.25	45,000	1,000
Unit No. 2	Krum Bay	In Service	Aug 1981	Jul 2011	1.25	1.25	45,000	1,000
Unit No. 6	Krum Bay	In Service	Dec 1983	Nov 2013	0.55	0.36	22,500	840
Unit No. 8	Krum Bay	In Service	Feb 1992	Jan 2022	1.4	1.4	50,000	1,050
5	**Total**				**4.45**	**4.26**	**162,500**	**3,890**

[2]Ibid.
[3]Ibid.

ISLAND OF ST. CROIX									
St. Croix									
6	Unit No. 3	Richmond	In Service	Dec 1981	Nov 2011	1.25	1.25	45,000	1,000
7	Unit No. 4	Richmond	In Service	Jul 1983	Jun 2013	0.55	0.55	22,500	840
8	Unit No. 5	Richmond	In Service	Sep 1983	Aug 2013	0.55	0.55	22,500	840
9	Unit No. 9	Richmond	In Service	Jun 1993	May 2023	1.30	1.30	45,000	1,000
10	Total					3.65	3.65	135,000	3,680
ISLAND OF ST. JOHN									
St. John									
11	Unit No. 7	Cruz Bay	In Service	Jul 1990	Jun 2020	0.15	0.15	0	0
12	**Total System**					**8.25**	**8.06**	**297,500**	**7570**

[1] Based on information provided by Authority
[2] As of June, 2007
[3] 26 psig.
[4] 150 psig.

2.3 Electrical Transmission and Distribution Systems

Transmission and distribution systems are distinguished by the voltage level at which the electric power is transmitted. The mainland grid power is transmitted at very high voltages (130–765 kV). Islands are smaller and generally transmit electricity at subtransmission levels (25–115 kV). The power on St. Thomas and St. Croix is transmitted at subtransmission voltage levels— 34.5 kV and 24.9 kV, respectively. St. Croix is in the process of upgrading its transmission system to 69 kV. The subtransmission power is delivered to the distribution substations around the islands. These substations contain transformers that reduce the voltage levels further to the distribution voltage level of 13.8 kV. The distribution system delivers power in one direction from the substation to the customer loads.

Bulk power producers are generally large (greater than 10 MW) and connected at the sub-transmission voltage level. Distributed energy resources (DER) are sources of electric power that are interconnected near the load to the electric power distribution system. These include distributed generation (DG) and distributed storage (DS). DG can include fossil fuel and renewable sources. Fossil fuel-based generation includes microturbines, small backup diesel generators, and fuel cells. Renewable generation includes PV systems, wind turbines, and biomass generators. There are several types of DS that leverage battery technologies, flywheels, and compressed air. A detailed overview of different types of wind turbines and DS technologies is included in the Appendices of this report. Various types of DG components can be combined with storage devices, inverters, and controls to meet the load demands on the islands.

This report focuses on some of the important considerations in the design of adding DER to the electrical distribution systems. The Siemens study (summarized in Section 5 of this report) models and analyzes the impact of adding bulk power from Puerto Rico to the USVI via an undersea cable. Because the island grids are small, the impact of adding generation either at the subtransmission or distribution level can have an impact on the central generating plants and the quality of power delivered to customers.

2.4 Electrical Load

The approximate average daily and annual system peak loads on the respective islands, together with the average and minimum loads on each island, are shown in Table 2-3.

Table 2-3. St. Thomas and St. Croix Load Information

Island	Average Daily Peak	Annual System Peak	Average Loads	Minimum Loads
St. Thomas	78 MW	88 MW	65 MW	50 MW
St. Croix	50 MW	55 MW	40 MW	35 MW

Source: WAPA

Electrical loads on both St. Thomas and St. Croix include residential, commercial (hotels, hospitals, and retail areas), and light industrial (airports, plantations, etc.). Residential loads comprise the largest total loads on each of the islands. Table 2-4 shows the load type, number of customers, and energy used in 2007.

Table 2-4. WAPA's Electricity Consumers[4]

Type	Number	Total Electric Energy in 2007 (Million kWh)
Residential	43,972	212
Commercial	8,402	102
Large Power	982	208
Primary Power	49	93
Street Lighting	600	16
Gov't Lighting	N/A	76
Total	**54,005**	**624**

[4]Source: Calculations based on information contained in the $85,335,000 Virgin Islands Water and Power Authority, Series 2010 A, B, C Electric System Revenue Bonds, March 2010 Official Statement.

From this broad base of customers, the largest single customers are commercial and industrial, as one might expect. Table 2-5 includes WAPA's nine largest commercial and industrial customers and the respective annual electrical energy consumption for each.

Table 2-5. Large Commercial and Industrial (C&I) Users' Electricity Consumption[5]

Top 9 Users Large C & I	Electricity (MWh)
Marriott Hotel	11,198
Westin St. John	10,869
R C Hotels	8,796
Caneel Bay Plantation	5,946
The Ritz Carlton Club	5,569
Plessen Enterprises	3,923
Plaza Extra (Sion Farm)	3,788
Plaza Extra (St. Thomas)	3,199
K-Mart #3829	2,488
Large C & I Totals	**55,775**

2.5 Fuel Costs

The HOVENSA refinery on St. Croix is a major industrial presence that produces its own electricity and water. WAPA has an agreement to buy low-cost fuel oil from HOVENSA for a 20-year period (2002–2022). The price WAPA pays is below market cost and is based on the average cost of crude oil delivered to the refinery. WAPA's recent per-barrel fuel costs are shown in Figure 2-1.

[5]Calculations based on information contained in the *$85,335,000 Virgin Islands Water and Power Authority, Series 2010 A, B, C Electric System Revenue Bonds, March 2010 Official Statement*.

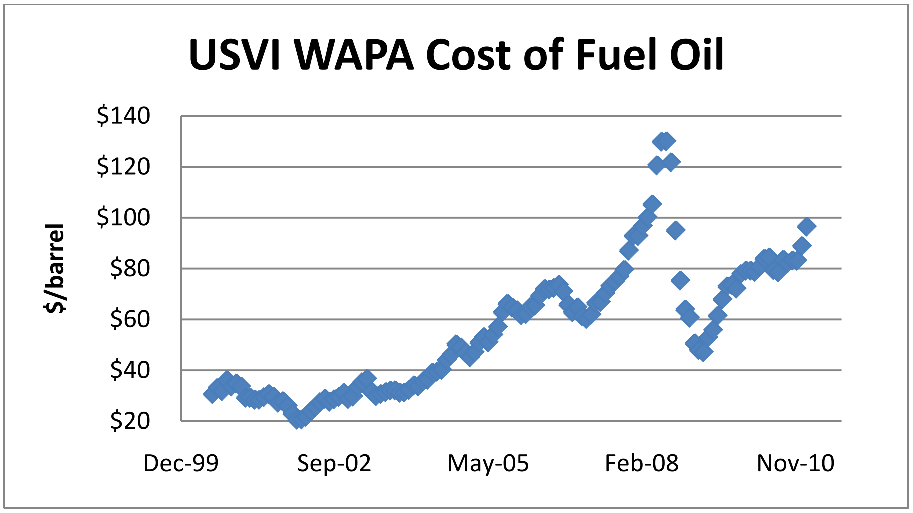


Figure 2-1. Historical WAPA diesel fuel costs

Source: NREL

2.5.1 Fuel Use and Cost for WAPA 2009–2010

Table 2-6 captures WAPA's fuel use for St. Thomas/St. John (STT) and St. Croix (STX). There are two scenarios for St. Croix fuel use: 1) before the new HRSG (unit #24) was installed and 2) after the new HRSG was installed. Detailed analysis of both scenarios is discussed further in this report. The fuel costs and savings are also included in Table 2-6.

Table 2-6. Fuel Use and Cost for WAPA (2009–2010)

USVI Annual Use 2009	Gallons	Barrels	Cost #2 ($101/Barrel)	Cost #6 ($85.50/Barrel)	Total Fuel Cost
STT #2 oil	46,545,426	1,108,224	$111,930,667		
STT #6 oil	3,215,300	76,555		$6,545,432	
Total fuel use STT	49,760,726	1,184,779			$118,476,100
Fuel use before new HRSG					
STX #2 oil	25,965,050	618,215	$62,439,764		
STX #6 oil	15,799,756	376,185		$32,163,789	
Total fuel use & cost	41,764,806	994,400			$94,603,553
Fuel use after new HRSG					
STX #2 oil	35,839,626	853,324	$86,185,768		
STX #6 oil	6	0		$0	
Total fuel use & cost	35,839,632	853,325			$86,185,768
Savings in STX only	5,925,174	141,076			$8,417,785
USVI total original	91,525,532	2,179,179	$174,370,432	$38,709,221	$213,079,653
USVI total after new HRSG	85,600,358	2,038,104	$198,116,435	$6,545,432	$204,661,868
Total Savings	5,925,174	141,076			$8,417,785

2.5.2 *Fuel Surcharge on Retail Electricity Sales*

The Levelized Energy Adjustment Clause (LEAC) is a fuel pass-through surcharge applied to customers' retail electricity bills. Figure 2-2 shows the retail LEAC rate plotted with fuel costs.

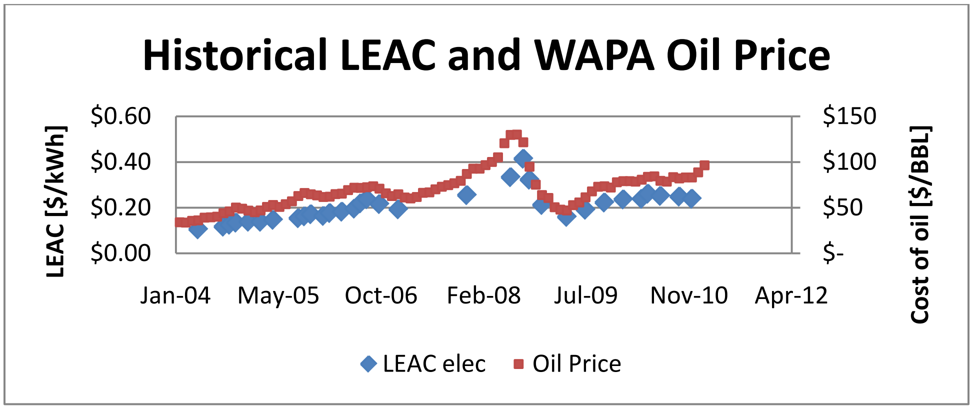


Figure 2-2. Historical retail electricity fuel surcharge and utility fuel costs

Source: NREL

3 Methodology to Economic Analysis of Integrating Renewables

Economics are key factors in integrating renewable energy technologies into the electric power systems of the USVI. Renewable energy generally requires a large capital investment compared with the standard fossil fuel generators. However, some renewable energy technology has no fuel cost and very little maintenance. The economic analysis compared the levelized cost of energy (LCOE) of the existing power production (base case) with the LCOE of a system with renewable energy added into the mix of generation. The LCOE calculation is detailed in Sections 4.3 and 4.5. Preliminary analysis was conducted by NREL and HOMER Energy LLC using the HOMER (Hybrid Optimization Model for Electric Renewables) modeling software. The results of the analysis will assist WAPA in identifying the conditions under which solar PV and wind turbines becomes cost effective for the USVI.

3.1 Data Request

NREL requested the following information to establish the base case model of the operating power plants:

- Load: multiple, recent years (2008–2009) worth of hourly load data (in megawatts) for both districts
- Existing generation
    - Capacities (in kilowatts) and operational mode
    - Monthly or hourly fuel use, output, and runtime for multiple recent years
    - Schedule and costs of maintenance and generator rebuilds
    - Fuel costs for multiple recent years
    - Ramp rates (in kilowatts per minute)
    - Minimum loading of generator
    - Efficiency curves for various power outputs
- Planned load growth and generation
    - Replacement or additional generators and renewable systems
        - Associated capacities, costs, and efficiencies.

Limited and faulty instrumentation prevented WAPA from providing all requested information, so site visits to the power plants and discussions with WAPA on operating configurations were employed to develop approximate models of the power plants. Load profiles were then generated along with fuel curves for all the generators that are modeled. Some generators with low capacity factors were combined to simplify the analysis.

3.2 Electrical Hybrid Optimization Analysis

NREL used the HOMER optimization tool to determine the conditions that enable PV and wind to be most economical and technically feasible.

3.2.1 HOMER – Technical and Economical Feasibility Analysis Tool

The HOMER software optimization tool used for the USVI analysis was developed at NREL and is now supported by HOMER Energy LLC. HOMER modeling simplifies the task of evaluating design options for both off-grid and grid-connected power systems for remote, stand-alone, and distributed energy resource (DER) applications. HOMER is a useful tool for comparing and evaluating hybrid power systems and determining the most cost-effective mix of renewable energy and fossil fuel generation. In the optimization process, HOMER simulates many different system configurations in search of the one that satisfies the technical constraints at the lowest life-cycle cost. The model's optimization and sensitivity analysis algorithms enable evaluation of the economic and technical feasibility of a great number of technology options while accounting for variation in technology costs and energy resource availability. HOMER models conventional and renewable energy resources, including:

- Power sources
    - Solar PV
    - Wind turbine
    - Run-of-river hydropower
    - Generator: diesel, gasoline, biogas, alternative and custom fuels, co-fired
    - Electric utility grid
    - Microturbine
    - Fuel cell
- Storage
    - Battery bank
    - Hydrogen
- Loads
    - Daily profiles with seasonal variation
    - Deferrable (water pumping, refrigeration)
    - Thermal (space heating, crop drying)
    - Efficiency measures
- Resource data—good wind and solar resource data is important for an accurate analysis.

NREL obtained resource maps for the USVI to help determine the feasibility of the projects. Renewable energy technologies that could be used include solar PV, concentrating solar power, wind, and WTE. To establish viability at a given site, each technology requires its own data set. Local resources related to the technologies considered must be obtained from cataloged data or on-site measurements. If sufficient data is not available, then it is necessary to collect data for periods of up to one year to capture seasonal variations.

Further in-depth assessment of the technologies that appear viable is required to ensure that the specific proposed siting meets the requirements of the individual technology and complies with zoning and other considerations. For example, PV arrays must be installed in unshaded locations on the ground or on building rooftops that have an expected life of at least 25 years.

4 Model Development for Analysis

The general resource and cost data and assumptions that are used in both HOMER models for St. Thomas and St. Croix are discussed in this section.

4.1 Resource and Cost Data

The general resource and cost data and assumptions used in the HOMER models include solar and wind solar resource data, levelized cost of energy, interest rate, fuel prices, cost of PV and wind, spinning reserve requirements, combined cycle generation, and desalination.

4.1.1 Solar

The solar resource data for this analysis is from NASA's Surface Solar Energy Data Set, which provides monthly average solar radiation data for anywhere on earth. The resolution is a 40 km grid.[6]

NREL hired a contractor to develop the diffuse and direct normal irradiance maps of the USVI from satellite data. Clean Power Research LLC developed the solar maps shown in Figure 4-1 below. They agree closely with the data from NASA's Surface Solar Energy Data Set.

[6]NASA Atmospheric Science Data Center. (2011). *Surface Meteorology and Solar Energy A Renewable Energy Resource Web Site (release 6.0).* http://eosweb.larc.nasa.gov/sse/. Accessed August 2011.

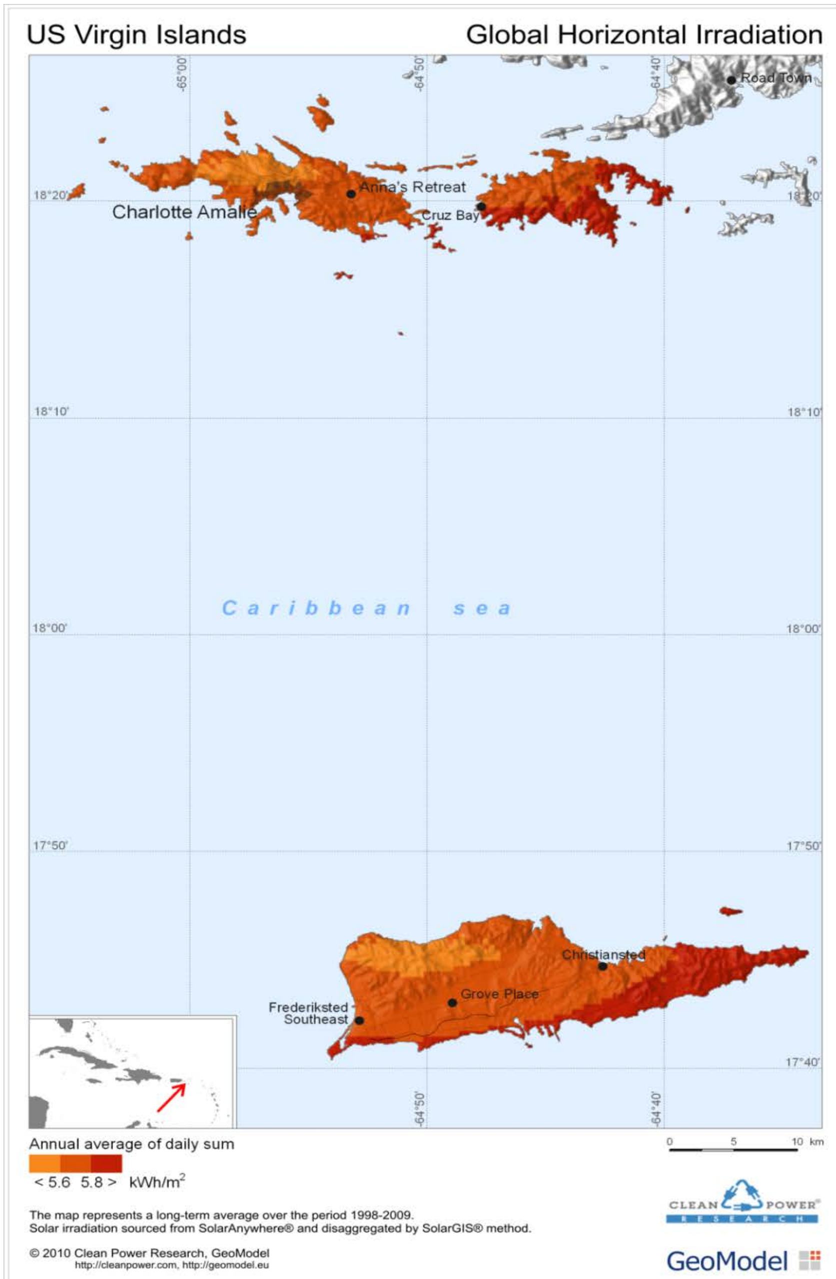


Figure 4-1. Solar global horizontal irradiation

Source: Clean Power Research

4.1.2 Wind

The wind resource data was obtained from a collaborative effort involving the DOE/NREL Wind Powering America program, the USVI, NREL's Wind Resource Group, and AWS Truewind. A comprehensive modeling and validation process produced detailed wind resource maps with a spatial resolution of 200 meters.

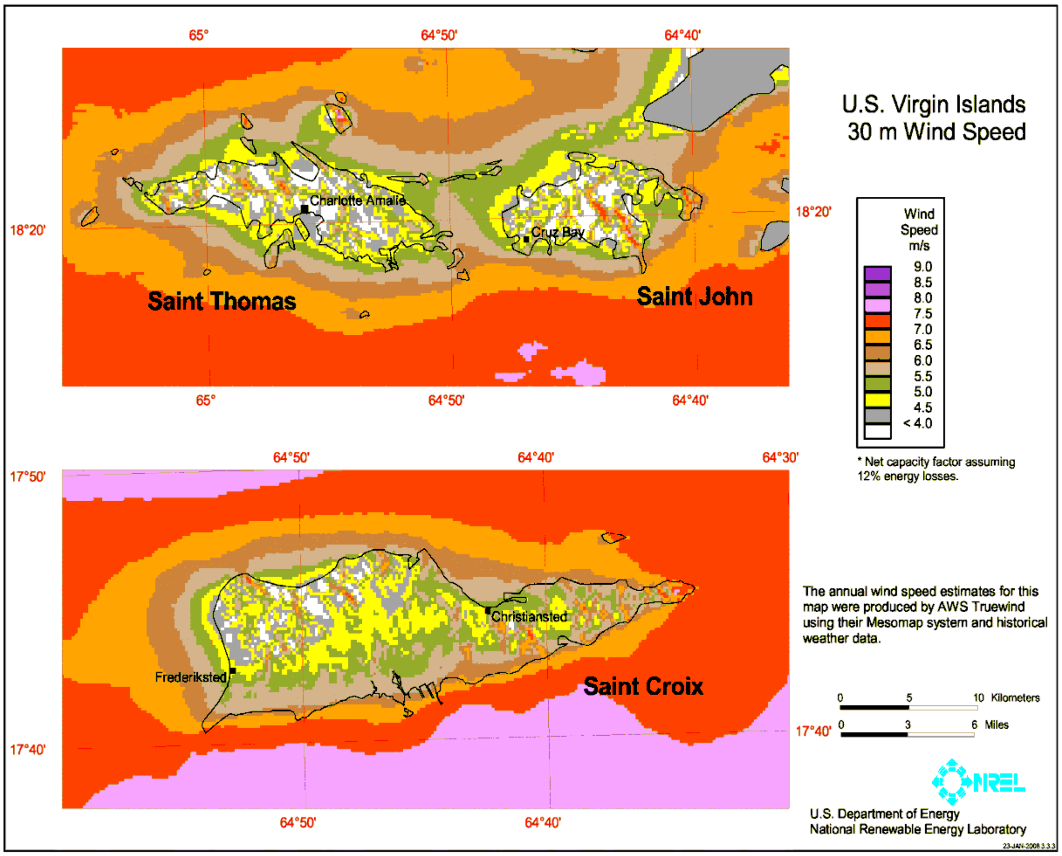


Figure 4-2. Wind speed at 30 m anemometer height

NREL is working with VIEO to install weather stations to obtain 60 meter wind and solar irradiance data at a few potential renewable energy sites.

4.1.3 Levelized Cost of Energy[7]

When comparing renewable energy to traditional generation options, consideration is given to the trade-off of high initial investment costs of renewable energy against lower initial costs of traditional generators and their future operating costs of fuel. For comparison of alternatives, it is useful to determine the LCOE generated by the options in standard units of $/kWh. This allows weighing of alternatives that may have different capacities, investment periods, financing terms, and lifetimes.

LCOE is the cost of the energy produced by a generator. It includes the initial investment, financing costs, and lifetime operations and maintenance costs, including fuel (if any). The LCOE calculation uses a discount rate in a time-value analysis to assign total life-cycle costs to each unit of energy generated over the analysis period, often the generator's useful life.

[7]Short, W., Packey, D.J., Holt, T. (1995) *A Manual for the Economic Evaluation of Energy Efficiency and Renewable Energy Technologies.* NREL/TP-462-5173. Golden, CO: National Renewable Energy Laboratory.

The LCOE is reported in dollars per kilowatt-hour (kWh), and it captures the following parameters:

- Capital costs, including financing and replacement costs
- Operations and maintenance costs
- Fuel costs
- Electricity production

The equation for LCOE is given below. The numerator of the equation is total life-cycle cost (TLCC). The denominator includes the sum of all energy generated over the system lifetime and also a term that "levelizes," or annualizes, the TLCC in the numerator (identical to a uniform capital recovery calculation).

$$\boldsymbol{LCOE = \frac{\sum_{n=0}^{N} \frac{C_n}{(1+d)^n}}{\sum_{n=1}^{N} \frac{Q_n}{(1+d)^n}}}$$

C_n is the total life-cycle cost
Q_n is the energy generated in year n
d is the discount rate
N is the analysis period

4.1.4 Interest Rate

The interest rate is a critical parameter that depends on factors that cannot yet be specified precisely. HOMER assumes that all prices escalate at the same rate over the project lifetime. A 3% interest rate corresponds roughly to attractive government funding, while 8% is less attractive private funding. The HOMER models use a real interest rate, which is approximately equal to the nominal or quoted rate minus the expected inflation rate over the life of the project. Sensitivity analyses were performed on these two extreme values of interest rate to bracket the range of possibilities.

4.1.5 Fuel Prices

A sensitivity analysis of renewable generation economic viability versus diesel fuel costs was performed using 1%, 1.8%, 2%, and 4% fuel cost escalation rates over the analysis period. The 1.8% rate is the U.S. Federal Energy Management Program's projected diesel cost escalation rate (above inflation) for the continental United States over the next 25 years. Table 4-1 shows the annualized (or levelized) cost of fuel versus energy cost escalation rates.

Table 4-1. Projected Levelized Cost of Fuel ($/Liter) for a Number of Energy Cost Escalation Rates

	Today/0%	1%	1.79%	2%	4%
#2 fuel @ 3% discount rate	$.52	$.581	$.636	$.652	$.831
#6 fuel @ 3% discount rate	$.44	$.492	$.538	$.551	$.703

4.1.6 Cost of Photovoltaics

The capital cost of PV is declining. Nationally, nonresidential systems cost on average approximately $6/W installed in 2010, while utility systems had an average installed cost of approximately $4.50/W.[8] This is in part due to declining costs of PV modules. Module prices have dropped 17% in the last year, and 3% just in the month of March (see Figure 4-3 graph of PV module price index).

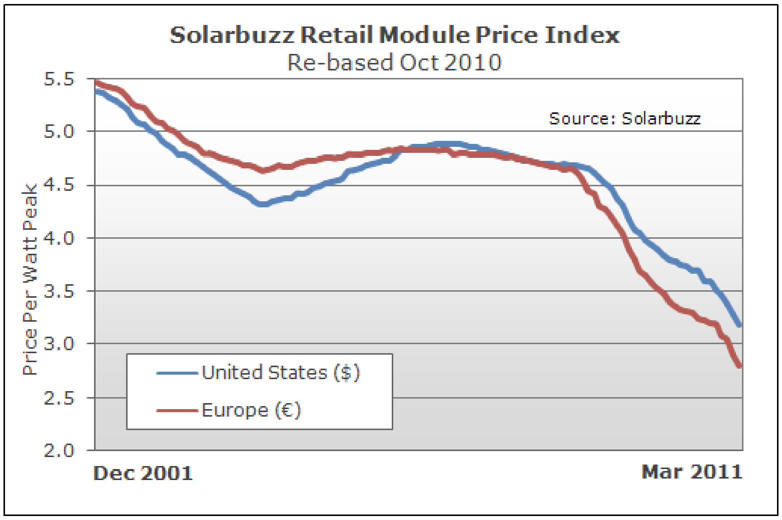


Figure 4-3. Solarbuzz retail module price index

Source: Solarbuzz, http://solarbuzz.com

The graph in Figure 4-3 was obtained from the Solarbuzz website: http://solarbuzz.com/facts-and-figures/retail-price-environment/module-prices. It does not include shipping and installation costs. The cost of PV varies widely across the United States; therefore, a sensitivity analysis was modeled in HOMER using PV capital costs varying from $4.50/watt to $7.50/watt.

4.1.7 Cost of Wind Turbines

A General Electric wind turbine rated at 1,500 kW AC was used to model the energy production from wind in the HOMER models. The base case cost of one turbine is assumed to be $3.5 M and reduces to $2.5 M for larger systems above 3 MW. This price is consistent with U. S. Energy Information Administration's (EIA's) 2010[9] estimate of wind costs. However, recent increases in wind turbine costs indicate that the upper range of wind costs may be more appropriate. (Note: EIA estimates $2,600/kW for wind in Puerto Rico.)

4.1.8 Operating Reserve

HOMER enforces an operating reserve (spinning reserve) constraint to require the system to have sufficient capacity on-line to cover sudden drops in output from the wind or PV systems. This reflects how conservative WAPA will be with regard to the variability of the renewable resources. A 100% operating reserve constraint requires the system to have sufficient spinning

[8]GTM Research. *U.S. Solar Market Insight: 2010 Year in Review*. Solar Energy Industries Association, 2010.
[9]U.S. Energy Information Administration. Independent Statistics and Analysis. *Updated Capital Cost Estimates for Electricity Generation Plants*. Washington, D.C.: EIA, November 2010.

reserve to cover the complete loss of solar or wind output within each of HOMER's one-hour simulation time steps. The less conservative assumption is that the system only needs spinning reserve sufficient to cover 50% of the solar output in any hour.

More detailed analysis considering short-term fluctuations in the resources, the stiffness of the WAPA grids, and other technical factors is required before we can make recommendations regarding the appropriate level of operating reserve. For example, 100% operating reserve may be most appropriate if all of the PV is packed tightly in a single array. If multiple smaller arrays are sufficiently separated geographically, individual clouds will not have the same near-simultaneous impact on the system output and a lower level of operating reserve could be possible. A 100% operating reserve requirement reduces the cost-effectiveness of PV significantly.

4.1.9 Combined Cycle Generating Units

Combined cycle operation is difficult to model in HOMER. However, consultation with other utility modeling companies revealed that their more complex models would have the same challenges. The steam supplied to the steam turbine portion of the combined cycle plant can come from a boiler burning #6 fuel or the heat recovery steam generator. Furthermore, the steam for desalination can be extracted at several different places. Finally, varying amounts of steam are needed at different pressures with different methods of pressure reduction. These variations all affect the efficiency of the combined cycle plant.

For these analyses, the power produced through the steam turbine by the steam generated by the HRSG was attributed to one of the combustion turbines feeding the HRSG. This increases the capacity modeled in HOMER for that combustion turbine. The capacity of the steam turbine was reduced to reflect the amount of power that can be produced just from the supplemental boiler burning #6 fuel.

4.1.10 Desalination

WAPA produces both power and water in the plants. HRSGs are installed in the exhaust stream of some of their combustion turbines. Each HRSG can be fired by two different combustion turbines. The steam generated from the HRSGs can be sent to either a steam turbine to produce electricity or to a desalination unit to produce water. While the steam turbine requires the highest pressure steam, the desalination unit requires steam at different and lower pressures. There are many different ways that the steam can be distributed between these two uses. Steam can be extracted for the desalination units from an extraction port on one of the steam turbines, or the steam can be sent through a pressure-reducing valve. Steam can also be produced by a simple boiler using heavy (#6) fuel oil. Each of these different configurations has an impact on the heat rate or efficiency of the electrical plant. In most cases, WAPA did not have data showing how much steam at what pressure and from what source was diverted to the desalination plant. This limited the ability to define the heat rates for each plant. As discussed below, simplifying assumptions were made to enable a HOMER analysis of the WAPA system.

4.2 Electrical Generation Baseline—St. Thomas

This base-case model represents all generating units with efficiencies close to those seen in the field, but operating under an optimum control strategy. Due to the complexity of the real-world operation of the generators and, particularly, the energy used for desalination, the base case created in HOMER is indicative of the relative economics of similar options rather than a precise description of WAPA's existing systems. It is advised that WAPA seek consultation from plant operations consulting engineers for a more detailed analysis of options to improve the control and operation of the plant.

4.2.1 Loads

The 2009–2010 load profile was created using the April 1, 2009–March 31, 2010 demand data provided by WAPA staff on St. Thomas. The schematic for the HOMER model is shown in Figure 4-4. The annual primary peak load for St. Thomas is approximately 85 MW, and the annual production is 526,885 MWh/yr. Based on the set of data provided, the following typical day profile (Figure 4-5) and monthly seasonal profile (Figure 4-6) were created. The variation in the load profile is minimal throughout the year due to the lack of seasonal variation of the tropical climate.

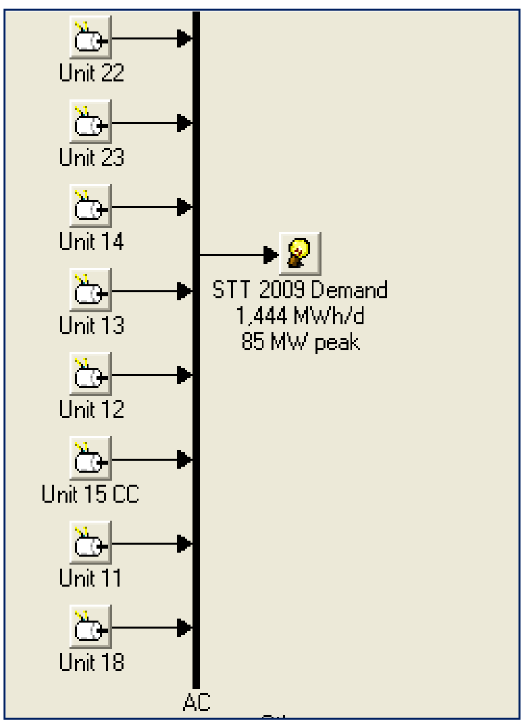


Figure 4-4. Model of St. Thomas power plant

Source: HOMER Energy LLC

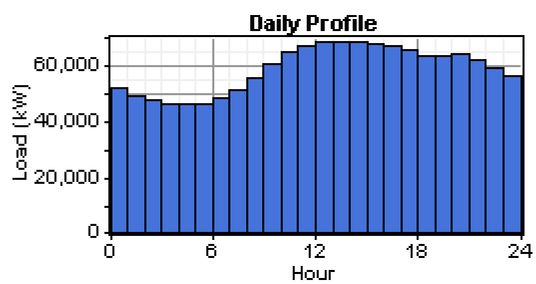


Figure 4-5. Daily load profile for St. Thomas

Source: HOMER Energy LLC

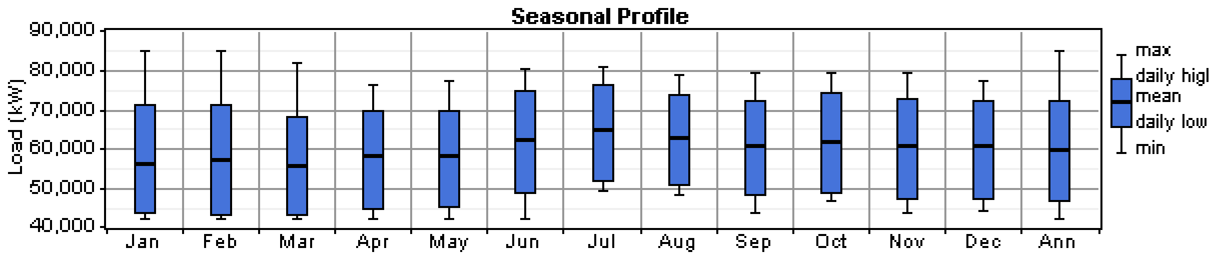


Figure 4-6. Twelve-month load profile for St. Thomas

Source: HOMER Energy LLC

4.2.2 Generators

The St. Thomas Randolph E. Harley Generating Station is located on the southwestern end of the island at Krum Bay. These generators also serve St. John, Hassel Island, and Water Island. The Krum Bay site also includes the water desalination systems and fuel storage facilities. The boilers used for desalination are 1, 2, and 5. Boilers 1 and 2 are set to retire in 2011, and boiler 5 is set to retire in 2013.[10] Details of the modeled generating facility for St. Thomas and St. John are outlined in the following sections.

4.2.3 HOMER Modeling

Full and partial load generator efficiency curves were derived from spreadsheets of data provided by WAPA. For each generator, assumptions were made as shown below in Table 4-2.

Table 4-2. Model Parameter Assumptions for All Generators

Parameter	Value
Model capital cost for existing generators	$0.00
Overhaul cost	$300/kW
O&M cost	$190/operating hour
Overhaul interval	10,000 hours
Minimum load ratio	25%

Table 4-3 lists the generators that were modeled from the files in HOMER. For each generator, the following assumptions were made.

[10]Beck, R.W. Power Supply Evaluation, 2008.

Table 4-3. Model Parameters for Each Generator

Unit No.	Installed Capacity (MW)	Modeled Capacity (MW)	Type	Fuel Used	Replacement Cost ($)
11	20.7	13	Steam	#6 oil	3,900,000
12	15.1	15.1	Combustion	#2 Diesel	4,530,000
13	36.5	36.5	Steam	#6 oil	10,950,000
14	16.1	15.1	Combustion	#2 Diesel	4,530,000
15 /CC	22.1	29.1	Combined Cycle	#2 Diesel	8,730,000
18	24.5	22	Combined Cycle	#2 Diesel	6,600,000
22	24.5	22	Combustion	#2 Diesel	6,600,000
23	42.5	39.2	Combustion	#2 Diesel	11,760,000

The fuel curves for all generators were created using data provided by WAPA for units 11, 12, 13, 14, 15, 18, 22, and 23. Unit 22 fuel curve data provided by WAPA was taken from the factory manual and indicated very high peak efficiency (45%). This unit was reduced to match the average efficiency of units 15 and 18 (28%), which are similar in size and type. The fuel curves were checked against linear trend lines created with an Excel spreadsheet. In the data provided by WAPA for St. Croix, the fuel use for desalination was not extracted from the fuel use for electricity generation.

To model the combined cycle of combustion turbine 15 and steam turbine 11, the operational data supplied by WAPA was used to identify the appropriate portion of the capacity of unit 11's steam turbine to combine with unit 15 to reflect the steam that is generated by unit 15's HRSG. The remaining capacity of unit 11 reflects its operation with just its own boiler burning #6 fuel oil. The combined cycle plant is the most efficient plant in the system, so its minimum load ratio was set to 100%.

4.2.4 Configuration of the St. Thomas Power Plant During Normal Operations

St. Thomas can run in many different configurations, but typical configurations are shown in Figure 4-7 and Figure 4-8 for steam turbine units #11 and #13. The steam supplied to the steam turbine portion of the combined cycle plant can come from a boiler burning #6 fuel or the HRSG. Steam turbine units #11 and #13 can run with either of the combined cycle units #15 or #18 separately or with both units #15 and #18. St. Thomas can get 14 MW from unit #11 if it runs both, but only 7 MW with a single combustion turbine and #11. This is similar for steam turbine #13. The difference is that steam turbine #11 works at 600 pounds per square inch (psi), and unit #13 requires 900 psi. This is complicated even more by the fact that St. Thomas can also extract steam from the steam turbines for desalination at the water plants.

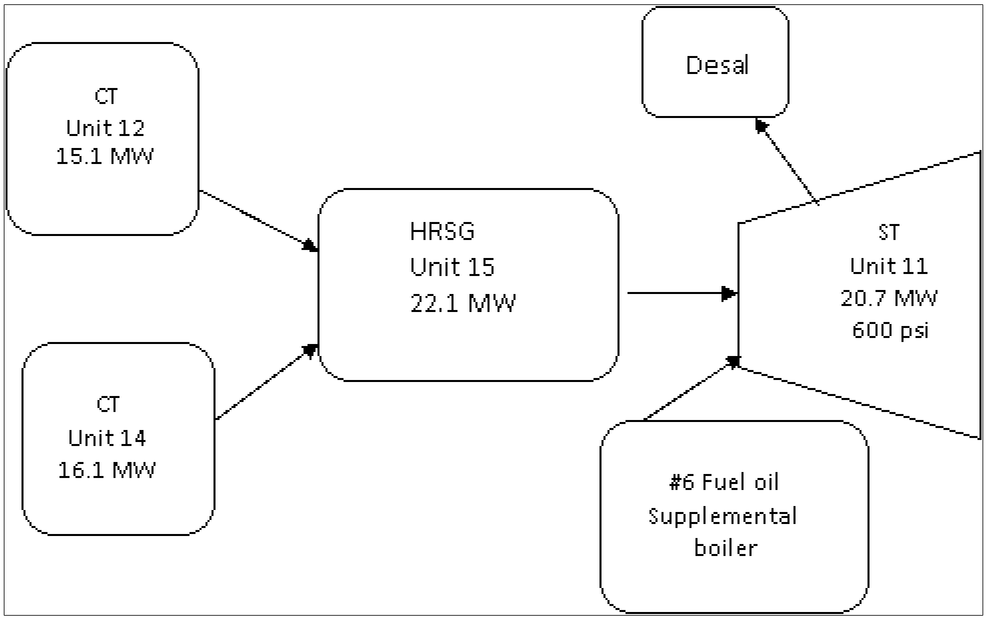


Figure 4-7. Typical configuration for steam turbine #11

Source: NREL

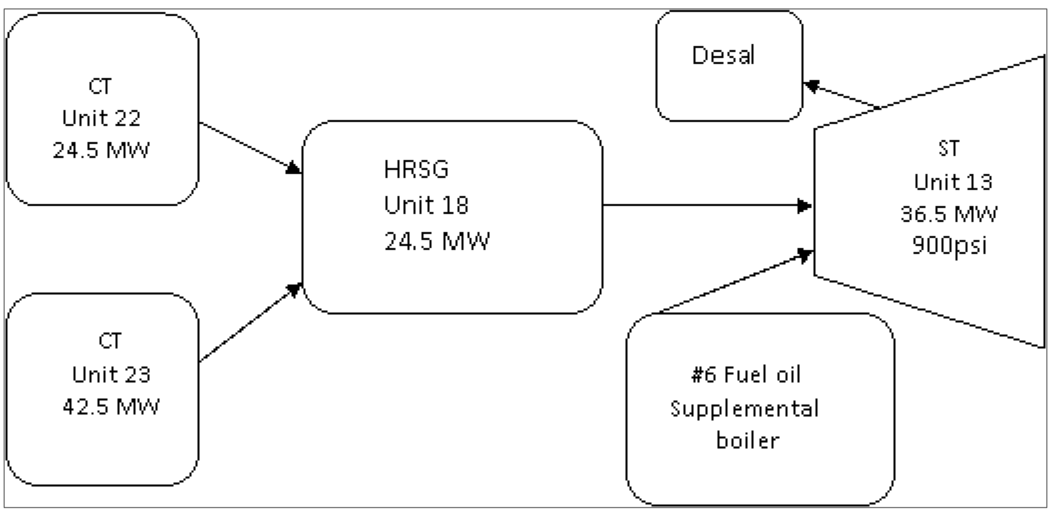


Figure 4-8. Typical configuration for steam turbine # 13

Source: NREL

4.2.5 Diesel Heat Rate

The heat rate was calculated from the HOMER base case simulation results. HOMER calculates for each time step (hour) what combination of units will meet the load at lowest cost. In practice, there may be operational constraints that make it impossible for the system operator to optimize as effectively as HOMER assumes.[11] In WAPA's case, the need to produce steam for desalination is an operational issue that was outside the scope of this analysis.

Table 4-4. HOMER Base Case Simulation Results

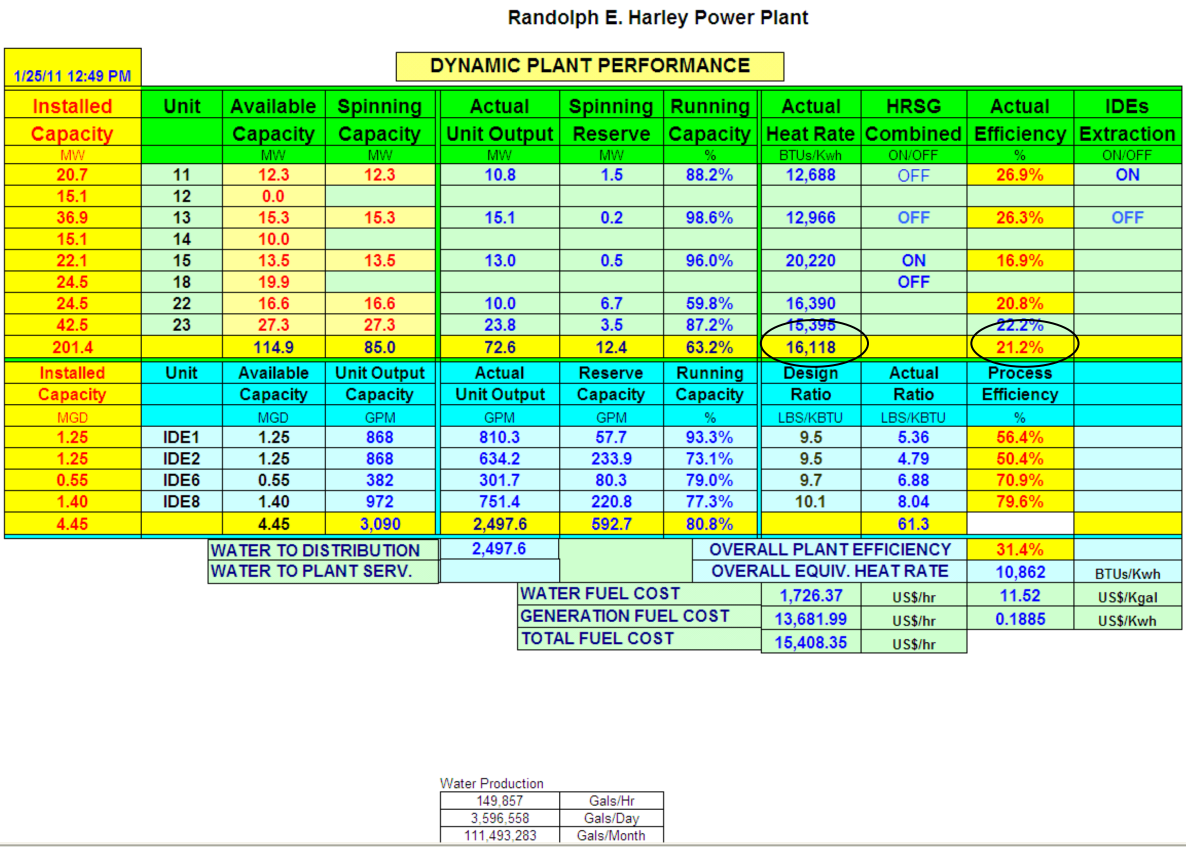
Fuel energy input	**7,081,538 MM Btu**
Output electricity	526,884,960 kWh
Average heat rate	13,440 Btu/kWh
Efficiency	25.39%

Heat rates are defined for the gas turbines and for the combined cycle, but not the steam cycle alone. Normally, the overall heat rate (Btu/kWh) for the combined cycle is calculated by summing the fuel burned in each of the gas turbines and the fuel burned in the duct burners (expressed in Btu) and dividing the summed Btu value by the total generation (kWh) from the gas turbine generator and the steam turbine generator. A screen shot of the actual power plant production of electricity and water in St. Thomas is captured in Figure 4-9. The screen shot indicates that the actual heat rate to produce electricity is 16,118 Btu/kWh and 21.2% efficiency. (Note the efficiency is calculated from the heat rate using the conversion factor 1 kWh = 3,412 Btu. Efficiency = 3,412/heat rate).

$$\text{Efficiency} = \frac{\mathbf{3{,}412}\ \boldsymbol{Btu/kWh}}{\mathbf{16{,}118}\ \boldsymbol{Btu/kWh}} = 21.2\%$$

This is due to the fact that at the St. Thomas plant, high-pressure steam is diverted from steam turbine unit #11 and sent through a pressure-reducing valve to produce water. The analysis indicates that a lower heat rate of 13,622 Btu/kWh could be achieved if low-pressure steam for desalination were only extracted from the back end of the steam turbines, rather than from high-pressure steam sent through a pressure-reducing valve.

[11]Note: In a separate study, the combined heat rate of the WAPA system was estimated at 15, 200 BTU/kWh (ref. Lantz, Eric; Olis, Dan; and Warren, Adam [2011]. *U.S. Virgin Islands Energy Road Map Analysis: 60% Reduction in Fossil Fuel by 2025*. NREL/TP-6A20-52360. Golden, Colorado: National Renewable Energy Laboratory.)



Randolph E. Harley Power Plant

1/25/11 12:49 PM

DYNAMIC PLANT PERFORMANCE

Installed Capacity	Unit	Available Capacity	Spinning Capacity	Actual Unit Output	Spinning Reserve	Running Capacity	Actual Heat Rate	HRSG Combined	Actual Efficiency	IDEs Extraction
MW		MW	MW	MW	MW	%	BTUs/Kwh	ON/OFF	%	ON/OFF
20.7	11	12.3	12.3	10.8	1.5	88.2%	12,688	OFF	26.9%	ON
15.1	12	0.0								
36.9	13	15.3	15.3	15.1	0.2	98.6%	12,966	OFF	26.3%	OFF
15.1	14	10.0								
22.1	15	13.5	13.5	13.0	0.5	96.0%	20,220	ON	16.9%	
24.5	18	19.9						OFF		
24.5	22	16.6	16.6	10.0	6.7	59.8%	16,390		20.8%	
42.5	23	27.3	27.3	23.8	3.5	87.2%	15,395		22.2%	
201.4		114.9	85.0	72.6	12.4	63.2%	16,118		21.2%	

Installed Capacity	Unit	Available Capacity	Unit Output Capacity	Actual Unit Output	Reserve Capacity	Running Capacity	Design Ratio	Actual Ratio	Process Efficiency
MGD		MGD	GPM	GPM	GPM	%	LBS/KBTU	LBS/KBTU	%
1.25	IDE1	1.25	868	810.3	57.7	93.3%	9.5	5.36	56.4%
1.25	IDE2	1.25	868	634.2	233.9	73.1%	9.5	4.79	50.4%
0.55	IDE6	0.55	382	301.7	80.3	79.0%	9.7	6.88	70.9%
1.40	IDE8	1.40	972	751.4	220.8	77.3%	10.1	8.04	79.6%
4.45		4.45	3,090	2,497.6	592.7	80.8%		61.3	

WATER TO DISTRIBUTION	2,497.6
WATER TO PLANT SERV.	

OVERALL PLANT EFFICIENCY	31.4%	
OVERALL EQUIV. HEAT RATE	10,862	BTUs/Kwh

WATER FUEL COST	1,726.37	US$/hr	11.52	US$/Kgal
GENERATION FUEL COST	13,681.99	US$/hr	0.1885	US$/Kwh
TOTAL FUEL COST	15,408.35	US$/hr		

Water Production

149,857	Gals/Hr
3,596,558	Gals/Day
111,493,283	Gals/Month

Figure 4-9. Snapshot of St. Thomas plant performance at 12:49 p.m. on January, 25, 2011

Source: WAPA

4.3 Hybrid Optimization Analysis—St. Thomas

Three cases are presented for the HOMER analysis of St. Thomas (STT). They all use the same base case but consider the economics of different mixes of renewables.

STT Case 1: PV—5 MW of new solar PV, but no wind

STT Case 2: Wind—15 MW of new wind, but no solar

STT Case 3: PV and wind—5 MW of new solar PV and 15 MW of new wind

4.3.1 St. Thomas Case 1: Photovoltaic Optimization Analysis

The results from the PV optimization analysis using the levelized cost of fuels from Table 4-1 with a 1.8% interest rate and a 3% discount rate ($0.636/liter [L] for fuel oil #2 and $0.538/ liter for fuel oil #6) are presented here. PV was modeled at $6.00 per watt, with no tracking, 18.3 degrees tilt, and a 50% solar operating reserve. Under these conditions, the optimal system has nominally 5 MW of PV. The fuel and cost savings can be seen below in Table 4-5. Adding PV to the existing system (base case) at St. Thomas saves roughly 2.4 million liters of #2 fuel oil and 0.5 million liters of #6 fuel oil. This represents a 1.6% reduction in fuel use from the base case. This also represents a $1.8 million reduction in annual expenditure on fuel.

Table 4-5. Fuel and Cost Savings for PV Optimization (STT Case 1) on St. Thomas as Compared to Base Case

	#2 Fuel Oil ($101/Barrel)	**#6 Fuel Oil ($85.50/Barrel)**	**Total**
Annual fuel savings for adding 5 MW of PV	2,405,000 L (15,100 barrels)	541,000 L (3,400 barrels)	**1.6% reduction in fuel use**
Annual fuel cost savings for adding 5 MW of PV	$1,530,000	$291,000	**$1.8 M savings/year**

Table 4-6 compares the LCOEs for each of the cases and includes the expected LCOE for PV alone.

Table 4-6. Levelized Cost of Energy for PV Optimization (STT Case 1) on St. Thomas

	Base Case Only	**PV Only**	**PV Integrated into Base Case**
LCOE	$0.265/kWh	$0.212/kWh	$0.265/kWh

4.3.2 St. Thomas Case 1: Photovoltaic Sensitivity Analysis

Figure 4-10 shows the combination of PV capital cost and diesel fuel price at which PV is cost effective. These are the two most important variables affecting the cost-effectiveness of PV. The PV prices used ranged from $4.50 to 7.50/W. Note that $7.50/W is substantially higher than installed capital costs for projects in the continental United States. The sensitivity analysis on this crucial parameter shows the impact if PV can be installed at a lower cost, either because the analysis performed was too conservative with regard to the premium required for construction in the Virgin Islands or because of the availability of subsidies.

The region where PV is cost effective is shown in light pink. The fuel price on the x-axis is in $/liter, and the PV capital cost on the y-axis is scaled from $4.50/W to $7.50/W. The fuel price ranges from $0.50/L to $0.90/L, which corresponds to oil prices ranging from $58.66/barrel to $105.60/barrel. PV is not cost effective in the region shown in deep red.

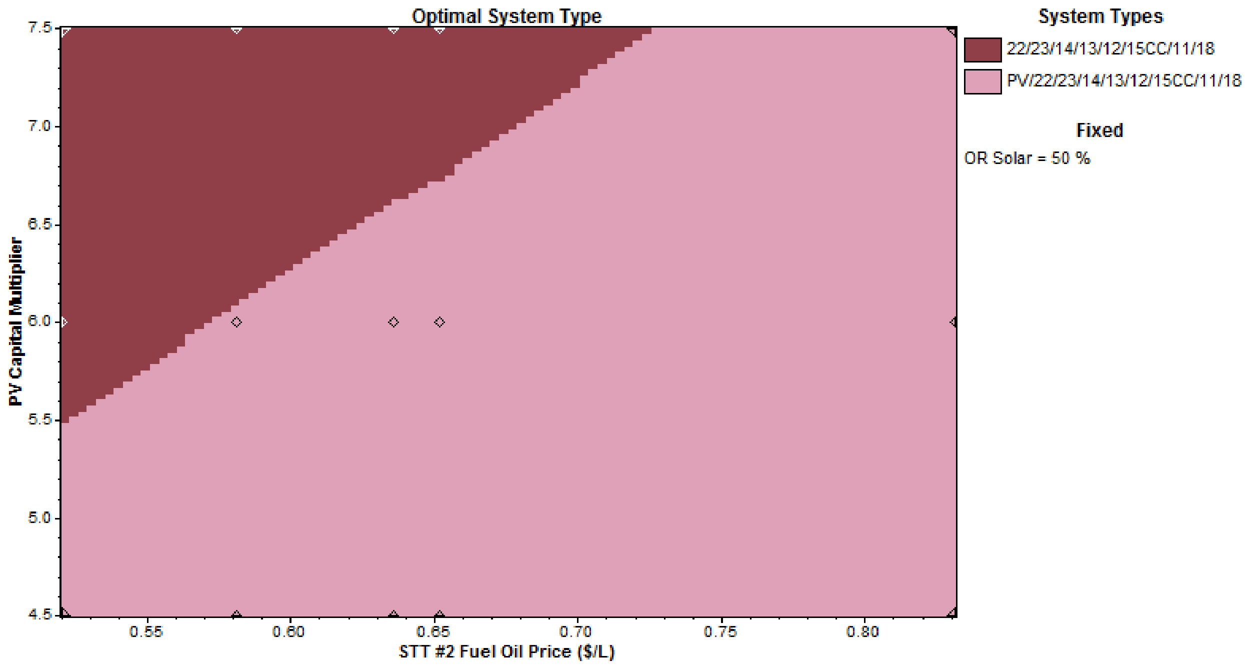


Figure 4-10. PV and generator sensitivity analysis with 50% operating reserve

Source: HOMER Energy LLC

Figure 4-10 show the sensitivity of this result to an assumption about how conservatively WAPA operates its system. The operating reserve (OR), sometimes referred to as spinning reserve, constraint in HOMER requires the system to have sufficient capacity online to cover sudden drops in output from the PV systems. The operating reserve on solar PV is labeled on the graph as "OR Solar." In this case, Figure 4-10 assumes that the system has sufficient spinning reserve to cover the complete loss of solar output within each of HOMER's one-hour simulation time steps. The assumption in Figure 4-10 is that the system only needs spinning reserve sufficient to cover 50% of the solar output in any hour. The more conservative assumption of Figure 4-11 reduces the cost-effectiveness of PV. All of the hybrid systems in these figures contain generating units 11, 12, 13, 14, 15CC, 18, 22, and 23.

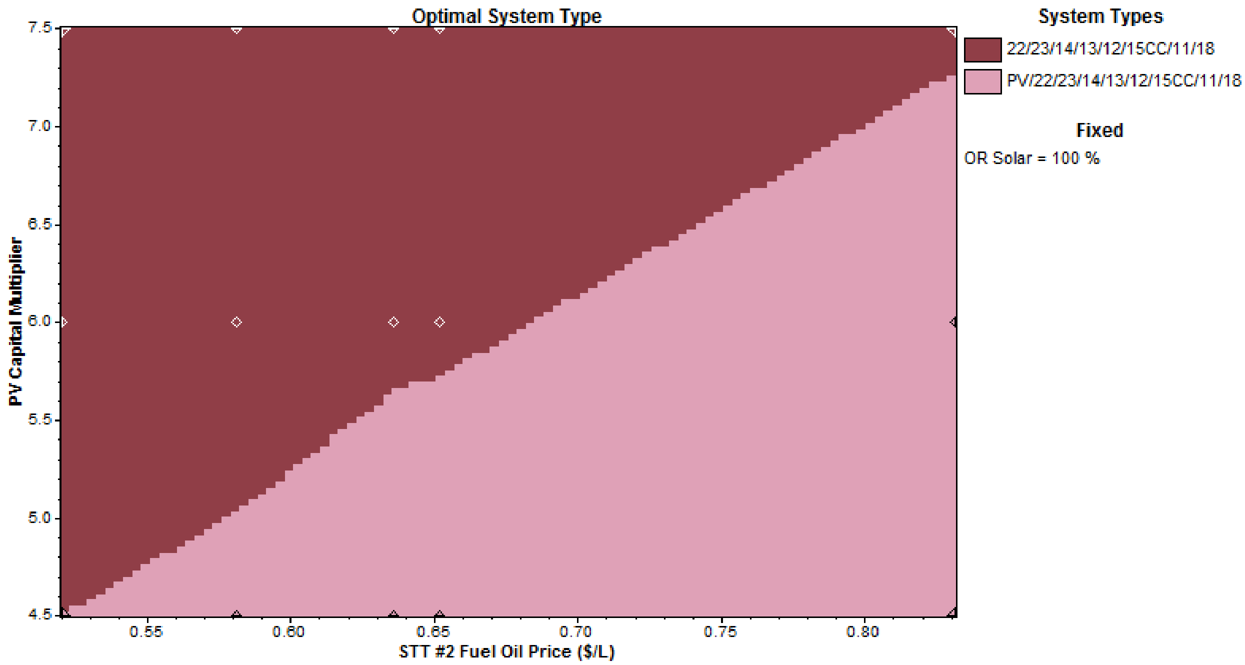


Figure 4-11. PV and generator sensitivity analysis with 100% operating reserve

Source: HOMER Energy LLC

4.3.3 St. Thomas Case 2: Wind Optimization Analysis

The results from the optimization analysis using the levelized cost of fuels from Table 4-1 with a 1.8% interest rate and a 3% discount rate ($0.636/L for #2 fuel oil and $0.538/L for #6 fuel oil) are presented here. The first 1.5 MW wind turbines were modeled at $3.5 million, and additional turbines would cost $2.5 million ($26 million for 15 MW), with a 50% operating reserve margin on generation from wind. Under these conditions, the optimal system has nominally 15 MW of wind generation.

The fuel savings are shown below in Table 4-7. Adding wind to the existing system (base case) on St. Thomas saves roughly 13.7 million liters of #2 fuel oil and 3.3 million liters of #6 fuel oil. This represents a 9% reduction in fuel use from the base case. This represents $10.5 million in annual costs for fuel purchases.

Table 4-7. Fuel and Cost Savings for Wind Optimization (STT Case 2) on St. Thomas Compared to Base Case

	#2 Fuel Oil ($101/Barrel)	#6 Fuel Oil ($85.50/Barrel)	Total
Annual fuel savings for adding 15 MW of wind	13,735,000 L (86,400 barrels)	3,302,000 L (20,770 barrels)	**9% reduction in fuel use**
Annual fuel cost savings for adding 15 MW of wind	$8,736,000	$1,776,000	**$10.5M savings/year**

Table 4-8 compares the LCOE for each of the cases and includes the expected LCOE for wind alone.

Table 4-8. Levelized Cost of Energy for Wind Optimization (STT Case 2) on St. Thomas

	Base Case Only	Wind Only	Wind Integrated into Base Case
LCOE	$0.265/kWh	$0.056/kWh	$0.2458/kWh

4.3.4 St. Thomas Case 2: Wind Sensitivity Analysis

Wind power is more cost effective than PV. It is also much more sensitive to the resource, so proper siting is crucial. Small changes in location and height can have a large impact on project economics. For this reason, an additional sensitivity analysis was performed on the annual average wind speed. There is also some uncertainty about the capital cost of a small wind farm in the USVI. The cost per installed turbine can be expected to be higher than typical wind farms in the continental United States because of the smaller size of the wind farm, logistical issues associated with construction in the Caribbean, and difficult topography in the Virgin Islands. The low capital cost case assumed that the first 1.5 MW wind turbine (GE 1.5sl or similar) could be installed for $3.5 million, and additional turbines would cost $2.5 million. At these costs, 10 turbines with a capacity of 15 MW would cost $26 million. The high capital cost case, shown here, assumed a very conservative cost multiplier of 2, or $52 million, for the same wind farm. This undoubtedly brackets the possible cost.

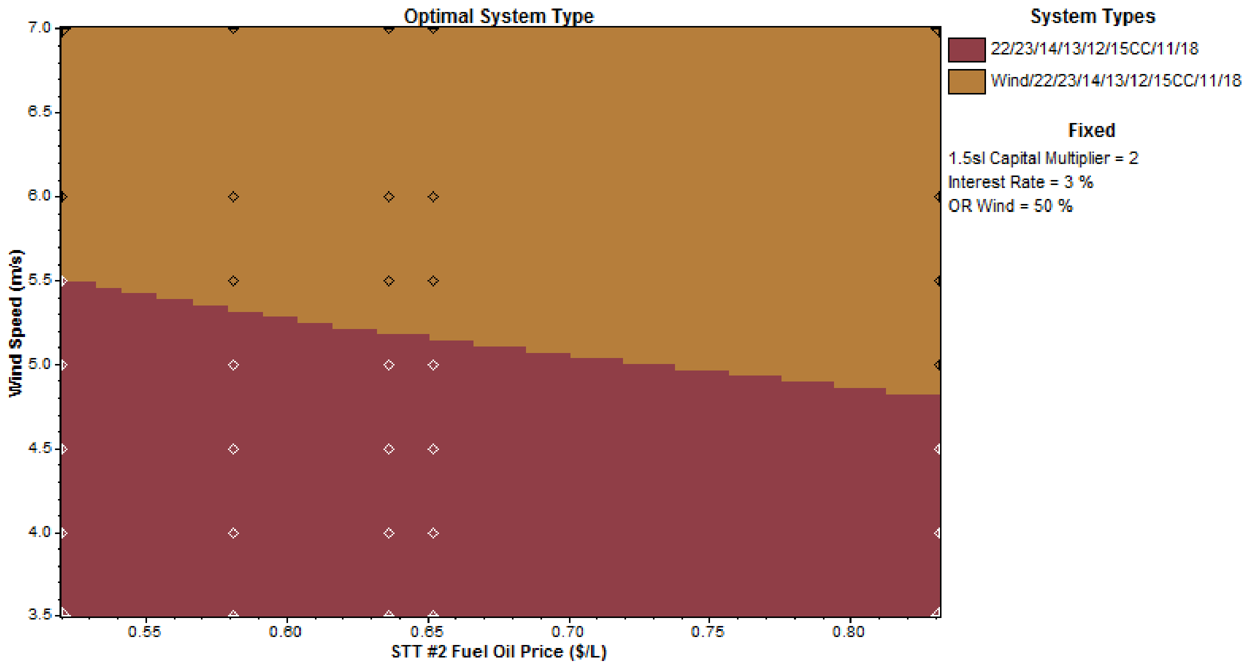


Figure 4-12. Wind and generator sensitivity analysis with expected assumptions (50% operating reserve, 3% interest rate, and a wind turbine cost multiplier of 2)

Source: HOMER Energy LLC

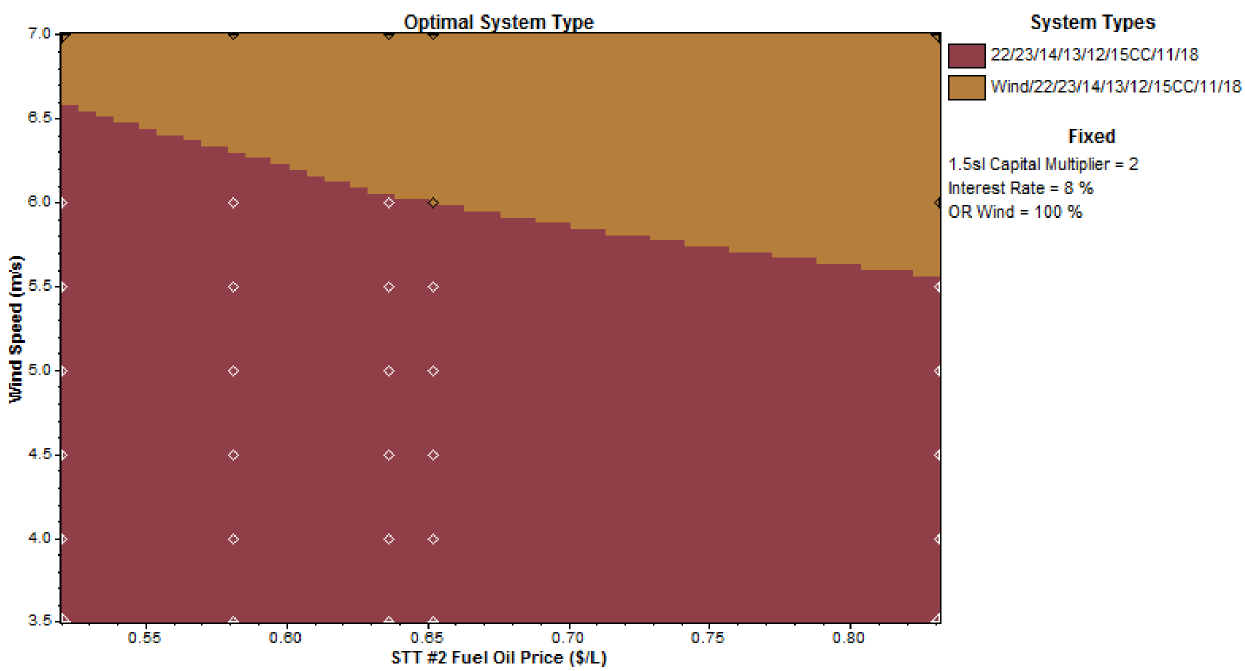


Figure 4-13. Wind and generator sensitivity analysis with conservative assumptions (100% operating reserve, 8% interest rate, and a wind turbine cost multiplier of 2)

Source: HOMER Energy LLC

Figure 4-12 and Figure 4-13 show that the wind farm is cost effective at wind speeds below 7 meters per second even at today's fuel price and the higher capital cost. Figure 4-13 makes additional conservative assumptions, including an operating reserve equal to 100% of the wind power and a higher real interest rate of 8% (~10% is nominal interest rate). All of the least-cost systems in these figures comprise generating units 11, 12, 13, 14, 15CC, 18, 22, and 23.

4.3.5 St. Thomas Case 3: Photovoltaic and Wind Sensitivity Analysis

In the final case, we considered a combination of 5 MW of solar PV and 15 MW of wind. The results indicate that wind is always part of the least-cost solution. The sensitivity figures below compare the cost of PV on the Y-axis to the increase cost of fuel on the x-axis. The brown color represents configuration with only wind and the generators, while the blue color represents the configuration with 15 MW wind and 5 MW PV in addition to the existing generators. Figure 4-14 and Figure 4-15 show that wind is cost effective even when the oil prices are low, below \$55/liter (which corresponds to oil prices as low as \$58.66/barrel).

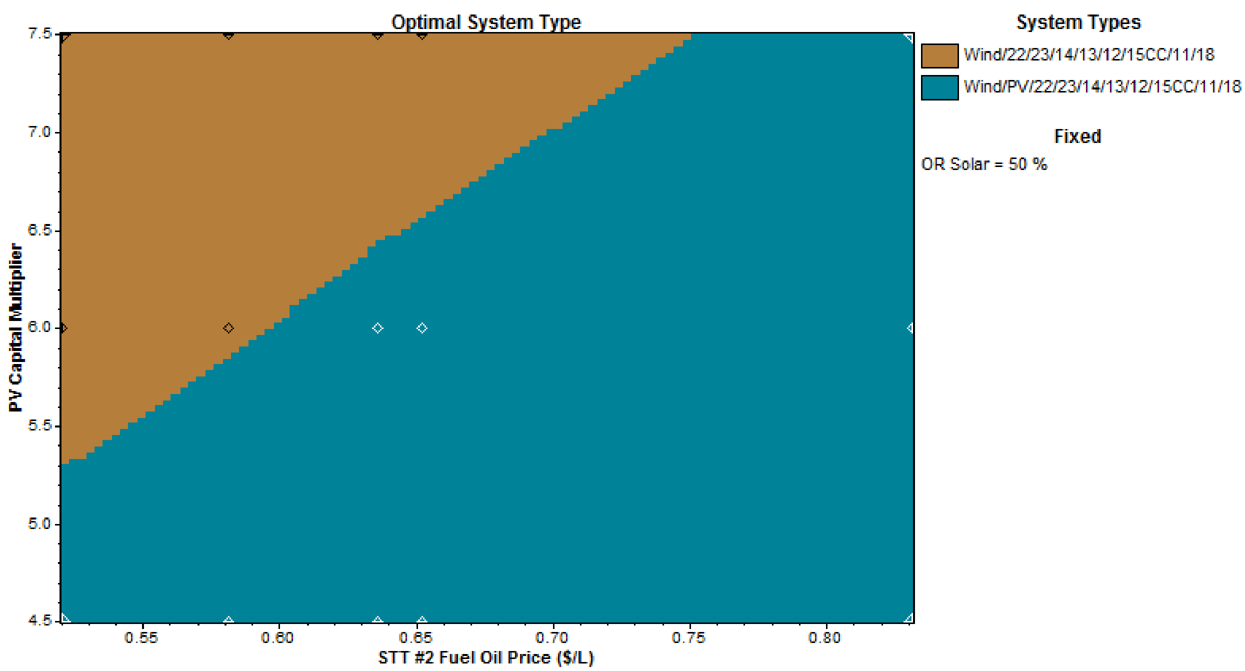


Figure 4-14. PV, wind, and generator sensitivity analysis with 50% operating reserve for both wind and solar

Source: HOMER Energy LLC

In Figure 4-15, the operating reserve was increased to cover 100% operating reserve margin on generation from PV and wind. The brown color represents the hybrid configuration which includes generators and wind turbines only, and the blue color represents the hybrid system with generators, PV and wind. The results show that the price of oil must increase above \$0.55/liter (\$58.66/barrel) for PV to become cost effective.

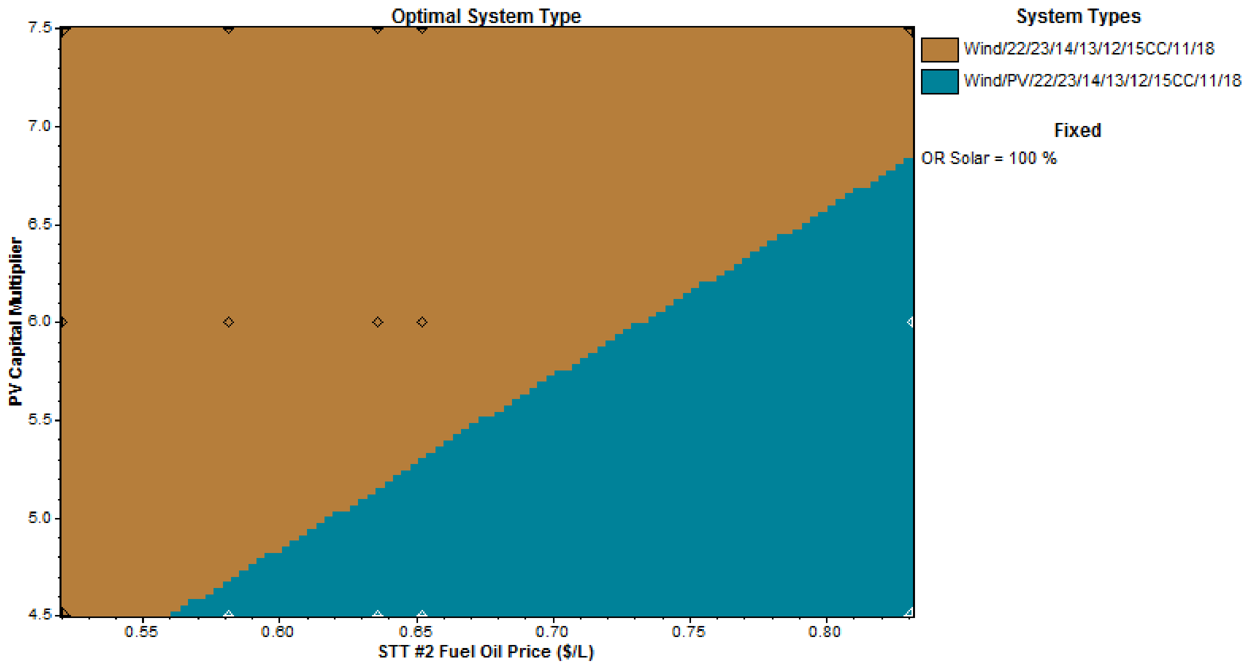


Figure 4-15. PV, wind, and generator sensitivity analysis with 100% operating reserve for both wind and solar

Source: HOMER Energy LLC

4.4 Electrical Generation Baseline—St. Croix

The analysis for St. Croix parallels that for St. Thomas, with two additional issues factored in: a calculation of the increase in overall plant efficiency after the new HRSG was installed and an evaluation of the cost-effectiveness of WAPA's contract with Alpine Energy Group for power from a new WTE plant.

4.4.1 Efficiency Gains from the HRSG

The base-case model for St. Croix includes the newly installed HRSG. Another HOMER model describes the power plant prior to the installation of a new HRSG. The base case was compared to a St. Croix model without the new HRSG (pre-HRSG case) and demonstrates the heat rate and efficiency improvement of the plant.

4.4.2 Loads for the Pre-HRSG Case

The original 2010 load profile for the pre-HRSG case was created using the April 1, 2009–March 31, 2010 demand data provided by the WAPA team in St. Croix. The schematic for the HOMER model is shown in Figure 4-16. The annual primary peak load for St. Croix is approximately 55 MW, with daily energy production of 910 MWh/day and annual production of 332,000 MWh/yr. The following typical day profile (Figure 4-17) and monthly seasonal profile (Figure 4-18) were created from this data.

The peak load in the pre-HRSG case at St. Croix is approximately 55 MW, the average is 38 MW, and the minimum is 20 MW. The variation in the load profile is minimal; the standard deviation is roughly 20% of the average load.

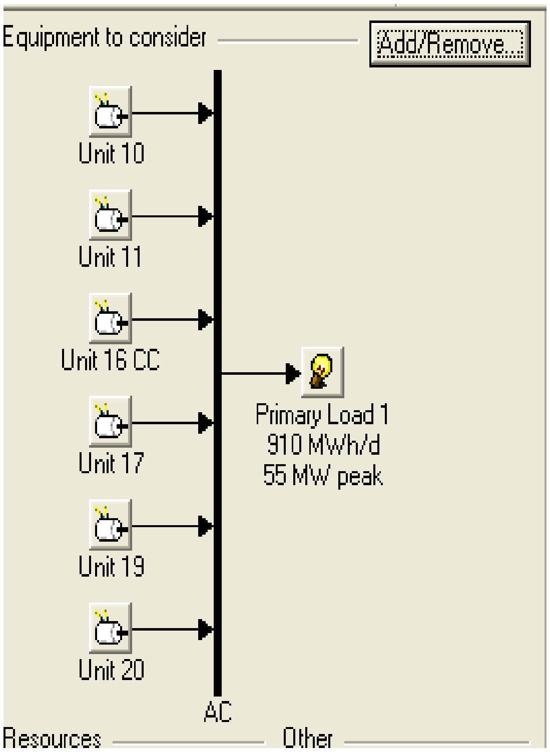


Figure 4-16. Model of St. Croix power plant pre-HRSG case (before the new HRSG was installed)

Source: HOMER Energy LLC

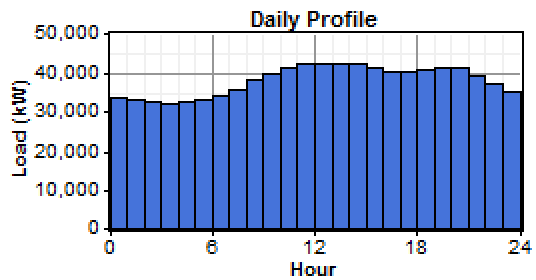


Figure 4-17. St. Croix daily load profile for the pre-HRSG case

Source: HOMER Energy LLC

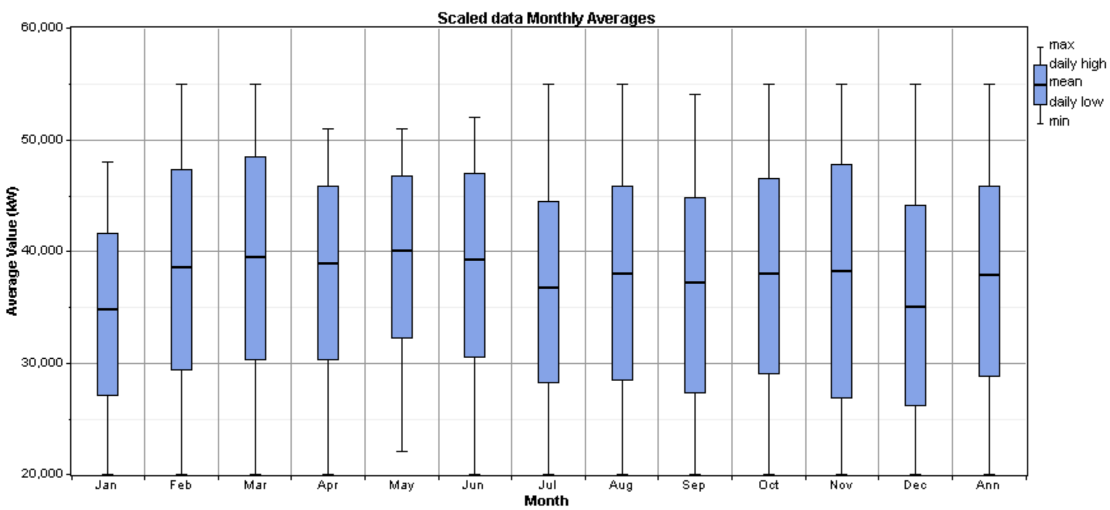


Figure 4-18. Monthly load profile for the pre-HRSG case

Source: HOMER Energy LLC

4.4.3 Loads for the Base Case

The HOMER base case model for St. Croix (see Figure 4-19) was built using the generation data provided by the WAPA team in St. Croix after the HRSG was installed. This covered the period from June 1, 2010 to December 31, 2010. The load data from that file was appended to the previous data to create a load profile for the whole 2010 calendar year. The decrease in the load between this data set and the pre-HRSG data set could reflect some missing data (see Figure 4-21).

The peak load in the base case for St. Croix is approximately 55 MW, the average is 35 MW, and the minimum is 20 MW. The variation in the load profile increased from the pre-HRSG case; the standard deviation is roughly 23% of the average load. However, the increased variability and lower average might be attributable to the missing data.

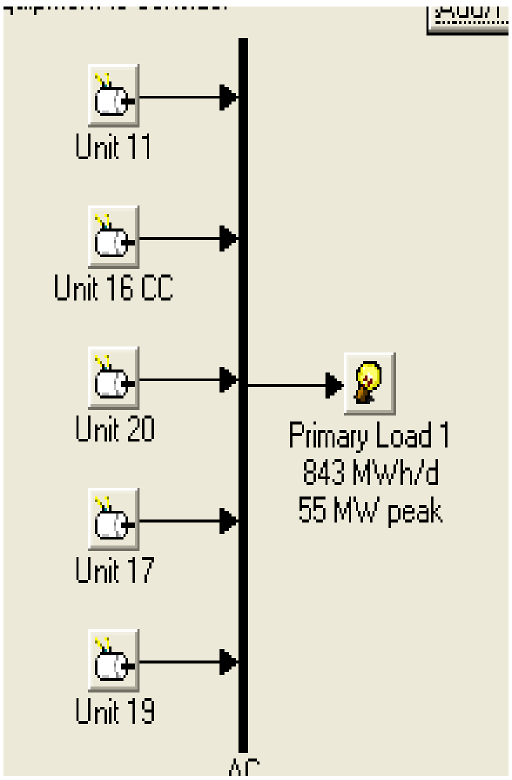


Figure 4-19. Model of St. Croix for the base case (after installing the new HRSGs)

Source: HOMER Energy LLC

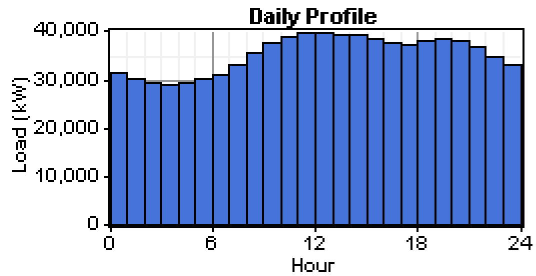


Figure 4-20. St Croix daily load profile for the base case (after installing the new HRSGs)

Source: HOMER Energy LLC

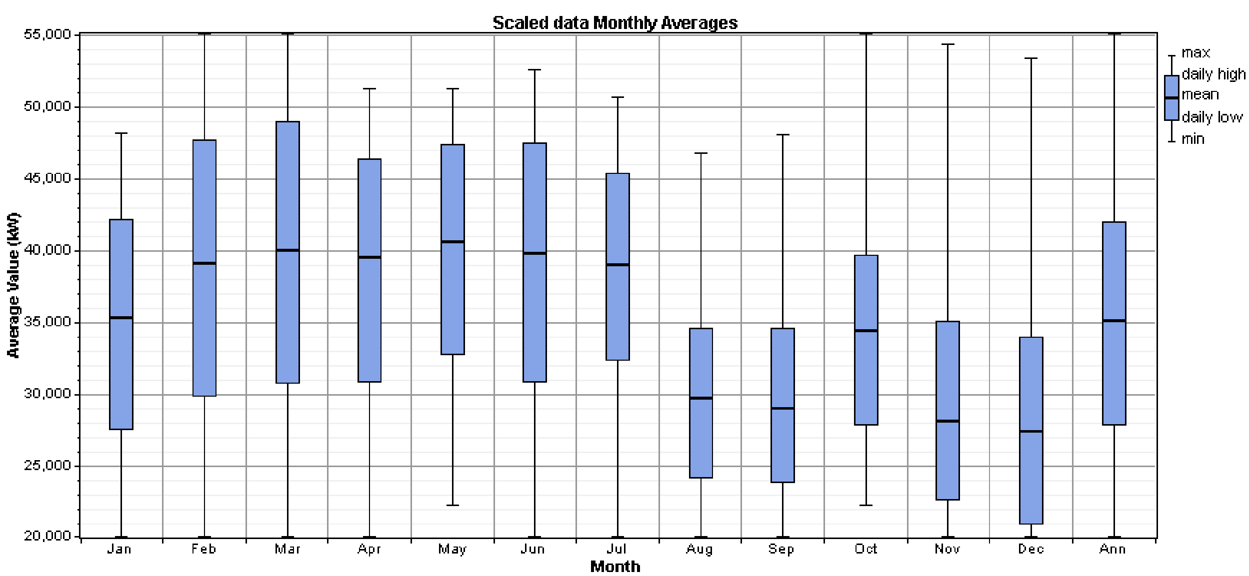


Figure 4-21. Monthly load profile for the base case (after installing the new HRSGs)

Source: HOMER Energy LLC

4.4.4 Generators and HRSGs on St. Croix

St. Croix has approximately 117 MW of installed capacity located at the Estate Richmond site on the north shore of the island near Christiansted. The power plant there has a combination of steam turbines and combustion turbine generators. The steam plants are fueled with No. 6 heavy oil, and the combustion turbines are fueled with No. 2 diesel oil. Steam is currently being taken from the steam turbines to provide energy for the desalination plants. The generator units and HRSGs are summarized below in Table 4-9.

Table 4-9. Summary of Generator Units and HRSGs at St. Croix

Unit #	Type	Nominal Rating	Notes
10	Steam turbine	10 MW	Standby unit. Collects steam from either HRSG and has a supplementary boiler fired with #6 fuel oil.
11	Steam turbine	19.1 MW	Collects steam from unit 24 and has a supplementary boiler fired with #6 fuel oil.
16CC	Combustion turbine	20 MW	Feeds waste heat into unit 24.
17	Combustion turbine	20 MW	Standby unit. Feeds waste heat into unit 21.
19	Combustion turbine	24.5 MW	Standby unit.
20	Combustion turbine	24.5 MW	Feeds waste heat into unit 24
21	HRSG	80,000 lbs/hr high-pressure (HP) steam	Standby unit. Collects waste heat from unit 17.
24	HRSG	231,000 lbs/hr 600 psi steam	Purchased March 2010. Collects waste from unit 16 and unit 20.

There are six generator units and two HRSGs. The unit #24 HRSG was purchased in March 2010, so the plant became more efficient in the last six months of 2010. The HRSGs are waste recovery boilers that capture exhaust heat from the combustion turbines for use in the steam turbines or the desalination plants.

WAPA normally operates several of the generator units at partial load for spinning reserve, to ensure system reliability in the event of a unit failure.

Unit #10 steam turbine is a standby unit. It can be supplied with steam from either HRSG or its own boiler fired with #6 fuel oil. Unit #17 and unit #19 combustion turbines are also standby units. Unit #21 HRSG is also a standby unit.

4.4.5 HOMER Modeling

For each generator, assumptions were made as shown below in Table 4-10.

Table 4-10. Model Parameter Assumptions for All Generators

Parameter	Value
Model capital cost for existing generators	$0.00
Overhaul cost	$300/kW
O&M cost	$190/operating hour
Overhaul interval	10,000 hours
Minimum load ratio	25%

Table 4-11 lists the generators that were modeled in HOMER based on data provided by WAPA.

Table 4-11. Model Parameters for Each Generator

Unit #	Installed Capacity (MW)	Modeled Capacity (MW)	Type	Fuel Used	Replacement Cost ($)
10	10	10	Steam	#6 oil	3,000,000
11	19.1	8	Steam	#6 oil	2,400,000
16/CC	20	28	Combustion	#2 Diesel	8,400,000
17	20	20	Combustion	#2 Diesel	6,000,000
19	24.5	24.5	Combustion	#2 Diesel	7,350,000
20	24.5	24.5	Combustion	#2 Diesel	7,350,000

The fuel curves for all generators in the pre-HRSG case HOMER model (before the new HRSG was installed) were created using the data WAPA provided for the period from April 1, 2009 to March 31, 2010.

The base case HOMER model (after the new HRSG was installed) used fuel curves derived from the generation data for June 1, 2010 to December 31, 2010 after the HRSG was installed. Unit #10 was not included in the model due to insufficient generator run-time data.

4.4.6 The Configuration of the St. Croix Power Plant During Normal Operations

Under normal operation, the waste heat from unit #16 and unit #20 combustion turbines feed into the unit #24 HRSG. Unit #24 HRSG uses the heat to generate steam that feeds the unit #11 steam turbine. Unit #24 HRSG can also be supplied by a boiler that burns #6 fuel oil. Unit #11 requires 265,000 lbs/hr steam to achieve its rated output of 19.1 MW, which exceeds the maximum output that unit #24 HRSG can supply on its own.

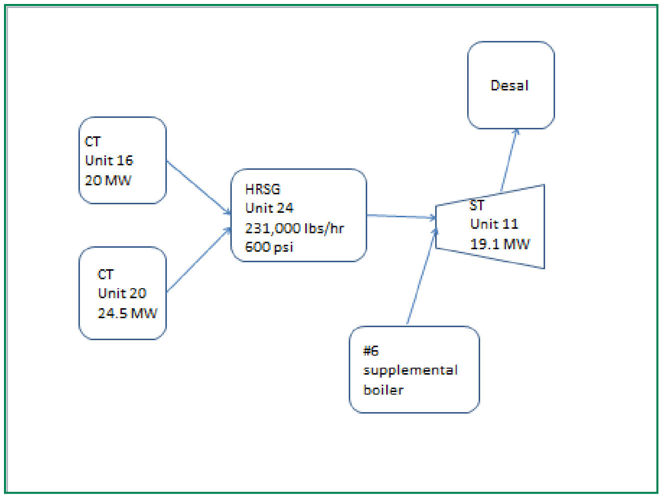


Figure 4-22. Normal operation of the power plant on St. Croix

Source: HOMER Energy LLC

For both the pre-HRSG case and base case HOMER models, unit #16 combustion turbine and unit #11 steam turbine, were modeled as a combined cycle plant with Unit #16 as the heat source and a minimum load ratio of 100% for unit #16. An additional 8,000 kW was added to the rated capacity of unit #16 based on the operational data from WAPA. Rated capacity of unit #11 steam turbine was reduced by the same amount to simulate combined cycle operation.

4.4.7 Diesel Heat Rate

The heat rate was calculated from the HOMER base case simulation results for both models (before and after the installation of the new HRSG). Efficiency was calculated from the heat rate with the conversion factor 1 kWh = 3,412 Btu. The efficiency is 3,412/heat rate. The results show a substantial improvement in aggregate power plant efficiency, from 20.67% to 30.82%.

Table 4-12. HOMER Pre-HRSG Case in St. Croix (Before New HRSG Was Installed)

Fuel energy input	**5,482,891 mmBtu**
Output electricity	332,148,608 kWh
Average heat rate	16,505 Btu/kWh
Efficiency	20.67%

Table 4-13. HOMER Base Case in St. Croix (After New HRSG Was Installed)

Fuel energy input	**3,406,994 mmBtu**
Output electricity	307,717,888 kWh
Average heat rate	11,071 Btu/kWh
Efficiency	30.82%

4.5 Hybrid Optimization Analysis—St. Croix

Similar to St. Thomas, five cases for St. Croix (STX) were analyzed using the latest HOMER base case model with the newly installed HRSG.

STX Case 1: PV—5.5 MW of new solar PV, but no wind

STX Case 2: Wind—15 MW of new wind, but no solar

STX Case 3: Wind and PV—5.5 MW of new solar PV and 15 MW of new wind

STX Case 4: WTE—16.5 MW new WTE PPA

STX Case 5: WTE and PV and wind—16.5 MW new WTE PPA, 5.5 MW of new solar PV, and 15 MW of new wind

4.5.1 St. Croix Case 1: Photovoltaic Optimization Analysis

The optimal results from the analysis using the LCOE in Table 4-1 with a 1.8% interest rate and a 3% discount rate (LCOE is $0.636 for #2 fuel and $0.538 for #6 fuel) are presented here. The 5 MW of PV was modeled at $6.00/W, with an 18.3 degree tilt, no tracking, and 50% solar operating reserve.

The fuel and cost savings can be seen below in Table 4-14. Adding PV to the existing system (base case) at St. Croix saves roughly 2.4 million liters of #2 fuel oil and 0.5 million liters of #6 fuel oil. This represents a 3.2% reduction in fuel use from the base case. This also represents a $1.8 million reduction in annual expenditure on fuel.

Table 4-14. Fuel and Cost Savings for Photovoltaic Optimization (STX Case 1) on St. Croix Compared to Base Case

	#2 Fuel Oil ($101/Barrel)	#6 Fuel Oil ($85.50/Barrel)	Total
Annual fuel savings for adding 5.5 MW of PV	2,412,000 L (15,200 barrels)	492,000 L (3,000 barrels)	**3.2% reduction in fuel use**
Annual fuel cost savings for adding 5.5 MW of PV	$1,534,000	$265,000	**$1.8M savings/year**

Table 4-15 compares the LCOE for each of the cases and includes the expected LCOE for PV alone.

Table 4-15. LCOE for Photovoltaic Optimization (STX Case 1) on St. Croix

	Base Case Only	PV Only	PV Integrated into Base Case
LCOE	$0.231/kWh	$0.212/kWh	$0.231/kWh

4.5.2 St. Croix Case 1: Photovoltaic Sensitivity Analysis

Figure 4-23 shows the results of a sensitivity analysis on the capital cost of PV and the diesel fuel price. PV prices used ranged from $4.50 to 7.50 per watt, and #2 fuel oil prices used ranged from $0.55/L ($58.66/barrel) to $0.80/L ($93/ barrel). For St. Croix, the graph shows that the cost of PV would need to be ~ $5.00/W or less to be cost effective (light pink area) at low fuel prices $0.55/L ($58.66/barrel). However, as fuel prices increase, the sensitivity analysis on this crucial parameter shows PV can be cost effective at a higher installed cost of around ~$6.5/W.

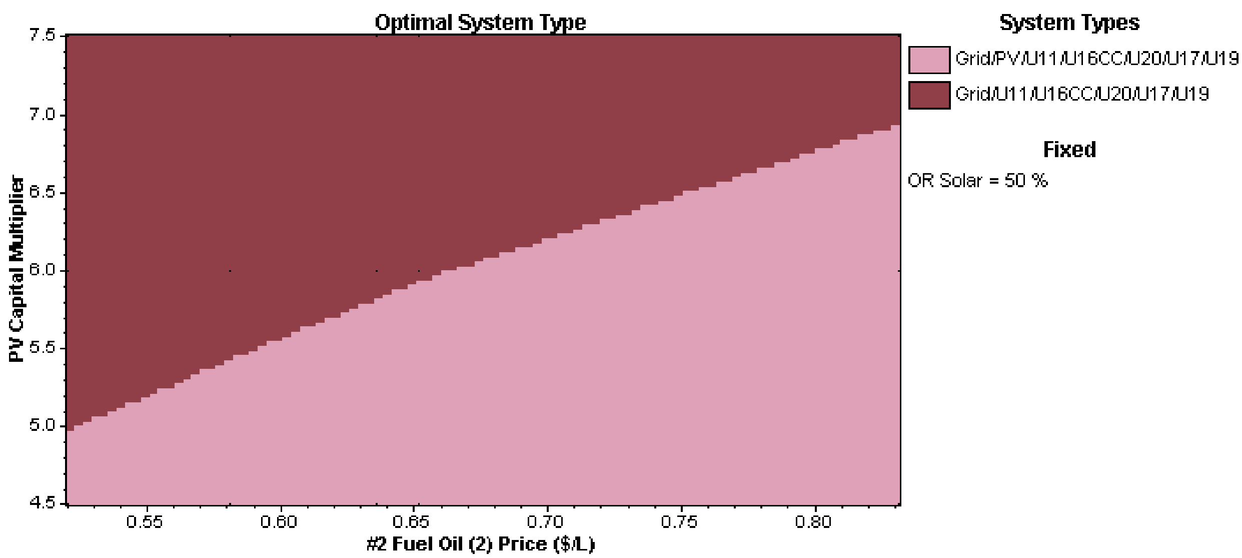


Figure 4-23. St. Croix PV and generator sensitivity analysis with 50% operating reserve

Source: HOMER Energy LLC

Figure 4-23 assumes that the system only needs spinning reserve sufficient to cover 50% of the solar output in any hour. The more conservative assumption of Figure 4-24 (100% operating reserve) reduces the cost-effectiveness of PV significantly. With the higher efficiency of the new plant and a conservative operating reserve assumption, PV would need a capital cost of approximately $4.50/W to be cost effective.

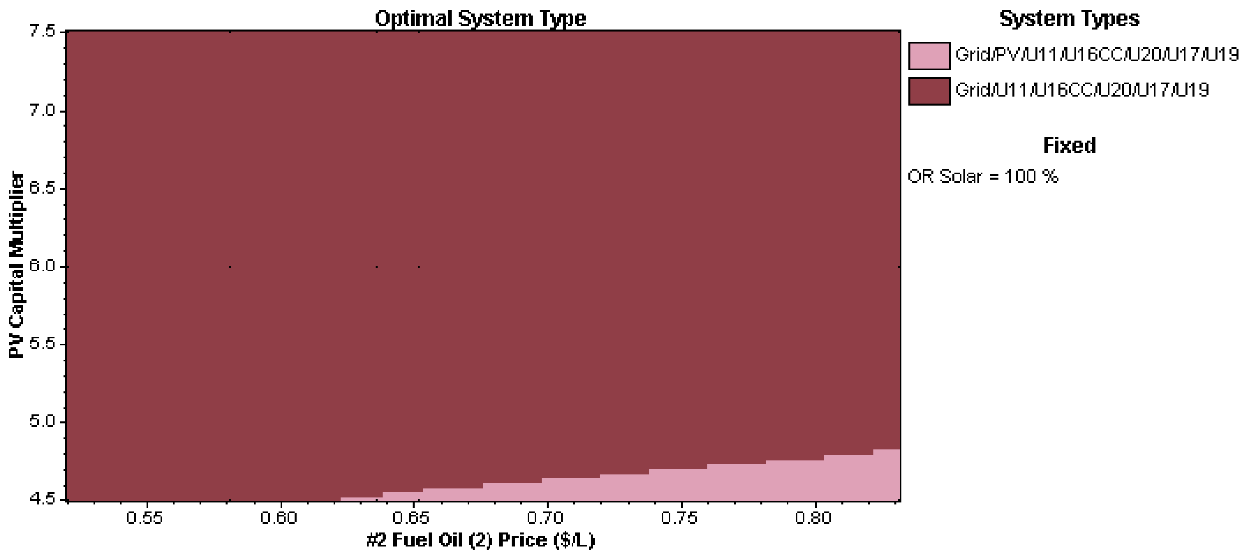


Figure 4-24. St. Croix PV and generator sensitivity analysis with 100% operating reserve

Source: HOMER Energy LLC

4.5.3 St. Croix Case 2: Wind Optimization Analysis

The optimal results presented here are from the analysis using the LCOE in Table 4-1, with a 1.8% interest rate and 3% discount rate (LCOE is $0.636 for #2 fuel and $0.538 for #6 fuel). The 15 MW of wind was modeled at ~$2,500 per kW, and 50% operating reserve.

The annual fuel and cost savings indicated by the analysis are presented in Table 4-16. Adding wind to the existing system (base case) at St. Croix saves roughly 13.7 million liters of #2 fuel oil and 3.3 million liters of #6 fuel oil. This represents a 14% reduction in fuel use from the base case. This also represents a $8.3 million reduction in annual expenditure on fuel.

Table 4-16. Fuel and Cost Savings for Wind Optimization (STX Case 2) on St. Croix Compared to Base Case

	#2 Fuel Oil ($101/Barrel)	#6 Fuel Oil ($85.50/Barrel)	Total
Annual fuel savings for adding 15 MW of wind	13,735,000 L (86,400 barrels)	3,302,000 L (20,800 barrels)	**14% reduction in fuel use**
Annual fuel cost savings for adding 15 MW of wind	$7,985,000	$383,000	**$8.3M savings/year**

Table 4-17 compares the LCOE for each of the cases and presents the expected LCOE for wind alone.

Table 4-17. Levelized Cost of Energy for Wind Optimization (STX Case 2) on St. Croix

	Base Case Only	Wind Only	Wind Integrated into Base Case
LCOE	$0.231/kWh	$0.056/kWh	$0.210/kWh

4.5.4 St. Croix Case 2: Wind Sensitivity Analysis

For St. Croix, as for St. Thomas, wind power is more cost effective than PV. Sensitivity analysis was done on the crucial parameter of wind speed, which is highly dependent on the site. Small changes in location and height can have a large impact on the project.

Figure 4-25 shows the results of a similar analysis that was done for St. Croix with conservative parameters—a capital cost multiplier of 2 and operating reserve at 50%. The sensitivity analysis shows that wind (light brown color) is cost effective with wind speeds as low as 5.5 meters per second and low fuel costs of $0.55/L ($58.66/barrel).

Figure 4-26 portrays the results of an analysis performed with even more conservative parameters—100% operating reserve and a high interest rate of 8%. Still, the analysis shows, wind is cost effective (the light brown color) at wind speeds above 6.5 meters per second.

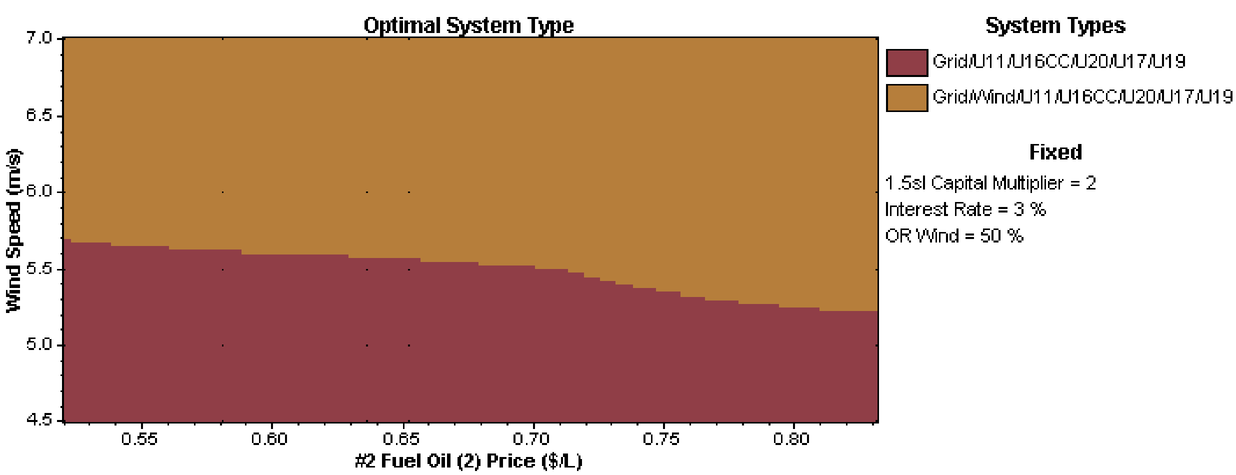


Figure 4-25. St. Croix wind and generator sensitivity analysis with 50% operating reserve

Source: HOMER Energy LLC

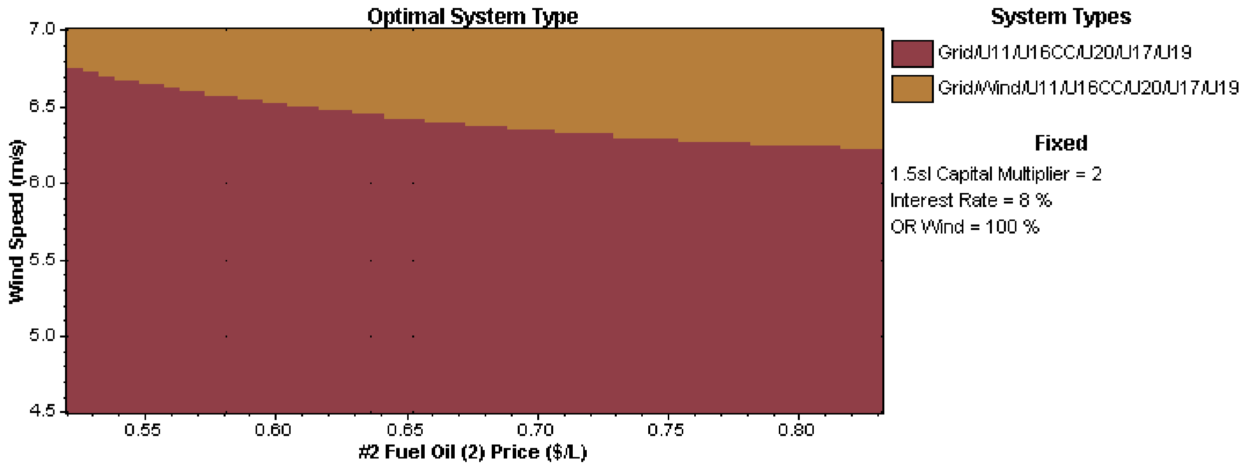


Figure 4-26. St. Croix wind and generator sensitivity analysis with 100% operating reserve

Source: HOMER Energy LLC

4.5.5 St. Croix Case 3: PV and Wind Sensitivity Analysis

The third case considered a combination of 5.5 MW of solar PV and 15 MW of wind. The results shown in Figure 4-27 and Figure 4-28 indicate that in the hybrid system solution, PV (blue) does not compete, especially at a high solar PV operating reserve of around 100%, as shown specifically in Figure 4-28. The brown color represents the hybrid configuration with wind turbines and diesel generators only (without PV).

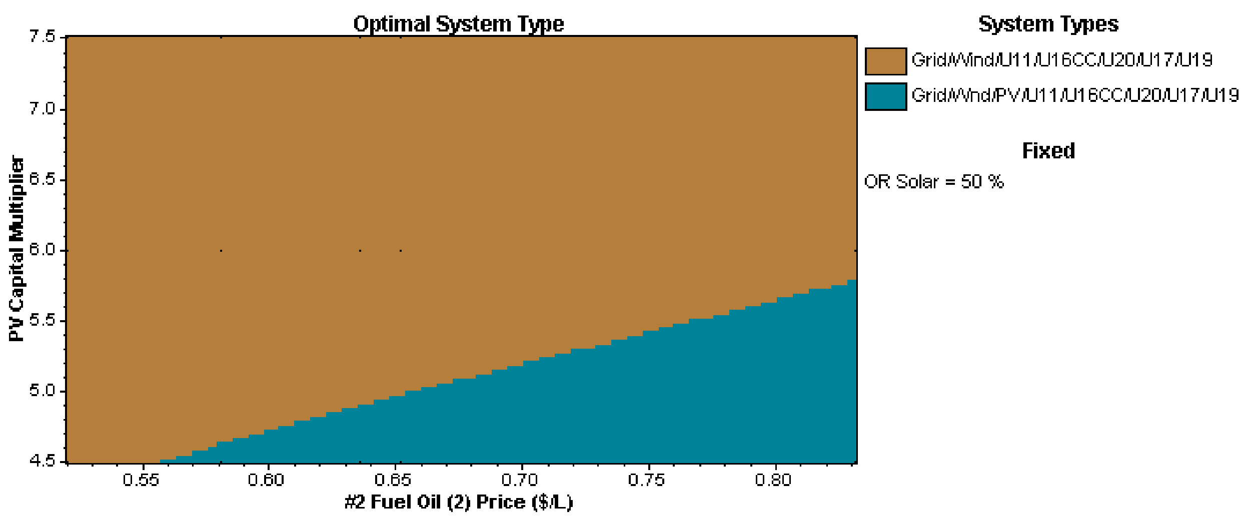


Figure 4-27. St. Croix PV, wind, and generator sensitivity analysis with 50% operating reserve

Source: HOMER Energy LLC

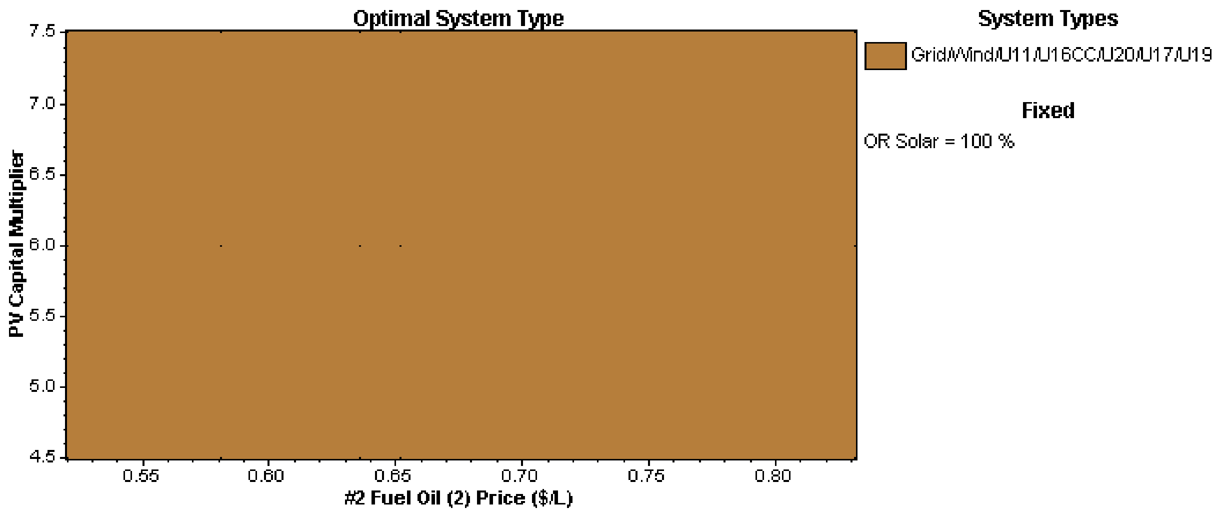


Figure 4-28. St. Croix PV, wind, and generator sensitivity analysis with 100% operating reserve

Source: HOMER Energy LLC

4.5.6 St. Croix Case 4: Waste-to-Energy

St. Croix has signed an agreement with Alpine Energy Group to install a 16.5 MW WTE plant, to be installed under a power purchase agreement (PPA).

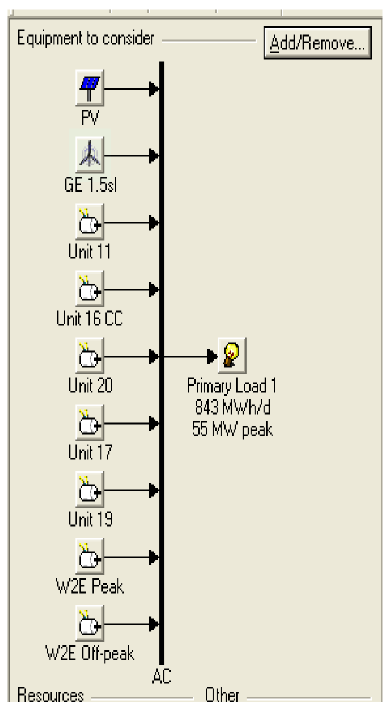


Figure 4-29. Model of St. Croix after the WTE plant has been installed; for case 4, the PV and wind quantities are set to zero

Source: HOMER Energy LLC

To model the WTE plant in HOMER, two new generators were added to the base case. One generator operates on the peak period pricing schedule, and the other is scheduled on the off-peak hours at off-peak pricing. The two generators are not allowed to run at the same time. The minimum load ratio for the WTE generators in HOMER was set to a sufficiently high level to achieve at least minimum annual energy purchase requirement, 91,646 MWh (approximately a 63.4% capacity factor). The expected purchase amount is summarized below in Table 4-18.

Table 4-18. Expected Energy Purchases Under the WTE PPA (STX Case 4) on St. Croix

	Peak	Off-Peak	Total
WTE energy purchased annually	60,710,000 kWh	51,170,000 kWh	111,880,000 kWh
Annual WTE PPA cost ($ million)	$11.1	$9.0	$20.1

The fuel and cost savings can be seen below in Table 4-19. Adding the WTE PPA to the existing system (base case) for St. Croix saves roughly 34.7 million liters of #2 fuel oil and 0.6 million liters of #6 fuel oil. This represents a 39% reduction in fuel use from the base case. This also represents a $22.4 million reduction in annual expenditure on fuel.

Table 4-19. Fuel and Cost Savings for the WTE PPA (STX Case 4) on St. Croix Compared to Base Case

	#2 Fuel Oil ($101/Barrel)	#6 Fuel Oil ($85.50/Barrel)	Total
Annual fuel savings for adding WTE PPA	34,720,000 L (218,400 barrels)	594,000 L (3,700 barrels)	**39% reduction in fuel use**
Annual fuel cost savings for adding WTE PPA	$22,057,000	$320,000	**$22.4M savings/year**

Table 4-20 compares the LCOE for the base case to the LCOE for the system after the WTE PPA.

Table 4-20. Levelized Cost of Energy for WTE PPA (STX Case 4) on St. Croix

	Base Case	WTE PPA Integrated into Base Case
LCOE	$0.231/kWh	$0.206/kWh

4.5.7 St. Croix Case 5: Waste-to-Energy, Photovoltaic, and Wind

To analyze the impact of PV and wind on the purchase of the waste-to-energy plant, the system was modeled with the 16.5 MW WTE PPA, 5.5 MW of PV, and 15 MW of wind added to the base case. The results from the HOMER simulation give the expected annual WTE energy purchases and fuel and cost savings. The expected purchase amount is summarized below in Table 4-21.

Table 4-21. Expected Energy Purchases under the WTE PPA with Photovoltaic and Wind (STX Case 5) on St. Croix

	Peak	Off-peak	Total
WTE energy purchased annually	60,180,000 kWh	44,510,000 kWh	111,880,000 kWh
Annual WTE PPA cost ($ million)	$11.0	$7.9	$18.9

The fuel and cost savings from the base case can be seen below in Table 4-22. Adding the WTE PPA to the existing system (base case) on St. Croix saves roughly 41.7 million liters of #2 fuel oil but uses roughly 0.08 million liters more of #6 fuel oil. Overall, this still represents a 46% reduction in fuel use from the base case. It also represents a $26.4 million reduction in annual expenditure on fuel.

Table 4-22. Fuel and Cost Savings for the WTE PPE with PV and Wind (STX Case 5) on St. Croix Compared to Base Case

	#2 Fuel Oil ($101/barrel)	#6 Fuel Oil ($85.50/barrel)	Total
Annual fuel savings for adding WTE PPA and wind and PV	41,685,000 L (262,200 barrels)	76,000 L *increase* (500 barrels)	**46% reduction in fuel use**
Annual fuel cost savings for adding WTE PPA and wind and PV	$26,482,000	$41,000 *increase*	**$26.4M savings/year**

In Table 4-23, the LCOE for the base case is compared to the LCOE for the system after the WTE PPA and the LCOE for the system with the WTE PPA, wind, and PV.

Table 4-23. LCOE for WTE PPA (STX Case 5) on St. Croix

	Base case	WTE PPA integrated into base case (STX Case 4)	WTE PPA, wind, and PV integrated into the base case (STX Case 5)
LCOE	$0.231/kWh	$0.206/kWh	$0.207/kWh

From the LCOE for STX Case 4 and STX Case 5, it can be seen that wind and PV only very marginally increase the cost of energy for St. Croix. However, wind and PV reduce the annual fuel expenditure by about $4.0 million below what it would be with the WTE PPA alone.

4.6 Summary of the HOMER Analysis

The HOMER analysis shows wind turbines appear to be the most economically feasible alternative power for both islands, even with very conservative assumptions for operating reserve and capital costs:

- Wind is cost effective even at low fuel prices.
- 15 MW of wind can reduce the fuel usage by 9% on St. Thomas and 14% on St. Croix.
- PV becomes cost effective when the cost is less than around \$6/W or as fuel prices go above \$99/barrel.
- Under the proposed PPA, modeling indicates that the WTE plant is cost effective. The WTE is also cost effective when combined with PV and wind.

These are only approximate or illustrative results. Precise results require much more information about the power system and the solar resource.[12] Examples of additional data required for precise results concerning the required level of spinning reserve are:

- Generating unit start-up times
- Generating unit ramp rates
- Automatic generating control (AGC) settings
- Frequency tolerances within the system
- Physical constraints within the transmission and distribution system
- Subhourly variability of the solar resource
- Quality of solar resource forecasting
- Geographic diversity of the PV installations.

The last point is worth further elaboration. The installation cost for a large PV array can be 10% to 20% lower than for multiple smaller arrays. However, if the multiple smaller arrays are sufficiently separated geographically, then individual clouds will not have the same near-simultaneous impact on the system output. One way to view the difference between 50% operating reserve and 100% operating reserve is that 100% operating reserve assumes that all of the PV is packed tightly in a single array, whereas 50% operating reserve assumes the PV is scattered throughout the island. These indicative results suggest that the cost premium for

[12]For example, systems with generating units that have short start-up times and fast ramp rates need less spinning reserve. This is affected by settings on the Automatic generating controls (AGCs). Many units have two different sets of ramp rates, one for normal conditions and a higher one for emergency conditions. The higher ramp rates can be used to avoid outages but create thermal and other stresses on the equipment. It is difficult to assess the economic impact of these higher ramp rates because the increased O&M cost is rarely quantified and is only part of the impact. The appropriate level of spinning reserve is also affected by the system's frequency stability requirements. This is tightly regulated in interconnected utilities, but island utilities have more latitude to tolerate frequency excursions. Nevertheless, it is good utility practice to limit frequency excursions because large excursions can be damaging to equipment and jeopardize system stability. The stability impacts of these transient events that occur at a time scale measured in seconds or less cannot be modeled with the same model that simulates an entire year of operation and performs optimizations and sensitivity analysis on economic factors.

distributed PV over a single large array might be more than compensated by savings in operating reserve. A firm conclusion on this question will require more detailed modeling that analyzes the other factors listed above over a short time frame.

Other factors that influence the cost-effectiveness of PV are the cost of capital for the PV and the efficiency and operations and maintenance (O&M) cost functions of the system's other generating units. The HOMER analysis performed for St. Thomas and St. Croix assumed a real (inflation-adjusted) interest rate of 3%. This is approximately equal to a 5% nominal interest rate. This is a low rate appropriate for entities with good credit ratings, loan guarantees, or other government support.

Overall, wind energy appears to be the most economically feasible alternative, even with very conservative assumptions for operating reserve and interest rate. Further detailed studies should be done to obtain quality wind resource data for specific chosen sites.

4.6.1 Resolution of Data Issues

These should be considered approximate results. It was not possible to verify the accuracy of much of the input data, some of which appears from a qualitative review to have significant gaps. Better data and modifications to the modeling methodology would be necessary for more accurate simulation of the run times and fuel consumption figures for individual WAPA generating units. Even very complex and expensive commercial utility models do not explicitly model the part-load performance of steam turbines in a combined cycle configuration, especially with multiple options for steam extraction for desalination.

Finally, it is recommended that all WAPA generating units have accurate meters that automatically record hourly fuel consumption, the pressures and flow rates of all steam flows, and each generator's power production.

5 Survey of Potential Sites for Renewable Energy

This section summarizes the efforts to measure the wind and solar resource on St. Thomas and St. Croix and outlines potential locations for implementing PV and wind turbines projects.

5.1 Wind and Solar Resource Measurements

As described in the previous section, wind appears to be quite cost-competitive under the current pricing structure, and PV can help diversify WAPA's generation mix to hedge against future price spikes. However, these technologies are difficult to finance and deploy without accurate measurements of the renewable energy resource.

To improve resource characterization, the Virgin Islands Energy Office (VIEO) is funding a wind and solar resource measurement effort with American Recovery and Reinvestment Act (ARRA) money and additional funding provided by WAPA. With a limited budget, VIEO is targeting two areas on each island that show both a promising wind resource and potential for development. Wind and solar resource measurement stations will be deployed on the Bovoni Point on St. Thomas and on the southern shore of St. Croix.

Wind measurements are important to acquire at least 12 months of "bankable" data. The energy generated from wind turbines is a function of the cube of wind speed. So a 25% error in estimation of the wind speed will result in a 95% error in energy production. Since the energy generated and therefore project economics are so sensitive to the wind resource, financiers often require a minimum of one year of wind resource data on a site before they will fund a project.

Solar resource instrumentation is being added to the wind anemometer stations at little additional cost to improve models of cloud movement. This data will contribute to models that will contribute to a better understanding of the impact of high levels of PV integration into the distribution system.

One challenge to significant penetration of renewable wind and solar PV systems is the land constraints inherent to the USVI's small, mountainous islands. This section describes a preliminary review of potential sites for PV and wind systems.

5.2 Locating Photovoltaic Systems

The first criterion for selecting a site for a PV system is that it not be shaded by adjacent trees, buildings, geographic features, etc. Individual grid-tied systems can be as small as a few kilowatts and as large as many megawatts, the maximum size being constrained by available space and the capacity of the utility's electrical distribution system.

PV systems can be installed on open space, roofs, or structures built above parking lots. USVI citizens and government could give first preference to developing PV systems on the built environment before developing open space. Both net-metered systems and systems owned by independent power producers (IPPs) selling power directly to WAPA can be located on roofs, but it is likely smaller roofs will be developed with net-metered systems because individual utility customers, if they can afford to self-finance PV systems, will find it far more cost effective to offset retail energy rates than to sell wholesale power to the utility. In addition, due to high fixed costs for each IPP site, smaller sites seem less likely to be developed for wholesale generation.

As part of this work, the USVI government (GVI) roof area was surveyed to estimate how much rooftop PV could potentially be deployed. Government roofs were identified by Allyson Gregory, WAPA distribution engineer, and analyzed by NREL for total potential PV nameplate capacity. Individual roofs were not inspected, and the appropriateness of any roof in terms of structural capacity and roofing condition will have to be determined to refine these preliminary numbers. The results assume 8 W/ft^2 of roof area, with one-fifth of the roof area being structurally sound and in good condition (typically less than 5 to 7 years old).

The results of the government roof area survey are show in Table 5-1, and a few of the roofs surveyed are shown in Figure 5-1. Roofs were screened using Google Earth to identify open areas without mechanical equipment or other penetrations, with reasonable southern exposure, and not obviously shaded by structures or trees. A summary of all buildings surveyed in both districts is shown in Appendix D.

Table 5-1. USVI Government Preliminary Rooftop Survey for PV

	St. Thomas	St. Croix
Area of roof top identified	15.8 acres	15.5 acres
Viable rooftop (assumes 20%)	3.2 acres	3.1 acres
Potential PV capacity of viable rooftop	1.1 MW	1.0 MW

Figure 5-1. Roof area survey screen shot, St. Thomas, with potential PV locations identified in green

GVI open space was also surveyed for potential location of ground mount systems. Promising sites will be secured by WAPA and included in WAPA's PV PPA RFP for potential development. Allyson Gregory identified GVI-owned open space. Ground sites were screened by estimating available PV system size based on acreage and checking the potential capacity of each feeder to support PV interconnection. Although no developable GVI-controlled sites have been identified on St. Thomas. St. Croix has some good parcels adjacent to highly loaded distribution. (See Table 5-2, Figure 5-2, and Figure 5-3.

Table 5-2. PV Capacity Potential of GVI Open Space

	Island	Land Area	Potential PV System Size	Notes
Spanish Town Substation	STX	12 acres	2 MW	Future site of new substation. Allows PV system to interconnect into feeder 8 and some portion of 9 and 10.
Vacant Site by Richmond Substation	STX	4.5 acres	0.75 MW	Allows PV system to interconnect directly into entire distribution system.

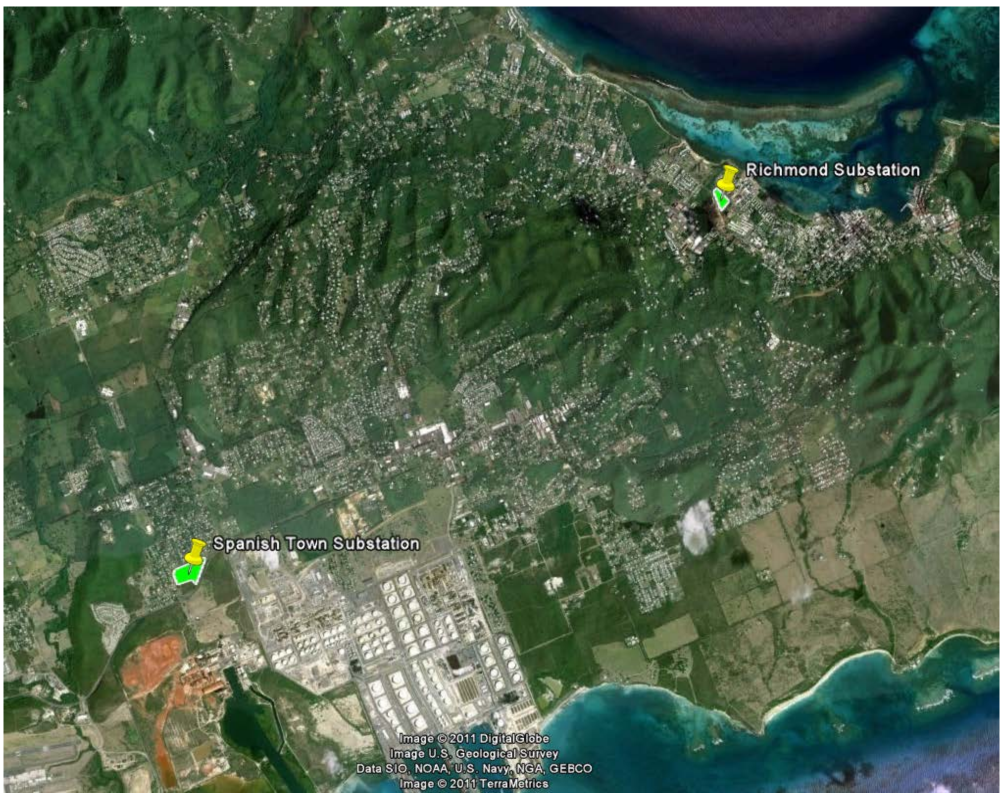


Figure 5-2. GVI-identified open space on St. Croix

Figure 5-3. GVI property on St. Croix

5.3 Locating Wind Energy Systems

Wind turbines need to be erected where the wind resource is best to maximize energy production and economic viability. In the USVI, trade winds prevail from the east. Per unit of generating capacity, individual wind turbines do not require as much open space as PV systems; however, they need to be spaced appropriately to ensure that one turbine doesn't interfere with another's wind resource and that the turbines do not impose on surrounding residential and commercial land.

Turbines need to be located in areas with exposure to the trade winds. The best sites are flat areas unobstructed by mountains or hills and along exposed ridge crests. Because of this, considerably fewer areas are appropriate for wind development than for PV. In addition, because the better wind resource is accessed by taller, larger systems, large-scale penetration of wind necessitates deployment of large, conspicuous turbines. It will be necessary to anticipate and begin to address wind development concerns regarding noise, viewscape, land values, and wildlife impact through balanced regulations and communicative interaction with the general population.

The southern shore of St. Croix identified in Figure 5-4, has excellent exposure to trade winds. And because it is flat, has a relatively low population, and includes a significant industrial presence, it has excellent development potential. Furthermore, the erection of wind turbines does not preclude continued use of the land for agriculture or other development.

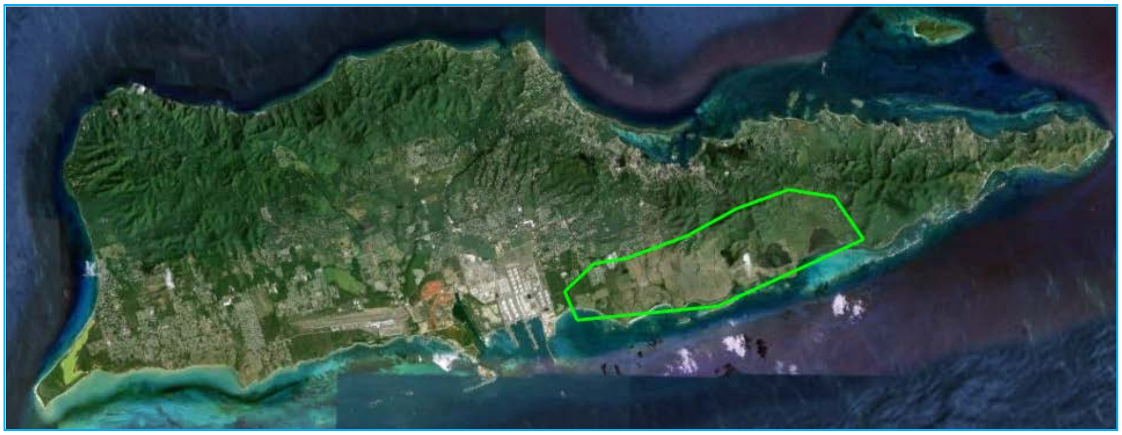


Figure 5-4. STX regions with excellent wind development potential

Figure 5-5. Bovoni Point on STT has promising potential for wind development

Bovoni Point on St. Thomas has good exposure to the easterly trade winds and is an industrial site that includes a landfill. There could be space for as much as 5 MW of wind generation there. The ridge crests on St. Thomas also have good exposure to the wind resource; however, development might be challenged by difficulty of access, which could limit the size of turbines that can be deployed in this area.

6 Impact of High Penetration of Renewables on the Electric Power System

6.1 Dispatchable and Nondispatchable Renewable Energy Generation

There is an important difference between renewable energy generated using renewable fuels in conventional power systems (e.g., internal combustion engine or boiler with steam turbine) and that energy generated from PV or wind systems. The utility can control, or dispatch, the output of the former, but it does not have complete control of intermittent energy sources like wind and solar. Wind and solar are highly variable resources. Wind varies by season, time of day, and from minute-to-minute. Solar insolation varies from day to night but also fluctuates quickly with passing clouds.

Because the "fuel" resources for wind and PV systems are intermittent, the power from these systems needs to be either used as generated, stored, discarded, or credited as "net-metered" energy. Energy that can be generated on demand is called "dispatchable," while energy that is generated intermittently as the sun shines or wind blows is "nondispatchable." Integration of energy storage devices with nondispatchable PV systems and wind turbines will convert them to dispatchable power systems. However, batteries, flywheels, and other such storage devices add significant costs. Net-metering permits a utility customer to use the utility like a battery; excess energy is sent to the grid, and the customer receives a credit that is redeemed the next time the customer's load exceeds the renewable energy system's output. However, net-metering as a policy does not address the technical challenges that may arise for the utility when significant levels of nondispatchable power are interconnected with an islanded system.

6.2 Nondispatchable Renewable Energy and Power Regulation

WAPA's power plants include control systems that follow the instantaneous power demands of its customers. Figure 6-1 shows a typical week's load profile for St. Thomas. The blue line shows the power needs of the customers. Since essentially all power is provided by the plant at Krum Bay, the profile of the power generated by the plant is identical to the load, and therefore the load demand profile shown in the figure is also the power generation profile of the plant.

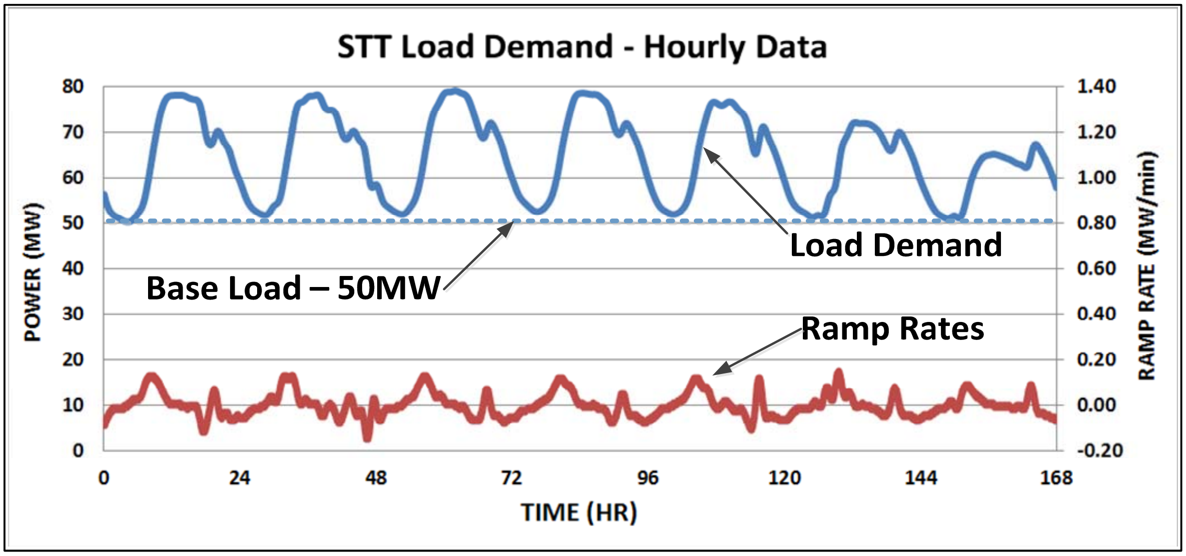


Figure 6-1. Typical weekly load profile on St. Thomas

Source: NREL

It is the task of the plant's operators, generators, and control system to adjust to the constantly changing power needs of its customers. This balancing of load and supply is called regulation. The rate of change of the load demand (MW/minute), or ramp rate, shown in red in Figure 6-1, describes the level of challenge the plant will have regulating to the load.

As distributed energy feeds into the distribution system and is consumed by utility customers, the central plant is no longer needed to meet the full demand, but its regulation responsibility remains. When the distributed energy generated is very small, the impact on the plant's power generation profile is slight and may be imperceptible to the plant's control system and operators. However, as the level of distributed generation (DG) increases, the load profile perceived by the plant will begin to change. With dispatchable DG, such as the planned waste-to-energy plant on St. Croix, the general shape of the load profile may not change, but it will shift downward. With significant levels of highly variable, nondispatchable PV or wind systems, the character of the load profile at the plant will begin to change.

As an extreme example, Figure 6-2 and Figure 6-3 demonstrate the potential impact that 30 MW of wind turbines may have. This represents about 37% wind capacity penetration (ratio between installed wind power capacity and peak load). The blue trace in Figure 6-2 shows the load needs of the utility customers is unchanged, as in Figure 6-1. The red trace shows power generation of the 30 MW wind system based on a model using a simulated variable wind resource.

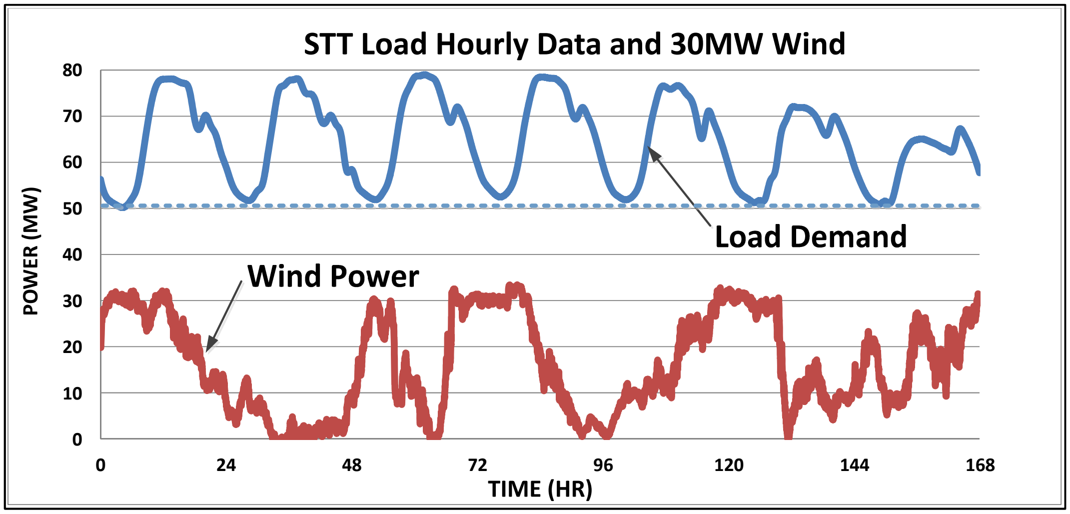


Figure 6-2. Typical weekly load and simulated power generated from a 30 MW wind system on St. Thomas

Source: NREL

The blue trace in Figure 6-3 shows how the customer load and DG combine, significantly changing the load profile that the central plant needs to meet. The minimum load has dropped 30 MW (from 50 MW to 20 MW), and the load no longer follows the regular habits of the utility customers but reflects more closely the irregularity of the wind resource.

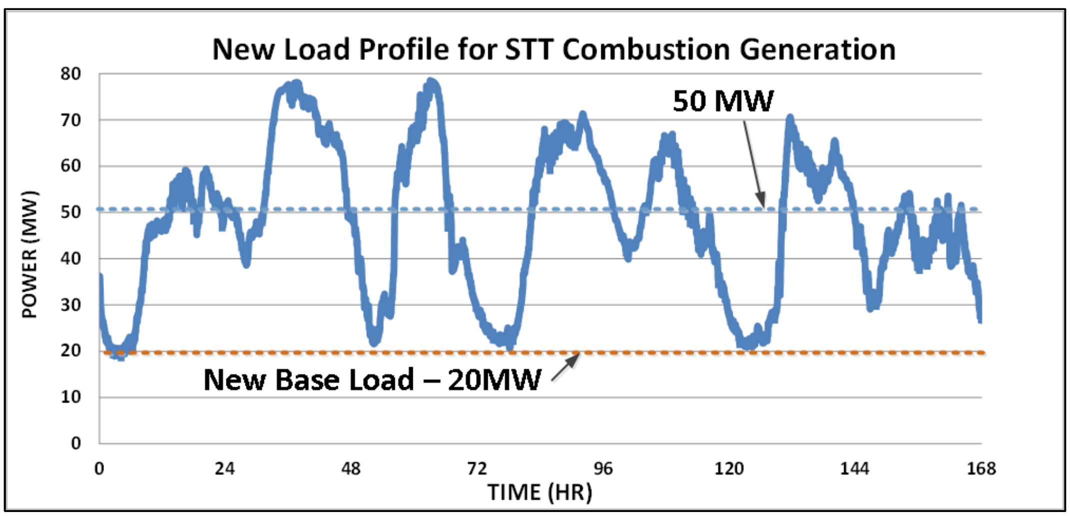


Figure 6-3. Simulated plant load demand on St. Thomas with 30 MW of wind turbines

Source: NREL

The total energy provided from the central plant is significantly lower, so less fuel is burned. However, the central plant's regulation task to balance supply and load is more challenging, as shown in Figure 6-4. The ramp rates with significant wind generation are shown in blue, with magnitude displayed on the left axis, while the ramp rates before wind are shown in red and on the right axis. In this extreme example, the central plant's combustion generators and control system need to be able to respond to a thirty-fold increase in ramp rates.

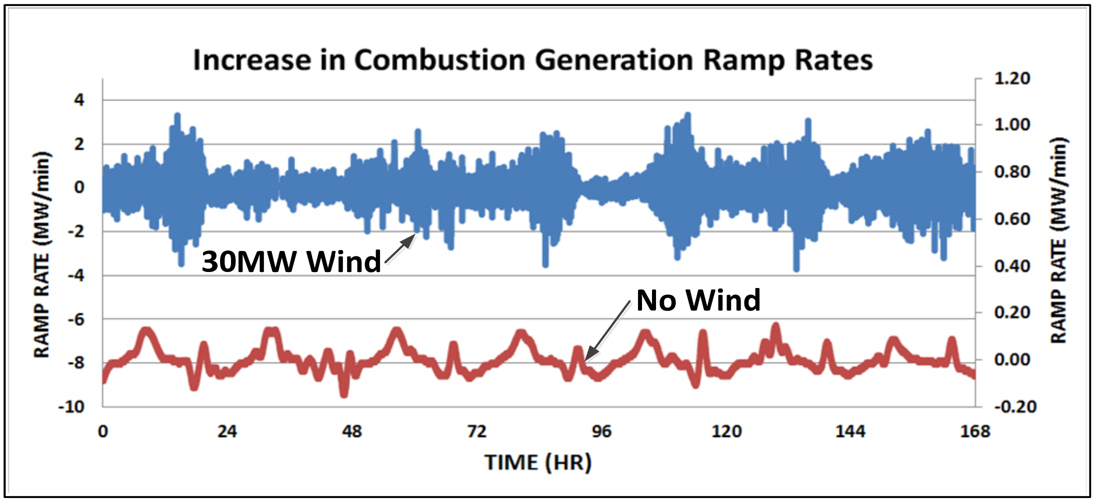


Figure 6-4. Simulated demand ramp rates on St. Thomas with and without 30 MW of wind

Source: NREL

With low levels of nondispatchable DG, WAPA's existing generation and distribution system will accommodate low levels of nondispatchable DG without concern or modification. As renewable energy penetration levels increase, significant DG with high variability will increase regulation requirements and potentially:

- Increase combustion generation wear and tear
- Increase emissions
- Reduce generator efficiency.

High levels of variable renewable generation require significant changes in utilities' operational practices. Improving conventional generation flexibility by adding faster response gas units and reducing minimum loading level on steam turbines is one potential solution. Additional methods may include incorporating wind power forecasting into utilities' day-ahead planning process. Other means of absorbing renewables' variability, such as demand response and energy storage, can be used as well.

In interconnected power systems including two or more islands, there are additional opportunities for sharing regulation resources, which helps lower the integration costs of variable renewable generation. For instance, for the regulation example shown in Figure 6-4, such increase in ramp rates can be met more cost-effectively by Puerto Rico's power system, since PREPA's generation has better heat rates and more flexible regulation reserves (assuming such interconnections exist between the USVI and Puerto Rico). Also, larger interconnected systems allow taking advantage of geographical diversity and consequent smoothing effects on aggregate wind or PV generation output. Such smoothing is another important mitigation factor helping absorb more variable generation on a regional rather than individual island level.
Nondispatchable DG Impact on the Distribution System

As part of the renewable energy integration analysis, an assessment of the existing electrical distribution system is required to determine whether the electrical infrastructure is robust enough to accommodate the proposed energy generation systems. As discussed, intermittent generation is more difficult to incorporate into small island grids than dispatchable generation such as biomass power. Basic calculations and a working knowledge of the capacity of the existing infrastructure can provide information necessary to determine the feasibility and approximate costs of the recommended energy projects.

When considering interconnection locations for distributed generation, a review of modifications to the secondary system, such as new distribution equipment, distribution transformer upgrades, and secondary protection system changes, are assumed to be a reasonable part of the design process, and this work should be completed as part of each project. Upgrades to the secondary distribution system that are necessary to safely implement the project should be included in the scope of individual project proposals.

Distribution system impacts depend on project size, location, and type of distributed generation (wind, solar, etc.). Many projects are expected to have minimal impact on the local distribution system and may in fact provide stability to the system when properly planned and coordinated. In general, PV projects that contribute less power than the minimum load on a feeder will offset the feeder load, with no power flow back to the substation.

6.2.1 Establishing Strategies and Limits for High Penetration of DG

Technical issues can be addressed with adequate planning and upgrades to the distribution system as needed. Clearly, up to some size level of DG deployment, we know WAPA doesn't need to worry about the high variability of wind and PV systems because their impact is within the design envelope of the existing regulation and distribution systems. However, to reach the 60% reductions prescribed by the 2025 road map, PV and wind penetration levels will have to increase to the point that the existing infrastructure will need to be upgraded. The precise level of DG that begins to challenge existing architecture will not be known until the system and its components (individual feeders or generation assets) are modeled and analyzed. High-penetration, variable-generation impact studies will:

- Model distribution systems
- Add target levels of wind and solar penetration
- Identify and quantify potential system performance and operational problems
- Identify and evaluate possible mitigation strategies.

These mitigation strategies can include:

- Load shedding through demand side management (DSM) programs and employment of deferrable load controls (e.g., water pumping or desalination)
- Energy and power storage systems
- Interconnection to the generation systems on neighboring islands via undersea cables
- Wind farm and PV system forecasting
- Advanced technologies of the DG systems themselves, including:

- Modern variable-speed wind turbines, which can provide limits on ramp rates, balance control, and limit power
- PV inverters, which in the near future will have utility-friendly features, including dynamic control of ramp rate and curtailment of power.

Before these studies are performed, a conservative upper limit for variable DG can be established to allow DG development to begin. First steps—already taken with net-metered utility customers, and to be followed by independent power producers operating in parallel to WAPA's central plants and selling energy directly to WAPA—have already begun to develop on-island knowledge, processes, and regulatory structures.

For WAPA's solar PV RFP released in May 2011, NREL, WAPA distribution engineers, and WAPA's hired attorneys developed DG interconnection procedures for the USVI that set an upper limit on penetration levels per feeder that allow DG installations to proceed without concern that the existing infrastructure will be unable to accommodate it. The limits are established per feeder and address distribution system considerations. Higher DG penetration levels will be allowed per feeder after engineering studies demonstrate that no adverse issues will arise or necessary mitigation strategies are identified and followed.

USVI interconnection requirements and procedures were developed from:

- A previous WAPA PPA
- Model procedures developed by the Interstate Renewable Energy Council (IREC) (ref: http://irecusa.org/wp-content/uploads/2010/01/IREC-Interconnection-Procedures-2010final.pdf)
- Review of Hawaii's Kauai Island Utility Cooperative procedures (ref: http://www.kiuc.coop/IRP/Tariff/Tariff_2.PDF
- Study of IEEE standard 1547, details of WAPA's feeders , and other utility interconnection requirements

7 Impact Analysis of the Electrical Distribution System

7.1 WAPA Electrical Distribution Systems and Loads

WAPA's electrical facilities include generating stations, subtransmission lines, and distribution electric power systems that deliver power to the customer loads (energy consumers). The WAPA distribution substations provide the tie between the subtransmission system, where most generation is currently interconnected, and the distribution system. The distribution system consists of the substation feeder breakers, poles, isolation switches/fuses, and circuits used to provide power to distribution transformers that serve individual or small groups of customers. WAPA distribution feeders are radial and have only one source of power (i.e., the distribution substation). The typical WAPA area electric power system (EPS) is regulated at its source substation with automatic load tap changing transformers and fixed shunt capacitor banks.

Feeder listings for customers on both St. Thomas/St. John and St. Croix, as shown in Table 7-1 and Table 7-2 respectively, can be found on WAPA's website http://www.WAPA.vi/Customers/Feeder.aspx.

Table 7-1. St. Thomas and St. John Feeder Listing

PARTNER OF THE YEAR

St. Thomas & St. John Feeder Listing

Feeder #5
C. E. K. Airport
Water Island
Best Western
Emerald Beach
Beach Comber

Feeder #6
Bonne Esperance
Bordeaux
Botany Bay
Bournefield
Caret Bay*
Contant*
Crown & Hawk
Crown Mountain
Fortuna
Hope
John Dunkoe*
Lindberg Bay
Nisky
Pearl Estate*
Plantation Manor
Santa Maria
Scott Free
Solberg*
Soto Town*
The Towers
Univ of VI
VI Source

Feeder #7A
Agnes Fancy
Altona & Welgunst
Bonne Resolution
Caret Bay*
Contant*
Dorethea
John Dunkoe*
Hull Bay*
Lerkenlund
Liliendahl
Mahogany Estate*
Marienhoj
Misgunst
Mountain Top
Nelttiberg
Nissky Center*
Northstar Village
Pearl Estate*
Solberg*
Sorgenfri *
St. Peter Mt Rd

Feeder #7B
1st Avenue
5th Street
7th Street
8th Street
9th Street
10th Street
Lockhart Gardens
Lucinda Millin*
Oswald Harris Court
Pmp Gardens*
Pueblo Longbay
Raphune Hill
Vitraco Park
Wheatley Center
Estate Thomas*

Feeder #7C
Annas Retreat*
Cassi Hill
Emerald Hill*
Foster Plaza
Fourwinds
Hidden Valley*
Lima Fire Co.
Mandahl*
New Tutu
Old Tutu*
Seventh Day Adv
Smith Bay*
Tabor & Harmony
Time Center
Tutu High Rise

Feeder #7D
American Yacht Harbor
Bottom Cassi Hill
Emerald Hill*
Frydendahl*
Kean High School
National Guard
Nazareth*
Point Pleasant
Red Hook
Rennaissance
Sapphire
Smith Bay
Red Hook Plaza
Water Bay Condo

Feeder #7E
STJ Substation/Echo
Bordeaux (STJ)*
Cruz Bay *
East End
Lameshur
Northside
Peterbay
Caneel Bay
Gallows Point

Feeder #8A
Agnes Fancy*
Annas Fancy
C. A. H. S.*
Contant*
Danish Consulate
Estate Ross
Garden Street
Hospital Ground*
Knud Hansen
Lockhart School
Lytton's Fancy
Mahogany Estate*
Nisky Center*
RLS Hospital*
Savan*
Staabiland
Vester Gade
WSTA

Feeder #8B
7th Day Street
Alexander Farelly Complex
Annas Retreat*
Bluebeard's Castle
Cable TV
Canaan
Donoe By Pass
Education Street*
Hotel Fire Co./Vendor's Plaza
Hospital Ground*
Lionel Roberts
Louisenhoj
Lucinda Millin*
Mafolie
Magens Bay
Mahogany Run/Estate Lovenlund*
Peterborg
Polyberg
Ross Estate
Skyline Drive
St. Joseph & Rosendhl
Taarneberg
Wintberg*

Feeder #9A
A. W. Post Office
Back Street
Dober School
Education Dept.
Evelyn Marcelli
Gers Bldg
Govt. Hill
Harbor View
Main Street
Miller Manor
Palms Court
St. Peter School*
Subbase*
Vitelco Bldg
Wapa Bus. Ofc
Savan*

Feeder #9B
1st Street
2nd Street
3rd Street
4th Street
6th Street
A. C. Ottley Post Ofc
Barbel Plaza
C. A. H. S.*
Estate Thomas*
Paragon Bldg
Polyberg*
RLS Hospital*
Sugar Estate*
Taarneberg
VI Daily News

Feeder #9C
Brookman
Charlotte Amalie
Fort Mylner
Hoffman*
Langsmath
Mandahl*
Mariendahl
Nadir*
Cost U Less
Doctor's Park
Donoe
Home Depot
Mahogany Run/Estate Lovenlund*
New Her Nut
Pricesmart
Yvonne Bowsky School
Wintberg Peak/Wintberg Garden

Feeder #9D
Benner Hill
Bolongo Bay
Bovoni
Bovoni Dump
Compass Point
Frenchman's Bay*
Frydenhoj
Gold Hill
Hawk Hill*
Nadir*
Nazareth Partial
Thomasville

Feeder #9E
Bordeaux (STJ)*
Centerline
Chocolate Hole
Contant (STJ)
Cruz Bay*
Enighed
Fish Bay
Pastory
Rendevous
South Side
Westin

Feeder #10A
Adelita Cancryn School
Drakes Passage
French Town & Post Office
Gotlieb's Gas Station
Hassel Island
Intl Plaza
Knight Qlty Station
Main Street
Raadets Gade
Sand Fill
St. Peter School*
Subbase*
Tortola Warf
Water Front
Windward Passage

Feeder #10B
Bakkero
BCB Middle School
Bolongo
Bovoni Warehouse
Estate Thomas*
Frenchman's Reef
Flag Hill
Frenchman's Bay*
Havensight
Hawk Hill*
Lime Tree Hotel
Pmp Gardens*
West Indian Co.

Ridge Road Feeder
Anchorage Villas
Cabrita Point
Cowpet Resort
Elysian Hotel
Montessori School
Nazareth/ Water Pt
Ridge Road
Ritz Carlton
Secret Harbor

Yacht Haven Grand
Yacht Haven Grand Fdr 1
Yacht Haven Grand Fdr 2

Tutu Park Feeder
Tutu Park Mall

* Partial – divided on two feeders

Note: This listing represents major locations on St. Thomas & St. John and may not include every section of a particular feeder.

Updated June 2011

Source: WAPA

Table 7-2. St. Croix Feeder Listing

St. Croix Feeder Listing

PARTNER OF THE YEAR

Feeder #1
C'sted Town to Hotel on the Cay
Caravelle
D. Hamilton Jackson (Red Brick)
DeChabert Housing to Watergut
LBJ Housing
Lower Part of Richmond
Pink Fancy Hotel
Ruby M Rouse (Watergut)

Feeder #2
Hope
Castle Nugent
Coakley Bay
Cotton Valley
Eliza's Retreat
Gallows Bay
North and South Grapetree
Marienhoj
Pearl B. Larsen Sch.
Sally's Fancy
Sierra Verde
Slob
Solitude
Southside of Christiansted
Teague Bay
Town
Turner's Hole
Upper part of Richmond
Welcome – Tide Village
WJKC Radio Transmitter
WJKC/WSTX Radio Studios

Feeder #3
All for the Better
Beeston Hill
Bugby Hole
Cane Garden
Castle Nugent
Catherine's Rest
Golden Rock Shopping Ctr. (partial)
Granard
Grange
Hermon Hill
Humbug
JFK Housing (partial)
Longford
Mt. Washington
Orange Grove
Pearl
Questa Verde
Tipperary - Southgate
Work and Rest
YRC

Feeder #4
Anna's Hope
Bellevue
Castle Coakley (partial)
Constitution Hill (Partial)
Free Will
Island Center
JFK Housing (partial)
Lew Muckle Sch.
Little Princesse Hill (partial)
Mary's Fancy
Miracle Mile
Peter's Rest (partial)
Pueblo –Golden Rock
Queen's Quarter
Rattan
Reef Broadcasting Studios
Ruby
Sion Farm
Sion Hill
Tan Tan Terrace
United Shopping Plaza (west wing)

Feeder #5
Alfredo Andrews School
Aureo Diaz Heights
Barren Spot
Bethlehem Village Candido
Guadeloupe (Fredensborg Old Village)
Charles H. Emanuel Sch.
Dept. of Finance
Estate Diamond
Innovative Business Office
John H. Woodon Sch.
Juan F. Luis Hospital
La Reine
Villa La Reine Shopping Center
National Guard
Ricardo Richards School
Strawberry
Sunny Acres
Sunny Isle Shopping Center (partial)
WAPA Business Office
WSVI-TV Studio

Feeder #6
Betsy's Jewel
Blue Mountain/Little Fountain
Canaan
Cane Bay / LaValley
Clifton Hill (partial)
Club St. Croix
Colony Cove
Concordia East
Elena Christian Sch.
Gentle Winds
Glynn
Harborview
JFK Housing (partial)
Judith's Fancy
La Grande Princesse (partial)
Manor School
Mill Harbor
Mon Bijou
Morning Star (partial)
Salt River
Slob
Estate St. John (partial)
Sugar Beach
Tool Box

Feeder #8
Alexander Henderson Sch.
Arthur A. Richards Sch.
Brookshill
Butler's Bay
Campo Rico
Cane Carlton
Carlton
Claude O. Marko Sch.
Concordia-West
Cruzan Rum Factory
Diageo Rum Factory Enfield Green
Frederikshabb
Frederiksted
Global Crossing
Good Hope School
Hamm's Bluff
Hannah's Rest
Harrigan Court
LaGrange (partial)
Marley Project
Mars Hill
Navy Tracking Station
Brooks hill
Prosperity
Transmitter
Rohlsen Airport
Smithfield
Sunshine Mall
Two Brothers
Two Williams
Walter M. Hodge
Wheel of Fortune
Whim
White Bay
White Lady
William's Delight

Feeder #9
Adventure
Bety's Hope
Car Race Track
Castle Burke
Central High School
Clifton Hill
Constitution Hill (partial)
Croixville
East Industrial Park
Educational Complex
Estate Diamond West
Estate Mountain
Evelyn M. Williams Sch.
Golden Grove/Prison
Golden Grove/UVI
Home Depot
Barren Spot (partial)
Lower Love
Mount Pleasant West
New Works
Orange Grove (partial)
Paradise
Peter's Rest
Peter's Rest Comm.
Profit
St. Croix Renaissance
St. George
Sunny Isle Shopping Center (partial)
United Shopping Plaza (east)
University of the Virgin Islands
Yellow Cedar

Feeder #10
Calquahoun
Carambola
Coble
Country Day School
Eulalie Rivera
Grove Place
LaGrande Princesse (partial)
LaGrange (partial)
Lorraine Village
Mahogany Road
Mon Bijou (partial)
Morning Star (partial)
Mt. Pellier
Mutual Homes
Orange Grove (West)
Plaza Extra-West
St. John (partial)
Upper Love

* Partial – divided on two feeders

Note: This listing represents major locations on St. Croix and may not include every section of a particular feeder.

Updated June 2011

7.2 St. Thomas Electrical Distribution System

The St. Thomas power distribution system comprises 34.5 kV subtransmission lines that supply five substations, where transformers step the voltage down to 13.8 kV distribution voltage level. From each of these five substations, distribution feeders supply the service transformers for residential, commercial, and industrial customers. These feeders range in length depending on the size and proximity of load to the substation. Some feeders supply customers in remote areas. Load distribution varies by substation, with the largest loads supplied by the Randolph Harley Substation and the smallest loads on the St. John Substation. An overview of the St. Thomas system is shown in the Feeder Routes and Switch Locations key map (Figure 7-1) on the following page.

Feeder layouts with capacitor bank locations and 2010 load information were provided by WAPA for analysis. This information was evaluated for daily load profile, annual maximum and minimum loads, daytime peaks and minimums, and load classification.

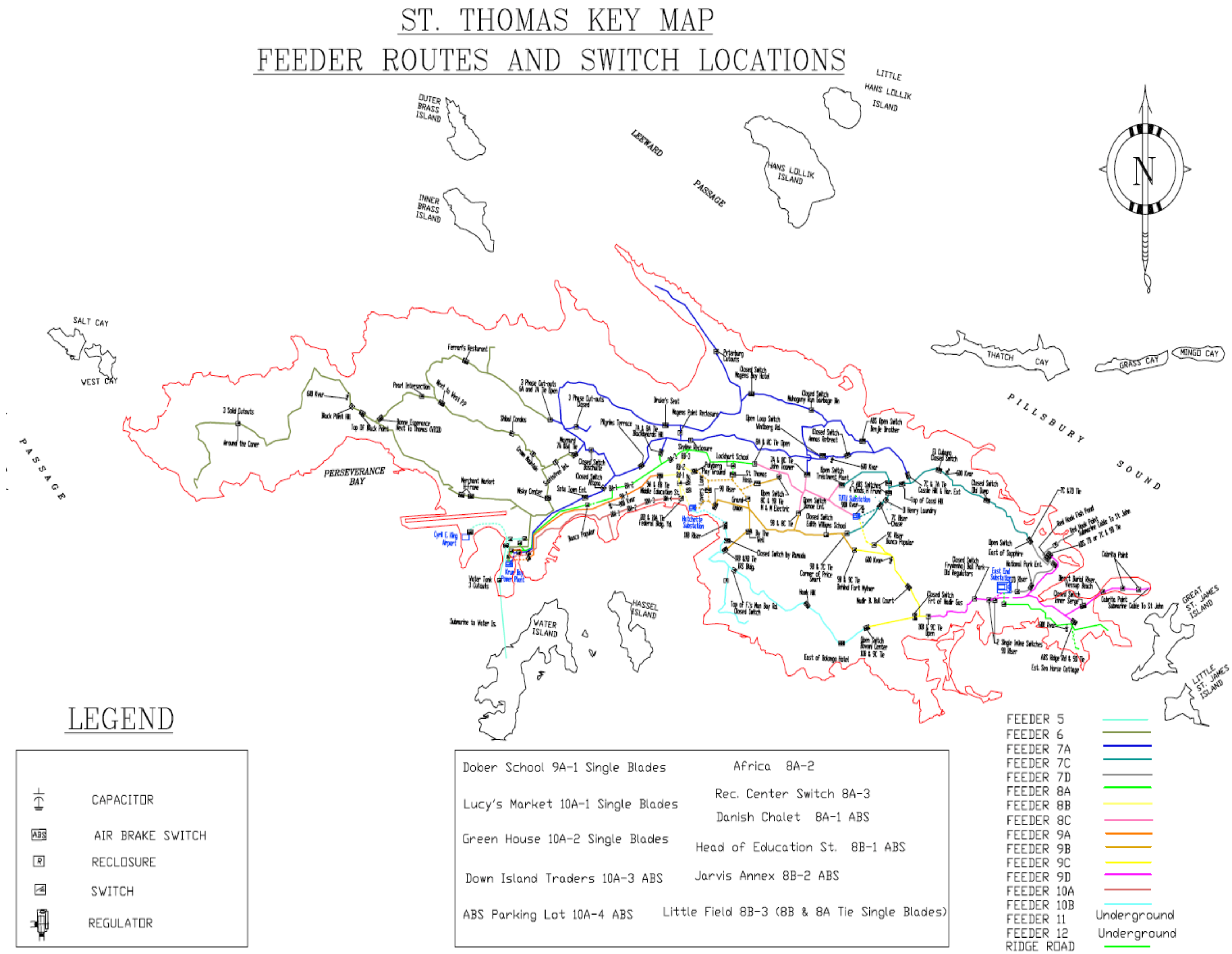


Figure 7-1. St. Thomas feeder map

Source: WAPA

Loads on the Randolph Harley Substation total over 25 MW, with feeder 10A being the most heavily loaded. This feeder is located near the power plant at Krum Bay. Large commercial/industrial loads are also present in this area, and a typical daily load profile (feeder 9A) that shows large load swings can be seen in Figure 7-2. The load increases significantly (around 3 MW) as employees arrive in the morning and production activity gets under way. At the end of the work day, machines are shut down and the plant or facility load drops off.

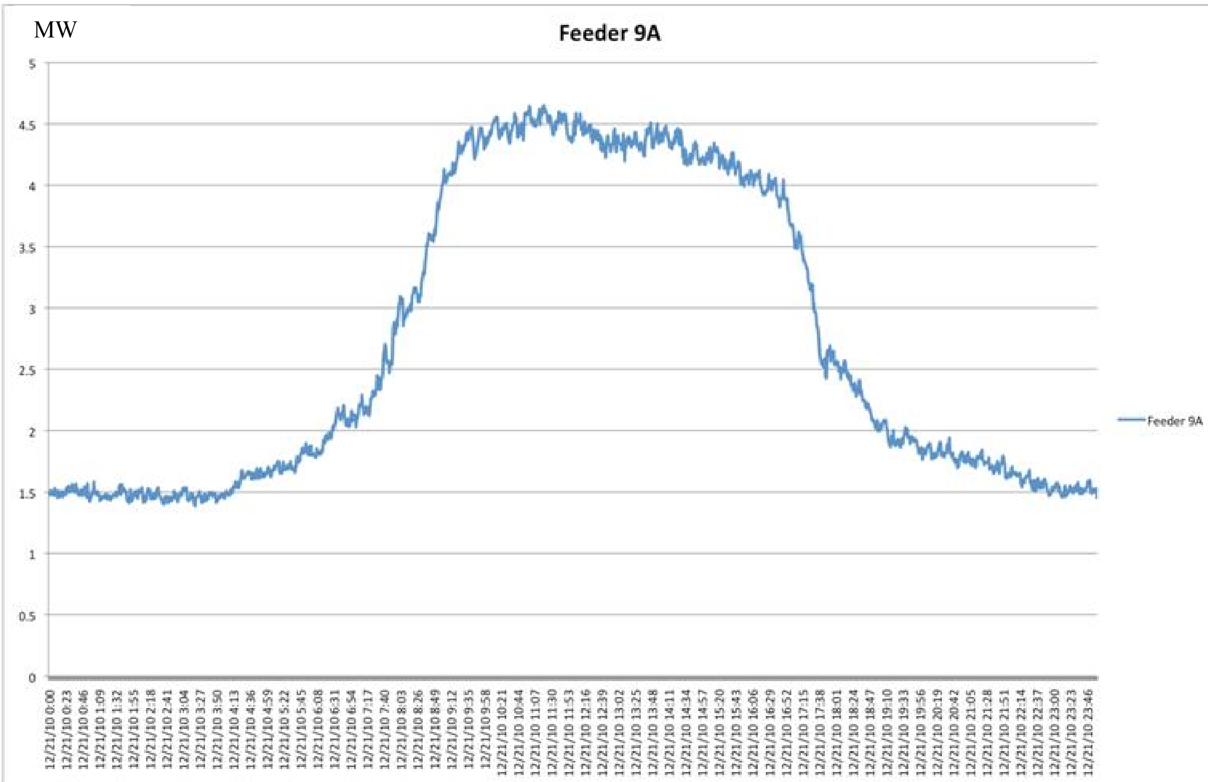


Figure 7-2. Typical commercial/industrial daily load profile – feeder 9A

Source: NREL

Some feeders show significant step changes over extended periods of time. In Figure 7-3, a 4 MW jump in the feeder load occurs from February through March on feeder 7E. This is likely due to load switching from one feeder to another during maintenance or construction activities.

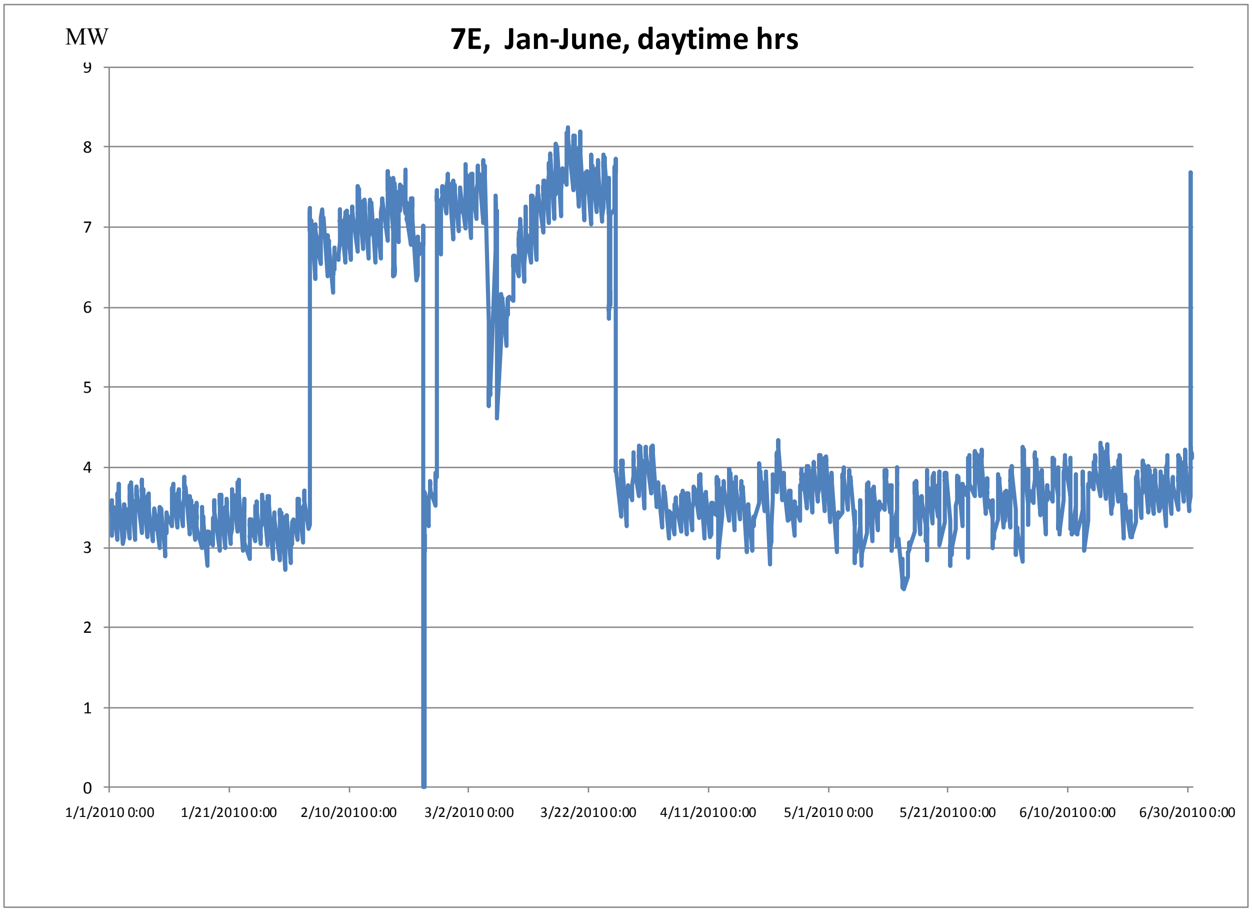


Figure 7-3. Load step change – feeder 7E

Source: NREL

Further observation of the feeder load profiles shows possible outages, metering issues (possibly caused by current transformer saturation), and gradual changes in load over time. In Figure 7-4 it can be seen that the load decreases steadily as the summer progresses toward the fall and winter months. This is likely due to slightly cooler weather patterns resulting in less demand for air-conditioning. The load begins to climb back up as the winter moves toward spring and summer.

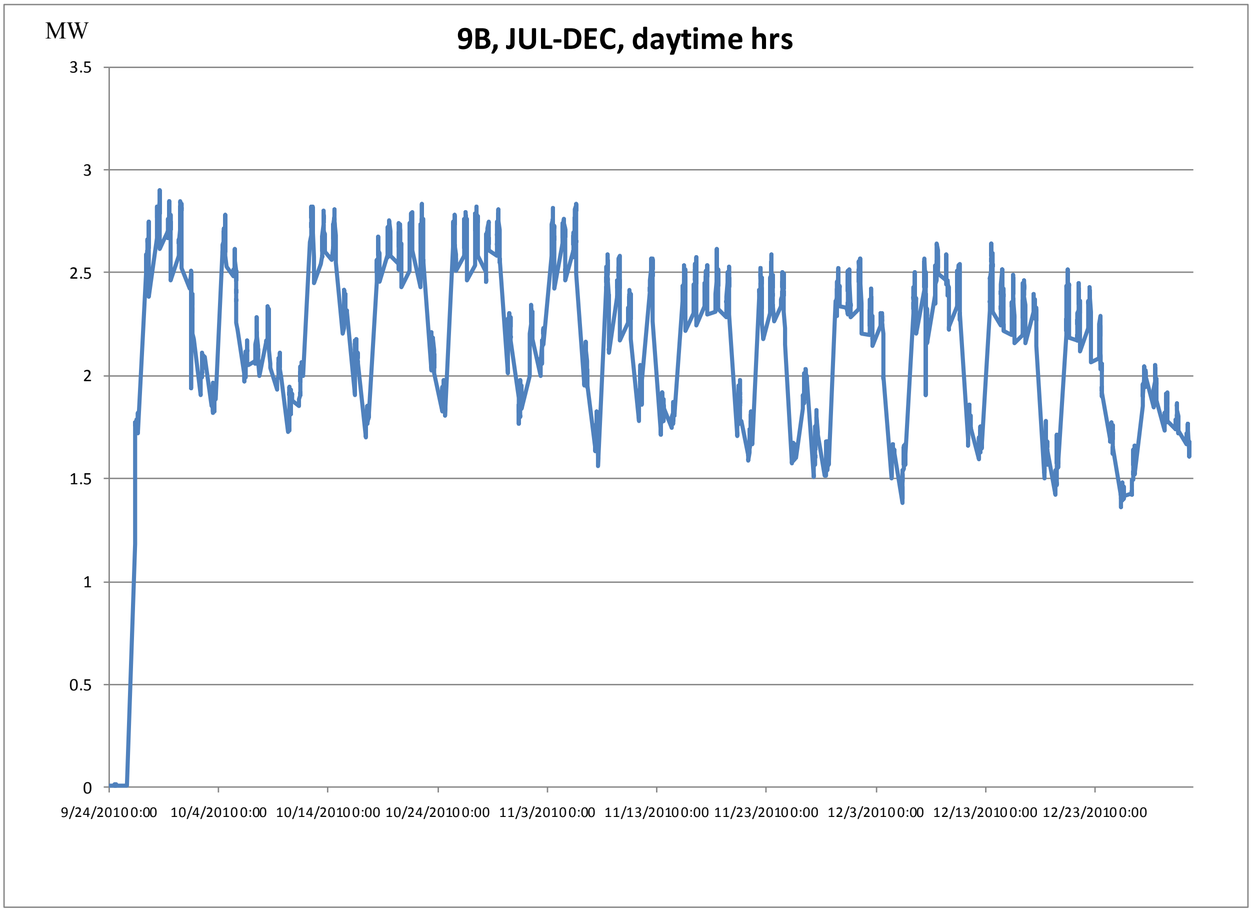


Figure 7-4. Gradual load change (seasonal) – feeder 9B

Source: NREL

7.3 St. Croix Electrical Distribution System

The St. Croix power distribution system currently consists of the Richmond substation and will eventually include a proposed new substation (to be called Spanish Town) to be located at the southwest part of the island near the airport. Distribution is at both 24.9 kV for longer feeders and 13.8 kV for those loads that are close to the Richmond Power Plant. Plans are under way for other significant changes to the St. Croix distribution system, and following a recent preliminary interconnection feasibility study for the Alpine power plant, with capacity up to 16 MW, the Alpine WTE plant appears to be moving forward. In addition to the required upgrades to the electrical infrastructure, the loads on selected feeders or portions of feeders will be moved from existing substation breakers near the Richmond Power Plant to the new Spanish Town substation. An overview of the St. Croix distribution system is shown in Figure 7-5.

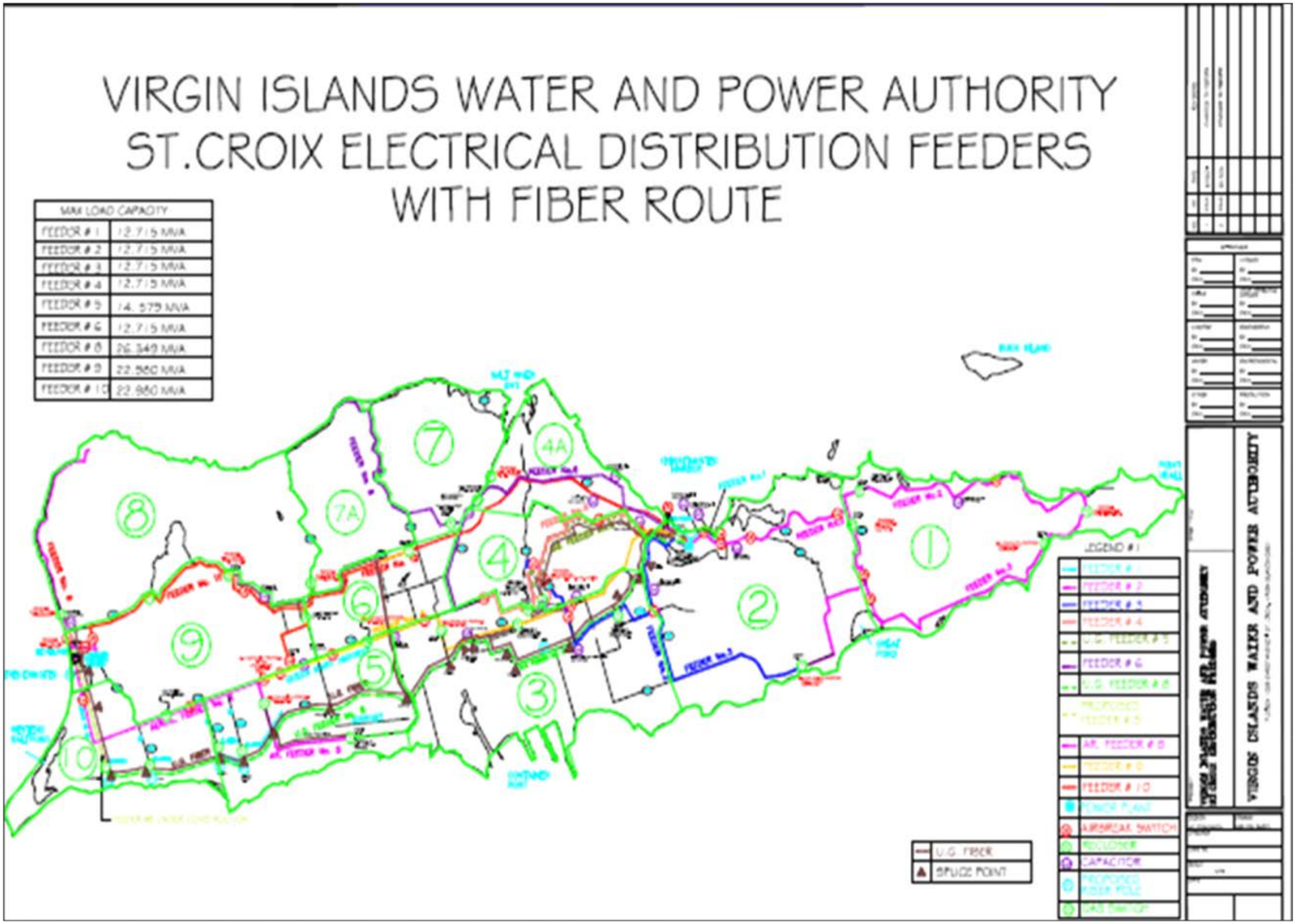


Figure 7-5. WAPA St. Croix electric distribution feeders

Source: WAPA

The single most heavily loaded distribution feeder on St. Croix is feeder 8, which supplies loads on the extreme southwest corner of the island. A typical daily load profile for this feeder is shown in Figure 7-6. The minimum load reaches approximately 7.5 MW, and the peak is around 10 MW, indicating a very high load factor. This is typical of circuits with high residential loads.

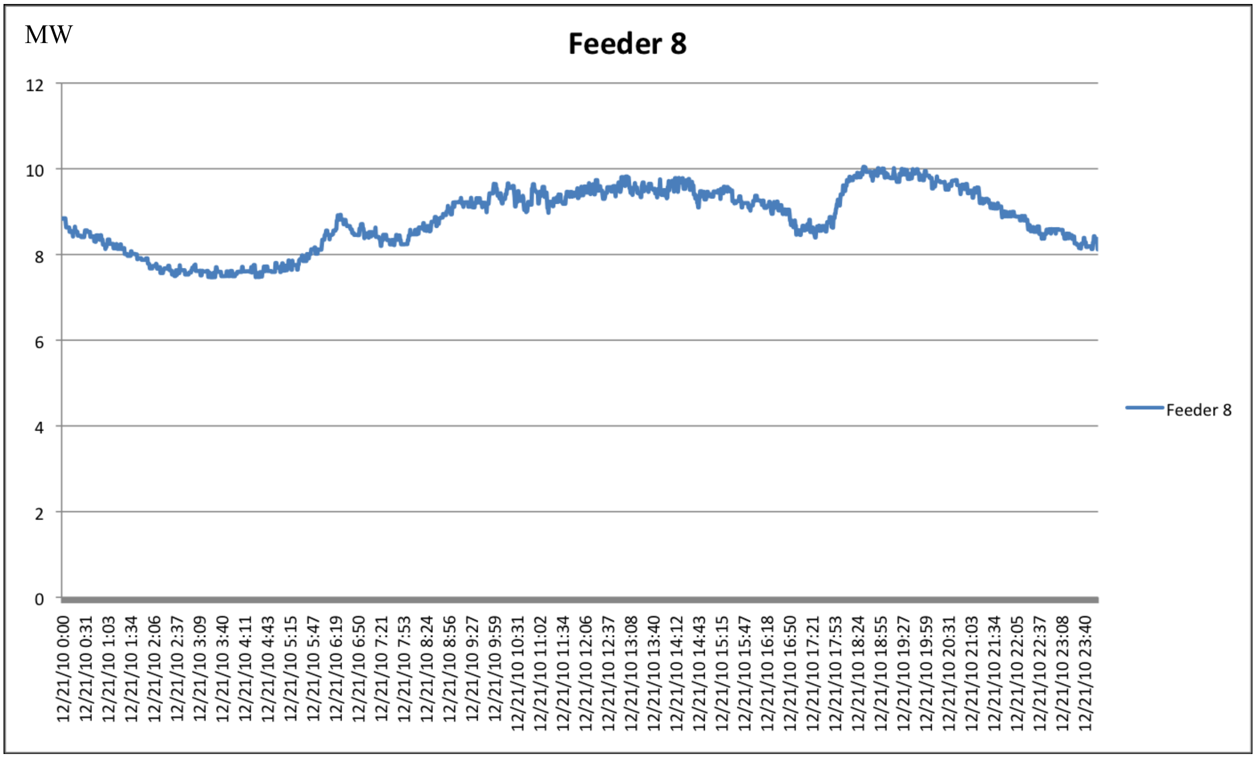


Figure 7-6. Typical daily load profile – feeder 8

Source: NREL

Further review of the feeder 8 load profile over a six-month period from July through December (see Figure 7-7) shows an increase in the load on this feeder beginning in early December 2010. This could be due to load switching between feeders as described previously; it could also indicate that a new load was added to the feeder.

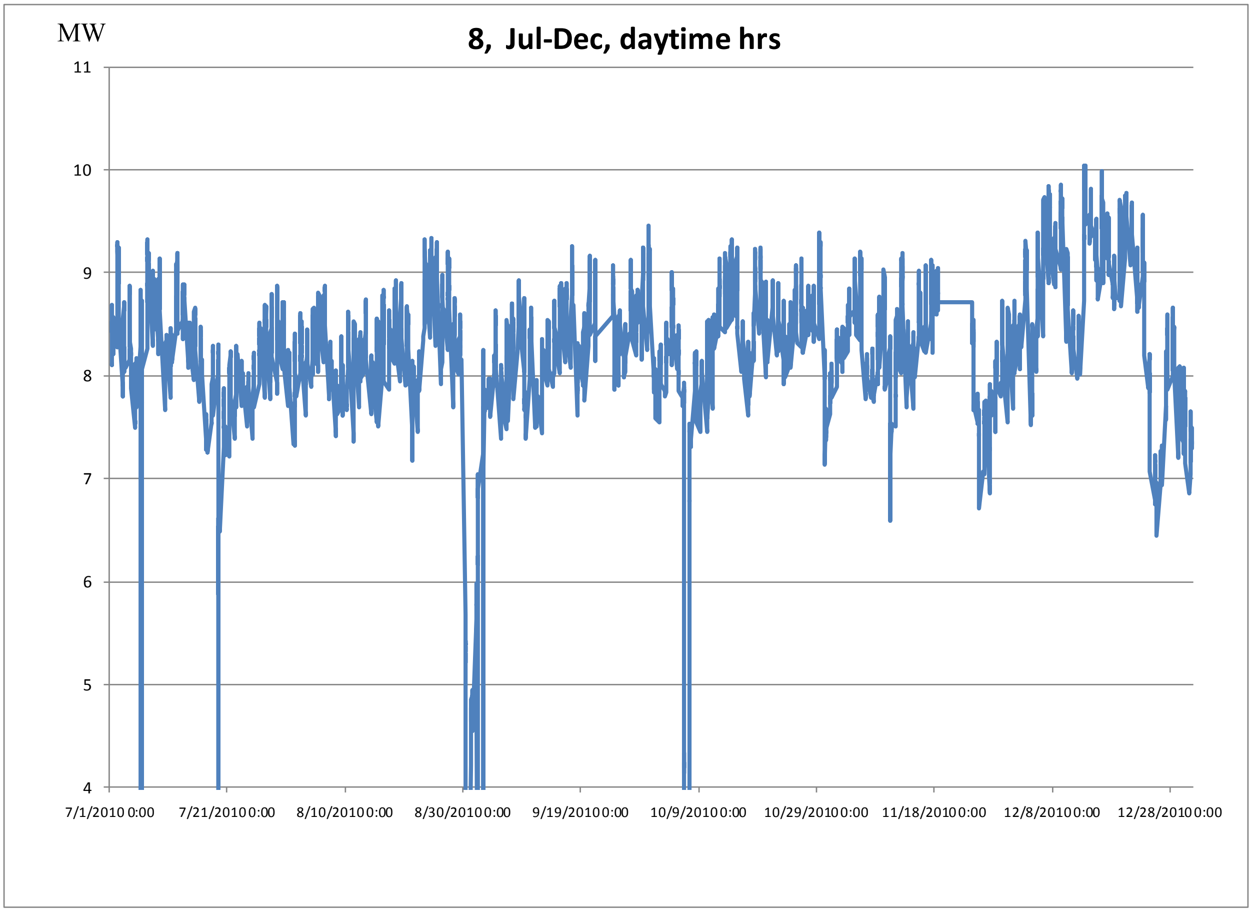


Figure 7-7. Six-month load profile with load increase – feeder 8

Source: NREL

Feeder 9 is also heavily loaded, reaching a peak of over 7.5 MW. WAPA is planning on moving all load from feeder 8 and half the load from feeders 9 and 10 to the new Spanish Town substation.

In Figure 7-8, it can be seen that the load on feeder 4 increases steadily as winter moves toward the spring and warmer summer months. This is likely due to the need for more air-conditioning (cooling) loads on the feeder.

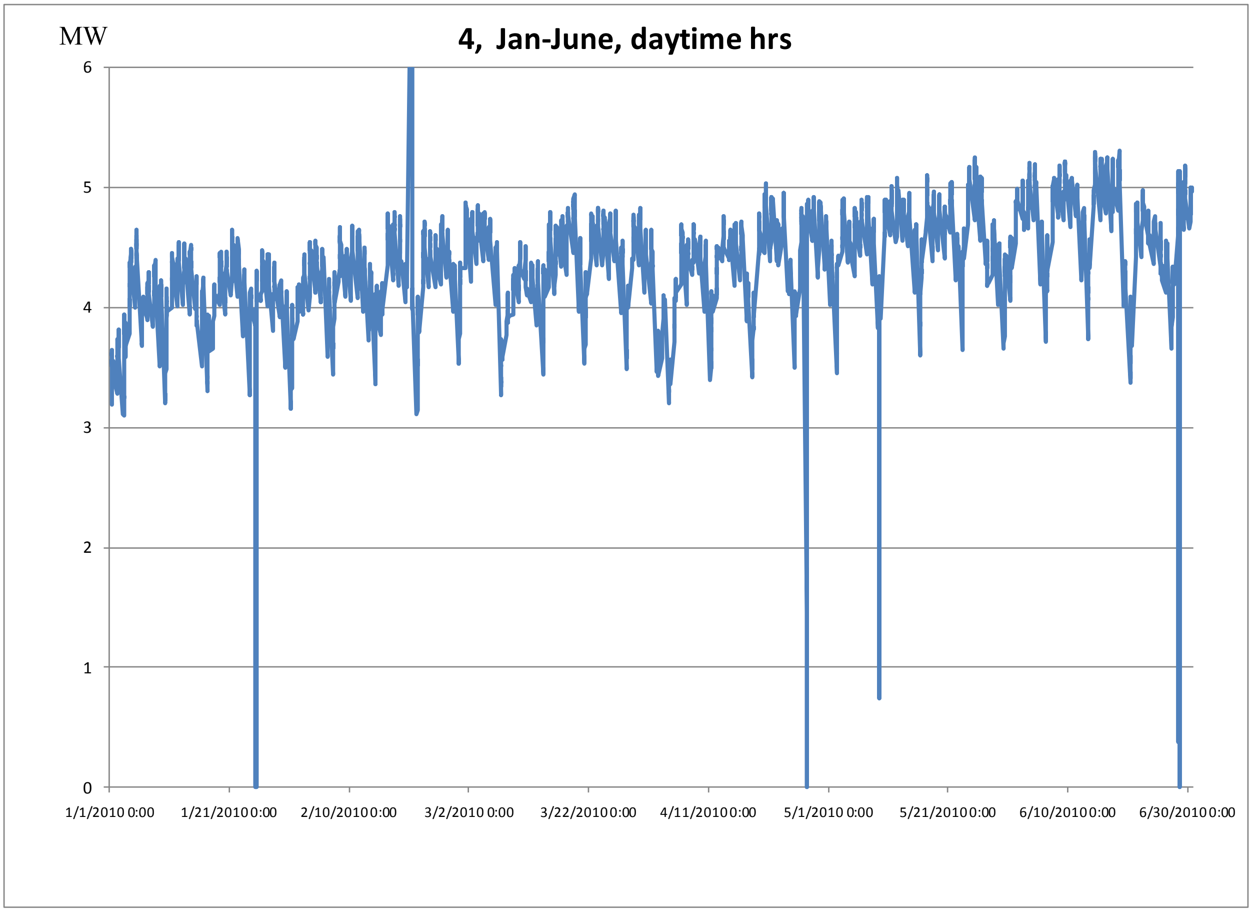


Figure 7-8. Six-month load profile with gradual load change (seasonal) – feeder 4

Source: NREL

7.4 Potential/Proposed PV Generation

Preliminary sites on both St. Thomas and St. Croix were identified as candidates for potential PV generation systems. Up to 5 MW of solar PV generation per island system is anticipated. The sites identified have the following approximate PV system capacities (although other locations are also under consideration):

<u>St. Thomas</u>

Bordeaux property, 200 kW

<u>St. Croix</u>

Spanish Town Substation GM, 12 acres, 2 MW

7.5 Impact of Distributed Intermittent PV Generation on the Electric Power System

One of the major technical challenges of distributed energy resources (DER) interconnection is the effect of DER on the local power distribution system and the larger grid, and this impact should be considered when applying DER. The electrical power system (EPS), defined by the Institute of Electrical and Electronics Engineers (IEEE) as the *facilities that deliver electric power to a load* and distinguished as either local or area, is affected in many ways by the addition of DER. These effects can range from inconsequential to severe, depending on the size and technology of the DER and various characteristics of the area EPS with which it is connected.

Many of the impacts of DER on the area EPS are presented in IEEE 1547.2 - *Application Guide for IEEE Std 1547, IEEE Standard for Interconnecting Distributed Resources with Electric Power Systems,* and include improper protective device coordination, reclosing issues, islanding of DER systems, voltage regulation problems, equipment overloading (transformer, fuses, and/or feeder), short circuit withstand and interrupting ratings, and nuisance tripping of DER inverters during switching operations, to name a few.

7.6 Voltage Regulation

Voltage regulation describes the process and equipment to maintain voltage within acceptable limits. Almost all electrical equipment is designed for use at a definite terminal voltage: the nameplate voltage rating. The voltage drops in each part of the EPS, from the source to the utilization devices, make it economically impractical to provide all customers with a constant voltage that corresponds to the nameplate voltage of their utilization devices. Thus, a compromise is typically necessary between the allowable deviation from utilization equipment nameplate voltage supplied by the power system and the deviation above and below the nameplate voltage at which satisfactory equipment performance can be obtained.

Voltage limits at the point of common coupling (PCC) with the utility are specified in ANSI C84.1-2006 for the area EPS and local EPS interconnection. This standard also shows the utilization voltage range. It is important to note that this standard does allow infrequent voltage excursions outside of the defined limits.

The voltage supplied to each customer at the PCC is an important measure of service quality. A satisfactory voltage level is required to operate lights, equipment, and appliances properly. The maximum permissible deviation from nominal system voltage at the PCC is typically 5%; this agrees with the service voltage limits of ANSI C84.1.

Factors involved in determining voltage drop on an area EPS include the primary voltage at which the area EPS is operating; the number, size, and type of conductors; the length of the lines; the size and power factor of the various loads; and the location of loads on the area EPS. Because of the dynamic nature of most customer loads, the load current and power factor at any given point on the area EPS are constantly changing. Accordingly, the voltage at any given point away from a generator bus is subject to constant change because of the voltage drops in the impedances between that point and the generators. Voltage regulation is required to maintain voltage within acceptable limits.

Another important aspect of voltage regulation is the need to maintain balanced three-phase voltage on the area EPSs. A significant portion of the customers on an area EPS might be served from single-phase tap lines or single-phase transformers connected to the main feeder of the area EPS. These single-phase loads could create unbalanced voltage drops on the area EPS, which result in unbalanced voltage at customer locations where there are three-phase utilization devices. The operation of three-phase motors and other three-phase utilization devices is adversely affected by unbalanced phase voltage.

Voltage regulation of the area EPS is based almost entirely on radial power flow from the substation to the loads connected to the area EPS (single direction). The introduction of DER could introduce a two-way power flow at certain times that might interfere with the effectiveness of standard voltage-regulating practices. If power from a DER device is injected into the power system, it will offset load current and thus reduce the voltage drop on the area EPS. The DER can completely offset the local EPS load, and the offset of this load could result in a voltage rise because of the elimination of the “voltage drop.”

In accordance with IEEE Std 1547-2003 4.1.1, DER devices cannot actively regulate voltage at the PCC, and DER devices cannot cause the area EPS service voltage at the local EPSs to go outside the requirements of ANSI C84.1 Range A. These restrictions will prevent many operating problems. However, in some situations, the operation of DER can still result in area EPS voltage regulation problems if precautions are not taken. The voltage regulation also might need to be reviewed when many individual residential-scale DER devices, a larger DER device, or multiple DER devices are to be located as follows (per IEEE 1547.2):

- On the load side of area EPS voltage regulators or load tap changing transformers that use line drop compensation under either system normal or alternate feed configurations
- On the area EPS and the DER device(s) has a fluctuating power source such as wind or solar
- On the area EPS and the DER device(s) could create reverse power flow conditions through voltage regulators or load tap changing transformers under either system normal or alternate feed configurations
- On the area EPS when a significant number of single-phase DER devices are installed
- On a line section of the area EPS in which the aggregate generation from DER devices will exceed 10% of the line section’s peak load

It is NREL’s understanding that WAPA does not utilize automatic voltage regulation devices or other line drop compensation equipment in its distribution system (see the first bullet item). Further, by requiring large-scale PV systems to be three-phase and by limiting the size of and the aggregate amount of PV generation capacity on a feeder (penetration level), WAPA can expect many potential voltage regulation issues to be mitigated.

7.7 Interconnection Procedure

To avoid potential issues with the distribution system, WAPA, with the assistance of NREL, has developed an interconnection procedure for the recently released solar RFP. This procedure seeks to minimize the technical studies that need to be conducted for PV systems that have a size and location that are likely to adversely affect the existing distribution system. An outline is presented below.

Distributed generation PV systems that meet the following criteria are unlikely to cause problems for the distribution system and should be considered for a more efficient, less detailed interconnection process:

1) The PV equipment meets all codes, standards, and certification requirements.

2) In accordance with IEEE 1547.2, Part 8.1.1.3 and to avoid voltage regulation issues, the aggregate capacity of all the connected PV systems and other distributed resources on a single feeder, including the proposed PV, shall not exceed 10% of annual peak demand of the feeder.

3) The PV systems should be located within ¼ mile of a substation or large load (comparable to the size of the PV system).

4) To avoid unbalance conditions, the PV systems shall be three-phase.

5) The PV systems should not exceed 75% of the capacity of the transformer between the system and the utility's electric system.

Additional considerations may be given to the fault current contribution from the PV systems, as further described below. This may result in additional requirements, depending on the existing fault currents and withstand ratings of WAPA equipment on each island.

The 10% penetration rule outlined above was considered for all feeders in the St. Thomas/St. John and St. Croix systems. On a distribution feeder, penetration level is defined in terms of a ratio of PV system power to the rating of the distribution peak load. The 10% rule, as described above, was applied to the peak loads on the St. Thomas feeders, and Table 7-3 was developed. This indicates that up to 7.6 MW of PV generation can be added without concern if distributed as shown in the table.

Table 7-3. St. Thomas Minimum Loads and Penetration Calculations

Feeder Name	Voltage (kV)	Min. Daytime Load (MW)	Peak Load (MW)	10% Screen PV Capacity (MW)*
RANDOLPH HARLEY SUBSTATION				
FEEDER 5A	13.8	3.5	6	0.60

Feeder Name	Voltage (kV)	Min. Daytime Load (MW)	Peak Load (MW)	10% Screen PV Capacity (MW)*
FEEDER 6A	13.8	1.2	2	0.20
FEEDER 7A	13.8	1.7	2.9	0.29
FEEDER 8A	13.8	2.3	4.2	0.42
FEEDER 9A	13.8	1.8	5	0.50
FEEDER 10A	13.8	2.2	6.4	0.64
	Subtotal	**12.7**	**26.5**	**2.7**
LONG BAY SUBSTATION				
FEEDER 7B	13.8	1.7	2.7	
FEEDER 8B	13.8	3.2	5.4	0.54
FEEDER 9B	13.8	1.4	2.8	0.28
FEEDER 10B	13.8	2.8	5.6	0.56
YH2	13.8	0.6	1.1	0.11
	Subtotal	**9.7**	**17.6**	**1.5**
TUTU SUBSTATION				
FEEDER 7C	13.8	3.5	4.8	0.48
FEEDER 9C	13.8	2.5	4.2	0.42
TUTU PARK MALL	13.8	1	1.7	0.17
	Subtotal	**7.0**	**10.7**	**1.1**
EAST END SUBSTATION				
FEEDER 7D	13.8	2.7	4.2	0.42
FEEDER 9D	13.8	2.6	4.2	0.42
RIDGE ROAD FEEDER	13.8	2	4.5	0.45
	Subtotal	**7.3**	**12.9**	**1.3**
ST. JOHN SUBSTATION				
FEEDER 7E	13.8	2	4.2	0.42
FEEDER 9E	13.8	3	6.5	0.65
	Subtotal	**5.0**	**10.7**	**1.1**

Feeder Name	Voltage (kV)	Min. Daytime Load (MW)	Peak Load (MW)	10% Screen PV Capacity (MW)*
	STT Total	**41.7**	**78.4**	**7.6**

* See Interconnection Requirements

The 10% rule was also applied to the peak loads on the St. Croix feeders, and Table 7-4 was developed. This indicates that up to 4.9 MW of PV generation can be added to the island without concern.

Table 7-4. St. Croix Minimum Loads and Penetration Calculations

Feeder Name	Voltage (kV)	Min. Load (MW)	Peak Load (MW)	10% Screen PV Capacity (MW)*
RICHMOND SUBSTATION				
FEEDER 1	13.8	1.4	2.7	0.27
FEEDER 2	13.8	4.5	5.5	0.55
FEEDER 3	13.8	2.6	4.8	0.48
FEEDER 4	13.8	3.2	5.2	0.52
FEEDER 5	13.8	0.6	1.8	0.18
FEEDER 6	13.8	3	6	0.60
FEEDER 9A	24.9	2.3	4.5	0.45
FEEDER 10A	24.9	1.3	2	0.20
	Subtotal	**18.9**	**32.5**	**3.3**
NEW SPANISH TOWN SUBSTATION				
FEEDER 8	24.9	6.5	10	1.00
FEEDER 9B	24.9	2.3	4.5	0.45
FEEDER 10B	24.9	1.3	2	0.20
	Subtotal	**10.1**	**16.5**	**1.7**
	STX	**29.0**	**49.0**	**4.9**

Feeder Name	Voltage (kV)	Min. Load (MW)	Peak Load (MW)	10% Screen PV Capacity (MW)*
Total				

* See Interconnection Requirements

For systems that do not meet the criteria above, a system impact study may need to be conducted by the utility. A system impact study identifies the electric system impacts to the subtransmission and/or distribution systems, as applicable, that would result if a proposed DER was interconnected without modifications to the EPS. The study focuses on potential adverse effects to the operation, safety, and reliability of the area EPS. A system impact study can range from a simple comparison of the attributes of the DER and the area EPS (simple impact study) to a detailed, comprehensive analysis that employs a variety of traditional power system studies.

Simple impact studies compare only the attributes of the DER and the area EPS and are primarily focused on making a subjective determination of whether IEEE 1547 requirements can be met. This determination can generally be made by considering the use of certified or listed DER equipment, the propensity to create an undetected island, the propensity to adversely affect protection and power quality on the area EPS, and the propensity to cause the area EPS to operate in excess of its ratings under both normal and fault conditions. The use of appropriately certified or listed equipment greatly simplifies the process of determining the impact of a proposed DER installation.

For interconnection of a proposed DER with a radial distribution circuit, it is generally agreed (IEEE 1547.2) that an undetected island cannot be created if the aggregated generation, including the proposed DER, on the circuit does not exceed 10% of the line section annual peak load.

Understanding the fault contributions from DER is an important aspect of electrical system protection that impacts the ratings and setting of protective equipment. PV inverters typically do not contribute significantly to the fault current in a system (fault current is usually about one to two times the full load amps of the inverter but can be higher depending on the manufacturer). In addition, the step-up transformer used to interconnect with the distribution system will act as a formidable choke on the inverter to limit fault current.

There is also a considerable difference in the performance under fault between a synchronous or induction machine and an inverter-connected source. Most inverter-fed sources have little or no inertia, and they can react to limit their output far more quickly than can a conventional rotating machine. It would therefore seem that induction motors supplied by the system would contribute significantly more than the PV inverters. Understanding how much DER can be added to a distribution feeder without affecting other equipment will become more important as higher DER penetration levels are reached.

When integrating DER into the distribution system, there are many important protection issues a utility must consider. It is generally agreed (IEEE 1547.2) that there is little chance of interfering with the power quality of the area EPS if the proposed DER, in aggregation with other generation on the distribution circuit, does not contribute more than 10% to the distribution circuit's maximum fault current at the point on the high-voltage (primary) level nearest the proposed point of change of ownership. This ensures that the fault current from the DER does not desensitize protection equipment on the area EPS, and any voltage disturbances that may occur because of normal or abnormal operation of the DER are not likely to have a significant effect on voltage supplied to other customers.

The available fault currents at the respective power plants in the two WAPA electrical systems, together with the associated circuit breakers ratings, are presented in Table 7-5. It is unknown whether the fault magnitudes are peak asymmetrical or steady state symmetrical values. The Richmond 13.8 kV breaker appears to be rated below the available fault current.

Table 7-5. Fault Current and Equipment Ratings

Bus	Breaker duty (kA)	Fault Current			
		3ph fault (kA)	SLG fault (kA)	LLG fault (kA)	Maximum (kA)
HARLEY 34.5 kV	40	18.8	23.7	30.7	30.7
HARLEY 13.8 kV	31.5	17.2	18.6	20.0	20.0
RICHMOND 69 kV	40	3.1	3.4	3.7	3.7
RICHMOND 25 kV	N/A	10.7	11.1	11.3	11.3
RICHMOND 13.8 kV	**37**	48.0	15.9	9.3	48.0

An example of fault current contribution by a PV inverter is as follows: for a 2 MW PV inverter at 13.8 kV in the St. Thomas system, the equipment rating would be approximately 83 amps at full load. Under fault conditions, it is not anticipated that the PV system would add more than approximately 200 amps (over two times rated) to the local system feeder, and the total fault current would still be well within the 31.5 kA system rating (20 kA plus 200 A). Assuming negligible drop in fault current in the 13.8 kV distribution system, 10% of the available fault current is 2,000 amps, and therefore the PV system should not interfere with the power quality of the area EPS per the IEEE rule of thumb described above. It is also assumed that other PV generation is distributed elsewhere in the system, and their contribution to a local fault would be minimal due to line impedances.

A more detailed system impact study (fault study) may still be required, depending on system size, location on the feeder, and ratings of equipment adjacent to the PV site (if lower than the power plant breakers). For the area EPS, it is anticipated that the system developers will perform short circuit and coordination studies as part of their design due diligence. Thus, all equipment to be installed will meet NEC requirements and include adequately rated equipment, and the developer will work with WAPA to confirm available fault current and system fault ratings. If necessary, current-limiting fuses can be used on the transformer to further limit fault current.

A detailed impact study is an engineering exercise that carefully reviews the potential effect of a DER unit on the area EPS. These studies may include analyses of power flow, short circuit conditions, voltage drop and flicker, protection and control coordination, and grounding to identify system reliability criteria violations, equipment overstress, power quality impacts, stability problems, and other issues relevant to the proper operation of the area EPS. The detailed studies may furthermore identify feasible mitigation measures for identified problems, provide recommendations for facility modifications, and include good-faith estimates of cost and construction time.

8 Overview of PREPA-WAPA Interconnection Study by Siemens PTI

8.1 Background

The interconnection of the PREPA, WAPA, and BVI Electricity Corporation grids was proposed as a means of decreasing the cost of energy for the USVI, increasing WAPA system reliability, reducing WAPA's spinning reserve requirements, and increasing the potential for high-penetration renewable energy in the USVI. The interconnection between St. Thomas and St. Croix will bring additional benefits for the WAPA power system.

The existing power system in Puerto Rico has an installed capacity of approximately 5.8 gigawatts (GW) and a peak power load of about 3.3 GW, whereas the existing power system St. Thomas has an installed capacity of 190 MW and a peak load of 88 MW, and the existing power system in St. Croix has an installed capacity of 105 MW and a peak load of 55 MW.

The study is funded under DOE award DE-OE0000111, with a funding amount of $469,000. A study RFP was sent out in August 2010, and six proposals were received from companies that are major players in power system study/simulation area. All proposals were reviewed and scored by the Technical Review Committee consisting of WAPA, PREPA, and NREL/DOE experts and consultants. A contract was awarded to Siemens PTI to perform a feasibility study.

8.2 Study Objectives

The project study objectives identified in WAPA's RFP included the following three interconnections:

- **Interconnection 1:** This approximately 50 mile (80 km) interconnection between Puerto Rico and the Randolph Harley power plant in Krum Bay on St. Thomas is envisaged to be either a 115 kV AC or a DC link with an expected power transmission capacity of at least 100 MW, up to 200 MW. The exact maximum transfer capability of the link and the operating voltage of the DC submarine cable will be determined as part of the study.
- **Interconnection 2:** This interconnection between St. Thomas and the BVI island of Tortola consists of two sections. The first section (A) was considered to be an AC link between the Randolph Harley substation in Krum Bay and the East End substation in Red Hook Harbor area on the eastern side of St. Thomas. The second section (B), which would consist of a submarine cable of similar design as an existing 34.5 kV AC cable between St. Thomas and St. John, will proceed from the east end of St. Thomas to Tortola on BVI, a distance of about 20 miles.
- **Interconnection 3:** This interconnection will link St. Thomas and St. Croix with a DC submarine cable.

The objectives of the feasibility study are to:

- Determine the power capacities and feasibilities of the three interconnections
- Determine the types and technical requirements of the interconnections, including:

    - Detailed evaluation of AC and DC transmission options
    - Determination of submarine cable configurations, e.g., individual single-phase cables or one three-phase cable for the AC options, or monopolar or bipolar arrangement for the DC options
- Perform a power system study and identify the necessary AC system reinforcements on St. Thomas and St. Croix to accommodate the interconnection project
- Provide a high-level estimate for the project equipment cost
- Demonstrate the potential benefits of the interconnection, in terms of generation costs and reliability, from the standpoint of WAPA.

The study considers only the impacts on and requirements within the WAPA power system and the points of interconnection within the PREPA and BVI power systems. Impacts on and intra-island requirements within the PREPA and BVI systems are outside the scope of the study.

8.3 Study Timeline

The study timeline and deliverables were set in the WAPA RFP according to following schedule:

- October 2010 – Project kickoff
- December 2010 – Interim report #1: high-voltage alternating current (HVAC)/high-voltage direct current (HVDC) requirement and submarine cable study
    - This interim report was delivered on time, and was reviewed, discussed, and accepted by the Technical Review Committee during a February 11, 2011, meeting in San Juan, Puerto Rico
- March 2011 – Interim report #2: power system study
    - This interim report was delivered on time during March 2011, and was discussed and accepted by the Technical Review committee.
- June 30, 2011 – Final interconnection study report was delivered on time; it has been reviewed, approved, and posted on the WAPA website.
- October 30, 2011 – Renewable scenarios study: impact of interconnection of levels of variable renewable generation in the USVI

8.4 Submarine Cable Study

The selection of either HVAC or HVDC interconnection largely depends on the transmission distance. The break point is usually only a few tens of kilometers. This is due to the impact of the cable's capacitive charging current, which increases with both voltage and cable length. At some distance, the capacitive charging current becomes equal to the thermal current rating of the cable, so no real power can be transmitted. This charging current can be compensated with shunt reactors installed at the cable ends. A 100% reactive compensation at the cable ends to extend the range of cross-linked polyethylene (XLPE) cables was used in several projects worldwide. The impact of system voltage, transmission capacity, and distance on cable selection is shown below in Figure 8-1.

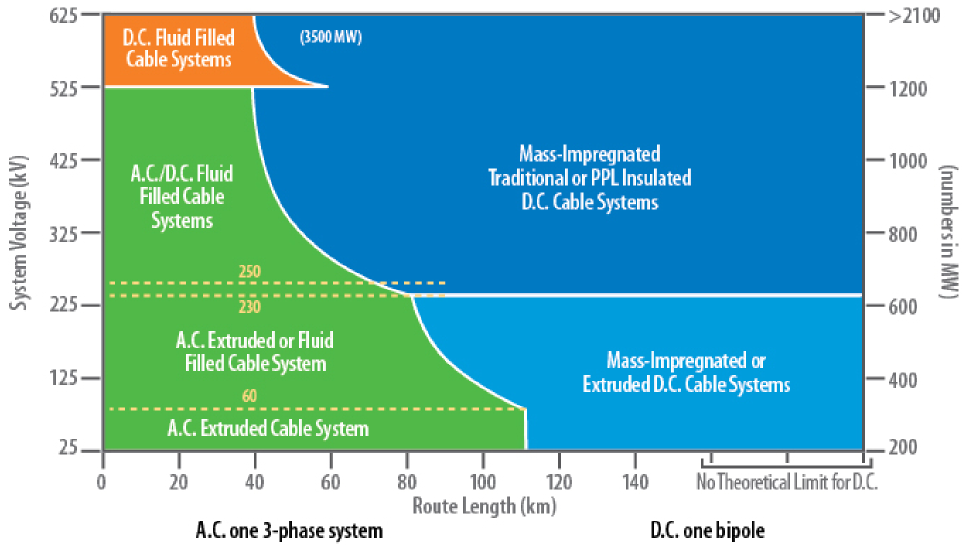


Figure 8-1. Transmission cable selection criteria

Source: NREL

Another important factor in submarine cable selection is sea depth. Deep water routes involve larger tensile loads on the cable as it is layed due to heavier cable weights. The map in Figure 8-2 shows transmission links that were part of the original WAPA RFP (request for proposals) (solid red lines). The maximum water depth for the proposed PREPA-St. Thomas interconnection is 50–60 meters. These depths do not represent a significant challenge in terms of the cable laying process. Therefore, AC and DC options were both considered originally for this link.

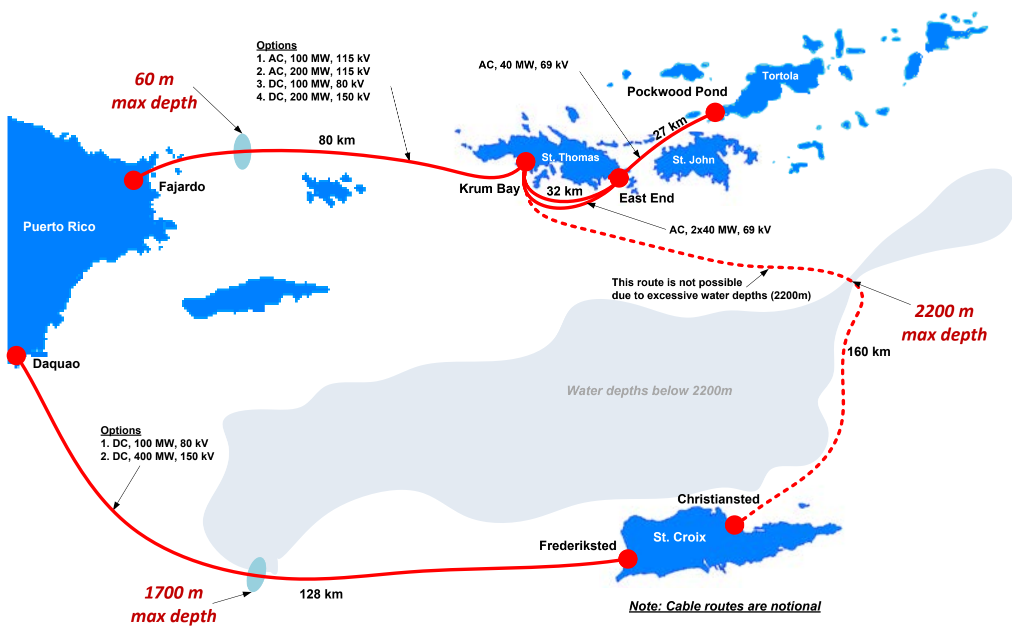


Figure 8-2. Study map (cable routes are notional)

Source: NREL

Different 115 kV AC XLPE submarine cable designs proved to be necessary for different power transmission capacity requirements for the PREPA-St. Thomas HVAC interconnection option. For the 100 MW level, a three-core cable type was found to be feasible, whereas for the 200 MW level, it was necessary to consider three single-core cables laid separately. The design options for the two HVDC options for the PREPA-St. Thomas interconnection are similar to the single-core 115 kV AC. However, the insulation of HVDC cables is a chemically modified cross-linked polyethylene designed for HVDC applications (XLDC), and galvanized steel is used for armor. It was found in the study that ±80 kV DC single-core XLDC cable can be used for the 100 MW HVDC transmission option, and ±150 kV DC single core XLDC cable can be used for the 200 MW option. The proposed converter technology for the PREPA-St. Thomas interconnection is based on voltage source converter (VSC) topology.

The 20-mile distance with 80 MW total power transfer capacity suggests two three-core, 69 kV AC XLPE cables, each rated at 40 MW, to be the optimum type and economic choice for the Krum Bay-East End interconnection in St. Thomas. The interconnection between the east end of St. Thomas and the west end of Tortola, BVI (Pockwood Pond substation), would only be 17 miles long and is anticipated to have 40 MW power transfer capacity. There are two 60 kV AC cable options that can be considered for this interconnection. One option is a conventional three-core XLPE cable with each core having a metal sheath water barrier. The other is a three-core wet design ethylene propylene rubber (EPR) cable with the EPR insulation in direct contact with the seawater.

The 100-mile submarine link between St. Thomas and St. Croix mandates HVDC transmission; however, the maximum water depths of approximately 2,200 m are well outside of current experience, which is limited to water depths up to 1,620 m. Thus, no fully reliable conclusion concerning the practicality of implementing this interconnection can be reached at this time. A full-scale development program according to CIGRE (International Council on Large Electric Systems) Recommendations for Mechanical Tests on Submarine Cables would need to be conducted by an experienced HVDC cable supplier in order to demonstrate feasibility. Based on these findings, the study review team decided to include the option of direct interconnection between Puerto Rico and St. Croix in the study scope, since maximum water depths for this route are around 1,700 m, well within of the realm of current submarine cable experience. This new addition to the study scope is shown in Figure 8-2 (red line between Daguao and Frederiksted).

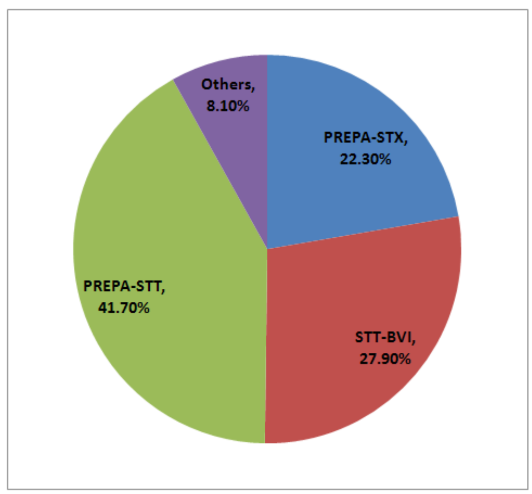


Figure 8-3. Cost breakdown by interconnections
Source: NREL

The cost estimate of the interconnection project includes the cost of cables, HVDC converter facilities, substations, and protection and communications equipment, as well as upgrades to the existing AC power systems. For confidentiality reasons, cost estimates are not included in this report. Instead, the report presents cost percentage breakdowns and comparisons of various options, as illustrated in Figure 8-3 and Figure 8-4. The estimated costs for each interconnection were compared. The PREPA-St. Thomas interconnection (Interconnection 1) has four technically feasible options (100 and 200 MW, based on both AC and DC), whereas the St. Thomas-BVI and PREPA-St. Croix interconnections have one option each. Figure 8-3 shows a comparison of the cost breakdown for the project with 200 MW DC for the PREPA-St. Thomas link.

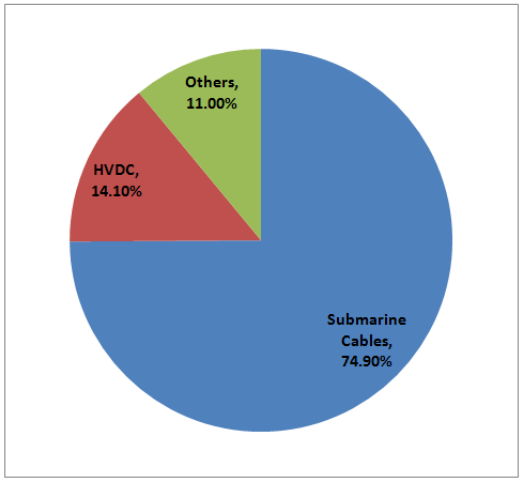


Figure 8-4. Cost breakdown by equipment
Source: NREL

A comparison of the total cost breakdown by major equipment for the interconnection project using the 200 MW DC option for the PREPA-St. Thomas link is shown in Figure 8-4 and Figure 8-5. It can be seen that equipment cost is dominated heavily by submarine cables, followed by HVDC converter facilities.[13]

The main difference among the options is the PREPA-St. Thomas configuration that can be AC or DC and rated at 100 MW or 200 MW. A percentage comparison of overall interconnection project costs is shown in Figure 8-5. The DC options are more costly due to the high cost of HVDC converters. The difference between AC and DC options is about 3%–4%. The cost of shunt capacitors required by the PREPA system for the 200 MW AC option was not included in the analysis. These capacitors may further reduce the difference between AC and DC options. Increasing the rating of the PREPA-St. Thomas interconnection from 100 to 200 MW will cost approximately 12%–13% extra for both AC and DC options.[14]

[13]Anderson, D.; Huang, L.; Kazachkov, Y.; Lam, B.P.; Lawson, G.W.; Pinheiro, A.; Xiaokang, X. (2011). *Interconnection Feasibility Study–Final Report.* Report R59-11, Project Number P/23-115094, Siemens PTI. http://www.viwapa.vi/AboutUs/Projects/ProjectDetails/11-08-02/USVI-BVI-Puerto_Rico_Interconnection.aspx
[14]Ibid.

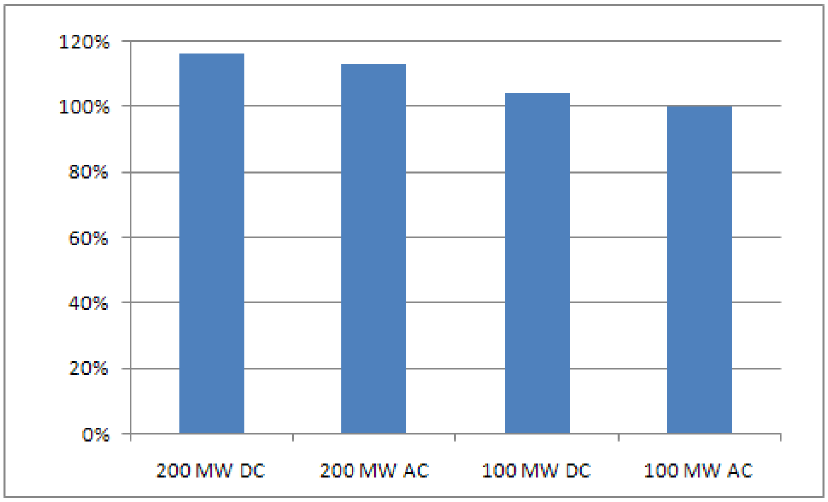


Figure 8-5. Comparison of total project costs
Source: NREL

Based on the above findings, it appears that the 200 MW HVDC option for the PREPA-St. Thomas link is the most reasonable solution from both a technical and an economic standpoint. A high-level electrical diagram of such interconnection is shown in Figure 8-6. The additional benefits of this topology include fast active power flow control that might be a useful feature for addressing the variability of wind and solar generation on St. Thomas and for avoiding under-frequency load shedding caused by generator outages in the USVI. In addition, this topology allows AC voltage control at the point of interconnection in both systems. The DC solution also provides some electrical separation between the PREPA and WAPA systems. Electrical faults occurring on the PREPA side will have less impact on the fault current in the WAPA system if the DC option is used.

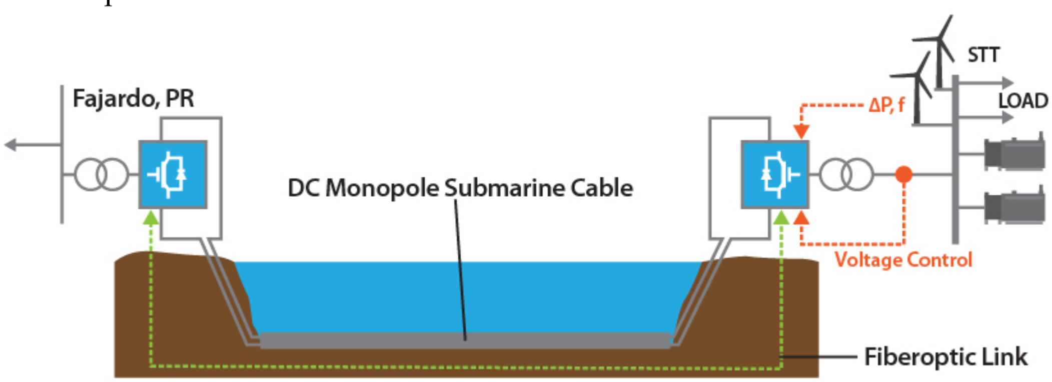


Figure 8-6. HVDC option for the PREPA-St. Thomas link

Source: NREL

8.5 Power System Study

The objectives of the power system study were to evaluate the performance of interconnected power systems and identify necessary upgrades and reinforcements for both St. Thomas and St. Croix. The power system study included the following:

- Models of the USVI power system
- Steady state assessment of the interconnected system
- Stability assessment of the interconnected system
- Short circuit analysis

The year 2025 was selected as the horizon year in the study, and all basic assumptions were based on WAPA's planning criteria. A set of scenarios was selected, including different power transfer levels between PREPA and WAPA, different thermal generation commitment and dispatch in the WAPA system, and peak and light load conditions. These scenarios were modeled to identify the major reliability problems. Steady state, short circuit, and stability analyses were performed for each scenario to ensure that the interconnection project meets reliability criteria, including system adequacy and security.

The power system study concluded that the proposed cable interconnection of the PREPA, USVI, and BVI systems is feasible. Some upgrades and reinforcements to all systems will be needed to accommodate such interconnections. Detailed recommendations and cost estimates for upgrades to the St. Thomas and St. Croix systems will be included in the final project report.[15] Some recommendations for PREPA and BVI systems will be included as well.

Results of the power system study, including the identified equipment related to each of the interconnections and all necessary upgrades involved in the interconnection of PREPA, WAPA, and BVI power systems, were also used in the cost-estimating portions of the study.

8.6 Benefits

One of the main purposes of the interconnection study is to demonstrate the benefits of the interconnections for WAPA. Such benefits may include reduced generation costs, fossil fuel savings, increased reliability, and potential for higher levels of variable renewable generation in the USVI.

Presently, oil is the only fuel source used by WAPA's generation fleet. WAPA has set an ambitious target of 60% reduction in dependence on imported oil by 2025 through deployment of renewable energy and energy efficiency technologies. Due to its present size and operational characteristics, the PREPA system seems to be able to absorb a much larger amount of variable renewable generation compared to WAPA. In this context, interconnection with PREPA is going to be an important factor in helping WAPA bring higher levels of renewable generation online. Using this interconnection, WAPA will have the opportunity to use ancillary services that

[15] Ibid.

PREPA can provide through the interconnection and thereby expand its ability to meet clean energy goals, reduce air pollution, and, most importantly, reduce its dependence on imported oil.

At this stage of the study, production cost simulations were performed to estimate the potential fuel savings WAPA could expect for the scenarios with and without the PREPA interconnection, and including 5 MW wind and 5 MW solar resources each for St. Thomas and St. Croix. The hourly net load of renewable energy provides metrics on how much base load energy can be imported from PREPA without overloading WAPA's system.

Other scenarios have been modeled as well, such as an alternate approach of continuous import of 20 MW of electric power from PREPA. Preliminary results showed that there would be a significant overgeneration problem in St. Croix if more than 5 MW of fixed energy were received on this island. Therefore, the 20 MW of import was split, with 15 MW going to St. Thomas and 5 MW going to St. Croix. A summary of potential benefits in terms of fuel cost savings when connected to PREPA is shown in Table 8-1. These results were calculated with an assumed purchase cost of \$150 per megawatt-hour (MWh) for PREPA imports.[16]

Table 8-1. Potential Fuel Cost Benefits[17]

	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Fuel and O&M Savings	36,107	36,657	42,097	40,028	44,568	43,484	41,891	47,665	47,952	48,269	48,333
PREPA import (GWh)	175	176	175	175	175	176	175	175	175	176	175
Cost of import (k$)	26,276	26,345	26,276	26,302	26,276	26,345	26,276	26,276	26,276	26,370	26,276
Cost of emergency (k$)	3,281	1,917	6,308	2,667	6,859	4,471	2,879	6,021	6,749	4,593	7,779
Net benefit (k$)	**6,549**	**8,395**	**9,513**	**11,049**	**11,433**	**12,668**	**12,736**	**15,337**	**14,927**	**17,306**	**14,227**

Currently, WAPA operates as a balancing authority for two isolated balancing areas—St. Thomas/St. John and St. Croix—by matching generation to demand. WAPA would be required to perform this function whether operating as an isolated system or interconnected to PREPA. Since this study found that St. Thomas and St. Croix cannot be interconnected at this point, there will not be any reserve sharing between these two islands. However, a "virtual" reserve sharing can be achieved via PREPA's system if both St. Thomas and St. Croix are interconnected with PREPA and a reserve sharing agreement exists among all entities. Such reserve sharing among all balancing areas (PREPA, St. Thomas, St. Croix, and BVI) creates a potential for additional fuel savings. For example, PREPA can activate its spinning reserve for the loss of a generator in St. Thomas, thus improving the overall system reliability, reducing the amount of contingency

[16]Ibid.
[17]Ibid.

reserves to WAPA, and providing additional fuel savings.[18] The Siemens PTI report also recommends that all parties enter into emergency energy agreements and coordinate their system restoration plans.

The interconnection between WAPA and PREPA should cause an immediate increase in overall reliability for WAPA. Table 8-2 shows the potential improvement in reliability in terms of reduction in expected loss of load hours per year. On average, there is a reduction of about 330 loss of load hours per year in an interconnected system. This is a significant improvement compared to the base case (i.e., WAPA isolated operation).

Table 8-2. Potential Improvements in Reliability[19]

	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Reduction in loss-of-load hours	**450**	**138**	**250**	**226**	**420**	**174**	**350**	**390**	**428**	**374**	**430**

Another major benefit of interconnecting the PREPA and WAPA systems is the reduction in carbon dioxide emissions. WAPA operates inefficient oil units with high carbon dioxide (CO_2) emission rates. The interconnection with PREPA will reduce the CO_2 production within the WAPA system by about 200,000 short tons a year as shown in Table 8-3 below (PREPA system emissions were not calculated).

Table 8-3. Potential CO_2 Reduction[20]

	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
CO_2 reduction (1,000 short tons)	**195**	**199**	**200**	**205**	**203**	**204**	**200**	**209**	**201**	**203**	**202**

The first part of the interconnection study illustrates that a link to PREPA can provide many benefits to WAPA in terms of fuel cost savings, reliability improvements, and emission reductions. The amount of benefit depends on the level and price of imported energy. The ongoing extension to the study is focused on estimating another important benefit—the impact of the interconnection on levels of variable renewable generation in USVI.

[18] Ibid.
[19] Ibid.
[20] Ibid.

9 Summary of Recommendations and Roadmap

This section of the report presents an overview of the recommendations and road map for achieving the USVI's clean energy goals based on the results of the HOMER analysis, site selection for renewable energy, and the Siemens interconnection study, as well as the *USVI Energy Road Map Analysis*.[21]

9.1 Summary of Recommendations

The recommendations summarized in this section are based on the results of the following: 1) the economic modeling performed using the HOMER hybrid optimization tool, 2) the analysis of the impact of renewable generation on the USVI's electrical distribution system and 3) the feasibility study on the interconnection of the PREPA, WAPA, and BVI Electricity Corporation grids via a submarine cable system. Overall, this report shows that transmission and distribution will not be an insurmountable barrier.

9.1.1 Economic Results from HOMER Model

The results of the HOMER analysis show that wind turbines are the most economically feasible alternative power for St. Thomas and St. Croix, even with very conservative assumptions for operating reserve and capital costs. Specifically, the results demonstrate that:

- Wind is cost effective even at low fuel prices
- 15 MW of wind can reduce the fuel usage by 9% on St. Thomas and 14% on St. Croix
- PV will become cost effective when the installed cost is less than around \$6/W, or when fuel prices go above \$99/barrel
- Under the proposed PPA, the 16.5 MW WTE plant is cost effective; it is also cost effective when combined with PV and wind.

9.1.2 Site Selection and Impacts on Electrical Power System

On a distribution feeder, the safe penetration level is defined in terms of a ratio of PV system power to the rating of the distribution peak load. The 10% rule was applied to the peak loads on the St. Thomas feeders. With this constraint applied, the analysis determined that a maximum of 8.3 MW of PV generation can be added on St. Thomas and 4.4 MW of PV can be added on St. Croix.

9.1.3 PREPA-WAPA Interconnection Study

The interconnection study reviewed existing transmission and generation development plans and selected study scenarios, performed WAPA system steady state and stability assessments, and conducted short circuit analysis. Based on this analysis, it appears that interconnections between Puerto Rico and St. Thomas, between St. Thomas and BVI, and between Puerto Rico and St. Croix are all technically feasible. The direct interconnection between St. Thomas and St. Croix does not appear to be technically feasible given today's state of the art.

[21] Lantz, E.; Olis, D.; Warren, A, (2011) *U.S. Virgin Islands Energy Road Map Analysis: 60% Reduction in Fossil Fuel by 2025*. NREL/TP-6A20-52360. Golden, Colorado: National Renewable Energy Laboratory.

9.2 USVI Energy Road Map

The results of the *U.S. Virgin Islands Energy Road Map Analysis* performed by NREL indicates that the deployment of renewable energy in the USVI has the potential to stabilize or lower energy prices while diversifying WAPA's energy sources. Although there are significant technical, financial, and social barriers to meeting the territory's goal of a 60% reduction in fossil fuel use by 2025, the *Energy Road Map Analysis* report suggests it is a feasible goal. Several other studies of the USVI energy economy are under way, including a more thorough examination of the energy efficiency and renewable energy tactics needed to achieve the USVI's aggressive goal.

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Appendix A: Wind Turbine Technology Overview

Presented here is an overview of various configurations of wind turbine generators and the impact large wind farms may have on electric power systems.

Wind Turbine Generator Configuration

A number of generator configurations are used in the modern wind turbine generator (WTG). The first-generation of utility-scale wind turbines (Type 1) were constant speed using squirrel cage induction generators directly connected to the grid (Figure A-1). Many such wind turbines are still in service today. The speed of induction generator changes slightly (up to 1%) with input mechanical power variations. Soft-starters are generally required in order to limit the in-rush currents during startup. Also, power factor correction (PFC) capacitors are needed to bring the power factor close to unity.

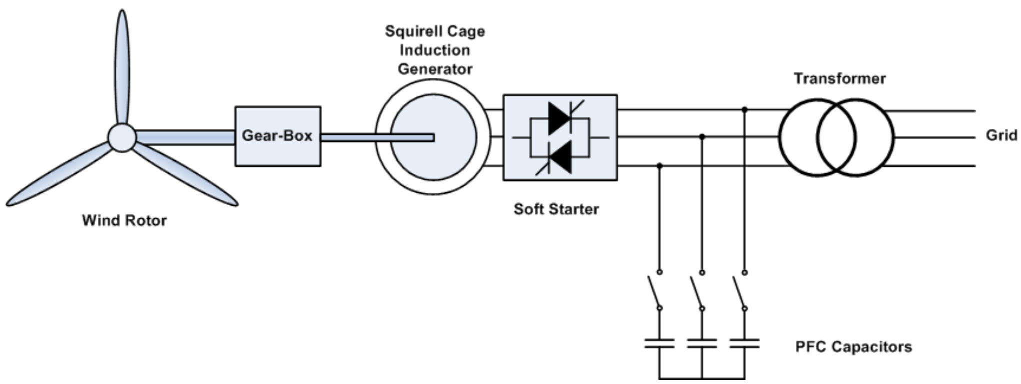

Figure A-1. Type 1 wind turbine

Source: NREL

These fixed-speed machines operate suboptimally, since at constant speed the energy capture efficiency is low. The variable slip operation (Type 2) has improved characteristics with slightly larger (up to 10%) generator speed range. This is achieved with an external variable resistor in the wind rotor circuit controlled by a high frequency semiconductor switch (Figure A-2).

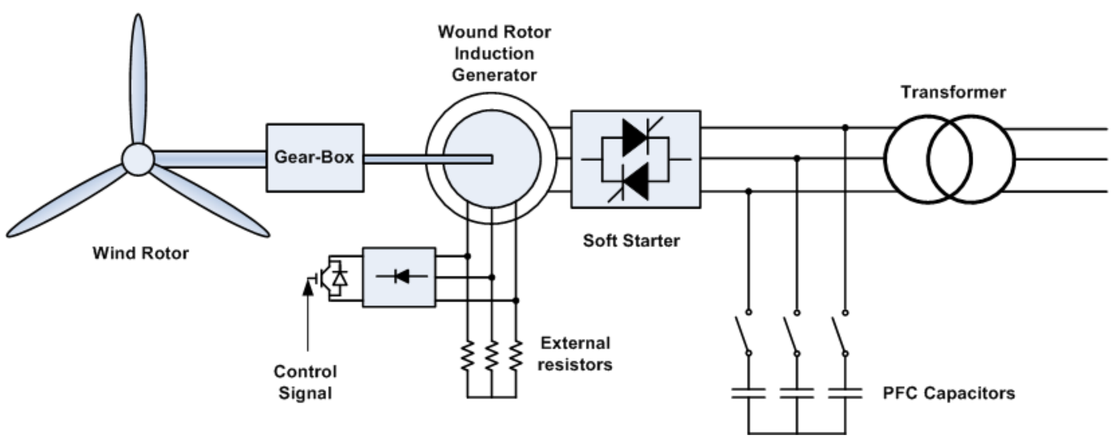

Figure A-2. Type 2 wind turbine

Source: NREL

Both types of WTGs usually use soft-starter circuits to reduce induction generator in-rush currents during startups. Also, both Type 1 and Type 2 topologies can both use two winding generator configurations. Each winding is rated for different power capacity, so switching between lower and higher power generator windings allows better utilization of wind resource.

By introducing power electronic control into the generator system, it is possible to decouple the rotational speed from grid frequency, allowing the rotor speed to vary. This variable-speed operation has a number of advantages, including better energy capture, lower acoustic noise, reduced mechanical stress, and real/reactive control capabilities. The rapid evolution from inexpensive low voltage (below 1 kV) to medium voltage (above 5 kV) power semiconductors and progress in packaging technology created opportunities for variable-speed wind generation.

The generator topology shown in Figure A-3 is currently the system favored by many manufacturers (Type 3). The double-fed induction generator (DFIG) is an induction machine with a wind rotor fed from a power converter that is rated at 25%–30% of the generator rating (partially rated converter), allowing the speed to vary by a similar amount. The pulse-width modulation (PWM) insulated gate bipolar transistor (IGBT) power converter DC bus voltage control loop ensures that DC voltage remains fixed. The power factor at generator terminals can be controlled as required by a network operator.

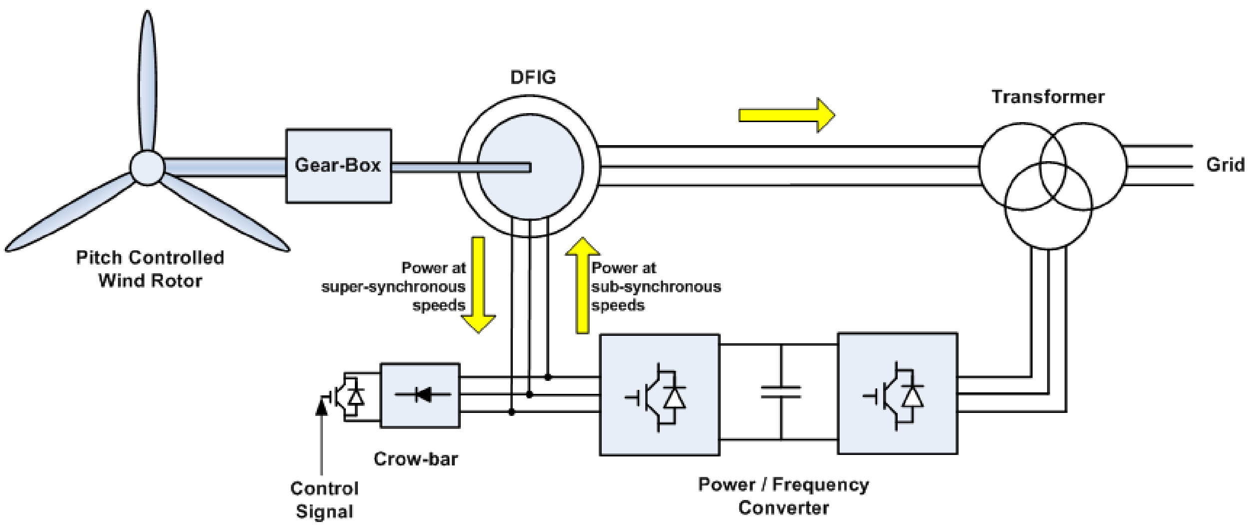

Figure A-3. Type 3 wind turbine

Source: NREL

In recent years, the wind turbine topologies with fully rated power converters (Type 4) have been adopted by many manufacturers. A direct drive (no gearbox) Type 4 system with permanent magnet synchronous generator (PMSG) is shown in Figure A-4. The fully rated converter allows control of the real and reactive power at wind turbine terminals. Another version of Type 4 is a wind turbine induction machine instead of synchronous generator. However, a gearbox is necessary in this case. The power converters used in this scheme are standard industrial drives that are normally used with induction motors. They are reliable and readily available from many manufacturers, both domestic and foreign.

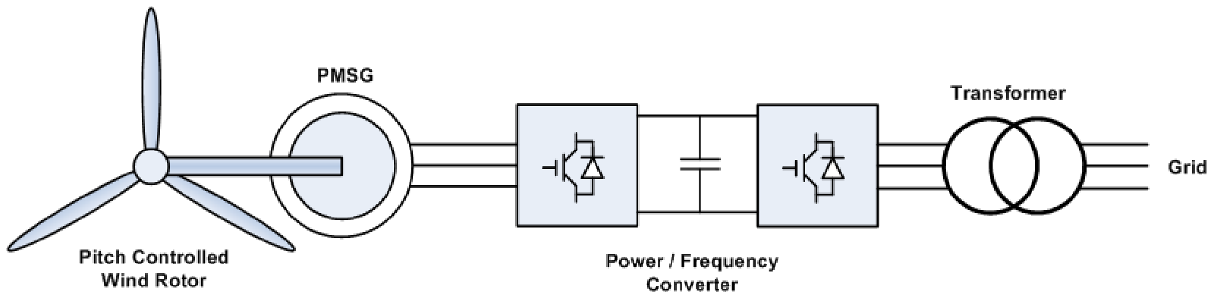

Figure A-4. Type 4 wind turbine

Source: NREL

An additional protection for the DC link in the form of DC-chopper circuitry is usually used in both Type 3 and Type 4 power converters. Large, megawatt-scale wind turbines usually use low voltage (LV) generators and power converters. The standard LV levels used in wind turbines are 480, 575, 600, and 690 VAC in the United States. In Europe, some wind turbines are rated for higher (up to 1,000 VAC) voltages. With growing demand for wind power, the rating of wind turbines is increasing, and medium voltage (MV) power converters have advantages over LV solutions at these higher powers. The MV power converters can be built with both IGBT and integrated gate commutated thyristor (IGCT) technologies using various self-commutated PWM control schemes to minimize losses and improve power quality. It is a common feature for such power converters to provide reactive power control or STATCOM (static synchronous compensator) functionality (even with periods of no wind), ensuring continuous and dynamic voltage control at the point of interconnect. Power converters also allow compensating torque pulsations in the wind turbine gearbox, thus improving the reliability and extending the life cycle of gearbox components.

Impact of Wind Farms on Power System Operations

With large wind farms connected to the HV transmission networks, the main technical constraint to take into account is the power system transient stability that could be lost when, for example, a voltage dip causes the switch off of a large number of wind generators. In the case of small island grids, larger levels of wind power penetration into small island power systems present certain challenges due to the random nature of the wind resource and the characteristics of wind turbine generators. In weaker island electric grids with medium-voltage distribution networks, the power quality issues may become a serious concern because of the proximity of the wind generators to the loads. Flicker emission, harmonics, voltage variations, and voltage dips are reported to be the main quality problems.

Power electronic converters used in wind turbines will play a crucial role in the expected impact of wind plants on power system operations. While wind plant terminal behavior is different from that of conventional power plants, it can still be compatible with the design and operation of existing power systems. In the event of system voltage faults, a requirement for wind turbines such as low-voltage ride through (LVRT), high-voltage ride through (HVRT), and zero-voltage ride through (ZVRT) become very important. Type 3 and 4 wind turbines are able to meet these LVRT requirements due to functionality introduced by power electronics converters. In general, Type 4 turbines have better LVRT capabilities because of complete isolation between the generator and the grid introduced by the power converter. In Type 3 turbines, various techniques such as crowbar circuit, larger capacitors, and short-term power storage can be used to enhance LVRT performance. For Type 1 and 2 wind farms, the LVRT capabilities can be enhanced by the use of STATCOM and SVC (static VAR compensator) on a wind farm level.

The generator at each turbine should be protected individually and independently because of the electrical diversity of the wind power plant (WPP). In practice, this is an advantage of a WPP compared to a conventional power plant. During a disturbance, the electrical characteristics at the terminals of each wind turbine are slightly different from the other turbines. Typically, in large, grid-connected wind farms, only the most affected WTGs will be disconnected from the grid. For general faults (distance faults at the transmission point), only 5%–15% of the turbines are disconnected from the grid. Thus, the loss of generation is not as severe as in a power plant with large generators. At the turbine level, the WTG generates at low voltage levels (480 V–690 V). The generator is connected to a pad-mounted transformer to step up the voltage to MV (typically 34.5 kV; may be lower for small island systems).

The short-circuit (SC) current contribution of a wind turbine generator is also affected heavily by the presence of a power converter in the system. For Type 4 wind turbines, the SC current contribution is limited to the temperature rating of the power converter (usually corresponding to 110% of current rating). In Type 3 wind turbines, the magnitude of SC currents can be limited by the power converter as well, depending on the proximity of the fault to the wind turbine terminals. In Type 1 and 2 wind turbines, the SC currents can be much higher due to the nature of induction generators. The fault current produced by an induction generator must be considered when selecting the rating for circuit breakers and fuses.

One of the technical aspects of displacing of conventional synchronous generation with wind power plants may result in an erosion of system inertial response, resulting in increased rates of change of grid frequency and larger frequency excursions. Variable-speed wind turbines with power converters are capable of providing rapid frequency response to power system disturbances. By utilizing the mechanical inertia of the turbine rotor, the power converter control allows the turbine to increase its output by 5%–10% of its rated power during several seconds and benefits the grid by allowing time for other nonwind power generation to increase production during large underfrequency events. This feature allows wind turbines to provide inertial response similar to conventional synchronous generators and enhance grid reliability. In general, the evolving interconnection regulations require wind farms to be able to contribute to control tasks on the same level as conventional power plants, constrained only by limitations imposed at any time by the existing wind conditions. These tasks may include equivalent governor droop functionality, power ramp rate limitations, participation in automatic generation control (AGC), etc.

The general steps in the typical wind energy integration study for small island systems include steady state and dynamic analysis. The steady state and fault analysis study criteria must include:

- Power flow (thermal) violations of lines with and without the planned WTGs
- Voltage-control capabilities with and without planned WTGs
- Three-phase fault current calculation with and without the WTGs, to determine the changes in the system short-circuit level.

The specific transient criteria require that the whole island system remain stable and recover during the wind gust scenario and after the fault scenario:

- Major wind gusts with an intact system
- Fault for nine or more electrical cycles and clearing fault with tripping load at the interconnection line
- Islanding operation

In general, for any system disturbance, the dynamic response of the wind farm must not cause system instability. In particular, in accordance with the LV protection setting of the WTG, as per the post-transition period LVRT limit applicable to an island-specific wind generation plant, the wind turbines must be able to withstand a voltage as low as the LV protection setting value for a three-phase or single-phase fault at the interconnection line.

Appendix B: Submarine Power Transmission Technology Overview

Submarine power transmission has been around for more than a century. Its uses shifted through the decades along with power transmission technology development. In the early days, submarine cables were used to supply electric power to small, near-shore loads such as lighthouses. Interconnecting near-shore islands to mainland power grids was a focus of the next stage of submarine power transmission technologies. Today, development in offshore wind power and longer-distance interconnections between countries and regions are becoming primary driving factors in submarine cable markets. In recent years, there have been significant advances in high-voltage DC (HVDC) transmission technologies, making it competitive with conventional high-voltage AC (HVAC) transmission methods.

HVDC vs. HVAC

A complete feasibility analysis, including technical merits, economic considerations, and environmental aspects, needs to be conducted for correct comparison between HVDC and HVAC transmission options for any given project. The selection criteria are dependent on many factors, such as transmission distance, voltage, and capacity. For a given transmission distance, the terminal cost of HVDC is higher than for HVAC due to the higher capital cost of HVDC converter stations. However, the overall cost of HVDC increases more slowly with transmission distance compared to HVAC (as shown in Figure B1 example). This is due to lower cost and fewer losses associated with DC lines. Also, the cost of intermediate reactive power compensation has to be taken into account for long AC lines. According to various reports, the breakeven distance is in the range of 500–800 km for overhead transmission, and 50–120 km for submarine transmission.

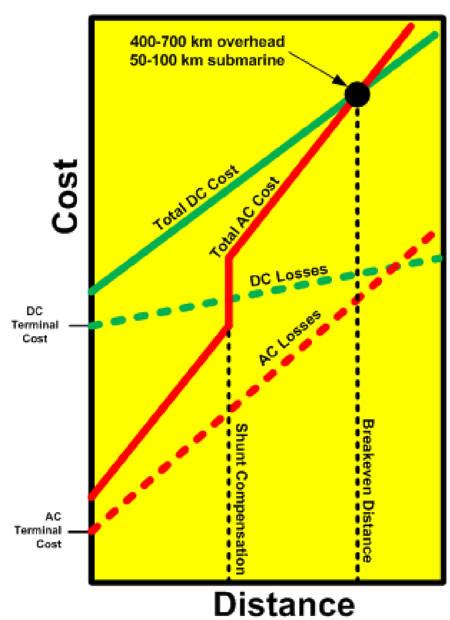

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Figure B-1. HVAC vs. HVDC example

Source: NREL

The fundamental difference between HVAC and HVDC is that a DC link allows power transmission between asynchronous AC networks (i.e., between islands). Also, inductive and capacitive characteristics of power cables do not limit the maximum distance of a DC transmission link, and a conductor cross-section is fully utilized, since there is no skin effect in the case of DC (with only two conductors vs. three for AC). Other advantages of some HVDC configurations include rapid power flow control, the possibility of acting as a buffer for certain types of disturbances, benefits to weaker grids, and grids with higher levels of variable renewable generation penetration. Also, HVDC does not contribute to the short-circuit current of the interconnected AC system. HVDC disadvantages include high cost of converter stations, complexity of control and communications, and sometimes higher maintenance costs.

Types of HVDC Terminals

The line-commutated converters (LCC)-HVDC terminals are based on thyristor valves and have more than 30 years of service experience. They can be used at very high power levels, up to 1,200 MW or higher for submarine transmission. Currently, HVDC projects worldwide are dominated by transmissions with terminals employing LCC technology. A typical LCC-HVDC terminal uses 12-pulse converters that can be connected in series or in parallel. An example of two-terminal bipolar LCC-HVDC system for offshore wind farm interconnection is shown in Figure B-2.

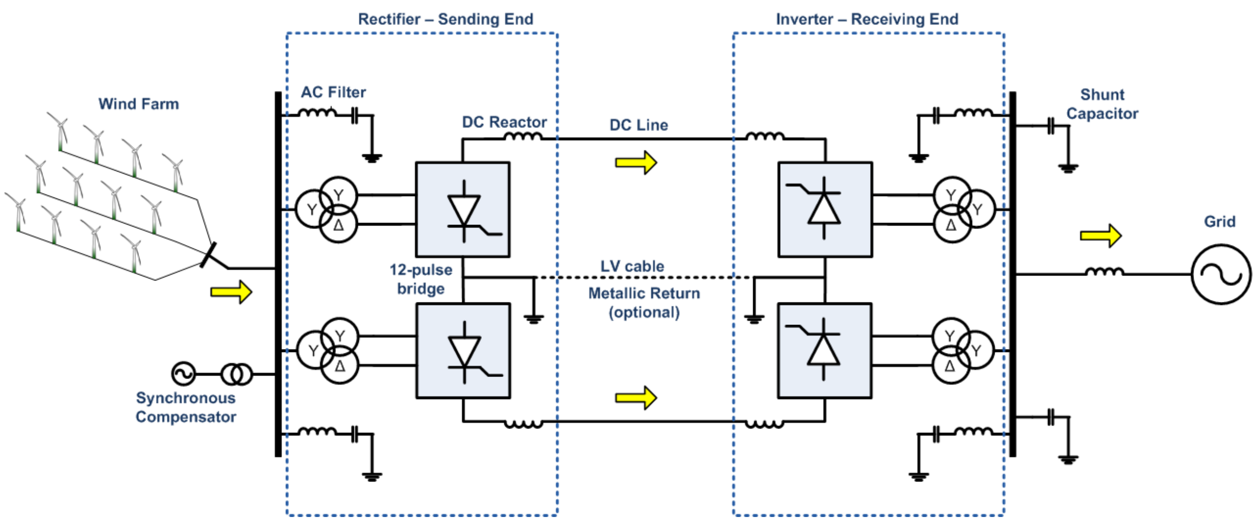

Figure B-2. Example of LCC-HVDC transmission

Source: NREL

It is necessary to provide a commutation voltage in order for the LCC-HVDC converter to operate. This commutation voltage can be provided by synchronous generators or compensators. LCC operates at lagging power factors, since the firing of the converter has to be delayed relative to voltage crossing to control the voltage in DC cables. Both sending- and receiving-end converters need a considerable amount of reactive power for their normal operation. Large AC filters are necessary to reduce harmonic emissions by LCC terminals. For a reversible power interconnection (i.e., interconnection between two island systems), the LCC-HVDC must change the polarity of the DC voltage. Strict minimum short-circuit levels are imposed on LCC-HVDC terminals.

New types of semiconductors available for power electronics with the ability to not only turn on (as thyristors) but also turn off (such as IGBTs and gate turn-off thyristors GTOs) made it possible to create a new type of converter known as a voltage source converter (VSC). The VSC-HVDC terminal provides significant advantages over LCC-HVDC that could be critical, especially for interconnecting weaker island systems. An example of a two-terminal bipolar VSC-HVDC system for offshore wind farm interconnection is shown in Figure B-3.

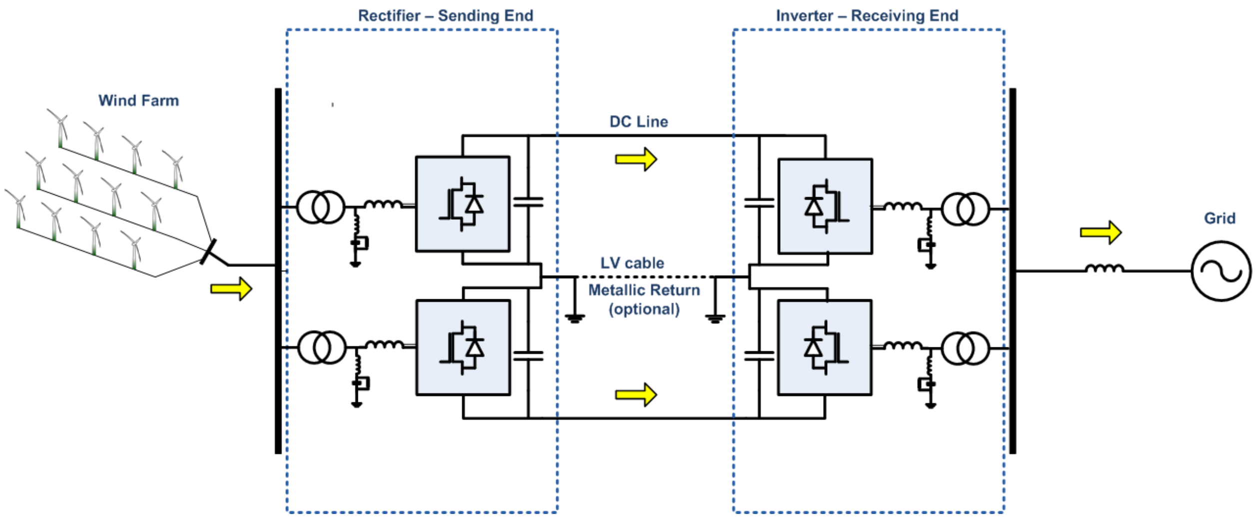

Figure B-3. Example of VSC-HVDC transmission

Source: NREL

The VSC-HVDC technology offers low sensitivity of the sending-end converter terminal to the characteristics of the AC system at the receiving end. The VSC terminal can operate at unity power factor and provide voltage control in the AC system to which it is connected, and reactive power control is independent on active power control. It can be used for black start of an islanded AC power system. The same VSC converter can serve as a rectifier and an inverter without DC voltage polarity reversal. This feature is important for submarine interconnection because lighter polymer cables can be used with VSC-HVDC. The VSC terminals can be controlled with PWM technique. Also, they can be controlled by utilizing a multilayer converter concept that provides lower losses and better harmonic content. In general, the VSC-HVDC system requires smaller filters than LCC-HVDC due to higher switching frequencies. However, the same higher switching frequency causes higher (by 1%–1.5%) losses for VSC compared to LCC.

Upon reaching the shore, the submarine cable is terminated and joined to an underground or overhead transmission line that goes to the onshore converter terminal station. A conceptual drawing and land usage for a typical 400 MW, +/- 150 KVDC transmission is shown in Figure B-4.

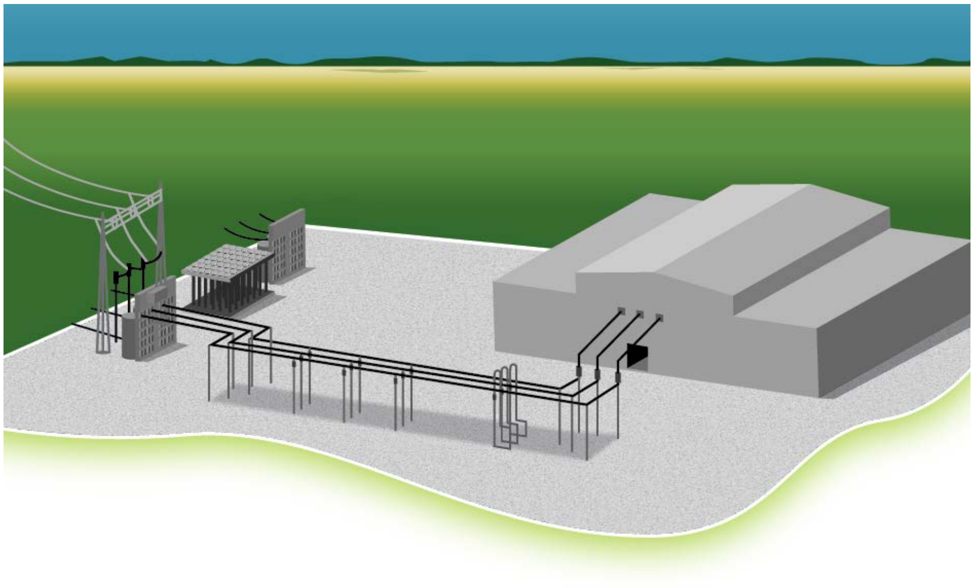

Figure B-4. VSC-HVDC converter station

Source: NREL

HVDC Configurations

The single-pole (monopole) configuration for a VSC-HVDC link is shown in Figure B-5. It can be used for long-distance submarine transmission with either a sea or a metallic return. In many cases, existing infrastructure and/or environmental concerns may require using metallic return. The metallic return uses low-voltage cable that can be bundled with the high-voltage DC cable and will result in significant reduction in magnetic field interference compared to a sea return. There is a new integral return conductor (IRC) cable technology that uses coaxial pair for main and return cables, allowing almost complete elimination of the magnetic field.

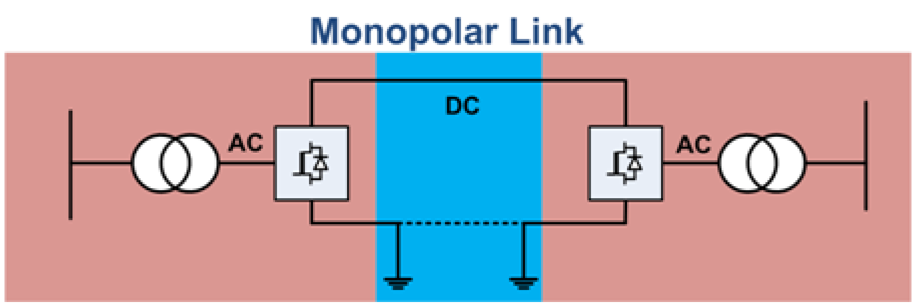

Figure B-5. Monopole VSC-HVDC

Source: NREL

A bipole link can be used to increase power transfer capability of VSC-HVDC systems. An example of bipole configuration is shown in Figure B-6. The bipole link also has an advantage of increased reliability, since it can still transfer 50% of rated power in case of loss on one pole. The bipole configuration has an option of construction staging when equipment can be installed in two steps with any desired time interval in between.

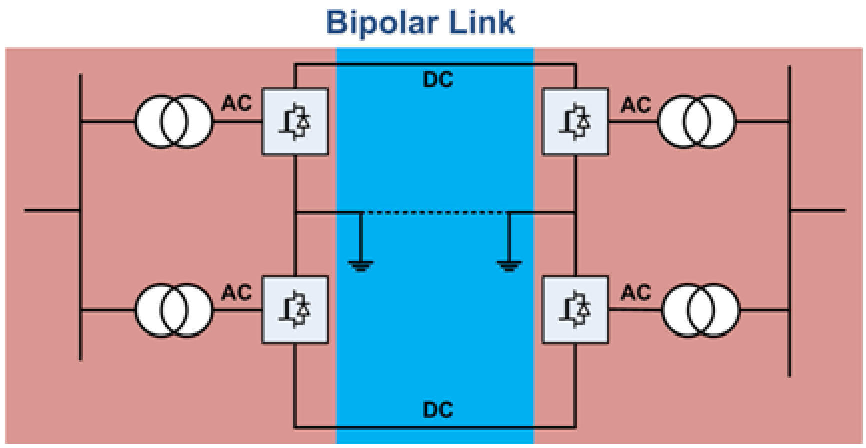

Figure B-6. Bipole VSC-HVDC

Source: NREL

Another advantage of VSC-HVDC is the possibility of multi-terminal configuration with parallel connection of converters, as shown in Figure B-7. The multi-terminal HVDC technology has been implemented widely, but it clearly offers the benefit of interconnecting multiple terminals at lower costs. There may be two different control approaches for multi-terminal HVDC: 1) the master-slave approach where one of the converters controls the DC voltage and the other converters control power flow, and 2) the coordinated control approach where the DC voltage and power flow are controlled in a coordinated manner by all converter stations. The latter requires reliable communications between terminals that can be achieved by using fiberoptic communication cables between individual terminals.

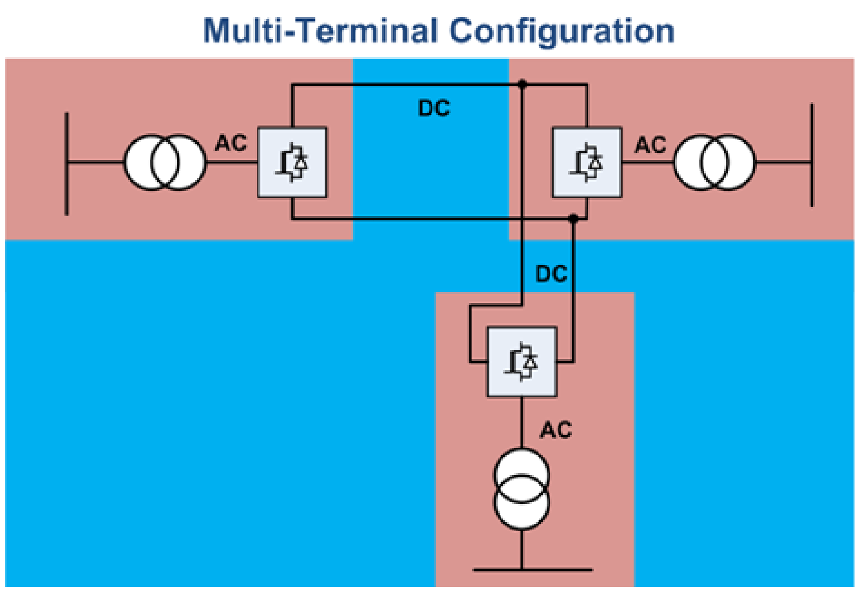

Figure B-7. Example of VSC-HVDC multi-terminal configuration

Source: NREL

Submarine Cables

The design of submarine power cables is identical to high-voltage underground cables, including polymer jacket or other metal sheath. However, submarine cables also have one or two layers of galvanized steel or copper wire armor. This armor, in turn, is protected against damage or seawater-caused corrosion by an outer layer of polymer material. Submarine cables also use special splicing techniques. Several different submarine cable types exist. The difference is mainly in the class of dielectric material.

Figure B-8. SCCF cable

Source: Prysmian Cables and Systems

Self-contained fluid-filled cables (SCFFs) are insulated with paper or laminated with paper tapes impregnated with low-viscosity synthetic oil. The oil is maintained under pressure in the cable duct by shore-based pumping stations. SCFF cables have been in submarine service for many years at high voltage levels up to 1,000 kVAC and 600 kVDC.

Figure B-9. Mass impregnated cable

Source: Prysmian Cables and Systems

The mass impregnated cables use paper tape insulation impregnated with a high-viscosity dielectric fluid. The mass impregnated cables are limited to operation in AC systems to voltages up to 69 kV due to voids in the insulation that may lead to failure at higher AC voltages. For HVDC applications, mass impregnated cables are in service volt voltages up to 500 kVDC.

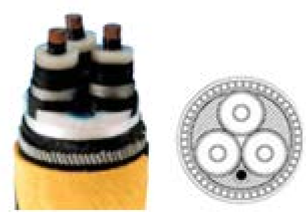

Figure B-10. 3-core XLPE cable

Source: Prysmian Cables and Systems

XLPE cables have been used in underground and submarine applications for many years. XLPE suppliers offer a number of cable materials, and dielectric properties of XLPE vary depending on brands. In submarine applications, the voltage levels of XLPE cables (245–345 kVAC) are limited by the voltage ratings of the joints. At 150 kVAC, three-core cables are often used due to lower constructions costs. A fiberoptic element can be implemented in three-core cable design for data and signal transmission.

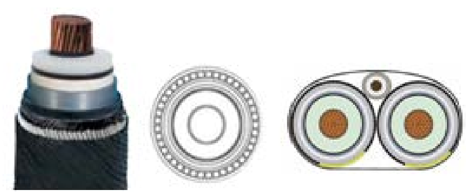

Figure B-11. XLDC cable cable

Source: Prysmian Cables and Systems

Cross-linked DC (XLDC) polymer cables are modified XLPE cables designed specifically for HVDC applications. The XLDC cables have better insulation design without the space charge accumulations that XLPE cables have in the DC voltage field. The XLDC cables have been used in submarine transmission systems for up to +/- 320 KVDC/ 800 MW. The XLDC (or modified XLPE) cables used with VSC converter technology are marketed as HVDC Light or HVDC Plus. A cable pair can be bundled together with a fiberoptic control cable.

Typical cable burial depths for submarine applications are 1–2.5 m in soft soils. Burial is typically carried out at the near-shore areas to water depths up to 100–150 m. The purpose of burial is to increase cable reliability by reducing risks of cable damage due to fishing and anchoring activities. Alternative protection methods include covering of submarine cables with concrete mattresses, installing the cables in split cast iron pipes, among others.

The longest submarine power transmission is the 450 kV, 700 MW, 580 km link between Norway and the Netherlands in the North Sea. The deepest one is the 200 kVDC, 200 MW Sardinia-Italy cable at a maximum water depth of 1,620 m.

Appendix C: Energy Storage Technology Overview

Electric energy storage is likely to become an important component of the future electricity grids that will have high levels of penetration of renewable energy sources, such as wind and solar. Both solar photovoltaic (PV) and wind energy have variable and uncertain output, which are unlike the conventional power sources used for electricity generation. The main concern regarding the reliability of an electric grid with high levels of variable generation is associated with the variable nature of wind and solar resources, as well as with the costs of reliably integrating large amounts of variable generation into the national grid.

The potential role of storage in the future power grid depends on many economical and technical factors. Obviously, energy storage offers clear benefits to enable greater penetration of variable renewable generation. However, the economics of energy storage must be analyzed in comparison with a variety of competing technologies that also allow greater penetration of wind and solar, such as demand response, transmission optimization, flexible generation, and improvements in operational practices of electrical utilities. It is important to note that the primary driver behind the strong interest in energy storage is variable generation.

There is a large variety of energy storage technologies either emerging or commercially available. Each technology has some inherent limitations or disadvantages that make each practical for a limited range of applications. The capability of each technology for high power and high energy applications is well defined and has been the subject of many studies. Utilities in several U.S. states have recently embraced new MW-scale energy storage technologies as part of their testing and demonstration projects to mitigate the effects of wind power variability.

Energy Storage Applications

The main distinction between energy storage applications is classified as those that are best suited for power applications and those best suited for energy applications. Energy storage designed for power applications has the capacity to store small amounts of energy per kW of rated power output, and require high power output for relatively short periods of time (from several seconds to 10–15 minutes). Storage designed for energy applications has large energy capacity with discharge durations up to many hours.

Another application for energy storage is capacity application that includes storage used to defer the need for other equipment, such as new generation or transmission and distribution equipment upgrades. Capacity applications in general require a relatively limited amount of energy discharge throughout the year compared to power and energy applications.

Energy storage design criteria are focused on the intended application and include two major parameters: power rating and discharge duration. Depending on these parameters, large-scale stationary applications of energy storage can be divided into three major functional categories:

- **Power Quality.** This category involves using energy storage for load equipment protection against short-duration events that may affect the quality of electric power delivered to the loads, such as voltage and frequency faults, low power factors, harmonics, service interruptions, etc. Power quality needs require stored energy to be applied for a few seconds up to a few minutes to assure continuity of quality power. In applications with variable renewable generation, this storage category can enhance voltage and frequency fault ride-through characteristics of wind turbine generators and PV inverters.

- **Bridging Power.** In this category, stored energy is used from seconds to minutes to assure continuity of the power supply when switching from one power generation system to another. Also, by balancing power flow fluctuations, energy storage can compensate for the short-term intermittency of renewable energy sources. It can help bridge between power generation modes during ramping periods, provide spinning reserves, contribute to grid frequency regulation, provide voltage or VAR support capability, help with transmission congestion relief, provide black start capability, etc.

- **Energy Management.** This category involves large energy capacity storage for various forms of electrical energy supply/demand dispatching with multi-hour discharge durations. Electric energy time-shift (arbitrage) involves purchasing inexpensive electric energy (including energy generated by renewables) to charge the storage plant, so it can be used or sold at a later time when the price is high. Load following and peak shaving during high demand hours are forms of longer discharge duration applications.

There are many potential application synergies when storage used in one application can provide services for other applications as well. Detailed descriptions of various energy storage applications and the role of storage with renewable energy generation can be found in the study for DOE's Energy Storage Program by Sandia National Laboratories[22]and the study by NREL on energy storage with renewable electric generation.[23] A high-level map of energy storage applications classified by discharge period and power rating is shown in Figure C-1.

[22]Eyer, J.; Corey, G. (2010). Energy Storage for the Electric Grid: Benefits and Market Potential Assessment Guide: A Study for the DOE Energy Storage Program. SAND2010-0815. Albuquerque, New Mexico: Sandia National Laboratories.
[23]Denholm, P.; Ela, E.; Kirby, B.; Milligan, M. (2010). The Role of Energy Storage with Renewable Electricity Generation. NREL/TP-6A2-47187. Golden, Colorado: National Renewable Energy Laboratory.

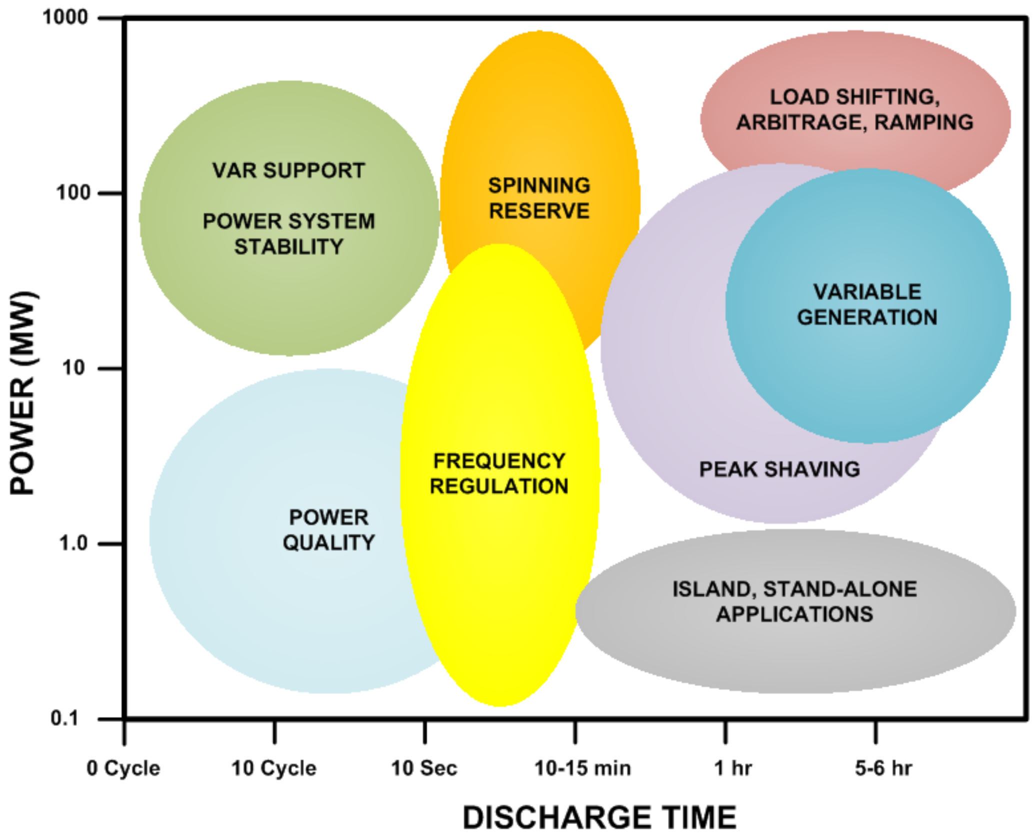

Figure C-1. Energy storage applications

Source: NREL

Overview of Energy Storage Technologies

There are multiple energy storage concepts employing various technologies that have wide ranges of capital and per-cycle costs, efficiencies, and energy densities (sizes and weights). The AC-to-AC round-trip efficiency (ratio between kWH_{in} to kWH_{out}) is one of the primary performance indicators for energy storage that is often vaguely reported, so it is difficult to perform an accurate assessment and comparison of different storage technologies for a given application. Availability of accurate storage efficiency is especially important for assessments of storage interactions with variable generation sources due to dynamic charging conditions. In many cases, accurate storage efficiencies for a given application can be obtained only by testing in parallel with real variable-generation systems such as wind turbines/wind farms or PV systems. It is important to note that the round trip efficiencies of several technologies cannot be compared directly since they do not have the same functional equivalent and are used in a system that requires both electricity and natural gas.[24]

This section provides a brief overview of the existing storage technologies with a focus on systems suited for renewable-heavy grid applications.

[24]Ibid.

Pumped Hydro Storage

Pumped hydro storage (PHS) is the only energy storage deployed on a gigawatt (GW) scale in the United States and worldwide (over 90 GW), and is used for energy management applications. Nationwide there were 31 GW of new PHS proposals pending at FERC in 2009. PHS uses two water reservoirs separated vertically (Figure C-2), pumps and turbines for pumping water during off-peak hours, and reversed water flow to generate electricity. Round-trip efficiencies that exceed 75% can be achieved. Underground PHS, using flooded mines, is also technically possible. Open sea can also be used as the lower reservoir (possible synergy with offshore wind).

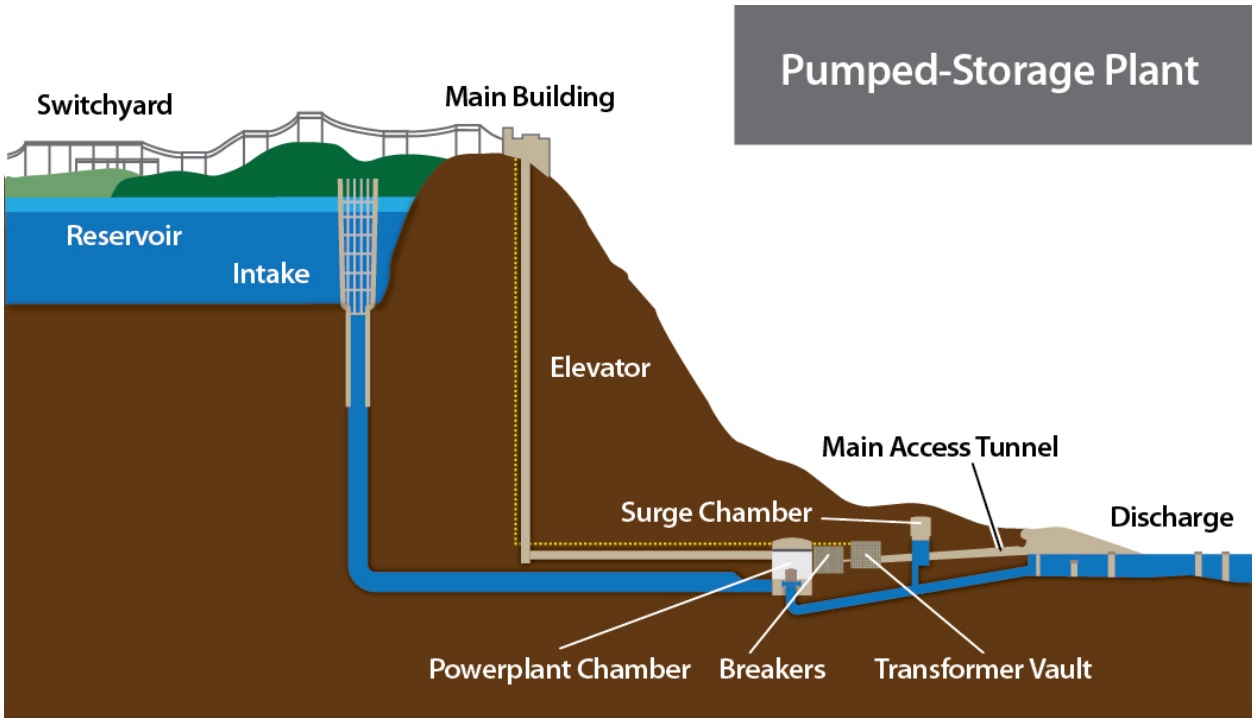

Figure C-2. Concept of pumped hydro storage

Source: NREL

Conventional PHS uses constant-speed motors for water pumping, so power consumed in the pumping mode is constant. The introduction of adjustable-speed technologies allows adding a high level of flexibility in pumping mode (active and reactive power control, load following, fast response, etc.). The role of PHS in high wind-penetration power grids has been studied intensively by many authors.[25] A 30 MW hydroelectric pumped energy storage that uses sea as a lower reservoir is located in Okinawa, Japan. Similar seawater-based pumped storage projects have been under consideration in many island nations and territories.

Compressed Air Energy Storage

Compressed air energy storage (CAES) technology is based on conventional gas turbines and stores energy by compressing air in an underground storage cavern. The CAES gas turbine uses 40% of the gas used in conventional gas turbines to produce the same amount of output power.

[25]Tuohy, A.; O'Malley, M. (2009). *Impact of Pumped Storage on Power Systems with Increasing Wind Penetrations*. Power and Energy Society General Meeting, 2009. IEEE.

This is achieved by combusting fuel after mixing it with stored air in the turbine (Figure C-3). CAES is used for energy management applications.

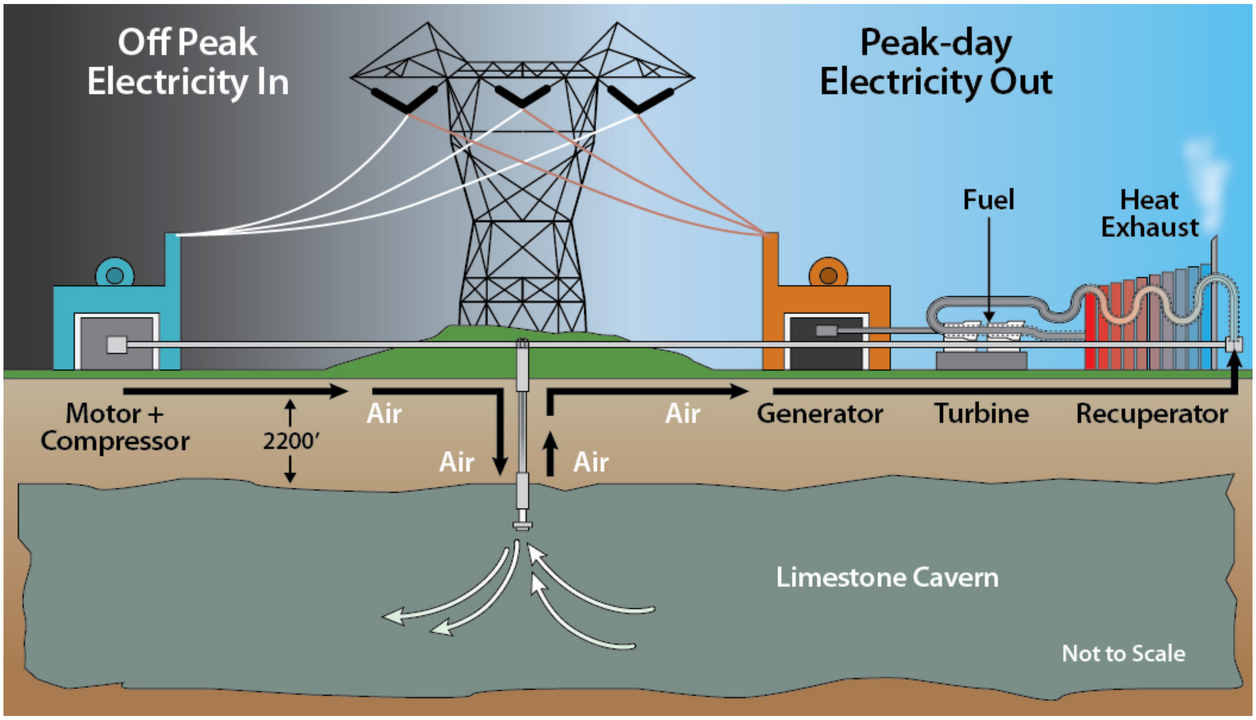

Figure C-3. Concept of CAES

Source: NREL

The primary disadvantage of CAES is the need for an underground cavern created inside salt rock. It also relies on fossil fuels for operation. These factors may limit CAES applications in small island grids.

Battery Technologies for Energy Management

Several battery technologies are suitable for energy management applications. These include two general types: high temperature batteries and liquid electrolyte flow batteries.

According to the Electricity Storage Association,[26] the **Sodium-Sulfur (NaS)** battery is the most mature high-temperature battery and has been demonstrated at over 190 sites in Japan totaling more than 270 MW with stored energy suitable for six hours daily peak shaving. The largest NaS installation is a 34 MW/245-MWh system for wind power stabilization in northern Japan. In the United States, several utilities have deployed NaS batteries for testing and demonstration purposes. American Electric Power demonstrated performance of two NaS battery modules each rated at 50 kW_{AC} and capable of supplying 350 kWh of energy.[27] Xcel Energy is in the process of testing a 1 MW NaS system with an 11 MW wind farm in Minnesota. This project is

[26]Electricity Storage Association (2011). Electricity Storage Association (ESA) website. www.electrisitystorage.org. Accessed August 2011

[27]Norris, B.; Newmiller, J.; Peek, G. (2007). *NAS Battery Demonstration at American Electric Power*. SAND2006-6740. Albuquerque, New Mexico: Sandia National Laboratories.

performed in partnership with NREL (wind-to-battery project).[28] Xcel's NaS system comprises 20 kWx50 kW battery modules capable of storing about 7 MWh of energy. The system weighs approximately 80 tons. Electric Transmission of Texas uses a 4 MW NaS battery system in Presidio, Texas, for providing transmission back up in the event of a line outage, improving power quality and reducing voltage fluctuations.

The NaS batteries operate at a 300–350°C temperature range to keep sulfur in a molten state. They have built-in heaters to keep the sodium and sulfur from solidifying. The NaS batteries have high energy density, high round-trip efficiency (up to 92%), long life cycle, and are fabricated from relatively inexpensive and abundant electrode materials. NaS batteries are different from common battery systems since electrodes are liquids and electrolyte is a solid (sodium iron-conducting ceramic) giving cell voltage somewhat over 2V. Large individual cells are enclosed in steel enclosures for safety reasons and can be arranged into parallel or series strings for providing the required voltage and storage capacity.

NaS batteries have fast a response time (milliseconds) making them suitable not only for time shifting and economic dispatch, but for frequency regulation purposes as well. The layout of 8 MW/57.5 MWh NaS battery system designed for a Hitachi factory in Japan is shown in Figure C-4. This system occupies an area of approximately 1150 m^2 (12,500 sq. ft).

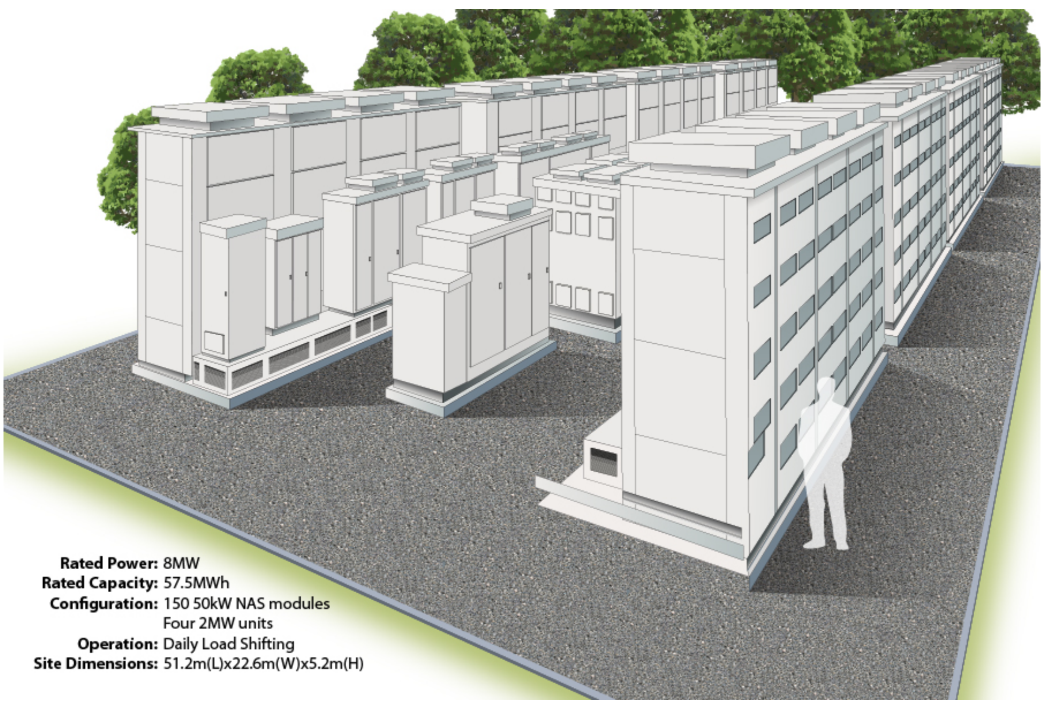

Figure C-4. Layout of 8-MW NaS battery system

Source: NREL

Alternative high-temperature chemistry batteries have been proposed and are in various stages of development and testing. One example is the sodium-nickel-chloride, or ZEBRA, battery. The

[28]Xcel Energy (2010). Sodium Sulfur Battery Energy Storage and its Potential to Enable Further Integration of Wind (Wind-to-Battery Project). Data collection and analysis report. July 2010.

general configuration of ZEBRA batteries is similar to that of the NaS cells. They also use liquid sodium as the negative electrode and sodium beta alumina as the solid electrolyte. However, the positive electrode is nickel in the discharged state and nickel chloride in the charged state. The operating temperature range of ZEBRA batteries is kept in the range of 270–350°C, and cell open-circuit voltage is 2.59 V. The specific energy of each individual cell is 790 W/kg (better than 760 W/kg for NaS cells).[29] Groups of ZEBRA batteries can be encased in a temperature-controlled container, and the configuration is designed to produce a ratio of power and energy of about two (50 kW/25 kWh). The complete ZEBRA battery stores about 120 Wh/kg specific energy. The main attractive feature of ZEBRA batteries is that their cells are fully reversible with close to 100% amp hour efficiency. Despite higher initial costs, it is claimed that life-cycle costs of ZEBRA batteries are less than for lead-acid due to a much longer lifetime.[30] Safety tests in Europe have indicated that these batteries are safer than NaS batteries and therefore are better suited for transportation applications. There are many testing and demonstration projects all over the world for ZEBRA batteries in vehicles, but not for energy-related grid applications.

Another group of high-energy batteries that have liquid electrode reactants are **flow batteries**. They use a liquid electrolyte flowing across a membrane. The liquid reactant is stored in tanks and is pumped through the cell part of the electrochemical system. The flow battery can be considered to be like rechargeable fuel cells. All reactants and products of the electro-active chemicals are stored externally to the fuel cell (Figure C-5).

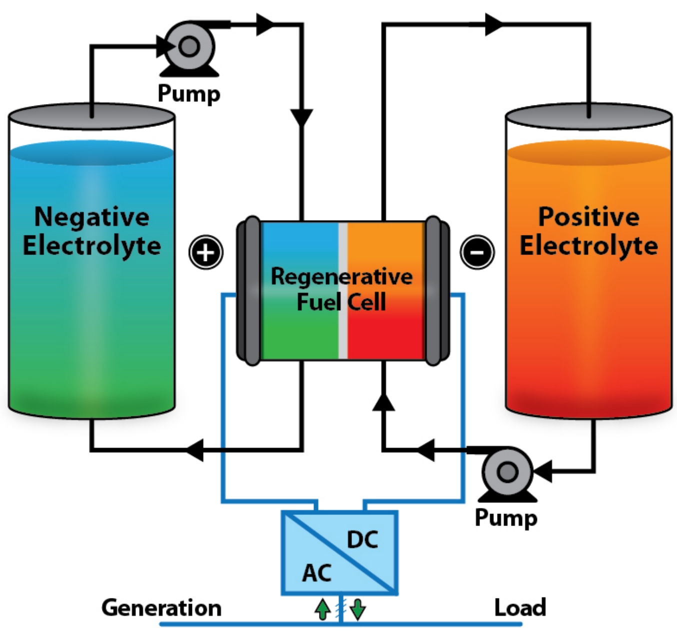

Figure C-5. General flow-battery diagram

Source: NREL

The reactant materials can be pumped into and out the regenerative fuel cell, so the capacity is not limited by the cell dimensions, but determined by the of storage tank size, resulting in very

[29]Huggins, Robert A. *Energy Storage*. New York: Springer, 2010.
[30]Ibid.

large capacities. The power (MW) and energy (MWh) ratings of the flow battery are independent of each other. The flow battery can be optimized for either energy or power delivery, can respond within milliseconds, and can ramp up from a full shutdown to full operation within a few minutes. These capabilities make them suitable for a wide variety of applications.

The electrode reactants are typically acidic that undergo reduction/oxidation (redox) reactions.[31] Various redox systems have been explored, and one of the most attractive flow systems involves flow batteries based on a vanadium redox battery (VRB) system.[32] Some of the redox systems used in flow batteries and their nominal open-cell voltages are shown in Table C-1.[33]

Table C-1. Various Redox Systems Used in Flow Batteries

System	Negative Electrode Reactant	Positive Electrode Reactant	Nominal Voltage (V)
V/Br	V	Bromine	1.0
Cr/Fe	Cr	Fe	1.03
V/V	V	V	1.3
Sulfide/Br	Polysulfide	Bromine	1.54
Zn/Br_2	Zn	Bromine	1.75
Ce/Zn	**Zn**	**Ce**	**<2**

Redox flow batteries have typical energy densities of 15 Wh/kg and 18 Wh/l, and typical round-trip efficiency of 70–75%.

In general, there has been limited deployment of two types of flow batteries—VRB and zinc-bromine. Other combinations (such as polysulfide-bromine) have been pursued and are currently under development.

Using MW-scale flow batteries in island grids may require additional investment in the form of housing for flow-battery components (electrolyte tanks, cell stacks, auxiliary equipment, etc.). There are also other solutions, such as foldable rubber tanks that can be placed directly on the ground or inserted into underground premises. One study estimated the size of a 2.5 MW/10 MWh VRB system to be up to 17,000 sq. ft.[34]

Environmental impact of flow batteries is minimal since liquid electrolytes can be refurbished and reused. There are no toxic chemicals that must be disposed of at the end of battery life, such

[31]Nguyen,T.; Savinell, R.E. (2010). "Flow Batteries." *The Electrochemical Society Interface*, Fall 2010
[32]Huggins, Robert A. *Energy Storage*. New York: Springer, 2010.
[33]Ibid.
[34]Eckroad, S. (2001). *Handbook on Energy Storage for Transmission or Distribution Applications*. Palo Alto, California: Electric Power Research Institute.

as are found in other electrochemical storage technologies.[35] In the VRB system, the only chemical is the vanadium electrolyte; ionic vanadium is sulfuric acid at approximately the same concentration found in flooded lead-acid batteries. Its handling and safety requirements are the same as for sulfuric acid. The VRB must be placed within a spill containment area compliant with local regulations using industrial-grade tanks and pressure-rated pipes and fittings.

Flow-battery systems in which one or more of the electro-active components are stored internally are called **hybrid flow-batteries**. Examples include the zinc-bromine or zinc-chlorine batteries. Similarly to conventional batteries, the energy densities of these hybrid flow batteries are limited by the amount of electro-active materials that can be stored within the batteries and they have limited scale-up advantages.[36]

A relatively new concept that could be useful for stationary storage applications is the use of an **all-liquid battery** in the form of three-component cell. The battery consists of three layers of liquids; liquid electrodes on the top and bottom, and electrolyte liquid in the middle. Since each liquid has a different density, the liquids automatically form three distinct layers (Figure C-6).

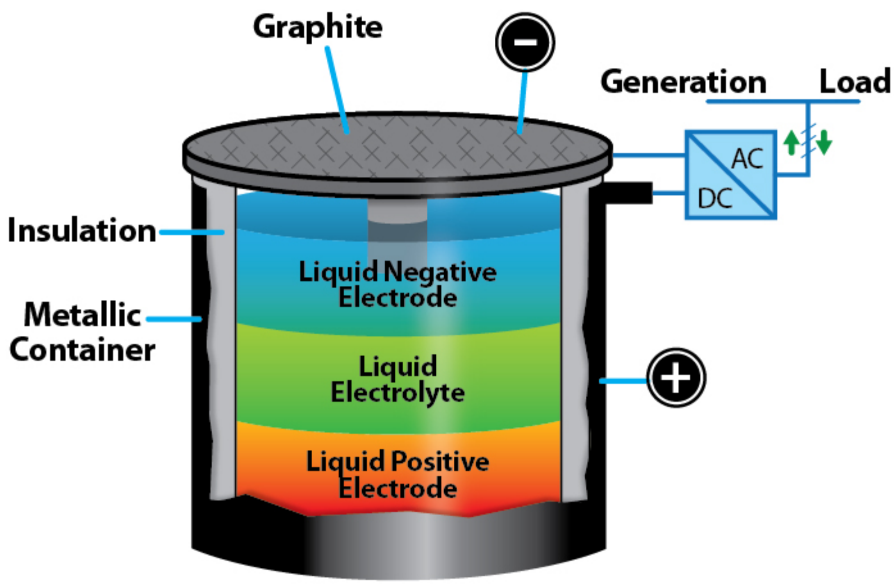

Figure C-6. Graphic representation of all-liquid battery

Source: NREL

The cost of all-liquid batteries will depend on the materials used in both electrodes and electrolyte, which can be less than a third of the cost of today's batteries, since the materials are inexpensive and the design allows for simple manufacturing.[37] The first prototype developed at MIT used molten metals; magnesium on the top and antimony on the bottom, and molten sodium sulfide as electrolyte. The potential for using other materials for improved performance is under investigation. The main advantage of all-liquid batteries is the capability of operating at very

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[35] Ibid.

[36] Nguyen,T.; Savinell, R.E. (2010). "Flow Batteries." *The Electrochemical Society Interface*, Fall 2010.

[37] MIT Technology Review. http://www.technologyreview.com/energy/22116/

high electrical currents (tens of times higher than any previous battery), making them capable of quickly absorbing large amounts of electricity.[38]

Thermal Energy Storage

Thermal energy storage (TES) is typically not used to store and then discharge electricity directly. However, in many applications TES is functionally equivalent to electricity storage. TES for energy management applications is usually associated with concentrating solar power (CSP) plants. In this application, thermal energy from the solar field is stored in some desired medium (steam or molten salt). This energy can be recovered at a later time of a day and used to generate electricity, turning this technology into a dispatchable source of energy.

Hydrogen Energy Storage

Hydrogen has the highest energy content per unit of weight of any known element. However, it is also the lightest element. As a result, hydrogen has a low volume of energy density and presents significant challenges to storing the large quantities of hydrogen necessary for utility-scale energy storage. The same critical challenge on a smaller scale is faced by the transportation industry where the need for an acceptable driving distance is constrained by weight, volume, efficiency, safety, and the cost of hydrogen storage.

In large-energy-capacity storage applications, hydrogen produced by steam reforming of natural gas or water electrolysis can then be stored in underground caverns at a 100–350 bar pressure.[39] Around 60 caverns are under construction in Germany. Each cavern will be capable of providing more than 500 MW for up a week in base-load operation (equivalent to 140 GWh) by consuming stored hydrogen in gas turbines modified for hydrogen use.

In transportation applications, hydrogen can be stored as compressed gas or in liquefied form using high-pressure tanks. Compressed hydrogen tanks for 5,000 and 10,000 psi have been certified worldwide. Future storage technologies include metal and chemical hydride, and carbon nanotubes.

Hydrogen energy storage for utility-scale applications represents the same challenge as CAES, since underground caverns are needed for both applications. Also, to store large quantities of hydrogen, one needs to produce it first. This means that a complete hydrogen production/consumption cycle needs to be built, including electrolyzers or natural gas reformers for production and gas turbines for electricity regeneration.

Storage Technologies for Bridging Power

This application is generally associated with "traditional" battery technologies, including lead-acid, nickel-cadmium, lithium-Ion, nickel-metal hydride and several others, and requires rapid response and discharge times in the range of up to about an hour.

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[38]Belifore, M. (2010). "Liquid Metal Batteries Could Lead to Power Storage Breakthrough." *Popular Mechanics.* www.popularmechanics.com/science/energy/next-generation/liquid-metal-batteries-storage-breakthrough. Accessed August 2011.

[39]Buck, Christian (2009). "Tomorrow's Power Grids." *Pictures of the Future* magazine. www.siemens.com/innovation/en/highlights/industry/update_02/plugging-buildings.htm. Accessed August 2011.

Over many years, the most common type of batteries used in a variety of applications were **lead-acid batteries** due to their relatively low cost, ease of manufacture, and favorable electrochemical charging characteristics, such as rapid kinetics and acceptable cycle life under controlled conditions.[40] Lead-acid batteries are still a popular choice for power quality, UPS, and spinning reserve applications. However, they have limited use in energy management, since their life cycle is short for such applications. Also, the amount of energy that a lead-acid battery can deliver is not fixed and depends on its rate of discharge[41] . Nevertheless, a few commercial projects used lead-acid batteries for energy management, such as a 40MWh system in Chino, California, built in 1988 and a 14 MWh system in Puerto Rico built in the 1990s.

The lead-acid batteries could be classified mainly into two technologies, depending on the state of electrolyte. **Flooded lead-acid batteries** use electrodes and separators immersed in the liquid electrolyte. This causes some water loss during overcharge conditions, so periodic maintenance is needed for flooded batteries. **Valve regulated lead-acid (VRLA) batteries** use a maintenance-free design with the electrolyte absorbed in a gel. In this design, internal gas recombination minimizes electrolyte loss over the life and eliminates the need for re-watering.[42] **Long life (LL) lead-acid batteries** have significant advantages over regular lead-acid batteries, including an extended (up to 15–17 years) life cycle with up to 4,500 charge-discharge cycles at 85% efficiency. These improvements are achieved by using high-density active materials for electrodes, adding silica to the electrolyte solution, and utilizing horizontal installation and advanced charging controls. There are a number of LL lead-acid-battery based MW-scale storage systems deployed in Japan operating with wind power generation. Energy density of LL lead-acid batteries is relatively low at about 28 Wh/kg.

Having relatively lower energy-density storage compared to other battery technologies, lead-acid batteries require a large area if used for high-capacity storage applications. An aerial view of a 10 MW/40 MWh lead-acid storage system in Chino, California, is shown in Figure C-7.

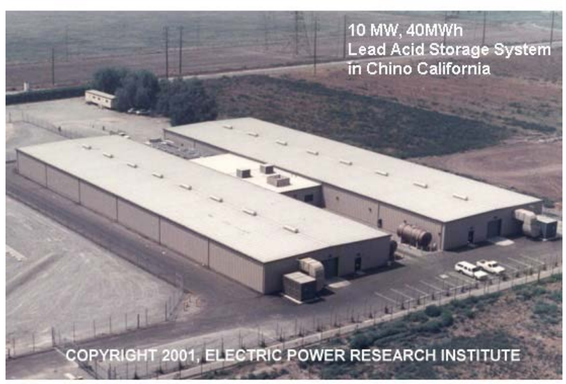

Figure C-7. Lead-acid storage system in Chino, California

Source: EPRI

[40]Huggins, Robert A. *Energy Storage*. New York: Springer, 2010.
[41]Electricity Storage Association (2011). Electricity Storage Association (ESA) website. www.electrisitystorage.org. Accessed August 2011.
[42]Lailler, P. (2003). Investigation on Storage Technologies for Intermittent Renewable Energies: Evaluation and Recommended R&D Strategy. Gennevilliers Cedex, France: EXIDE Technologies.

The list of large facilities that have been commissioned in various locations around the world is shown in Table C-2.

Table C-2. Lead-Acid Battery Storage Facilities

Plant Name and Location	Installed (Year)	Rated Energy (MWh)	Rated Power (MW)
Chino, California	1988	40	10
HELCO, Hawaii	1993	15	10
PREPA, Puerto Rico	1994	14	20
BEWAG, Germany	1986	8.5	8.5
Vernon, California	1995	4.5	3

Lithium-ion (Li-ion) batteries have achieved significant penetration into the portable electronics market and are making the transition into hybrid and electric vehicle markets as well. If the industry's growth in the vehicles and electronics markets yield improvements and manufacturing economies of scale, Li-ion batteries will likely find their way into grid storage applications too.[43] Li-ion batteries offer 80% depth of discharge, have higher energy density (up to 115 Wh/kg) and better efficiencies (90–96%) than LL lead-acid batteries. However, they have much higher cost due to special packaging needs and internal overcharge protection circuits, and shorter cycle life (up to 3,000 charging cycles).

The cathode in Li-ion batteries is lithiated metal oxide, and the anode is made of graphitic carbon with a layer structure. The electrolyte is a lithium salt dissolved in organic carbonates. When the battery is being charged, the lithium atoms in the cathode become ions and migrate through the electrolyte toward the carbon anode, where they combine with external electrons and are deposited between carbon layers as lithium atoms. This process is reversed during discharge.[44]

In November 2009, AES Energy Storage and A123 Systems announced the commercial operation of a 12 MW frequency regulation and spinning reserve project at a substation in the Atacama Desert in Chile.[45] Southern California Edison is cooperating with DOE to develop and conduct a comprehensive demonstration of an 8 MW/32 MWh Li-ion energy storage system in the Tehachapi area.[46] This battery would stabilize the flow of wind power to the utilities' load

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[43]Doughty, Daniel H.; Butler, D., P.C.; Akhil, A.A.; Clark, N.H.; Boyes, J.D. (2010). "Batteries for Large-Scale Stationary Electrical Energy Storage." *The Electrochemical Society Interface.* http://www.electrochem.org/dl/interface/fal/fal10/fal10_p049-053.pdf. Accessed August 2011.

[44] Electricity Storage Association (2011). Electricity Storage Association (ESA) website. www.electrisitystorage.org. Accessed August 2011.

[45]Doughty, Daniel H.; Butler, D., P.C.; Akhil, A.A.; Clark, N.H.; Boyes, J.D. (2010). "Batteries for Large-Scale Stationary Electrical Energy Storage." *The Electrochemical Society Interface.* http://www.electrochem.org/dl/interface/fal/fal10/fal10_p049-053.pdf. Accessed August 2011.

[46]http://www.greentechmedia.com/articles/read/socal-edison-wants-a123s-biggest-grid-battery-ever/

centers in Southern California. A graphic representation of this future storage system is shown in Figure C-8.[47]

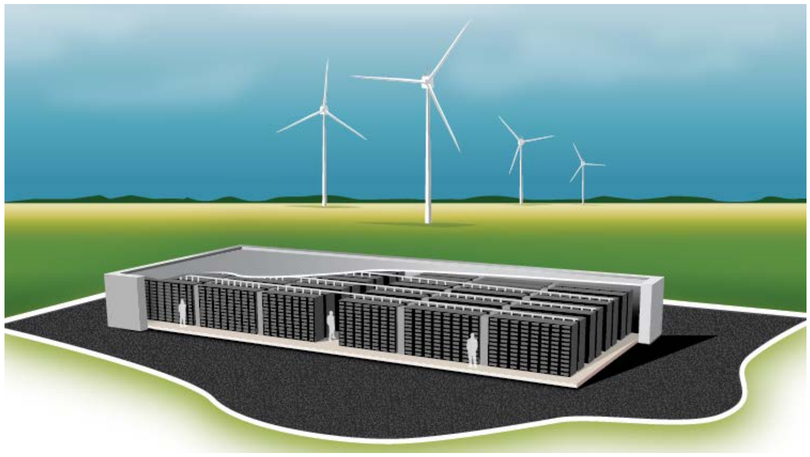

Figure C-8. Artist's rendering of future Li-ion storage near Tehachapi, California

Source: NREL

Nickel-cadmium (NiCd) and **nickel-metal hydride (Ni-MH)** batteries have relatively higher capital cost, which has prevented their widespread use in large stationary applications. Some concerns about cadmium toxicity and associated recycling costs represent a barrier to gaining consent for large-scale implementation of NiCd technology based energy storage. Nevertheless, there may be some utility markets in which nickel batteries can compete on a life-cycle cost with lead-acid batteries, since nickel batteries can operate at extreme temperatures and deliver high currents over short periods of time, and can reach up to around 1,500 deep cycles. Golden Valley Electric Association (GVEA) in Fairbanks, Alaska, installed a 27 MW for 15 minutes NiCd battery system. The racks holding 13,760 NiCd modules are shown in Figure C-9.[48] Connected in series, this system functions as a 5 kVDC battery.

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[47] A123 Systems (2010). *Applying Large Scale Li-ion Storage Technology to Support Renewable Integration and Grid Services*. IEPR Staff workshop, California Energy Commission. www.energy.ca.gov/2011_energypolicy/documents/2010-11-16_workshop/presentations/08_Vartanian_Applying_Large_Scale_Li-Ion_Energy_Storage_Tech.pdf. Accessed August 2011.

[48] Wicker, K. (2005). "Big Batteries Blooming." *Power Magazine.* www.powermag.com/renewables/wind/Big-batteries-blooming_1042.html. Accessed August 2011.

Figure C-9. Inside GVEA NiCd energy storage

Source: Power Magazine

Metal-air batteries are the most compact and, potentially, the least expensive batteries developed to date.[49] They are also environmentally benign. Their main disadvantage is that electrical recharging is very difficult and inefficient. Fluid Energy (an Arizona-based company) is researching and developing a metal-air battery that uses ionic liquids, which would address many of the problems that have constrained metal-air batteries in the past.[50] Energy densities 11 times greater than for Li-ion batteries at costs one-third the price of Li-ion technology is expected. However, the ionic liquids are still made in small quantities, making them expensive compared to other solvents, so metal-air ionic liquid batteries are not yet ready commercially.

Storage Technologies for Power Quality

Power quality applications require rapid response—often within less than a second—and include transient stability and frequency regulation. As with the other applications, the time scales of discharge may vary, but this class of services typically requires discharge times of up to about 10 to 15 minutes. Technologies for these applications include flywheels, capacitors, superconducting magnetic energy storage (SMES), and some types of batteries.

Flywheel energy storage consists of rotating massive rotor that is supported by magnetically levitated bearings and placed in a low vacuum environment to minimize friction losses. The rotor is connected to a motor/generator that interacts with the power grid via a power electronics converter. The flywheel system is a kinetic battery, spinning at very high speeds (up to 16,000 rpm) to store energy that is instantly available when needed. Some of the advantages of flywheels are low maintenance costs, long life (20+years or tens of thousands of deep cycles), and no environmental impacts. A layout of a 20 MW 5-minute flywheel storage plant proposed by Beacon Bower is shown in Figure C-10.[51] This plant occupies an area of 3.5 acres. It consists of 200 individual 100-kW flywheels and associated power electronics.

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[49]Electricity Storage Association (2011). Electricity Storage Association (ESA) website. www.electrisitystorage.org. Accessed August 2011.
[50]Buck, Christian (2009). "Tomorrow's Power Grids." *Pictures of the Future* magazine. www.siemens.com/innovation/en/highlights/industry/update_02/plugging-buildings.htm. Accessed August 2011.
[51]Beacon Power (2008). "Smart Energy Matrix 20MW Frequency Regulation Plant." www.beaconpower.com/files/SEM_20MW.pdf. Accessed August 2011.

Figure C-10. Concept of 20-MW frequency regulation plant

Source: Beacon Power

Electrochemical capacitors (EC), also known as supercapacitors, store electric energy in the two series capacitors of the electric double layer that is formed between electrodes and the electrolyte ions. A charge is stored electrostatically, not chemically as in batteries. The amount of capacitance is directly related to the surface are of the electrode. ECs have a long life with thousands of charge cycles, low cycle costs, high rates of charge and discharge, and high cycle efficiencies, among other advantages. Disadvantages are in the lower energy densities and voltage variations with the amount of stored energy. Supercapacitor systems are mainly used in power quality enhancement applications to improve low voltage ride-through capabilities of various distributed generation, including wind turbines or PV inverters, by reinforcing DC buses in power converters during transients.[52] They are also used in reactive power and voltage control devices such as STATCOMs, dynamic voltage restorers, etc. The purpose of this system is to minimize power fluctuations from wind turbines.

Superconducting Magnetic Storage stores energy in a magnetic field of a coil made of superconducting material. SMES is similar to capacitors in that it has an extremely fast response time, but it is limited by the total energy capacity. This feature restricts SMES primarily to "power" applications. Several 1 MWh units have been deployed for power quality control around the world. A string of distributed SMES units is used in northern Wisconsin to enhance stability of a transmission loop. The Engineering Test Model (ETM) is a large SMES facility storing 20 MWh and serving as a technology demonstration. The coil, 96 meters in diameter, operates in superfluid helium at 1.8°K, and is based on 200 kA cable-in-conduit conductor (CICC).[53] The market for SMES is growing, but at slower pace compared to other storage technologies such as

[52]Li, D.; Zhang, H. (2010). *A Combined Protection and Control Strategy to Enhance the LVRT Capability of a Wind Turbine Driven by DFIG*. 2nd IEEE International Symposium on Power Electronics for Distributed Generation Systems. ieeexplore.ieee.org/stamp/stamp.jsp?arnumber=05545850. Accessed August 2011.

[53]Parsons, B.K.; Luongo, C.A.; Cooke, K.M.; Kreinbrink, K.; Hood, C.; Barnes, C. (1994). "Design of Cryogenic Systems for the 20 MWh SMES-ETM." *Cryogenics*, pp. 127–130.

capacitors and flywheels. The reason is that SMES devices are comparatively expensive, with parasitic losses and low energy density.

D-SMES is a shunt-connected flexible AC transmission (FACTS) device designed to increase grid stability, improve power transfer, and increase reliability. The system is enclosed in mobile trailers. Each trailer contains four quadrant, IGBT inverters rated at 250 kW and 3MJ SMES.

Dry cell or gel batteries are gaining popularity in power quality and bridging power storage markets. Traditionally, dry-cell batteries used zinc-carbon chemistry with several types of electrolytes. More advanced dry-cell batteries use fiberglass packing with sulfuric acid. The packing absorbs the acid to create a highly conductive gel-like substance. Lately, an advanced dry-cell battery utilizing a solid-state design and chemistry was proposed by Xtreme Power of Kyle, Texas.[54] These battery systems are marketed as PowerCells and can be assembled in massive parallel and series matrices, making them suitable for grid applications. A complete package is available in a containerized unit as a system called Dynamic Power Resource (DPR) with a microsecond response rated for 1.5 MVA/1 MWh (Figure C-12). A few such systems are being installed in Hawaii as part of wind and PV projects.

Figure C-11. Xtreme Power DPR 15-100C system

Source: Xtreme Power

Lithium titanate (nLTO)-based batteries use nano-structured technology and provide extremely fast charge/discharge rates, high round-trip efficiencies, long life cycle, and wide operating temperature range. Such batteries, made by AltairNano, began commercial operation within the PJM control area in 2008. Today, the Alti-PM 1 MW/250 kWh system operates nearly continuously, 24 hours a day, providing grid stabilization services to PJM.[55] This system is housed in a 53-foot shipping container.

[54]Xtreme Power, Inc. (2011). www.xtremepower.com. Accessed August 2011.
[55]Altairnano (2011). www.altairnano.com. Accessed August 2011.

Emerging Storage Technologies

A large fraction of the long-term research in both government and university laboratories in the United States and worldwide is now aimed at advanced storage technologies. One of the primary objectives of energy storage research efforts is the development of durable and affordable advanced storage systems for various grid related applications. New alternatives are emerging. Many of them are still in the early small-scale laboratory demonstration stages, so it is too early to judge their significance. Some of them have been recognized by various groups as promising for larger-scale demonstration and testing. For example, a promising **hydrogen-bromine (H2-Br2)** flow-battery system for grid application is under development by Lawrence Berkeley National Laboratory and its team of industrial partners. Air-flow batteries, novel ultra-high-capacity thin-film batteries, **Na+/Cu2+ associated anion (NCAA)** batteries, nano-capacitors, magnetic capacitors, advanced hybrid storage systems, and many others are being investigated by various groups. Sandia National Laboratory conducts research in the area of **lead/carbon (Pb/C)** batteries [56]. Unlike conventional lead-acid batteries containing a positive electrode made of lead dioxide and a negative electrode made of metallic lead, the Pb/C uses negative electrode made from activated carbon. The primary goal of lead-carbon research is to extend the life cycle of lead-acid batteries and increase their power. Lead-carbon batteries are different from other types of batteries because they combine the high energy density of a battery and the high specific power of a supercapacitor in a single low-cost device.

Continuous improvements in the existing technologies are also under way in the form of research for more efficient organic electrode materials, new materials preparation and cell fabrication methods, and alternate electrolytes and catalysts, etc.

Energy Storage Technology Comparison

Comparative capabilities of the above-mentioned storage technologies for high-power and high-energy applications are consolidated in Table C-3[57] Discharge and rated power ranges of some of the above-described storage technologies are shown in Figure C-12.[58] This figure also shows that many technologies can provide services across various time scales.

Table C-3. Comparison of Storage Technologies

Source: Energy Storage Association

Technology	Advantages (Relative)	Disadvantages (Relative)	Power Application	Energy Application
PHS	High capacity, low cost	Special site requirement	○ ○	● ●
CAES	High capacity, low cost	Special site requirement, need gas fuel	○ ○	● ●
Flow Batteries	High capacity,	Low energy density	○ ●	● ●

[56]Walmet, P.S. (2009). Evaluation of Lead/Carbon Devices for Utility Applications. A Study for the DOE Energy Storage Program. SAND2009-5537. Albuquerque, New Mexico: Sandia National Laboratories.
[57]Electricity Storage Association (2011). Electricity Storage Association (ESA) website. www.electrisitystorage.org. Accessed August 2011.
[58]Ibid.

	independent power and energy ratings			
Metal-Air	High energy density	Electric charging is difficult	○ ○	● ●
NaS	High power and energy densities, high efficiency	Production cost	● ●	● ●
Li-ion	High power and energy densities, high efficiency	High production cost, requires special charging circuit	● ●	○ ○
Ni-Cd	High power and energy densities, efficiency	-	● ●	○ ●
Lead-acid	Low capital cost	Limited cycle life when deeply discharged	● ●	○ ○
Flywheels	High power	Low energy density	● ●	○ ○
SMES	High power	Low energy density, high production cost	● ●	○ ○
EC Capacitors	Long cycle life, high efficiency	Low energy density	● ●	○ ●

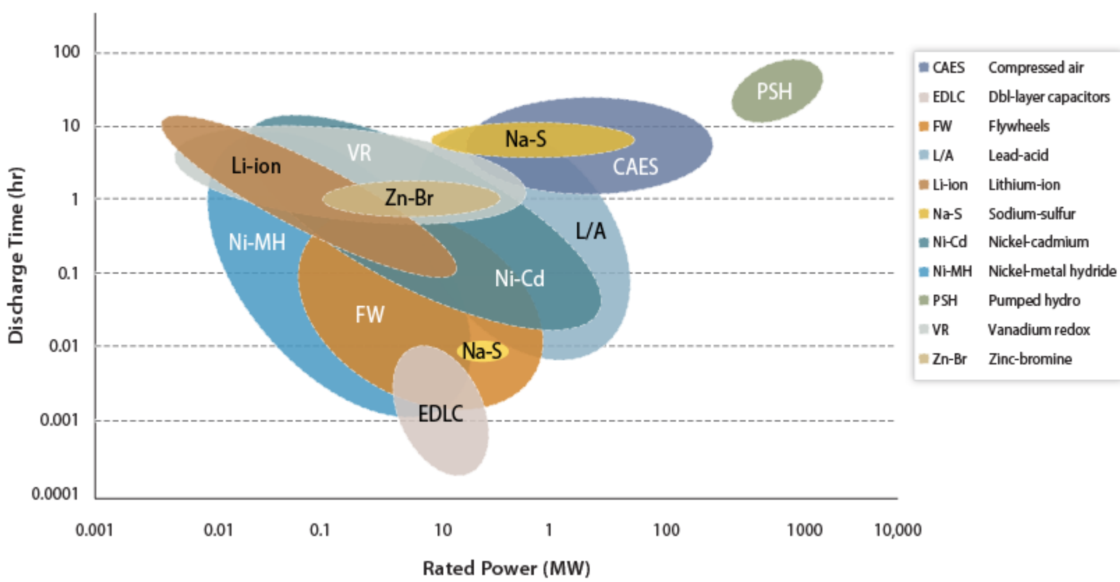

Figure C-12. Storage systems ratings

Source: NREL

Energy Storage in Ancillary Service Applications

In weak island grids, energy storage may play an important role in stabilizing variable renewable energy generation. Some energy storage technologies can also play an important role in the areas of power quality and frequency regulation applications, as described earlier in this report. From a power quality perspective, an energy storage system may help improve power system responses to various types of grid voltage faults (single-, two-, and three-phase voltage drops or voltage swells).This can be done for stand-alone storage systems or in combination with wind turbines or PV arrays. FERC low voltage ride-through (LVRT) and NERC LVRT and high-voltage ride-through (HVRT) requirements for wind turbines are shown in Figure C-13.

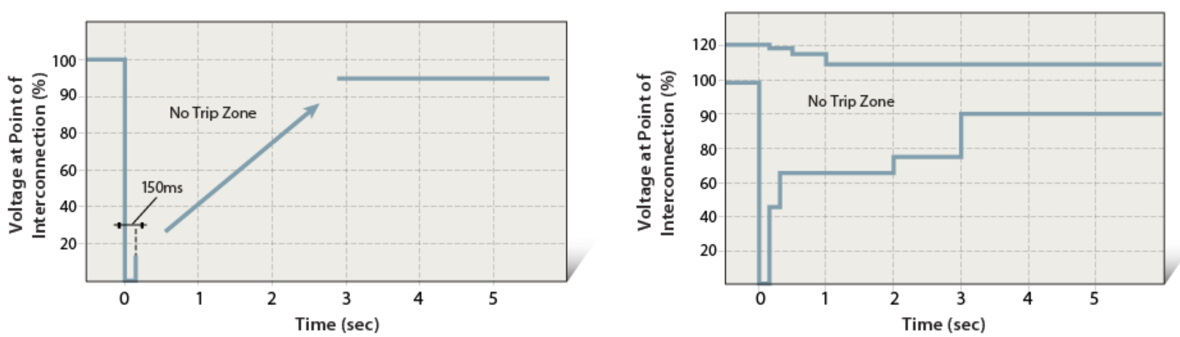

Figure C-13. FERC LVRT (left) and NERC PRC-024 LVRT/HVRT (right) requirements

Source: NREL

For frequency regulation applications, energy storage can provide fast power balancing capability in response to frequency variations in the grid. This response may include simulating synthetic inertia, simulating governor droop, and following an automatic generation control (AGC) signal. An example of Beacon Power data for flywheel energy storage providing fast regulation is shown in Figure C-14.

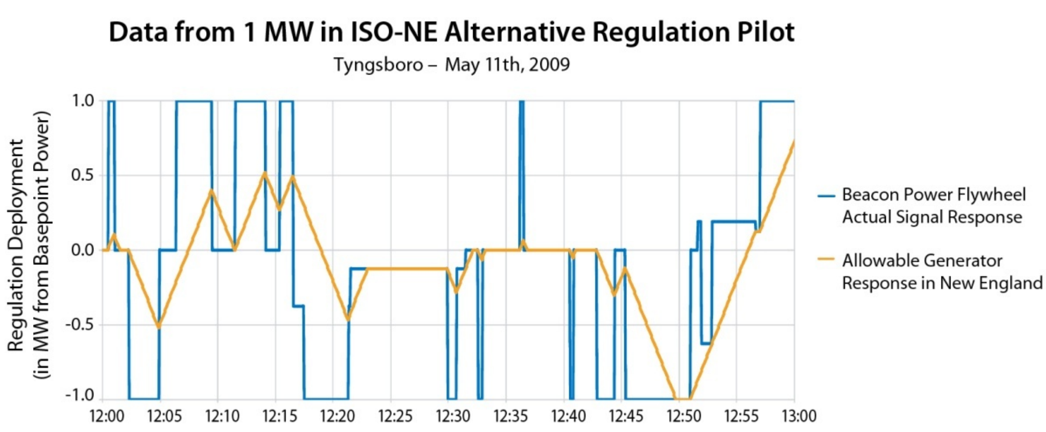

Figure C-14. Fast-response flywheel storage providing frequency regulation

Source: Beacon Power

An example of energy storage system providing both positive and negative governor droop functionality when grid frequency exceeds dead band range in shown in Figure C-15.

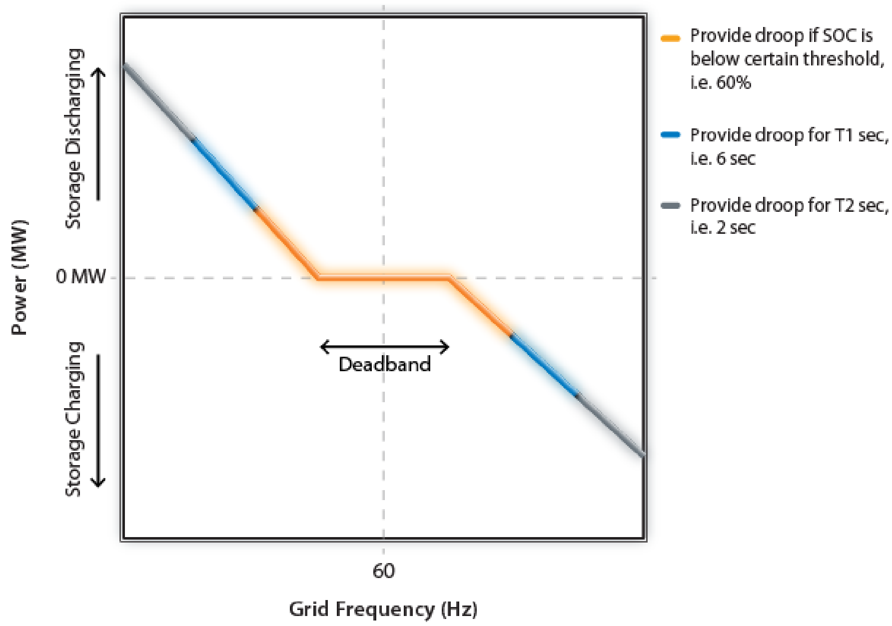

Figure C-15. Example of energy storage droop response operation

Source: NREL

The droop response by storage has some distinctions compared to conventional generators and wind power. The droop response by storage can be characterized not only by dead band and droop ratio, but also by intervals when storage state of charge (SOC) is at certain levels, and by time durations when storage is capable of providing droop response for large frequency excursions (as shown in Figure C-15). In frequency regulation applications, it is important to maintain energy storage SOC at such level that both charge and discharge (same as up and down regulation) is possible at any time when needed.

The initial frequency response of a power system is dominated by the inertial response of spinning generators. Energy storage can provide similar "synthetic" inertial response at the beginning of grid frequency disturbance, helping to arrest both rate of change and peak of frequency deviation. This can become important for power systems with high penetration of variable generation, such as wind and solar. A theoretical example of energy storage contributing to grid frequency control is shown in Figure C-16, where inertial response, droop control, and AGC participation can be seen at different time scales.

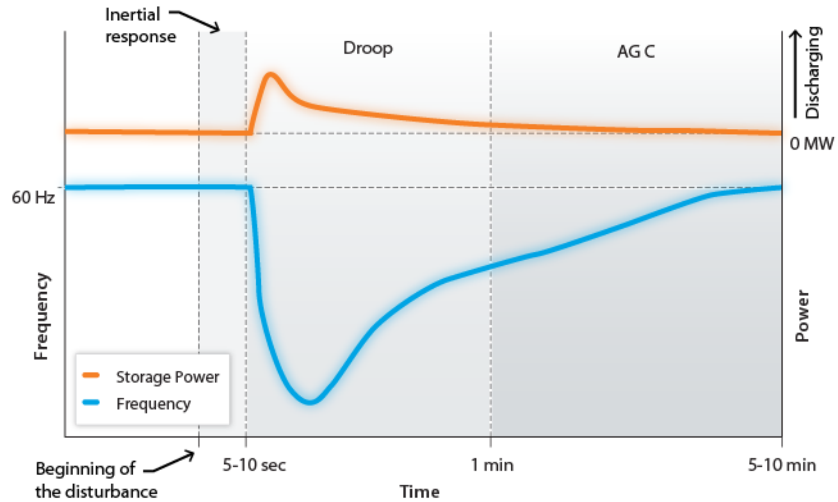

Figure C-16. Energy storage contributing into frequency regulation

Source: NREL

Both wind and PV are weather-driven generation, and their output changes rapidly with weather conditions. Varying wind speed or large clouds moving across a PV array can cause the output of wind or PV power plants to change in ramp-like fashion. Each utility must follow this change with its own generation. Extremely large and expensive energy storage may be required to keep the variable generation output constant at any time. Instead, smaller and less expensive energy storage can be used to remove short-term rapid variations in variable generation output, letting conventional generation provide load following at larger time scales. Example time series for energy storage, providing ramp rate control for a 30 MW wind farm and 1.2 MW PV array, are shown in Figure C-17 and Figure C-18. The storage can respond to varying power commands so that maximum sustained and instantaneous ramp rates are not exceeded. In addition, the ability of energy storage to maintain its target SOC during ramp rate limiting can be tested as well.

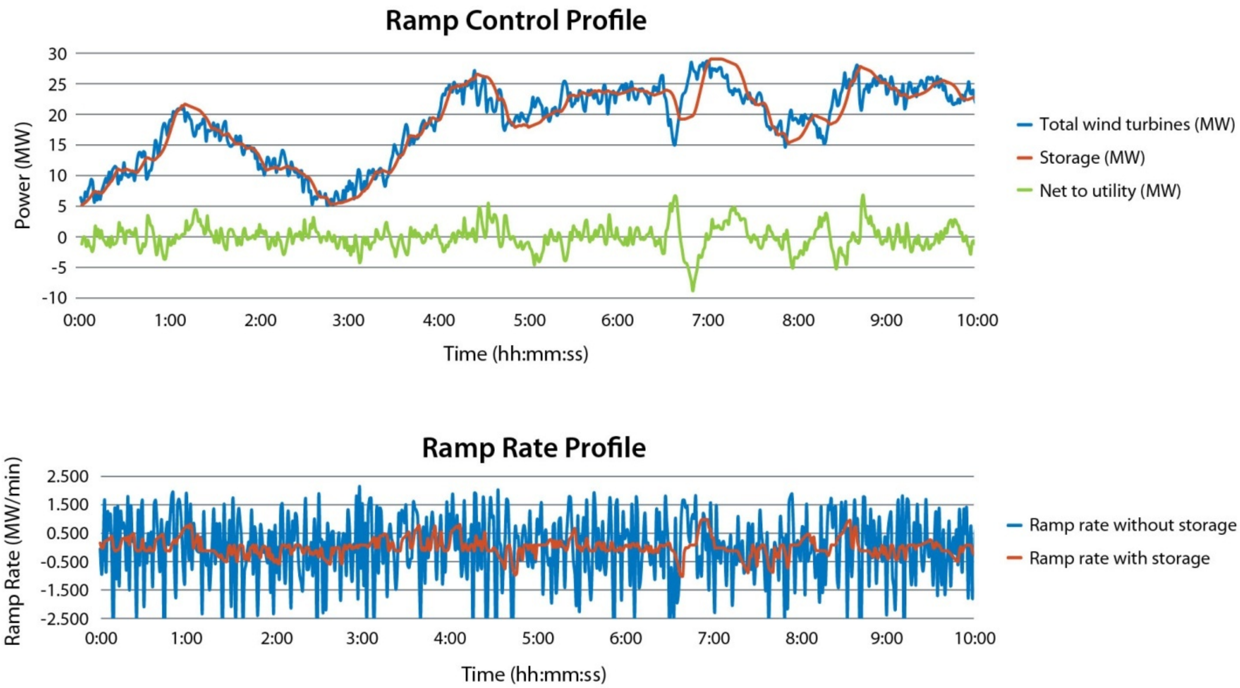

Figure C-17. Example of energy storage providing ramp control for wind farm

Source: Xtreme Power

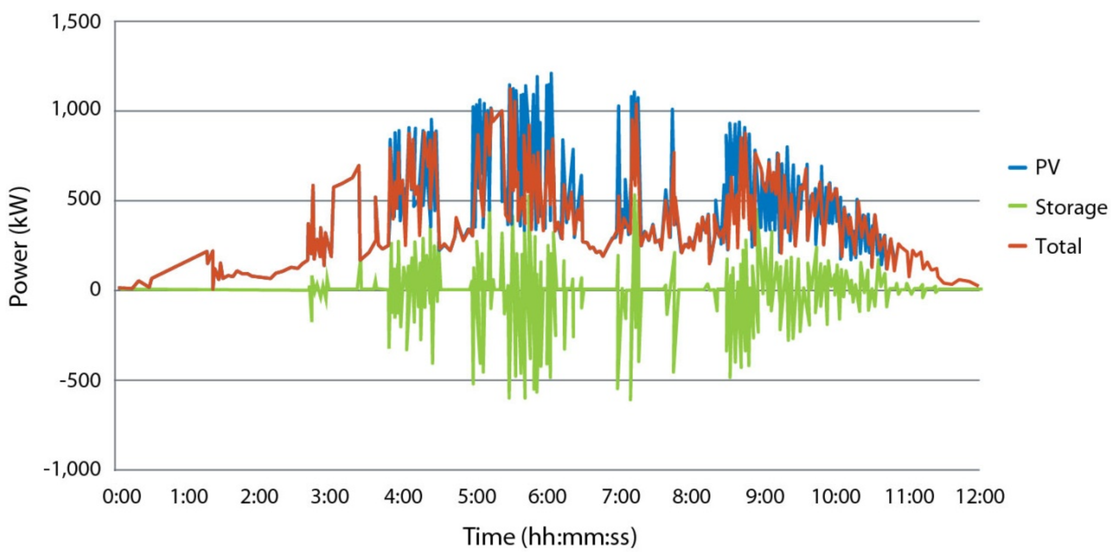

Figure C-18. Example of energy storage providing ramp control for PV

Source: Xtreme Power

Appendix D: Water and Power Authority Generation and Heat Rate Calculations

St. Thomas Energy and Water Production Indices

On 1/25/2010, Coury Hodge, current operations manager at the STT plant, opened a live spreadsheet (overview 29-6.xls) of Dynamic Plant Performance and shared a screen shot (Figure D-1) that shows the current units running, their heat rates, and fuel use and fuel apportioning to electricity and water.

1/25/11
12:49 pm

Dynamic Plant Performance

Installed capacity	Unit	Available capacity	Spinning capacity	Actual unit output	Spinning reserve	Running capacity	Actual heat rate	HRSG combined	Actual efficiency	IDEs extraction
MW		MW	MW	MW	MW	%	BTUs/Kwh	on/off	%	on/off
20.7	11	12.3	12.3	10.8	1.5	88.2%	12,688	off	26.9%	on
15.1	12	0.0								
36.9	13	15.3	15.3	15.1	0.2	98.6%	12,966	off	26.3%	off
15.1	14	10.0								
22.1	15	13.5	13.5	13.0	0.5	96.0%	20,220	on	16.9%	
24.5	18	19.9						off		
24.5	22	16.6	16.6	10.0	6.7	59.8%	16,390		20.8%	
42.5	23	27.3	27.3	23.8	3.5	87.2%	15,395		22.2%	
201.4		114.9	85.0	72.6	12.4	63.2%	16,118		21.2%	

Installed capacity	Unit	Available capacity	Unit output capacity	Actual unit output	Reserve capacity	Running capacity	Design ratio	Actual ratio	Process efficiency
MGD		MGD	GPM	GPM	GPM	%	LBS/KBTU	LBS/KBTU	%
1.25	IDE1	1.25	868	810.3	57.7	93.3	9.5	5.36	56.4%
1.25	IDE2	1.25	868	634.2	233.9	73.1%	9.5	4.79	50.4%
0.55	IDE6	0.55	382	301.7	80.3	79.0%	9.7	6.88	70.9%
1.40	IDE8	1.40	972	751.4	220.8	77.3%	10.1	8.04	79.6%
4.45		4.45	3,090	2,497.6	592.7	80.8%		61.3	

Water to distribution	2,497.6	Overall plant efficiency	31.4%
Water to plant serv.		Overall equiv. heat rate	10,862

Water fuel cost	1,726.37 U.S.$/hr	11.52 U.S.$/Kgal
Generation fuel cost	13,681.99 U.S.$/hr	0.1885 U.S.$/Kwh
Total fuel cost	15,408.35 U.S.$/hr	

Water production
149,857 gals/hr
3,596,558 gals/day
111,493,283 gals/month

Figure D-1. Randolph E. Harley power plant

Source: WAPA

The following table shows the fuel parameters included in the Dynamic Plant Performance spreadsheet (Overview 29-6.xls) at that time used in the calculations shown in Figure D-1.

Table D-1. Current Fuel Parameters Assumed in Dynamic Plant Performance Spreadsheet

Fuel	Density	HHV	HHV	Price		
	Lbs/Gal	BTU/Lb	MMBTU/barrel	$/BBL	$/Lb	$/MMBTU
#2	7.28	19,490	5.959	$80.76	$0.26	$13.55
#6	7.89	18,816	6.235	$77.78	$0.23	$12.47
Fuel mix*	7.43	19,322	6.03	$80.02	$0.25	$13.28

HHV=Higher heating value. 1 barrel = 42 gallons
* Assumes blend of 75% #2 and 25% #6 by volume calculated by summing totals from both district using values in December 2010 Monthly Report. (Ratios on STT and STX differ significantly but impact on blended values above are small due to near uniformity.)

Heat Rate Calculations from HOMER Model

Table D-2. Heat Rate Calculations for St. Thomas

	#2 Fuel Oil	#6 Fuel Oil	
liters	176,308,432	12,179,16	(Totals from HOMER simulation)
gals	46,545,426	3,215,300	(0.265 gallons/liter)
lbs /gal	7.280	7.890	Fuel Density—Table D-1
lbs	338,850,702	25,368,718	
Btu/lbs	19,490	18,816	High Heating Value (HHV) – Table D-1
			Total for Power plant
BTUs	6,604,200,174,758	477,337,792,136	7,081,537,966,894
kWhs			526,884,960 (HOMER simulation)
average heat rate:			**13,440.39** Btus/kWh
efficiency (3412 Btu/kWh)/(heat rate)		**25.39%**	

Table D-3. Heat Rate Calculations for St. Croix Before the New HRSG

	#2 Fuel Oil	#6 Fuel Oil	Total
liters	106,253,776	38,328,644	
gals	28,050,997	10,118,762	
lbs/gal	7.280	7.890	
lbs	204,211,257	79,837,032	
Btu/lbs	19,490	18,816	
BTUs	3,980,077,402,242	1,502,213,599,874	5,482,291,002,116
kWhs			332,148,608
average heat rate			16,505.54
efficiency			20.67%
Note: #2 fuel oil is 0.636/liter			

Table D-4. Heat Rate Calculations for St. Croix After the New HRSG

	#2 Fuel Oil	#6 Fuel Oil	Total
liters	84,697,248	5,980,293	
gals	22,360,073	1,578,797	
lbs/gal	7.280	7.890	
lbs	162,781,335	12,456,711	
Btu/lbs	19,490	18,816	
BTUs	3,172,608,216,736	234,385,476,195	3,406,993,692,931
kWhs			307,717,888
		average heat rate	11,071.81
efficiency			30.82%

Appendix E: Roof Survey for PV Potential

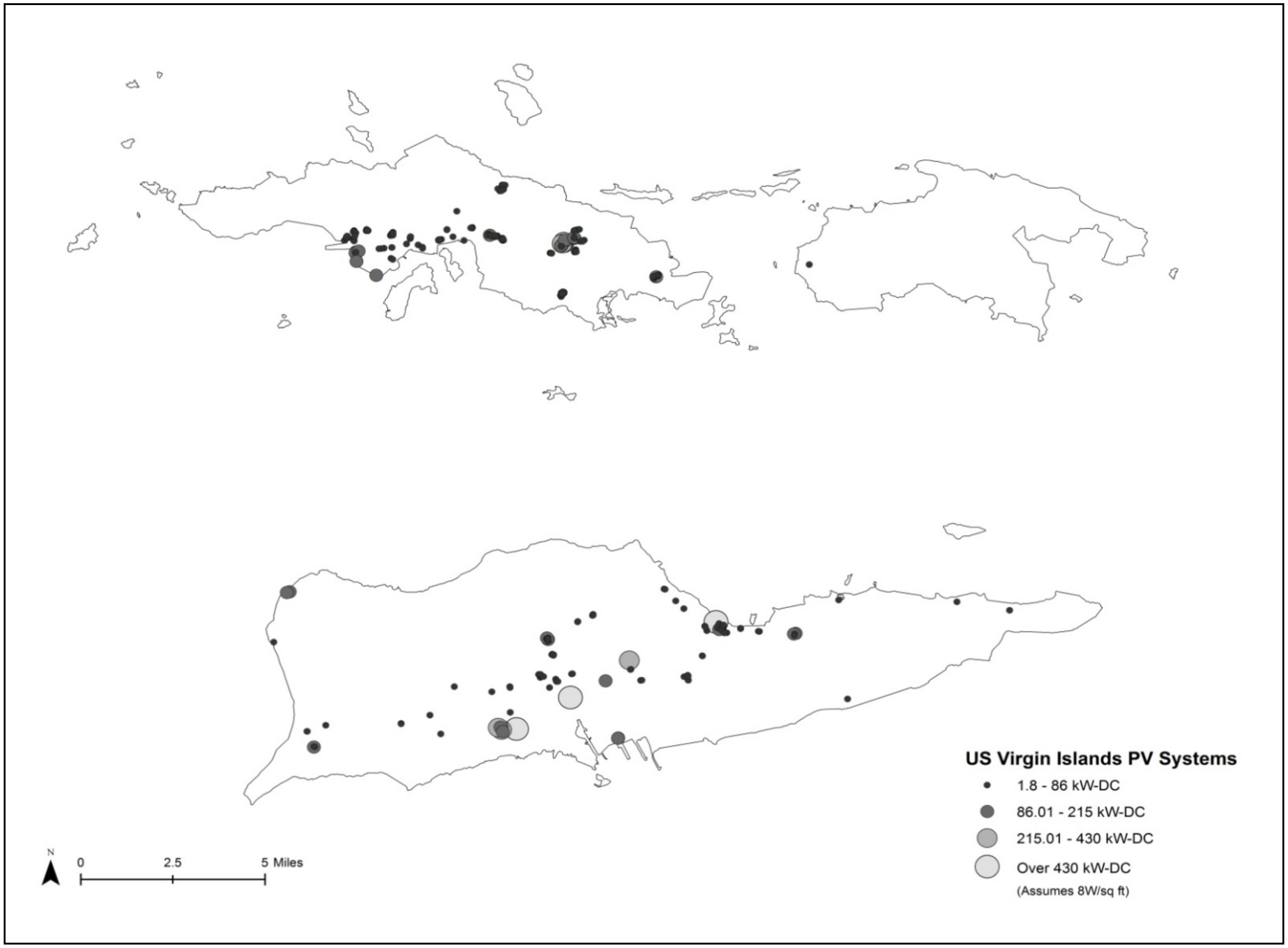

Figure E-1. Potential PV system sites in the USVI

Source: NREL

Table E-1. St. Thomas Roof Survey Summary

St. Thomas	
WAPA Maximum Demand [MW]	85
Potential PV Capacity Identified [MW]	5.5
PV Capacity Fraction of Max. Demand	6.5%
WAPA Load [MWh/yr]	515,351
PV Generation Identified [MWh/yr]	7,702
PV Fraction of total generation	1.5%
Area [acres]	15.8

Table E-2. St. Thomas Roof Survey Results Details

NAME	Area [ft2]	Closest Feeder	Distance to Feeder [m]	Facility Type	System Size [kW]	Generation [MWh/yr]
ANNAS RETREAT HOUSING 1	1,052	Feeder 07C	48.9	HOUSING	8.4	11.8
ANNAS RETREAT HOUSING 10	692	Feeder 07C	15.5	HOUSING	5.5	7.8
ANNAS RETREAT HOUSING 11	727	Feeder 07C	13.6	HOUSING	5.8	8.1
ANNAS RETREAT HOUSING 12	1,287	Feeder 07C	14.0	HOUSING	10.3	14.4
ANNAS RETREAT HOUSING 2	977	Feeder 07C	28.7	HOUSING	7.8	10.9
ANNAS RETREAT HOUSING 3	993	Feeder 07C	11.2	HOUSING	7.9	11.1
ANNAS RETREAT HOUSING 4	865	Feeder 07C	38.6	HOUSING	6.9	9.7
ANNAS RETREAT HOUSING 5	2,328	Feeder 07C	0.5	HOUSING	18.6	26.1
ANNAS RETREAT HOUSING 6	3,291	Feeder 07C	14.5	HOUSING	26.3	36.9
ANNAS RETREAT HOUSING 7	1,337	Feeder 07C	14.6	HOUSING	10.7	15.0
ANNAS RETREAT HOUSING 8	1,290	Feeder 07C	14.5	HOUSING	10.3	14.4
ANNAS RETREAT HOUSING 9	2,260	Feeder 07C	11.7	HOUSING	18.1	25.3
Contant Knolls 1	3,024	Feeder 06A	0.0	HOUSING	24.2	33.9
Contant Knolls 10	3,063	Feeder 06A	21.5	HOUSING	24.5	34.3
Contant Knolls 2	2,980	Feeder 06A	6.5	HOUSING	23.8	33.4
Contant Knolls 3	3,071	Feeder 06A	1.1	HOUSING	24.6	34.4
Contant Knolls 4	2,861	Feeder 06A	4.4	HOUSING	22.9	32.0
Contant Knolls 5	3,199	Feeder 06A	1.4	HOUSING	25.6	35.8
Contant Knolls 6	3,050	Feeder 06A	1.0	HOUSING	24.4	34.2
Contant Knolls 7	2,920	Feeder 06A	8.4	HOUSING	23.4	32.7
Contant Knolls 8	3,082	Feeder 06A	2.3	HOUSING	24.7	34.5

NAME	Area [ft2]	Closest Feeder	Distance to Feeder [m]	Facility Type	System Size [kW]	Generation [MWh/yr]
Contant Knolls 9	3,112	Feeder 06A	6.1	HOUSING	24.9	34.9
Lovenlund 1	1,164	Feeder 08B	19.2	HOUSING	9.3	13.0
Lovenlund 10	1,684	Feeder 08B	0.0	HOUSING	13.5	18.9
Lovenlund 2	1,319	Feeder 08B	12.8	HOUSING	10.5	14.8
Lovenlund 3	1,171	Feeder 08B	16.8	HOUSING	9.4	13.1
Lovenlund 4	992	Feeder 08B	28.4	HOUSING	7.9	11.1
Lovenlund 5	1,101	Feeder 08B	6.2	HOUSING	8.8	12.3
Lovenlund 6	1,305	Feeder 08B	12.4	HOUSING	10.4	14.6
Lovenlund 7	1,514	Feeder 08B	10.4	HOUSING	12.1	17.0
Lovenlund 8	1,753	Feeder 08B	8.4	HOUSING	14.0	19.6
Lovenlund 9	1,347	Feeder 08B	17.3	HOUSING	10.8	15.1
PATRIOT MANOR 2	1,065	Feeder 07A	20.0	HOUSING	8.5	11.9
PATRIOT MANOR 3	2,167	Feeder 07A	9.8	HOUSING	17.3	24.3
PATRIOT MANOR 4	1,857	Feeder 07A	0.0	HOUSING	14.9	20.8
PATRIOT MANOR 5	2,139	Feeder 07A	0.0	HOUSING	17.1	24.0
PATRIOT MANOR 6	673	Feeder 07A	16.7	HOUSING	5.4	7.5
PATRIOT MANOR1	2,415	Feeder 07A	10.7	HOUSING	19.3	27.0
SCHNEIDER REGIONAL HOSPITAL 1	4,110	Feeder 09B	57.9	MEDICAL	32.9	46.0
SCHNEIDER REGIONAL HOSPITAL 10	1,477	Feeder 08A	108.7	MEDICAL	11.8	16.5
SCHNEIDER REGIONAL HOSPITAL 11	607	Feeder 08A	109.7	MEDICAL	4.9	6.8
SCHNEIDER REGIONAL HOSPITAL 12	1,217	Feeder 08A	128.4	MEDICAL	9.7	13.6
SCHNEIDER REGIONAL HOSPITAL 13	792	Feeder 08A	121.7	MEDICAL	6.3	8.9
SCHNEIDER REGIONAL HOSPITAL 2	1,814	Feeder 08A	62.3	MEDICAL	14.5	20.3
SCHNEIDER REGIONAL HOSPITAL 3	1,637	Feeder 08A	83.6	MEDICAL	13.1	18.3
SCHNEIDER REGIONAL HOSPITAL 4	1,412	Feeder 08A	93.5	MEDICAL	11.3	15.8
SCHNEIDER REGIONAL HOSPITAL 5	693	Feeder 08A	90.7	MEDICAL	5.5	7.8
SCHNEIDER REGIONAL HOSPITAL 6	311	Feeder 08A	98.6	MEDICAL	2.5	3.5
SCHNEIDER REGIONAL HOSPITAL 7	1,598	Feeder 09B	103.8	MEDICAL	12.8	17.9
SCHNEIDER REGIONAL HOSPITAL 8	437	Feeder 09B	122.3	MEDICAL	3.5	4.9
SCHNEIDER REGIONAL HOSPITAL 9	594	Feeder 09B	106.9	MEDICAL	4.8	6.7
Tutu1	50,440	Mall	53.8	PRIVATE	403.5	564.9
Tutu2	39,032	Mall	6.7	PRIVATE	312.3	437.2
Tutu3	26,918	Mall	6.1	PRIVATE	215.3	301.5

NAME	Area [ft2]	Closest Feeder	Distance to Feeder [m]	Facility Type	System Size [kW]	Generation [MWh/yr]
Tutu4	25,164	Feeder 07C	50.7	PRIVATE	201.3	281.8
Tutu5	13,167	Mall	1.9	PRIVATE	105.3	147.5
Tutu6	18,802	Feeder 07C	23.7	PRIVATE	150.4	210.6
Tutu7	13,405	Feeder 07C	21.3	PRIVATE	107.2	150.1
Tutu8	10,471	Feeder 07C	27.3	PRIVATE	83.8	117.3
Tutu9	7,684	Feeder 07C	29.7	PRIVATE	61.5	86.1
BCB Middle School 1	3,763	Feeder 09D	4.8	SCHOOLS	30.1	42.1
BCB Middle School 10	5,278	Feeder 09D	52.5	SCHOOLS	42.2	59.1
BCB Middle School 11	4,966	Feeder 09D	59.0	SCHOOLS	39.7	55.6
BCB Middle School 12	3,938	Feeder 09D	66.1	SCHOOLS	31.5	44.1
BCB Middle School 13	4,478	Feeder 09D	73.7	SCHOOLS	35.8	50.2
BCB Middle School 14	2,421	Feeder 09D	83.1	SCHOOLS	19.4	27.1
BCB Middle School 15	3,687	Feeder 09D	65.3	SCHOOLS	29.5	41.3
BCB Middle School 16	2,277	Feeder 09D	50.5	SCHOOLS	18.2	25.5
BCB Middle School 2	2,889	Feeder 09D	10.7	SCHOOLS	23.1	32.4
BCB Middle School 3	4,578	Feeder 09D	51.5	SCHOOLS	36.6	51.3
BCB Middle School 4	4,028	Feeder 09D	35.4	SCHOOLS	32.2	45.1
BCB Middle School 5	1,815	Feeder 09D	37.8	SCHOOLS	14.5	20.3
BCB Middle School 6	1,230	Feeder 09D	36.4	SCHOOLS	9.8	13.8
BCB Middle School 7	1,040	Feeder 09D	42.5	SCHOOLS	8.3	11.6
BCB Middle School 8	6,265	Feeder 09D	26.6	SCHOOLS	50.1	70.2
BCB Middle School 9	3,398	Feeder 09D	30.2	SCHOOLS	27.2	38.1
Cancryn JHS 1	1,530	Feeder 10A	50.7	SCHOOLS	12.2	17.1
Cancryn JHS 2	1,409	Feeder 10A	61.2	SCHOOLS	11.3	15.8
Cancryn JHS 3	2,884	Feeder 10A	61.0	SCHOOLS	23.1	32.3
CHARLOTTE AMALIE HS 1	11,119	Feeder 09B	26.3	SCHOOLS	89.0	124.5
CHARLOTTE AMALIE HS 2	5,187	Feeder 09B	25.4	SCHOOLS	41.5	58.1
CHARLOTTE AMALIE HS 3	10,199	Feeder 08A	48.3	SCHOOLS	81.6	114.2
CHARLOTTE AMALIE HS 4	5,604	Feeder 08A	42.7	SCHOOLS	44.8	62.8
CHARLOTTE AMALIE HS 5	9,621	Feeder 08A	15.8	SCHOOLS	77.0	107.8
CHARLOTTE AMALIE HS 6	2,510	Feeder 09B	15.9	SCHOOLS	20.1	28.1
CHARLOTTE AMALIE HS 7	2,472	Feeder 09B	29.4	SCHOOLS	19.8	27.7
CHARLOTTE AMALIE HS 8	1,644	Feeder 09B	17.4	SCHOOLS	13.1	18.4
EBO School 1	4,943	Feeder 07C	35.0	SCHOOLS	39.5	55.4

NAME	Area [ft2]	Closest Feeder	Distance to Feeder [m]	Facility Type	System Size [kW]	Generation [MWh/yr]
EBO School 2	2,080	Feeder 07C	9.5	SCHOOLS	16.6	23.3
EBO School 3	1,035	Feeder 07C	16.9	SCHOOLS	8.3	11.6
EBO School 4	631	Feeder 07C	29.7	SCHOOLS	5.0	7.1
EBO School 5	234	Feeder 07C	103.4	SCHOOLS	1.9	2.6
EBO School 6	313	Feeder 07C	80.3	SCHOOLS	2.5	3.5
EBO School 7	417	Feeder 07C	127.1	SCHOOLS	3.3	4.7
EBO School 8	409	Feeder 07C	74.3	SCHOOLS	3.3	4.6
Edith Williams School 1	850	Feeder 09C	33.9	SCHOOLS	6.8	9.5
Edith Williams School 2	545	Feeder 09C	34.9	SCHOOLS	4.4	6.1
Edith Williams School 3	541	Feeder 09C	37.6	SCHOOLS	4.3	6.1
Edith Williams School 4	345	Feeder 09C	48.4	SCHOOLS	2.8	3.9
EDUCATION/CURRICULM CENTER 1	11,319	Feeder 07C	13.0	SCHOOLS	90.6	126.8
EDUCATION/CURRICULM CENTER 2	10,728	Feeder 07C	30.9	SCHOOLS	85.8	120.2
EDUCATION/CURRICULM CENTER 3	10,853	Feeder 07C	24.8	SCHOOLS	86.8	121.5
EDUCATION/CURRICULM CENTER 4	6,323	Feeder 07C	20.3	SCHOOLS	50.6	70.8
IVANNA EUDORA KEAN HS 1	17,328	Feeder 07D	3.1	SCHOOLS	138.6	194.1
IVANNA EUDORA KEAN HS 10	830	Feeder 07D	10.2	SCHOOLS	6.6	9.3
IVANNA EUDORA KEAN HS 11	856	Feeder 07D	8.4	SCHOOLS	6.8	9.6
IVANNA EUDORA KEAN HS 12	632	Feeder 07D	11.1	SCHOOLS	5.1	7.1
IVANNA EUDORA KEAN HS 13	678	Feeder 07D	13.1	SCHOOLS	5.4	7.6
IVANNA EUDORA KEAN HS 14	789	Feeder 07D	30.7	SCHOOLS	6.3	8.8
IVANNA EUDORA KEAN HS 15	862	Feeder 07D	34.3	SCHOOLS	6.9	9.7
IVANNA EUDORA KEAN HS 16	783	Feeder 07D	28.1	SCHOOLS	6.3	8.8
IVANNA EUDORA KEAN HS 17	816	Feeder 07D	12.8	SCHOOLS	6.5	9.1
IVANNA EUDORA KEAN HS 18	568	Feeder 07D	97.5	SCHOOLS	4.5	6.4
IVANNA EUDORA KEAN HS 19	550	Feeder 07D	103.9	SCHOOLS	4.4	6.2
IVANNA EUDORA KEAN HS 19	5,752	Feeder 07D	14.4	SCHOOLS	46.0	64.4
IVANNA EUDORA KEAN HS 2	708	Feeder 07D	28.6	SCHOOLS	5.7	7.9
IVANNA EUDORA KEAN HS 3	693	Feeder 07D	26.0	SCHOOLS	5.5	7.8
IVANNA EUDORA KEAN HS 4	1,063	Feeder 07D	23.8	SCHOOLS	8.5	11.9
IVANNA EUDORA KEAN	991	Feeder 07D	24.1	SCHOOLS	7.9	11.1

NAME	Area [ft2]	Closest Feeder	Distance to Feeder [m]	Facility Type	System Size [kW]	Generation [MWh/yr]
HS 5						
IVANNA EUDORA KEAN HS 6	1,189	Feeder 07D	39.2	SCHOOLS	9.5	13.3
IVANNA EUDORA KEAN HS 7	1,308	Feeder 07D	56.4	SCHOOLS	10.5	14.6
IVANNA EUDORA KEAN HS 8	916	Feeder 07D	65.4	SCHOOLS	7.3	10.3
IVANNA EUDORA KEAN HS 9	995	Feeder 07D	36.3	SCHOOLS	8.0	11.1
Jane E Tuitt School 1	939	Feeder 08A	23.0	SCHOOLS	7.5	10.5
Jane E Tuitt School 2	531	Feeder 08A	3.7	SCHOOLS	4.2	5.9
Joseph Sibily School	517	Feeder 08B	14.0	SCHOOLS	4.1	5.8
Julius Sprauve School	2,595	Feeder 9E BKR	0.0	SCHOOLS	20.8	29.1
Kirwan Terrace Elementary 1	6,461	Feeder 06A	13.4	SCHOOLS	51.7	72.4
Kirwan Terrace Elementary 2	607	Feeder 06A	8.0	SCHOOLS	4.9	6.8
Kirwan Terrace Elementary 3	840	Feeder 06A	26.3	SCHOOLS	6.7	9.4
Kirwan Terrace Elementary 4	537	Feeder 06A	27.5	SCHOOLS	4.3	6.0
Kirwan Terrace Elementary 5	660	Feeder 06A	20.8	SCHOOLS	5.3	7.4
Kirwan Terrace Elementary 6	724	Feeder 06A	9.5	SCHOOLS	5.8	8.1
Kirwan Terrace Elementary 7	688	Feeder 06A	14.2	SCHOOLS	5.5	7.7
Kirwan Terrace Elementary 8	776	Feeder 06A	8.8	SCHOOLS	6.2	8.7
LOCKHART ELEMENTARY 1	2,838	Feeder 09B	38.9	SCHOOLS	22.7	31.8
LOCKHART ELEMENTARY 2	3,707	Feeder 08A	74.5	SCHOOLS	29.7	41.5
LOCKHART ELEMENTARY 3	3,914	Feeder 08A	29.1	SCHOOLS	31.3	43.8
LOCKHART ELEMENTARY 4	1,359	Feeder 09B	51.6	SCHOOLS	10.9	15.2
LOCKHART ELEMENTARY 5	2,747	Feeder 08A	39.8	SCHOOLS	22.0	30.8
LOCKHART ELEMENTARY 6	3,882	Feeder 08A	6.1	SCHOOLS	31.1	43.5
Ulla Muller School	5,279	Feeder 07A	21.7	SCHOOLS	42.2	59.1
UVI 1	8,081	Feeder 06A	11.1	SCHOOLS	64.7	90.5
UVI 10	386	Feeder 06A	0.0	SCHOOLS	3.1	4.3
UVI 11	429	Feeder 06A	4.5	SCHOOLS	3.4	4.8
UVI 12	473	Feeder 06A	22.2	SCHOOLS	3.8	5.3
UVI 13	339	Feeder 06A	22.3	SCHOOLS	2.7	3.8
UVI 14	903	Feeder 06A	13.3	SCHOOLS	7.2	10.1
UVI 15	971	Feeder 06A	8.3	SCHOOLS	7.8	10.9

NAME	Area [ft2]	Closest Feeder	Distance to Feeder [m]	Facility Type	System Size [kW]	Generation [MWh/yr]
UVI 16	911	Feeder 06A	6.6	SCHOOLS	7.3	10.2
UVI 17	2,732	Feeder 06A	23.5	SCHOOLS	21.9	30.6
UVI 18	538	Feeder 06A	18.4	SCHOOLS	4.3	6.0
UVI 19	691	Feeder 06A	0.0	SCHOOLS	5.5	7.7
UVI 2	5,930	Feeder 06A	16.4	SCHOOLS	47.4	66.4
UVI 3	1,475	Feeder 06A	0.0	SCHOOLS	11.8	16.5
UVI 4	2,564	Feeder 06A	29.1	SCHOOLS	20.5	28.7
UVI 5	2,538	Feeder 06A	36.0	SCHOOLS	20.3	28.4
UVI 6	434	Feeder 06A	22.7	SCHOOLS	3.5	4.9
UVI 7	455	Feeder 06A	11.5	SCHOOLS	3.6	5.1
UVI 8	374	Feeder 06A	7.3	SCHOOLS	3.0	4.2
UVI 9	462	Feeder 06A	1.4	SCHOOLS	3.7	5.2
Dept of Labor 1	3,323	Feeder 09A	3.6	VI GOVERNMENT	26.6	37.2
Dept of Labor 2	1,769	Feeder 10A	10.4	VI GOVERNMENT	14.2	19.8
GERS bldg 1	630	Feeder 09A	18.1	VI GOVERNMENT	5.0	7.1
GERS Bldg 2	354	Feeder 10A	9.5	VI GOVERNMENT	2.8	4.0
GERS Bldg 3	863	Feeder 10A	6.2	VI GOVERNMENT	6.9	9.7
GERS Bldg 4	378	Feeder 09A	9.2	VI GOVERNMENT	3.0	4.2
GERS Bldg 5	698	Feeder 09A	13.7	VI GOVERNMENT	5.6	7.8
KNUD HANSEN COMPLEX 1	1,865	Feeder 08A	27.5	VI GOVERNMENT	14.9	20.9
KNUD HANSEN COMPLEX 2	1,363	Feeder 08A	11.3	VI GOVERNMENT	10.9	15.3
KNUD HANSEN COMPLEX 3	3,281	Feeder 08A	11.7	VI GOVERNMENT	26.3	36.8
KNUD HANSEN COMPLEX 4	4,408	Feeder 08A	35.9	VI GOVERNMENT	35.3	49.4
Legistlature Bldg	1,597	Feeder 08B	21.3	VI GOVERNMENT	12.8	17.9
Propoert & Procurement bldg	4,353	Feeder 10A	10.7	VI GOVERNMENT	34.8	48.8
Public Library	2,131	Feeder 10A	8.4	VI GOVERNMENT	17.0	23.9
SCHOOL LUNCH (SUBBASE)	4,370	Feeder 10A	4.6	VI GOVERNMENT	35.0	48.9
STT Airport 4	15,407	Feeder 05A	92.6	VI GOVERNMENT	123.3	172.6
STT Airport 5	8,322	Feeder 05A	92.3	VI GOVERNMENT	66.6	93.2
STT Airport 6	12,453	Feeder 05A	17.4	VI GOVERNMENT	99.6	139.5
STT Airport 7	11,461	Feeder 05A	5.8	VI GOVERNMENT	91.7	128.4

NAME	Area [ft2]	Closest Feeder	Distance to Feeder [m]	Facility Type	System Size [kW]	Generation [MWh/yr]
STT Airport 8	15,145	Feeder 05A	62.7	VI GOVERNMENT	121.2	169.6
STTAirport1 GM	4,600	Feeder 05A	8.0	VI GOVERNMENT	36.8	51.5
STTAirport2 GM	8,057	Feeder 05A	30.2	VI GOVERNMENT	64.5	90.2
STTAirport3 GM	9,539	Feeder 06A	94.1	VI GOVERNMENT	76.3	106.8
VITEMA 1	2,569	Feeder 06A	11.1	VI GOVERNMENT	20.6	28.8
VITEMA 2	2,511	Feeder 06A	18.1	VI GOVERNMENT	20.1	28.1
Waste Management	2,904	Feeder 08A	2.3	VI GOVERNMENT	23.2	32.5

Table E-3. St. Croix Roof Survey Summary

St. Croix	
WAPA Maximum Demand [MW]	55
Potential PV Capacity Identified [MW]	5.4
PV Capacity Fraction of Max. Demand	9.8%
WAPA Load [MWh/yr]	332,148
PV Generation Identified [MWh/yr]	7,565
PV Generation Fraction	2.3%
Area [acres]	15.5

Table E-4. St. Croix Roof Survey Results Details

NAME	Area [ft2]	Closest Feeder	Distance to Feeder [m]	Facility Type	System Size [kW]	Generation [MWh/yr]
Agape Medical Center 1	3,071	Feeder 06	25.3	Medical	24.6	34.4
Agape Medical Center 2	3,185	Feeder 06	25.8	Medical	25.5	35.7
Air National Guard 1	2,115	Feeder 09	54.6	Government Agencies	16.9	23.7
Air National Guard 2	1,455	Feeder 09	90.0	Government Agencies	11.6	16.3
Alfredo Andrews	9,504	Feeder 06	15.5	Schools	76.0	106.4
Alternative Education 1	13,087	Feeder 03	17.7	Schools	104.7	146.6
Alternative Education 10	6,506	Feeder 03	17.5	Schools	52.1	72.9
Alternative Education 11	3,341	Feeder 01	18.1	Schools	26.7	37.4
Alternative Education 2	13,136	Feeder 08	40.8	Schools	105.1	147.1
Alternative Education 3	8,709	Feeder 02	61.5	Schools	69.7	97.5
Alternative Education 4	3,935	Feeder 08	6.4	Schools	31.5	44.1
Alternative Education 5	3,602	Feeder 02	18.7	Schools	28.8	40.3

NAME	Area [ft2]	Closest Feeder	Distance to Feeder [m]	Facility Type	System Size [kW]	Generation [MWh/yr]
Alternative Education 6	3,925	Feeder 02	13.8	Schools	31.4	44.0
Alternative Education 7	3,541	Feeder 03	84.5	Schools	28.3	39.7
Alternative Education 8	5,074	Feeder 02	50.9	Schools	40.6	56.8
Alternative Education 9	6,269	Feeder 03	32.2	Schools	50.2	70.2
Beeston Hill Medical Center 1	378	Feeder 09	23.0	Medical	3.0	4.2
Beeston Hill Medical Center 2	575	Feeder 09	15.3	Medical	4.6	6.4
Boy Scout Camp	2,965	Feeder 02	25.3	Community Centers	23.7	33.2
Boys & Girls Club	669	Feeder 09	38.8	Community Centers	5.4	7.5
Casino Control Commission	3,285	Feeder 04	6.0	Government Agencies	26.3	36.8
Central High School	6,702	Feeder 09	60.6	Schools	53.6	75.1
Charles H. Emmanuel Elementary School	6,626	Feeder 06	4.9	Schools	53.0	74.2
Charles Harwood Hospital	1,835	Feeder 02	18.2	Medical	14.7	20.6
Christiansted Library	3,351	Feeder 01	17.9	Libraries	26.8	37.5
Claude Markoe 1	2,405	Feeder 08	23.5	Schools	19.2	26.9
Claude Markoe 2	2,232	Feeder 08	32.1	Schools	17.9	25.0
Cotton Valley Fire Station	809	Feeder 02	34.7	Fire	6.5	9.1
Country Day School	3,359	Feeder 10	32.0	Schools	26.9	37.6
Department Of Agriculture	6,210	Feeder 09	62.4	Government Agencies	49.7	69.5
Department Of Housing	1,752	Feeder 06	20.2	Government Agencies	14.0	19.6
Department of Justice 1	7,026	Feeder 09	16.0	Government Agencies	56.2	78.7
Department of Justice 2	5,706	Feeder 09	17.0	Government Agencies	45.6	63.9
Department Of Personnel	10,343	Feeder 09	4.5	Government Agencies	82.7	115.8
Department of Planning & Natural Resources 1	4,634	Feeder 08	22.9	Government Agencies	37.1	51.9
Department of Planning & Natural Resources 2	4,704	Feeder 08	5.2	Government Agencies	37.6	52.7
DPNR Marine Office 1	904	Feeder 01	11.9	Government Agencies	7.2	10.1
DPNR Marine Office 2	313	Feeder 01	15.3	Government Agencies	2.5	3.5
Education Complex 1	8,584	Feeder 09	126.8	Schools	68.7	96.1
Education Complex 2	5,978	Feeder 09	123.2	Schools	47.8	66.9
Education Dept. Warehouse 1	2,461	Feeder 03	25.8	Schools	19.7	27.6
Education Dept. Warehouse 2	1,805	Feeder 03	20.4	Schools	14.4	20.2
Elena Christian 1	2,215	Feeder 06	29.6	Schools	17.7	24.8

NAME	Area [ft2]	Closest Feeder	Distance to Feeder [m]	Facility Type	System Size [kW]	Generation [MWh/yr]
Elena Christian 2	1,890	Feeder 06	26.3	Schools	15.1	21.2
Eulalie Rivera	9,012	Feeder 10	8.3	Schools	72.1	100.9
Free Will Baptist School	9,195	Feeder 04	16.4	Schools	73.6	103.0
GERS	1,740	Feeder 04	12.0	Government Agencies	13.9	19.5
Global Crossing Bldg 1	11,166	Feeder 08	18.5	Fiber Route	89.3	125.1
Global Crossing Bldg 2	20,413	Feeder 08	5.8	Fiber Route	163.3	228.6
Good Shepard School 1	2,739	Feeder 08	27.2	Schools	21.9	30.7
Good Shepard School 2	1,835	Feeder 08	39.1	Schools	14.7	20.6
Good Shepard School 3	1,029	Feeder 08	36.7	Schools	8.2	11.5
Green Cay Marina	729	Feeder 02	103.0	Harbors	5.8	8.2
Henry E. Rholsen 1	15,947	Feeder 08	23.5	Airports	127.6	178.6
Henry E. Rholsen 2	11,231	Feeder 08	54.1	Airports	89.8	125.8
Henry E. Rholsen 3	5,478	Feeder 08	60.9	Airports	43.8	61.4
Henry E. Rholsen 4	11,694	Feeder 08	0.0	Airports	93.6	131.0
Henry E. Rholsen 6	3,359	Feeder 08	48.4	Airports	26.9	37.6
Henry E. Rohlsen 5	4,309	Feeder 08	50.2	Airports	34.5	48.3
Herbert Gregg Home 1	955	Feeder 09	77.5	Government Agencies	7.6	10.7
Herbert Gregg Home 2	1,024	Feeder 09	91.1	Government Agencies	8.2	11.5
Homeland Security	809	Feeder 08	13.4	Government Agencies	6.5	9.1
Human Services 1	1,285	Feeder 01	36.6	Government Agencies	10.3	14.4
Human Services 2	2,065	Feeder 01	13.0	Government Agencies	16.5	23.1
Human Services Diamond	718	Feeder 09	44.7	Government Agencies	5.7	8.0
Human Services(Anna's Hope) 1	1,118	Feeder 03	29.7	Government Agencies	8.9	12.5
Human Services(Anna's Hope) 2	705	Feeder 03	76.4	Government Agencies	5.6	7.9
Industrial Park 1	28,236	Feeder 09	24.2	Government Agencies	225.9	316.2
Industrial Park 2	21,833	Feeder 09	40.1	Government Agencies	174.7	244.5
Industrial Park 3	29,016	Feeder 09	31.5	Government Agencies	232.1	325.0
Industrial Park 4	15,350	Feeder 09	21.7	Government Agencies	122.8	171.9
Iraq Academy School	3,177	Feeder 08	27.8	Schools	25.4	35.6
John Woodson 1	8,263	Feeder 10	72.3	Schools	66.1	92.5
John Woodson 2	13,146	Feeder 10	34.6	Schools	105.2	147.2
John Woodson 3	7,080	Feeder 10	94.7	Schools	56.6	79.3
John Woodson 4	7,882	Feeder 10	48.4	Schools	63.1	88.3

NAME	Area [ft2]	Closest Feeder	Distance to Feeder [m]	Facility Type	System Size [kW]	Generation [MWh/yr]
John Woodson 5	4,067	Feeder 10	59.7	Schools	32.5	45.6
John Woodson 6	2,563	Feeder 10	85.0	Schools	20.5	28.7
John Woodson 7	15,200	Feeder 06	90.4	Schools	121.6	170.2
John Woodson 8	2,029	Feeder 10	103.1	Schools	16.2	22.7
John Woodson 9	9,698	Feeder 06	39.0	Schools	77.6	108.6
John Woodson10	3,749	Feeder 06	77.3	Schools	30.0	42.0
Juan Luis Hospital & Medical Center	42,939	Feeder 05	14.9	Medical	343.5	480.9
Juanita Gardine	2,031	Feeder 02	39.6	Schools	16.2	22.7
Manor School	4,226	Feeder 06	8.6	Schools	33.8	47.3
Naval Tracking Range	3,234	Feeder 08	6.0	Government Agencies	25.9	36.2
Patrick Sweeney Police Headquarters	8,468	Feeder 09	3.5	Police	67.7	94.8
Pearl B. Larson	8,612	Feeder 02	13.9	Schools	68.9	96.5
Police Headquarters	11,429	Feeder 08	20.7	Police	91.4	128.0
Port Authority Main Harbor(Container Port) 1	14,505	Feeder 09	48.2	Government Agencies	116.0	162.5
Port Authority Main Harbor(Container Port) 2	10,839	Feeder 09	36.1	Government Agencies	86.7	121.4
Property & Procurement	3,273	Feeder 01	16.2	Government Agencies	26.2	36.7
Public Works Department East	1,669	Feeder 03	23.1	Government Agencies	13.4	18.7
Queen Louise Home For Children	1,245	Feeder 08	94.4	Government Agencies	10.0	13.9
Ricardo Richards	21,289	Feeder 04	11.9	Schools	170.3	238.4
Richmond Substation	437	Feeder 06	6.5	Substations	3.5	4.9
Seaborne Airlines 1	5,701	Feeder 01	42.4	Airports	45.6	63.9
Seaborne Airlines 2	5,434	Feeder 01	29.8	Airports	43.5	60.9
Special Education	10,390	Feeder 06	17.0	Schools	83.1	116.4
St. Patrick School 1	1,600	Feeder 08	15.0	Schools	12.8	17.9
St. Patrick School 2	1,347	Feeder 08	6.2	Schools	10.8	15.1
Sunny Isles Medical Center 1	2,211	Feeder 05	11.8	Medical	17.7	24.8
Sunny Isles Medical Center 2	2,190	Feeder 05	0.0	Medical	17.5	24.5
Vietma 911 1	5,085	Feeder 06	7.0	Police	40.7	57.0
Vietma 911 2	2,373	Feeder 06	10.9	Police	19.0	26.6
Virgin Islands National Guard Station 1	4,299	Feeder 08	7.5	Government Agencies	34.4	48.2
Virgin Islands National Guard Station 2	643	Feeder 08	6.5	Government Agencies	5.1	7.2
Waste Management Building 1	9,445	Feeder 08	21.0	Government Agencies	75.6	105.8
Waste Management Building 2	9,043	Feeder 08	21.8	Government Agencies	72.3	101.3
Yatch Club	1,488	Feeder 02	31.5	Harbors	11.9	16.7