Design of a Resilient Underground Microgrid in Potsdam, NY

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Design of a Resilient Underground Microgrid in Potsdam, NY

Final Report

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Acronyms, Abbreviations and Nomenclature

A	ampere
AC	alternating current
ANSI	American National Standards Institute
BCA	benefit-cost analysis/benefit cost assessment
BEMS	building energy management system
BTU	British thermal unit
CEA	Canadian Electrical Association
CF	capacity factor
CHP	combined heat and power
CLF	current limiting fuse
CO_2	carbon dioxide
COG	coefficient of grounding
CSP	converged services platform
CT	current transformer
CYMDIST	CYME Distribution System Analysis
DC	direct current
DDC	direct digital control
DER	distributed energy resources
DER-CAM	Distributed Energy Resources Customer Adoption Model
DG	distributed generation
DR	demand response
DS	diesel
DT	distribution transformer
DTT	direct transfer trip
EMF	electromotive force
EMS	energy management system
EMTP	Electro Magnetic Transients Program
ESS	energy storage system
ETAP	electrical transient and analysis program
FOM	fixed operations and maintenance
GE MAPS	GE Multi Area Production Simulation model
GT	gas turbine
HMI	human machine interface
HR	heat rate
HVAC	heating, ventilation, and air conditioning
Hz	hertz
IC	internal combustion

ICE	internal combustion engine
IEc	Industrial Economics, Inc.
IED	intelligent electronic device
IEEE	Institute of Electrical and Electronics Engineers
IRR	internal rate of return
ITIC	Information Technology Industry Council
kV	kilovolt
kVA	kilovolt amp
kVar	kilovolt amp reactive
kW	kilowatt
kWh	kilowatt-hour(s)
LTC	load tap changer
MCM	thousands of circular mils
MG	microgrid
MG EMS	Microgrid Energy Management System
MHz	megahertz
MMBtu	millions of BTU
MVA	megavolt ampere
MVAR	megavolt ampere reactive
MW	megawatts
NEMA	National Electrical Equipment Manufacturers Association
NG	natural gas
NOX	nitrogen oxides
NYISO	New York Independent System Operator
O&M	operations and maintenance
PCC	point of common coupling
PLC	programmable logic controller
PF	power factor
PV	photovoltaic
R	resistance
RE	reciprocating engine
REV	Reforming the Energy Vision
RMS	root mean square
SCADA/HMI	supervisory control and data acquisition/human machine interface
SO_2	sulfur dioxide
SOX	sulfur oxides
SUNY	State University of New York
THD	total harmonic distortion
Therm	unit of thermal load and generation

TOV	temporary overvoltage
UFLS	under-frequency load shedding
UPS	uninterruptible power supply
U.S. DOE	United States Department of Energy
V	volts
VAR	volt ampere reactive
VOM	variable operations and maintenance
WACC	Weighted Average Cost of Capital
X	reactance

The following nomenclature is used in the demand response section.

ACF	autocorrelation function
ARMAX	autoregressive-moving-average with exogenous inputs
GHI	Global Horizontal Irradiance
LOLE	Loss of Load Expectation
PACF	partial autocorrelation function
PLCC	peak load carrying capability
WTA	willingness to accept
WTP	willingness to pay

Indices:

b	index for energy storage systems
ch	superscript for energy storage system charging mode
d	index for loads
dch	superscript for energy storage system discharging mode
i	index for distributed energy resources
s	index for scenarios
t	index for time
^	calculated variables

Sets:

G	set of dispatch units
S	set of energy storage systems

Parameters:

AR	autoregressive polynomial
DR	ramp down rate
DT	minimum down time
F(.)	generation cost
MA	moving average polynomials
MC	minimum charging time
MD	minimum discharging time
MU	minimum operating time
SOC	state of charge
U	outage state of the main grid line
UP	ramp up rate
UT	minimum up time
ρ	market price

Variables:

C	energy storage system state of charge.
D	demand load
I	commitment state of the dispatchable unit
P	distributed energy resources output power
P_M	main grid power
SD	shut down cost
SU	start-up cost
T^{ch}	number of successive charging hours
$\mathrm{T}^{\mathrm{dch}}$	number of successive discharging hours
T^{on}	number of successive ON hours
T^{off}	number of successive OFF hours
u	energy storage system discharging state
v	energy storage system charging state
Y_{ct} / Y_{dt}	represent when energy storage system (ESS) is switched to the charging/discharging status

Constants:

c	fixed cost due to charging and discharging

Summary

Extreme weather conditions in recent years, such as ice storms, major snow events, and excessive rain and flooding in the North Country of Upstate New York has created the need to provide an alternative source of electricity during major storms to power essential service providers, such as emergency services, staging areas, utilities, and providers of housing, fuel, and food. The Potsdam Resilient Underground Microgrid will connect multiple critical service entities within the Village of Potsdam during emergency conditions to allow for greater communication and disaster relief for the larger North Country area. This report includes the planning and preliminary design studies for the Potsdam Microgrid.

The work contained in this report was accomplished through a New York State Energy Research and Development Authority (NYSERDA) project (41309) titled, Design of a Resilient Underground Microgrid in Potsdam, NY, and sponsored by NYSERDA with co-funding provided by National Grid. Clarkson University led the project with subcontractors GE Energy Consulting and Nova Energy Specialists.

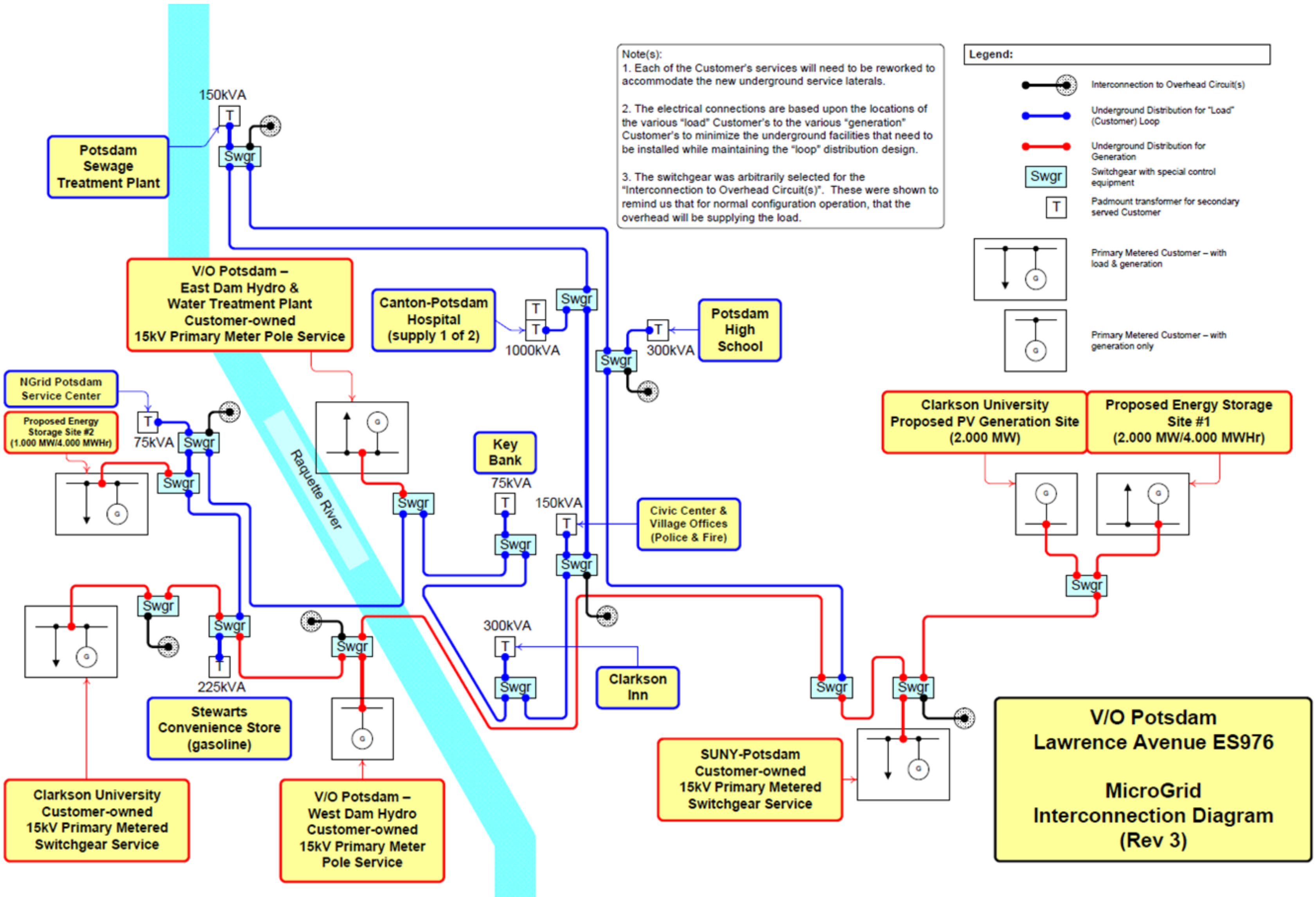
The initial vision for the microgrid as shown in Figure S-1 is the system studied in this project, with only minor differences. The major entities considered for connection to the microgrid are the following:

- SUNY Potsdam with a 4,000-student college campus, capability to provide emergency food and shelter to the community and recovery crews.
- Clarkson University with a 4,000-student college campus, capability to provide emergency food and shelter to the community and recovery crews.
- Village of Potsdam
  - Water treatment plant
  - Sewage treatment plant
  - Civic Center—police, fire, and rescue squads
- Canton Potsdam Hospital with a community healthcare facility certified for 94 beds and core programs in emergency medicine, acute care, hospitalist medicine, and critical care.
- Potsdam High School with the capability to provide emergency food and shelter to the community and recovery crews.
- National Grid Service Center

The microgrid will also include retail entities that provide critical needs during an extended emergency. Entities considered for inclusion are the following:

- Potsdam IGA—grocery store
- Stewarts Shop—fuel and convenience store
- Kinney Drug—pharmacy
- Clarkson Inn—shelter
- North Country Savings Bank—ATM/banking

Figure S-1. Initial Conceptual Diagram of the Potsdam Microgrid



A significant amount of generation capability currently exists in Potsdam, improving the feasibility of creating a microgrid. These generation resources include the following:

- SUNY Potsdam: 2.8-megawatt (MW) Combined Heat and Power (CHP) plant (natural gas)
- Clarkson:
  - Main Campus: piston engine CHP plants (natural gas fired, 290 kW and 370 kW), 195-kW micro turbine CHP plant (natural gas)
  - 2-MW third-party owned photovoltaic array located east of town
- Village of Potsdam: East and West Dam hydro facilities with a combined rating of 1 MW
- Significant amount of emergency, non-synchronizable standby generation at the major entities of the microgrid, fueled by either natural gas or diesel

These entities would be connected by a primary underground distribution network owned and operated by National Grid. The underground network would be the primary service connection for microgrid entities. An entity would have a main point of connection to an existing overhead feeder coming out of National Grid's Lawrence Avenue Substation. The connection point would be fully instrumented and automated and would provide separation and reconnection capability. Five other points of connection to overhead feeders would be available to provide operational flexibility.

The microgrid entities would cooperate to develop, operate, and maintain the microgrid system. During normal (blue sky) conditions, the system would be operated to minimize costs for the project partners, while providing reliability and power quality benefits. In the event of a long-term outage of the bulk power grid, the microgrid would provide electric power service to its partners for an extended period of two weeks or more.

This project includes the following:

- Generation and load study
- Microgrid design study
- Cost/benefit study
- Dynamic studies and power quality analysis
- Microgrid mode scheduling, reliability, and benefits analysis

The studies have shown that the microgrid is technically feasible and provide sufficient cost and benefit analysis for stakeholders involved in the project. The project has been selected by National Grid as one of their Reforming the Energy Vision (REV) Demonstration Projects. The REV project will perform a detailed design of the microgrid as well as develop a governance plan with input from the stakeholders.

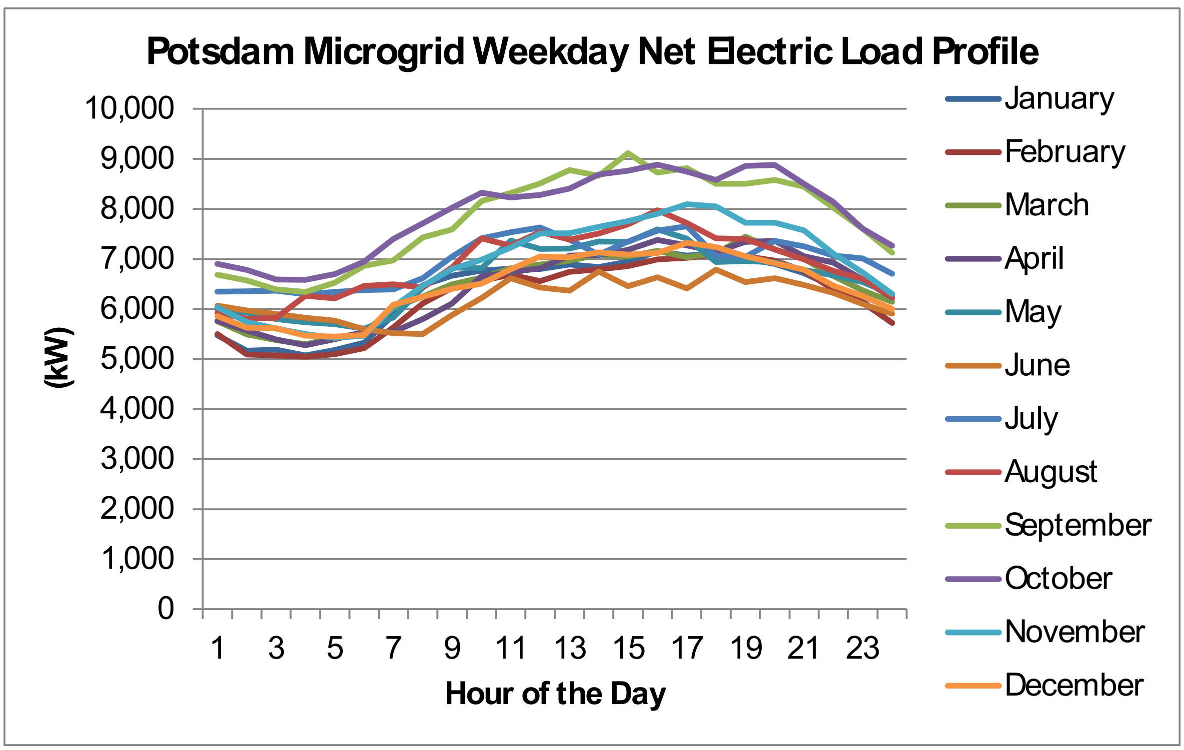
S.1 Generation and Load Study

The generation and load study of the microgrid was led by GE Energy Consulting. The study began with an extensive data collection from local stakeholders, and full details are presented in section 2 of the report.

Stakeholders completed an extensive questionnaire, which was followed by a site visit from the project team. The stakeholders released one year's worth of load data, gathered by National Grid, in the form of hourly demand for the larger customers and monthly energy and demand data for the smaller entities. Billing data was also supplied by one partner.

The annual data was used to determine typical weekday and weekend load profiles for each month of the year. The weekday load profiles are shown in Figure S-2.

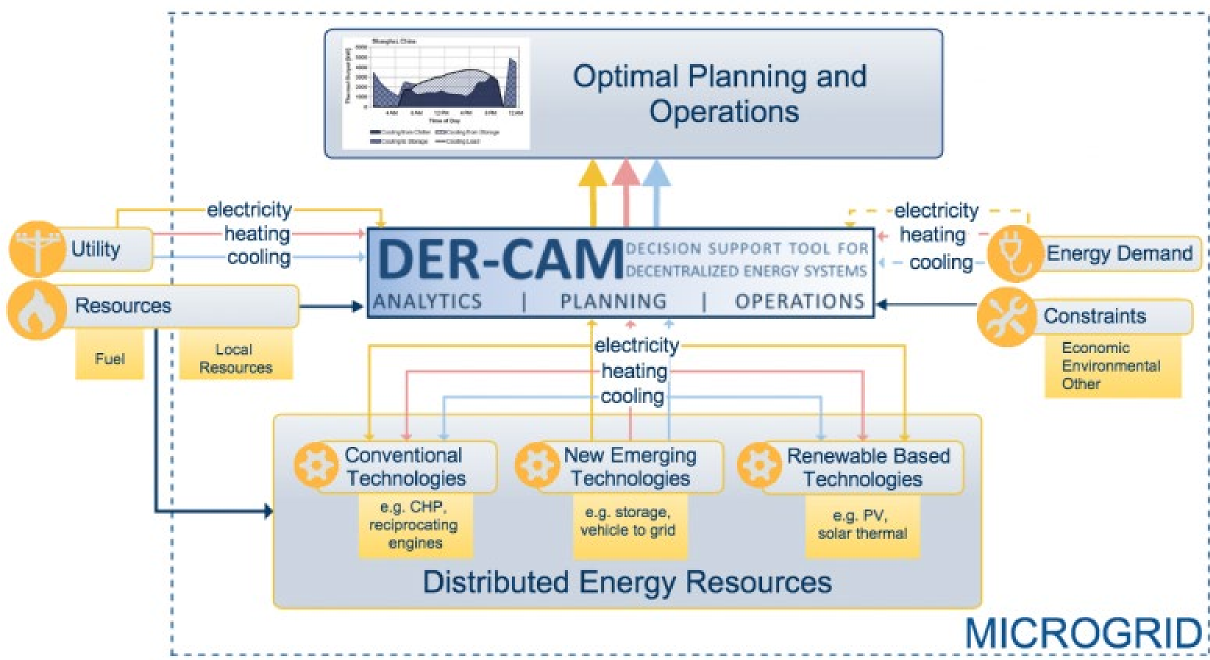
Figure S-2. Typical Weekday Microgrid Load Profile by Month



An analysis of existing generation sources was conducted as well as a fuel accessibility study. In addition, an inventory of suitable new generation options was developed, which included technology, fuel choice, efficiency, emissions, and cost projections, and a thermal load profile for Potsdam High School was completed.

From this data, multiple scenarios were created and analyzed with DER-CAM (Figure S-3), with results shown in Table S-1. The studies were compared with the baseline study (51A) of no extended outage plus no demand response (DR), with the microgrid loads analyzed as a single entity. Apart from the base case, the case studies were run assuming a two-week outage of the main grid. Under these assumptions, the results reported in the study show a reasonable expectation that the annualized costs to the microgrid partners would not go up significantly with the addition of 4 MW of new natural gas generation. Details of these case studies are reported in section 2.

Figure S-3. DER-CAM Schematic



These results were presented to the potential generation stakeholders of the Potsdam Microgrid in two meetings, one on May 6, 2015 and the other on October 24, 2016. The group concurred that the addition of 4 MW of new generation would provide the best solution for the proposed microgrid. The group suggested studying dual fuel (natural gas and diesel) in addition to conventional natural gas reciprocating engines. While the study showed that both natural gas and diesel fuel sources are highly reliable, the team felt that having a dual-fuel unit for one or both new generators should be considered.

Table S-1. Microgrid Generation Life-Cycle Cost Analysis for Multiple Case Scenarios

Scenario	Description	New DG Type	New DG Capacity (kW)	Number of New DG Units	Total New DG Additions (kW)	Utility Purchase (MWh)	DG Generation (MWh)	Annualized Cost ($K)	Annualized Cost Change from Baseline ($K)
51A	Baseline: No Outage + No DR Electric Service Rate: SC-3A Utility Purchase Only - No Internal Generation Updated Util Rates + Cap Costs $300/kW More	N/A	0	0	0	57,001	0	4,247	0
52A	2 Wk Outage + 2 Wk 2000 kW DR Electric Service Rate: SC-3A All Existing DG + No New DG	N/A	0	0	0	33,817	22,513	4,038	-209
53A	2 Wk Outage + 2 Wk 2000 kW DR Electric Service Rate: SC-3A Partial Existing DG + New DG <= 2000 kW WACC set at 8.3%	RE-NG-2000	2000	2	4000	3,801	52,720	3,946	-301
54A	Based on 53A Exception: with Electric Service Rate SC-7	RE-NG-2000	2000	2	4000	26,994	29,527	4,236	-10
55A	Based on 54A Exception: New DG Size Limit set to 1000 kW	RE-NG-1000	1000	4	4000	27,209	29,120	4,321	74
56A	Based on 54A Exception: $300/kW added to Capital Costs	RE-NG-2000	2000	2	4000	26,915	29,415	4,348	101
57A	Based on 54A Exception: $600/kW added to Capital Costs	RE-NG-2000	2000	2	4000	26,994	29,527	4,486	240

S.2 Microgrid Design Study

The microgrid design study included seven parts (relevant sections of the full report are indicated):

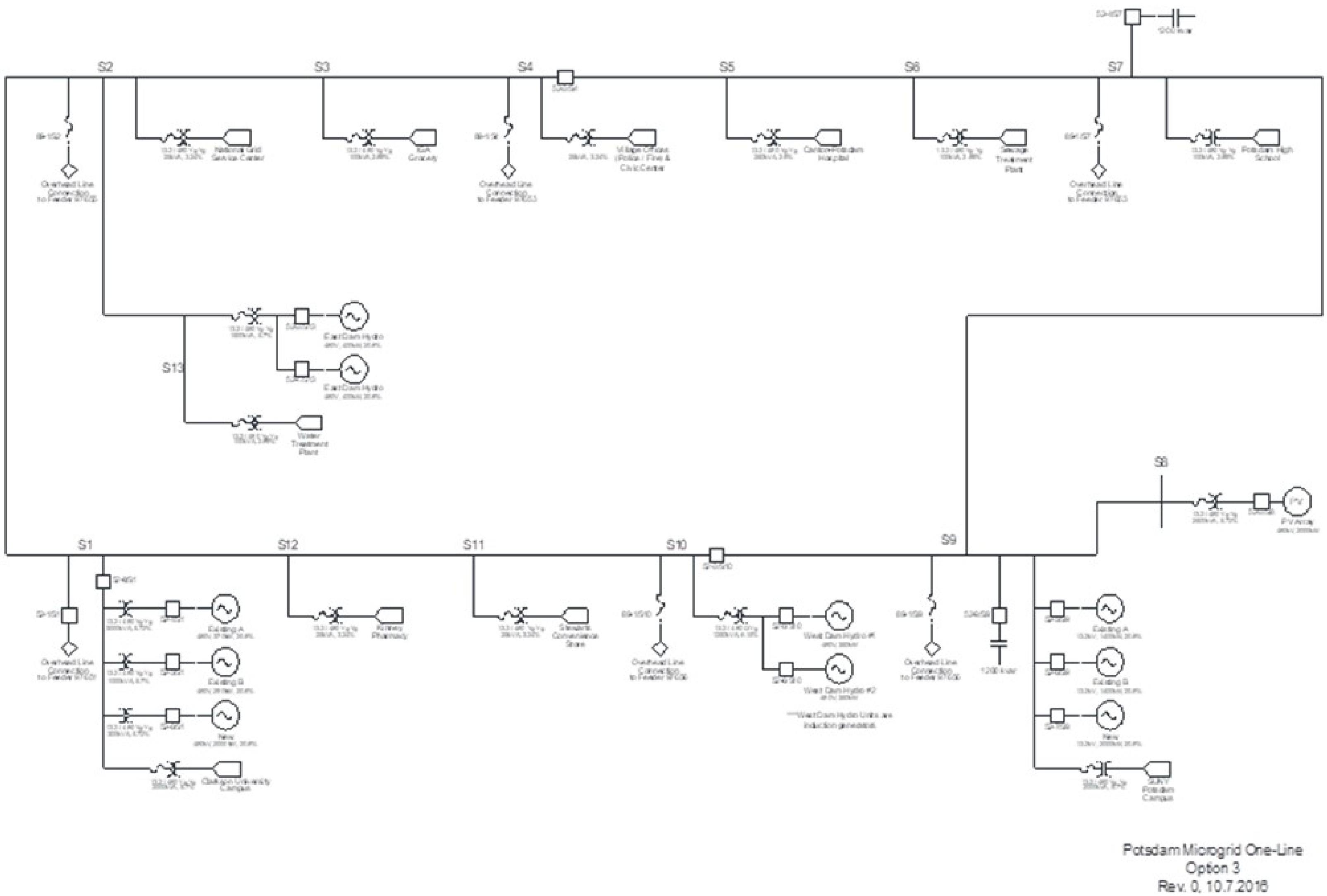
- Steady state (section 3)
- Fault study (section 3)
- Protection and control (section 3)
- Microgrid availability analysis (section 6)
- Demand response system design (section 6)
- Dynamic and overvoltage study (section 5)
- Communication system conceptual design (section 3)

S.2.1 Steady-State Study

S.2.1.1 Grid-Connected Operation

The one-line diagram of the system studied is shown in Figure S-4. The studies included five scenarios for grid-connected mode.

Figure S-4. Potsdam Microgrid One-Line Diagram, Option 3



Case 1 is the normal scenario in which the entire microgrid is fed by a dedicated overhead feeder from National Grid's Lawrence Avenue Substation. The overhead section needs to be reinforced to carry the entire 9-MW load of the microgrid during normal operation with microgrid generation. The other four scenarios involved feeding the microgrid from more than one overhead feeder as described in the report. In these cases, the microgrid splits to allow the load. The minimum voltage in these cases was 0.964 per unit. The studies assume a 500 thousand circular mils (MCM) underground cable and that the new power factor correction capacitors were 2.4 megavolt ampere reactive (MVAR) and online during this study.

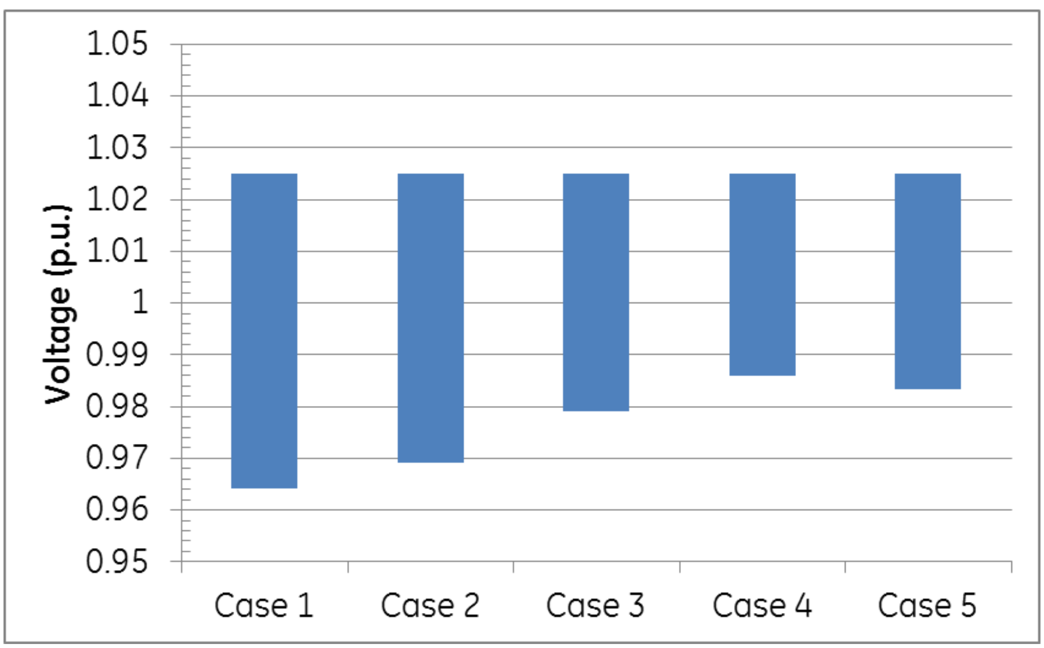
The following two scenarios ran for each case:

- Peak load and generation determined by the DER-CAM solution
- Microgrid generation

Thermal and voltage limits were considered for all cases.

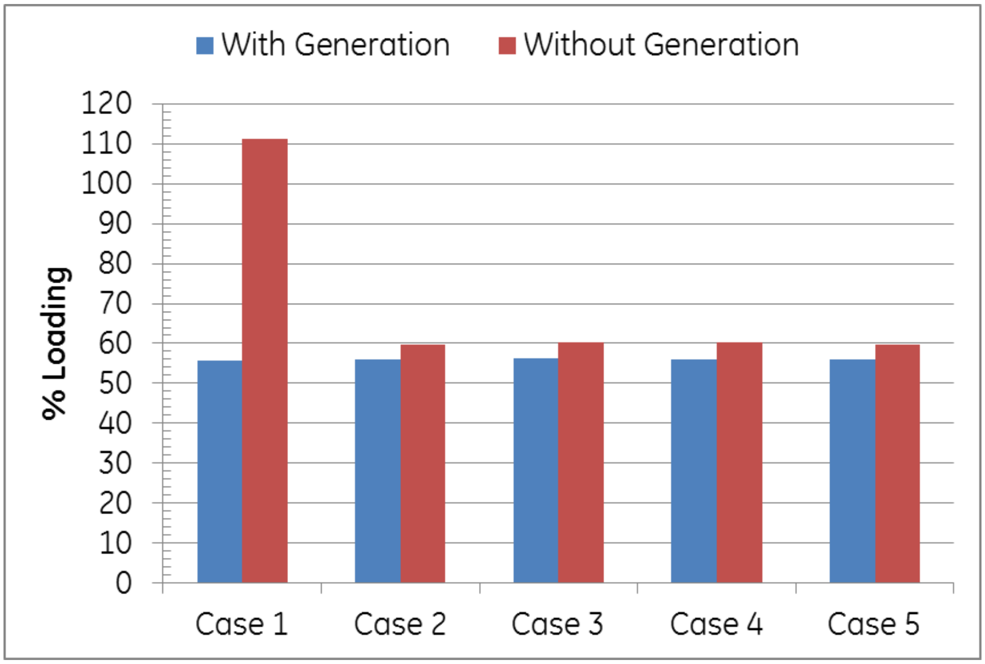
Voltage results for the no generation scenario are shown in Figure S-5. The minimum voltage in these cases is 0.964 per unit.

Figure S-5. Voltage Range for Grid Connected, No Generation Scenario



The results of the loading study for the underground microgrid system are shown in Figure S-6. The study showed one overload of 11% in the case 1 normal feed without generation. This overload occurs in a single short section of cable between the dedicated overhead feeder and the Clarkson University main bus. This section of the microgrid will need to be upgraded to 750-MCM cable.

Figure S-6. Loading Study of the Underground Microgrid



S.2.1.2 Isolated Operation

The second part of the steady-state study involved operation in the isolated mode with no connection to the main power grid. The peak load study assumed load curtailments shown in Table S-2 were put into effect and made a worst-case assumption of zero output from the solar photovoltaic (PV) array to provide for operation during low-solar insolation days.

Table S-2. Load Curtailment used in the Peak Load Study

Location	Original (kW)	Curtailed Load (kW)	Curtailed %	Microgrid Load (kW)
Clarkson	4,886	1,049	22%	3,837
SUNY Potsdam	4,166	895	22%	3,271
Hospital	560	56	10%	504

The designers elected to install two new 1.2-MVA power factor correction capacitor banks to supply the load VARs in the microgrid mode. The primary results of are shown in Table S-3 and show reasonable performance during microgrid operation when separated from the main power grid.

Table S-3. Results of the Steady-State Peak Load Study

	PV	No PV
Min Voltage per unit:	0.9567	0.9567
Max Voltage per unit:	1.0075	1.0075
Max Conductor Loading:	46.9%	46.9%
Swing Generator Real Power:	1,196 kW	1,748 kW
Swing Generator Real Power Margin:	804 kW	252 kW
Swing Generator Reactive Power:	430 kVar	422 kVar

PV = photovoltaic

S.2.1.3 Current Imbalance

The microgrid generators will have current imbalance limits to avoid derating. An 8% current imbalance is a typical limit for generators. In grid connected mode, a portion of the unbalanced current will flow to the grid, while in microgrid mode, the generators must supply all this current. As a result, the microgrid load imbalance must be monitored and, if necessary, imbalance limits could be imposed on each entity connected to the microgrid to avoid generator overheating in microgrid mode.

S.2.2 Fault Study

A comprehensive fault study was performed for ten different operating configurations for the microgrid. The microgrid configuration and maximum three-phase fault current predicted for the 13.2-kV system are shown in Table S-4.

The results show small but workable fault-current levels during isolated operation. The grid connected results show that the highest fault levels will occur in several of the non-standard microgrid topologies. All topologies were considered in designing the system to withstand the fault currents, and in setting the fault clearing requirements of the circuit breakers, reclosers, and fuses. These levels will also be used in determining the appropriate protective relay settings in the future.

Table S-4. Summary of Maximum Three-Phase Fault Currents on the 13.2 kV System

Case	Description	Highest Fault Current and Location (13.2 kV system only)
MG Only	Microgrid Ring complete, in-service All OHL sources out of service (OOS)	2.6 kA at the SUNY Potsdam Bus S9
1	OHL_SRC1 Source In-service Only, all others OOS Clarkson New Generator (Swing) Microgrid Ring with all cable sections in-service	5.6 kA at the Clarkson bus S1
2	OHL_SRC3 and OHL_SRC6 Sources In-service, all others OOS Clarkson New Generator (Swing) Microgrid Ring complete, all in-service	10.4 kA at the Stewarts bus S11
2A	OHL_SRC3 and OHL_SRC6 Sources In-service, all others OOS Microgrid Ring broken into 2 Sub-systems Clarkson and SUNY Potsdam New Generators set both for Swing operation mode	6.1 kA at the Village Office bus S4
3	OHL_SRC3 and OHL_SRC5 Sources In-service, others OOS. Clarkson New Generator (Swing) Microgrid Ring complete, all in-service	12.5 kA at the SUNY Potsdam bus S9
3A	OHL_SRC3 and OHL_SRC5 Sources In-service, all others OOS Microgrid Ring broken into 2 Sub-systems Clarkson and SUNY Potsdam New Generators set both for Swing operation mode	8.0 kA at the SUNY Potsdam bus S9
4	OHL_SRC2 and OHL_SRC4 Sources In-service, all others OOS Clarkson New Generator (Swing) Microgrid Ring complete, all in-service	11.2 kA at the high school bus S7
4A	OHL_SRC2 and OHL_SRC4 Sources In-service, all others OOS Microgrid Ring broken into 2 Sub-systems Clarkson and SUNY Potsdam New Generators set both for Swing operation mode	7.2 kA at the high school bus S7
5	OHL_SRC2 and OHL_SRC6 Sources In-service, all others OOS Clarkson New Generator (Swing) Microgrid Ring complete, all in-service	10.3kA at the W. Dam hydro bus S10 and Stewarts bus S11
5A	OHL_SRC2 and OHL_SRC6 Sources In-service, all others OOS Microgrid Ring broken into 2 Sub-systems Clarkson and SUNY Potsdam New Generators set both for Swing operation mode	5.8kA at the W dam hydro bus S10

S.2.3 Protection and Control

Three protection scenarios have been developed for the primary underground network that is the backbone of the microgrid. The three scenarios offer a range of performance and price. See Table S-5 for a high-level overview of the scenarios.

Table S-5. Overview of Cost and Capability of the Three Protection Scenarios Considered in the Study

Scenario Number	Primary protection scheme	Fault clearing means	Performance Goal	Projected cost[a]
1	Transmission Line Current Differential Schemes	3 circuit breakers at each entity connection	Underground line segment fault clearing in 100 mses with no loss of load, bus fault clearing in 100 msec with loss of load to the service feed on that bus	$12,720,900
2	Transmission Line Current Differential Schemes	2 circuit breakers+ transformer fuse at each location	Underground line segment fault clearing in 100 msec with no loss of load. Bus clearing would coordinate with transformer fuses	$11,905,000
3	Time Overcurrent Protection	1 recloser at main riser pole, 2 reclosers to separate east and west sections of underground system, transformer fuses	Underground line segment fault would cause interruption of half of the primary network, with manual or automated switching of failed segment followed by restoration of the good segments	$2,150,000

[a] Distribution system plus protection system

The choice between these competing options will be based on the cost/performance trade-offs and made in the next phase of the project.

S.2.4 System Availability

A design goal has been set for the Potsdam Microgrid to provide 98% availability during microgrid (grid independent) operation. An availability study was conducted for six different generator scenarios. The analysis assumed that the underground distribution network and the natural gas supply had significantly higher availabilities than the natural gas generation. It was also recognized the microgrid primary network does not experience congestion for the levels of generation in the study. The study considered a range of un-availabilities of the individual generator units, with an unavailability of 0.03 considered as the best estimate for existing generation and also the generation to be added. Finally, the hydro and photovoltaic generation has not been considered in this study.

Table S-6 shows the results of the system availability study. The system can serve approximately 6 MW with 98% availability when 4 MW of new generation are added to the existing generation. Several scenarios will provide this level of availability, such as new generation with 3 to 4 units. However, adding 4 MW with two 2-MW units does not provide the same level of availability.

Table S-6. Peak Load Capability of the Microgrid while Maintaining 98% Availability

Generators in the system: 1.4 MW, 1.4 MW, 0.3 MW, 0.2 MW, 0.06 MW, 0.06 MW, 0.06 MW (total=3.48 MW)			
Case	**Added generators**	**Maximum load that can be served to have an availability of at least 0.98**	**Unavailability at the load level of previous column**
I	1 × 2.5 MW 1 × 1.5 MW	4.98	0.0091
II	2 × 1.25 MW 1 × 1.5 MW	5.98	0.0172
III	1 × 2.5 MW 2 × 0.75 MW	4.98	0.0081
IV	4 × 1.25 MW	7.02	0.0190
V	4 × 0.75 MW	5.08	0.0197
VI	4 × 1 MW	6.08	0.0198
VII	2 × 2.5 MW	5.98	0.0129

S.2.5 Demand Response

An efficient model for building a microgrid optimal operation schedule, considering both grid-connected mode and islanding mode, has been developed as part of this study. An islanding criterion was introduced for ensuring the generation adequacy of the microgrid operation when islanded, considering a 24-hour disconnection from the main grid. Islanding cuts were further utilized to coordinate these two problems. Mixed integer programming was used to model the microgrid components, including loads, generating units, and energy storage systems (ESS). Numerical simulations evaluate the effectiveness of the studied microgrid optimal operation model and show that the islanding criterion provides significant reliability benefits while slightly increasing the microgrid total operation cost. Additionally, the line-flow capacity limits between different buses of the microgrid system would be considered as network constraints of the microgrid system during optimal operation model building in the future work. The demand response capability of the microgrid during the grid-connected and islanded mode could also be analyzed through load shedding cost modeling using the proposed model.

S.2.6 Dynamic and Overvoltage Study

The main objectives of the dynamic analysis were the following:

- Understand/mitigate power quality conditions during various microgrid conditions
  - Temporary over-voltages/faults
  - Loss of load

    - Motor starts, load pickup and power variations
- Understand/mitigate stability limits/issues of the microgrid that might impact reliability
    - Transient stability
    - Steady-state stability

The study identified the following:

- The need for effective grounding of the microgrid to avoid ground fault overvoltage and to stabilize line to neutral voltage while the system is isolated from the main National Grid system. To accomplish this, the study recommends the addition of two new grounding transformers. The transformers would be strategically placed on each side of the microgrid (one at or near SUNY Potsdam and one at or near Clarkson University) so the microgrid if necessary could be operated in a split mode.
- The expectation that short-term, 20% voltage dips will occur during energization of some transformers due to inrush and load pickup conditions.
- No issues with motor starting since the calculated voltage dips during full-current starts of the largest motors expected on the system should be no more than about 2% on the main primary cables. This would not cause unreasonable voltage flicker.
- Concerns with load rejection that can potentially be addressed through operating procedures to ensure that a region of the microgrid with a significant surplus of generation is not suddenly isolated with only a small amount of loading.
- Concerns with ferro-resonance that can likely be addressed through operating procedures, particularly with respect to the power factor correction capacitors to be added to the system.

Regarding energy storage, the study identifies the following two areas that would likely require an energy control system for the microgrid:

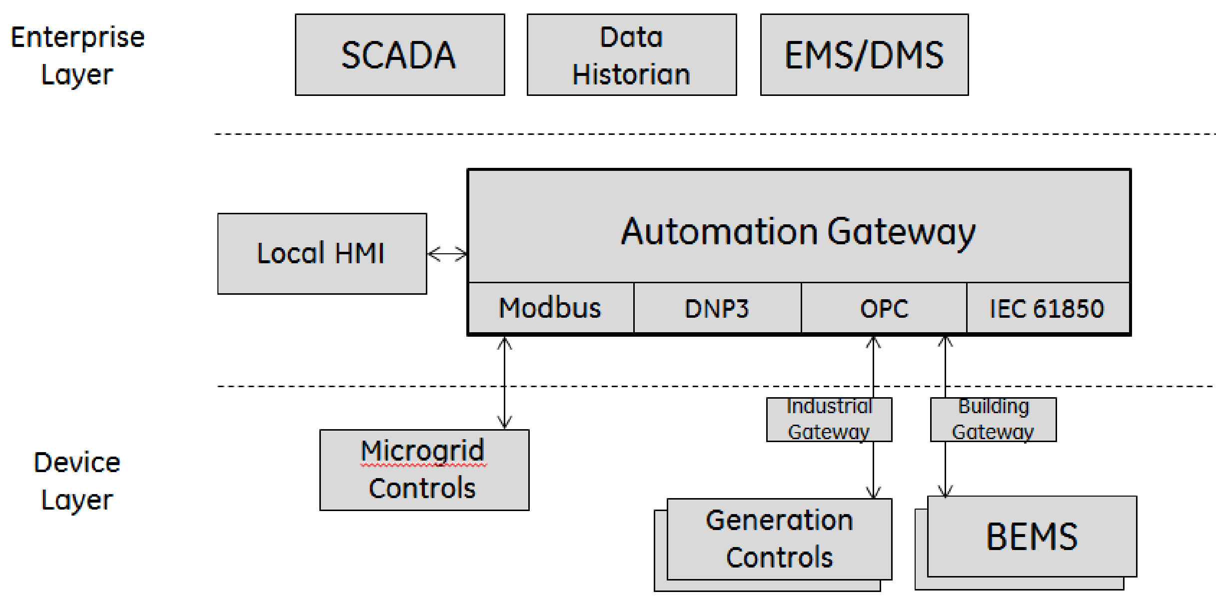
- PV array: An energy storage system (ESS) and dynamic reactive power control would be needed to reduce microgrid frequency variations and voltage excursions due to the PV array power fluctuations that occur during partly cloudy days when the PV array is connected.
- Transition from grid-connected to microgrid mode: A significant amount of energy storage up to several megawatt-hours of energy and high-speed switching equipment (maybe even a static switch) would be required to provide a nearly seamless transition to microgrid mode upon a fault on the overhead primary system with a deep voltage sag. Such a scheme adds significant cost and some operational risk of failed/false transitions and is likely not to justify cost in this case. A slower changeover with an interruption period of up to five to 20 minutes of outage time may be more reasonable for these loads and the project objectives.

These issues were discussed with local stakeholders. The need for a seamless transfer to microgrid mode during a deep-voltage sag was not a high priority for the group. There was also concern that the detection system may trigger in response to recoverable sags, resulting in unnecessary rapid start-up of microgrid generation.

S.2.7 Communication System Conceptual Design

An assessment of the control and communications infrastructure required for the project is also included. The software components of the control architecture are shown in Figure S-7. The design involves a fiber optic data network for communication among the project entities with the fiber optics running in a cell of the ductwork holding the primary power cables. The individual entities would be responsible for providing the link between this system-level control and their various generation and building-management control systems.

Figure S-7. Software Components of the Control Architecture



S.3 Benefit-Cost Analysis

The benefit-cost analysis includes the following:

- Detailed cost study for the Potsdam Microgrid
- Benefit-cost analysis (BCA)
- Preliminary cost study for reduced buildout of the microgrid

S.3.1 Detailed Cost Study

The detailed cost study quantifies the major microgrid components, including their ratings and costs. The study included the following three generation options in addition to the three primary distribution options discussed in the previous section:

- Two 2-MW dual-fuel (natural gas/diesel) piston engine units and generating set
- Two 2-MW natural-gas fired piston engine units and generating set
- Two 2-MW hybrid-fuel cell/natural gas engines and generating set

All three options consider one generator operating at 480 V and the second operating at 13.2 kV.

Table S-7 summarizes the cost estimates for the generations options. The control and communications as well as the design, commissioning, and miscellaneous categories are the same for all options.

Table S-7. Summary of Cost Estimates for the Three Generation Options and the Three Distribution Options Studied

Option	Description	Cost Estimate
Generation Option 1	Dual Fuel	$5.5 million
Generation Option 2	Natural Gas	$4.2 million
Generation Option 3	Fuel Cell	$28.5 million
Distribution Option 1	High speed, high reliability	$26.4 million
Distribution Option 2	Slower speed, high reliability	$25.6 million
Distribution Option 3	Slower speed, reduced reliability	$15.9 million
	Control and Communications	$4.3 million
	Design, commissioning and miscellaneous	$2.4 million

This analysis shows a range of initial investment costs for the project varying from $23.8 million dollars to $61.6 million dollars. The benefits analysis for this project will be considered in determining the final design choices for the microgrid.

S.3.2 Benefit-Cost Analysis (BCA)

A BCA was conducted for the Potsdam Microgrid project. The primary source for the benefits analysis was the spreadsheet analysis developed by Industrial Economics, Inc. (IEc) for NYSERDA and used as a resource for NYSERDA'S NY Prize competition. The analysis for this project goes beyond the basic IEc method by using the DER-CAM results for generator dispatch and the resulting economic performance.

The following benefit categories were considered in this study:

- Major power outage benefits
- Avoided emissions damages
- Avoided emissions allowance costs
- Power quality improvements
- Reliability improvements
- Distribution capacity cost savings
- Generation capacity cost savings
- Fuel savings from CHP
- Reduction in generating costs

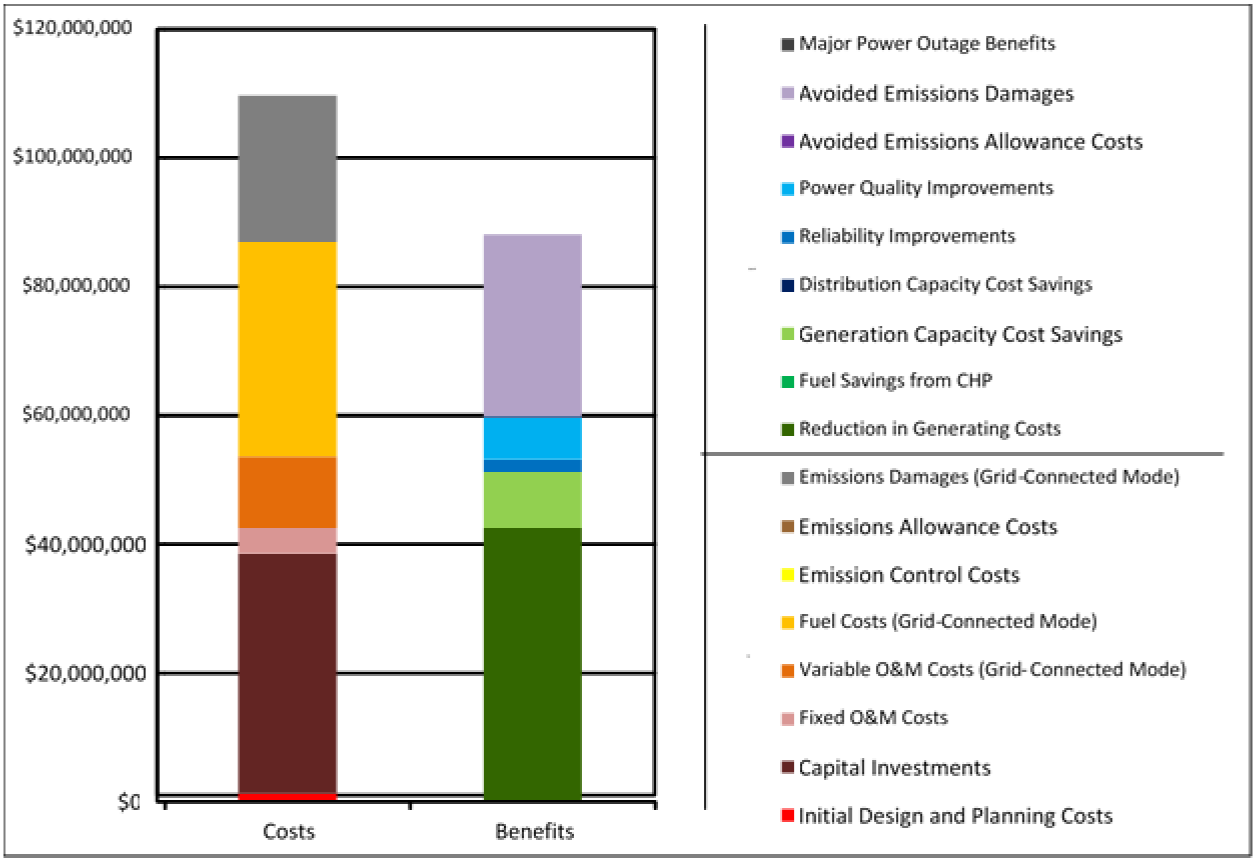
The following two scenarios were considered in this study:

- Scenario one predicts the costs and benefits for no major power outages over the 20-year life of the project. A benefit cost ratio of greater than one in this scenario indicates that the microgrid should be built without regard to major power outage considerations.
- Scenario two considers the average annual occurrence duration of one or more major power outages over the 20-year life of the project. This scenario determines the average annual major power outage rate that provides the breakeven point between project benefits and costs.

Scenario 2 includes both monetary and societal costs and benefits. The average annual breakeven rate provides a figure of merit for the project that can be compared with predicted risk factors for the microgrid. It also provides a figure of merit for the project that can be compared with competing resilient microgrid projects across the State.

The baseline project considered is the dual-fuel generation option with high-speed high-reliability distribution. The result of this base case option for the scenario with no major resiliency outages over 20 years is shown in Figure S-8. Present value costs and benefits are shown in this figure. The scenario shows a benefit to cost ratio of 0.8.

Figure S-8. Base Case Potsdam Microgrid Societal Benefit-Cost Analysis with No Major Power Outages during Project Life



In this case, the scenario two analysis showed benefit-cost parity for an average annual major power outage rate of 0.73 days.

Table S-8 shows the BCA for the nine cases studied. The table shows that all these options have a benefit/cost ratio of less than one when major power outage benefits are not included. The outage days/year needed to achieve a benefit/cost ratio of one range from 0.33 days per year (6.7 days over 20 years) to 1.56 days per year (31.2 days over 20 years).

Table S-8. Benefit-Cost Analysis Summary for the Nine Cases Studied

	Gen. Option 1 Dist. Option 1	Gen. Option 1 Dist. Option 2	Gen. Option 1 Dist. Option 3	Gen. Option 2 Dist. Option 1	Gen. Option 2 Dist. Option 2	Gen. Option 2 Dist. Option 3	Gen. Option 3 Dist. Option 1	Gen. Option 3 Dist. Option 2	Gen. Option 3 Dist. Option 3
NPV of Total Costs ($M)	109.67	108.85	99.10	108.37	107.55	97.80	132.67	131.85	122.10
NPV of Total Benefits ($M)	88.11	88.11	88.11	88.11	88.11	88.11	88.11	88.11	88.11
NPV of Net Benefits ($M)	-21.55	-20.74	-10.98	-20.25	-19.44	-9.68	-44.55	-43.74	-33.98
Annualized Costs ($M)	8.67	8.61	7.88	8.57	8.51	7.78	10.40	10.34	9.61
Annualized Benefits ($M)	7.12	7.12	7.12	7.12	7.12	7.12	7.12	7.12	7.12
Annualized Net Benefits ($M)	-1.55	-1.49	-0.75	-1.45	-1.39	-0.66	-3.28	-3.22	-2.49
Benefit/Cost Ratio	**0.80**	**0.81**	**0.89**	**0.81**	**0.82**	**0.90**	**0.66**	**0.67**	**0.72**
Outage Days/Year Needed for B/C=1	**0.75**	**0.72**	**0.38**	**0.70**	**0.67**	**0.33**	**1.56**	**1.53**	**1.19**

S.3.3 Options for Reduced Buildout of the Microgrid

The analyses of the nine options in the previous section all include a near full buildout of the microgrid (Figure S-1). The cost estimates do not include the ESS shown in this figure (see full report, section 4).

Further cost reductions could be realized by limiting the underground distribution network. Preliminary discussions have identified the photovoltaic installation as the most likely link that could be eliminated. The footage of underground cable needed to connect the PV plant is significant, and the plant output following an ice storm is uncertain. Therefore, the benefit to the microgrid of having this generation available during daylight hours is difficult to quantify, which in turn reduces the benefit received. Other options for reducing the footprint of the microgrid are available as can be seen in Figure S-1. These would generally result in a quantifiable loss of benefit that would offset the reduction in cost. Detailed analysis of these options will be conducted in the next phase of the project.

S4 Summary

A proposed structure for the Potsdam Underground Resilient Microgrid has been developed. The analysis of generation and load conducted in this study has shown that an additional 4 MW of generation plus 2 MW of demand response will be needed for a successful implementation. The study predicts that most, if not all, of the costs of this generation can be recovered during normal grid operation.

The microgrid design study shows that the microgrid is technically feasible. There will be a need for voltage support capacitors and for grounding transformers to ensure proper operation during stand-alone operation. The study suggests that energy storage could be needed to smooth the power output variations of the PV array but would not be needed if the array is not connected.

The study includes three generation options and three distribution options with BCAs for the nine resulting cases. The benefits of each option are also identified, and these analyses will provide the project partners continue power and communication between entities in the event of power loss from the main electrical grid.

1 Introduction

The New York State Energy Research and Development Authority (NYSERDA) and National Grid engaged Clarkson University and its partners, GE Energy Consulting and Nova Energy Specialists, to perform a feasibility study and develop a functional design of a resilient microgrid in the town of Potsdam, NY.

The objective of the project was to perform an optimization study and develop a design for a resilient microgrid that will provide reliable power for essential services and allow Potsdam to act as a hub for emergency operations during North Country disaster conditions, such as ice storms, major snow events, and micro-burst weather conditions experienced in recent years.

The design includes a new underground system for power and communications that interconnects approximately twelve operational entities, including emergency service providers, utilities, generation sources, staging areas, and other essential service providers (housing, fuel, financial, food, etc.). The target duration for self-sustained islanded operation is two weeks, which may be extended depending on the performance of renewable generation.

When not in islanded operation, the microgrid is intended to operate in concert with the existing distribution system to optimize the value of the interconnected renewable and stationary generation, energy storage, and load-control systems to the benefit of their owners and the electric system.

The planned entities connected to the underground microgrid will include Clarkson University, State University of New York (SUNY) Potsdam, Canton-Potsdam Hospital, Village of Potsdam buildings, and Potsdam Central School plus commercial providers of fuel, food, and other essential commodities and services.

The deliverable for the project is the design and cost estimates for a self-sustaining resilient underground microgrid in Potsdam, NY. The goals after the project has been accomplished are to complete the design, seek project approval and financing, and construct the microgrid.

The following are the primary goals of the study:

- Design a resilient community microgrid in the North Country of New York State to improve disaster response
- Construct a National Grid underground system for resilient power and communications (to be developed by National Grid)
- Interconnect 10+ entities: Clarkson University, SUNY Potsdam, Canton-Potsdam Hospital, Potsdam Central School, and Village of Potsdam buildings, plus commercial providers of fuel, food, and other essential emergency services

A resilient microgrid would be a key component in the North Country region addressing New York State's goal of significantly improving disaster response capability. It would also serve as a model for other regions of the State.

For the proposed Potsdam Microgrid, several of the listed customers already operate their own generation within the grounds of their facility to offset some of their load. A few of the entities listed above (such as the Clarkson University photovoltaic (PV) array and the East and West Hydropower Dams) are not part of physical customer load sites but are instead dedicated power generation sites that will likely participate in the microgrid. The conventional generation is to be coordinated via a central microgrid controller to supply the needed generation capacity during periods of islanded operation (i.e., separated from the main utility source) and to provide other generation dispatch coordination, as needed, to fulfill any microgrid ancillary functions. Load shedding of the less important loads within buildings will be used abundantly to allow the microgrid to meet major operational objectives, even though the total generation capacity will, at times, be less than the total peak demand of all coincident loads combined.

As a general operating plan, under normal conditions (the clear majority of the time) the microgrid will operate in parallel with the bulk National Grid power system source. During conditions in which the conventional supply is compromised (such as ice storms, wind storms, natural disasters, etc.) the microgrid transitions to the islanded mode to continue to provide service for customers. The microgrid may be required to operate in an islanded state for up to about two weeks at a time in a worst-case scenario that involves the loss of the National Grid bulk power source. However, most severe ice storms and other types of catastrophic outage events would typically be of significantly shorter duration, ranging from many hours up to a few days.

The microgrid transition from grid-parallel to islanded status is not intended to provide a seamless transfer in the event the bulk power supply is lost. “Seamless” in power quality terminology means that the 60 Hz waveform has no noticeable load disrupting waveform characteristics present during the transition. Such a feature would require greater cost and complexity and is not deemed necessary in this case due to the nature of the loads present. The objective of the proposed microgrid is to provide “backup generation grade power” and not “uninterruptible power supply (UPS) grade power” to those loads. Any critical functions of a specific portion of the customer load on the microgrid would, by necessity, have smaller local UPS systems running off the microgrid to ensure seamless power transition.

A seamless transition to islanded mode will be available for planned separations. For this transition, the microgrid generation and load must be matched prior to separation. However, during the transition to islanded mode due to an unplanned outage event, the transition will not be seamless, and the power interruptions are expected to range from several minutes to just over 20 minutes as the grid is automatically and/or manually reconfigured for islanded microgrid operation.

To be successful, the microgrid must operate reliably when connected to the bulk power system and when operating independently. The design goal for independent operation of the microgrid is to achieve an availability rate of 98%.

The microgrid must also be economically justifiable. The overall microgrid design focuses on improving the resiliency of the local area, and the benefits of the project have been assessed. Both economic and social benefits were evaluated during both normal operation and resiliency events. These evaluations inform design choices to achieve the best possible benefit-cost scenario.

This report contains the full study results, including sections on generation needs, the steady-state performance of the distribution system, fault performance and fault isolation, dynamic system performance, microgrid benefits and costs, reliability, and demand response.

2 Load and Supply Study

An initial step in the project was to conduct a needs assessment for the Potsdam Microgrid. The work presented in this section includes the following:

- The development of an overall rationale for a resilient microgrid in the Potsdam community
- Identification of critical service providers with potential to be connected to the microgrid
- Development of an initial system diagram for connecting these entities
- Completion of a survey of these entities, identifying loads, generation, and needs
- Identification of new generation needs and generation options
- Conducting an economic study of the microgrid generation and ranking new generation options

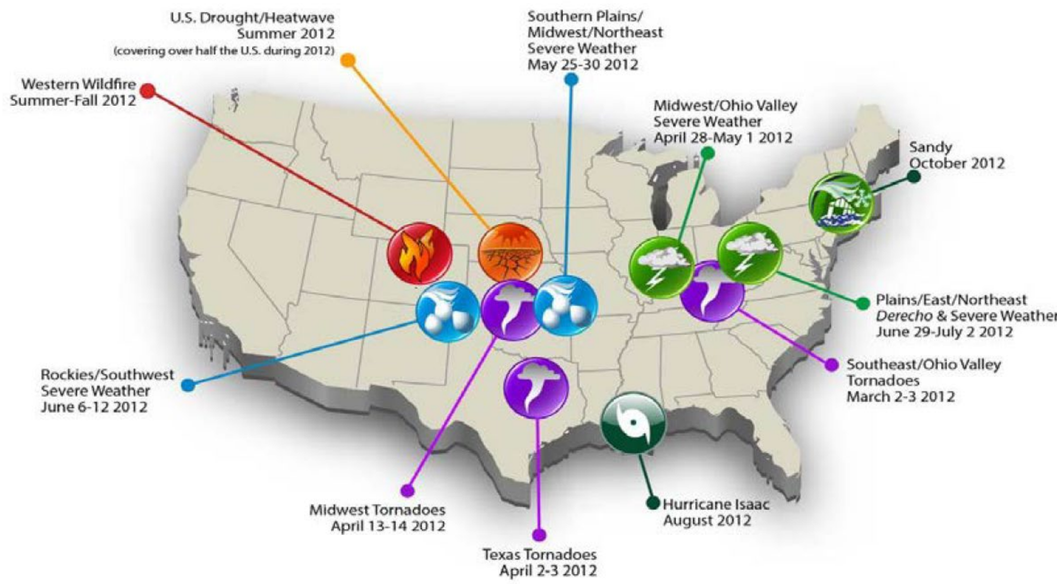
2.1 Project Background

2.1.1 Grid Resiliency and Need for Microgrids

Extreme weather and other natural disasters can threaten lives, disable communities, disrupt economic activities, and damage electric utilities' generation, transmission and distribution infrastructure. According to the United States Department of Energy (DOE), severe weather, such as thunderstorms, hurricanes and blizzards, has been the cause of 58 percent of outages observed since 2002 and the cause of 87 percent of outages affecting 50,000 or more customers. Over the last two years, the State of New York has experienced several unprecedented weather events, including Hurricane Irene, the October 2011 snow storm and Superstorm Sandy in 2012, which caused significant damage across the State and led to costs of well over a billion dollars (Figure 1). According to most experts, the frequency and intensity of extreme weather events is expected to increase, even as utilities struggle with physical, fiscal, and resource constraints, increased regulatory scrutiny, and rising expectations for performance.

Figure 1. Billion Dollar Weather and Climate Disasters in 2012

Source: National Oceanic and Atmospheric Administration (NOAA)



In June 2011, President Obama released "A Policy Framework for the 21st Century Grid" which set out a four-pillared strategy for modernizing the electric grid. The initiative directed billions of dollars toward investments in 21st century smart grid technologies focused on increasing the grid's efficiency, reliability, and resilience to make it less vulnerable to weather-related outages and reducing the time to power restoration after an outage occurs. In August 2013, the Executive Office of the President issued a report titled "Economic Benefits of Increasing Electric Grid Resilience to Weather Outages." That report estimates the annual cost of power outages caused by severe weather between 2003 and 2012 and describes various strategies for modernizing the grid and increasing grid resilience. One such strategy is to increase system flexibility and robustness by employing microgrids. A microgrid is a small, self-sustaining electric grid with its own generation resources and internal interconnected loads that may or may not be connected to the larger "macrogrid."

Impacted by several weather events, the State of Connecticut has already developed policies that position microgrids as a central element in resilient energy supply. Connecticut's microgrid strategy aims to keep the power on at facilities like hospitals, sewage treatment plants and prisons during severe weather events. New Jersey also has a plan for making its grid resilient and is currently focused on its transit system, which is the third largest in the nation, transporting 900,000 passengers a day. The New Jersey transit system is also a major evacuation route for Manhattan. The microgrid will have more than 50 megawatts (MW) of power, consisting of smart grid technologies and distributed energy resources, such as backup generators, small wind and solar, and energy storage. GE Energy Consulting has recently completed a project to review the storm preparedness plans of the electric distribution companies in New Jersey and recommend options for improving grid resiliency.

New York State has identified a critical need for improving the State's emergency preparedness and response capabilities. A key aspect of this effort is hardening the energy infrastructure. NYSERDA has taken the leadership position in studying the impact of climate changes statewide. A report of findings from a NYSERDA study—Responding to Climate Change in New York State (ClimAID)—is posted on the NYSERDA website.[1] A report by the Moreland Commission and the City of New York on utility storm preparation and response is also available. [2]

NYSERDA, New York State Department of Public Service (DPS), and New York State Division of Homeland Security and Emergency Services (DHSES) have worked collaboratively to assess how microgrids can be used in New York State to support mission critical operations during severe weather events. GE Energy Consulting contributed to the recent report by the agency group, evaluating the feasibility of microgrids at five sites in different locations within New York State, each site housing clusters of critical public facilities.

The North Country of Upstate New York has seen its share of devastating weather events. Because of its latitude and proximity to the Great Lakes, and Lake Ontario in particular, ice storms and major snow events occur with greater regularity than in other parts of the National Grid's service territory. Although the worst events are winter-based, the area is prone to other extreme occurrences, including microbursts and excessive rain with associated widespread flooding. The Village of Potsdam is the home of Clarkson University, SUNY Potsdam, Canton-Potsdam Hospital, and National Grid's Potsdam Service Center. All these entities have proven critical to the restoration of services after emergency events in the North.

Country. Clarkson President Tony Collins serves as a member of the Moreland Commission on Utility Storm Preparation and Response and has been directly involved in defining the need for improving the disaster response capability throughout the State. This proposed design for a resilient microgrid in Potsdam will address a critical aspect of this need.

The project team has performed the following principal tasks in the initial phase of this study:

- Collected detailed relevant data on site characteristics, existing power supply, and electric loads
- Performed load and supply analysis using the Distributed Energy Resources Customer Adoption Model (DER-CAM) to determine an economic mix of generation resources required by the resilient microgrid

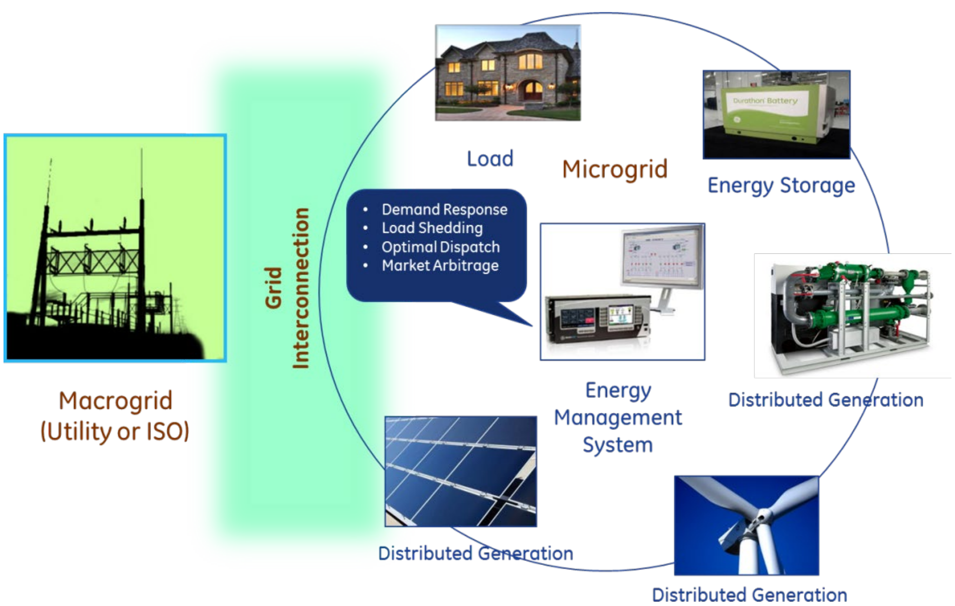
This section provides documentation of the Load and Supply Analysis, describing the approach and methodology, summary of key findings, and the study recommendations.

2.1.2 Definitions of a Microgrid

Current microgrid definitions include:

- New York's Microgrid Study Team has defined a "microgrid" as "a group of interconnected loads and distributed energy resources that form a single controllable entity capable of operating continuously in both grid-connected and islanded mode"
- NYSERDA provides the following definition: "The term 'microgrid' shall mean a group of interconnected loads and distributed energy resources that form a single controllable entity capable of operating continuously in both grid-connected and islanded mode to support mission critical loads. Critical loads are deemed essential services that are required for public safety and health. The type of microgrid configurations, incorporating various distributed generation (DG) technologies including but not limited to, combined heat and power, renewable and energy storage that could optimally support mission critical services for extended grid outages greater than one week"

Figure 2. Components of a Microgrid



2.1.3 Study Objectives

In responding to the above needs, NYSERDA sought a study to identify options to strengthen the resiliency of the electric distribution infrastructure that serves New York State. GE Energy Consulting[3] was engaged to pursue this portion of the study.

2.2 Potsdam Microgrid Description

The Potsdam Microgrid is being designed and developed as a resilient microgrid. It will provide select entities within the village of Potsdam continuity of power in the event of a loss of the main electrical grid during extreme weather conditions. The following entities within the village of Potsdam are under consideration for inclusion in the microgrid:

- Clarkson University Campus
- SUNY Potsdam Campus
- Stewarts Convenience Store and Gas Station
- Kinney Drugs
- Village of Potsdam Water Treatment Plant
- National Grid Service Center
- IGA Grocery Store
- Village of Potsdam Civic Center and Village Offices (including Police and Fire stations)
- Canton-Potsdam Hospital
- Village of Potsdam Sewage Treatment Plant
- Potsdam High School

In addition to selected existing fossil fuel-based backup generators, the following three existing renewable energy resources, one solar, and two hydro plants will also be included in the design of the microgrid:

- The Clarkson University Photovoltaic (PV) Array
- West Hydropower Dam
- East Hydropower Dam

At the load and supply analysis phase of the project, the data for the National Grid Service Center was not complete and is therefore not represented in the load and supply analysis work. However, the team included it in the next phase of microgrid design.

The need for additional least-cost supply and demand side resources is determined through a Load and Supply Analysis using the DER-CAM model.

2.2.1 Potsdam Microgrid Electric Network

The Potsdam Microgrid design will include a new underground primary distribution loop for power and communications, interconnecting all involved microgrid facilities, including all the critical loads and existing and new generation resources. National Grid will perform design and specification work for the underground power and communications systems and will specify power system equipment and interconnect to overhead distribution.

The loop will connect the critical loads in the village and will connect to National Grid's overhead primary distribution at three points. When islanded operation is required, the underground system will separate from the overhead to carry only the connected emergency service providers. This underground loop will provide the necessary reliability and integrity of a primary distribution system required of the microgrid.

Figures 3 to 5 show the preliminary diagram of the existing electrical network and the proposed microgrid and interconnection details.

Figure 3. Existing Electrical Network (Preliminary Representation)

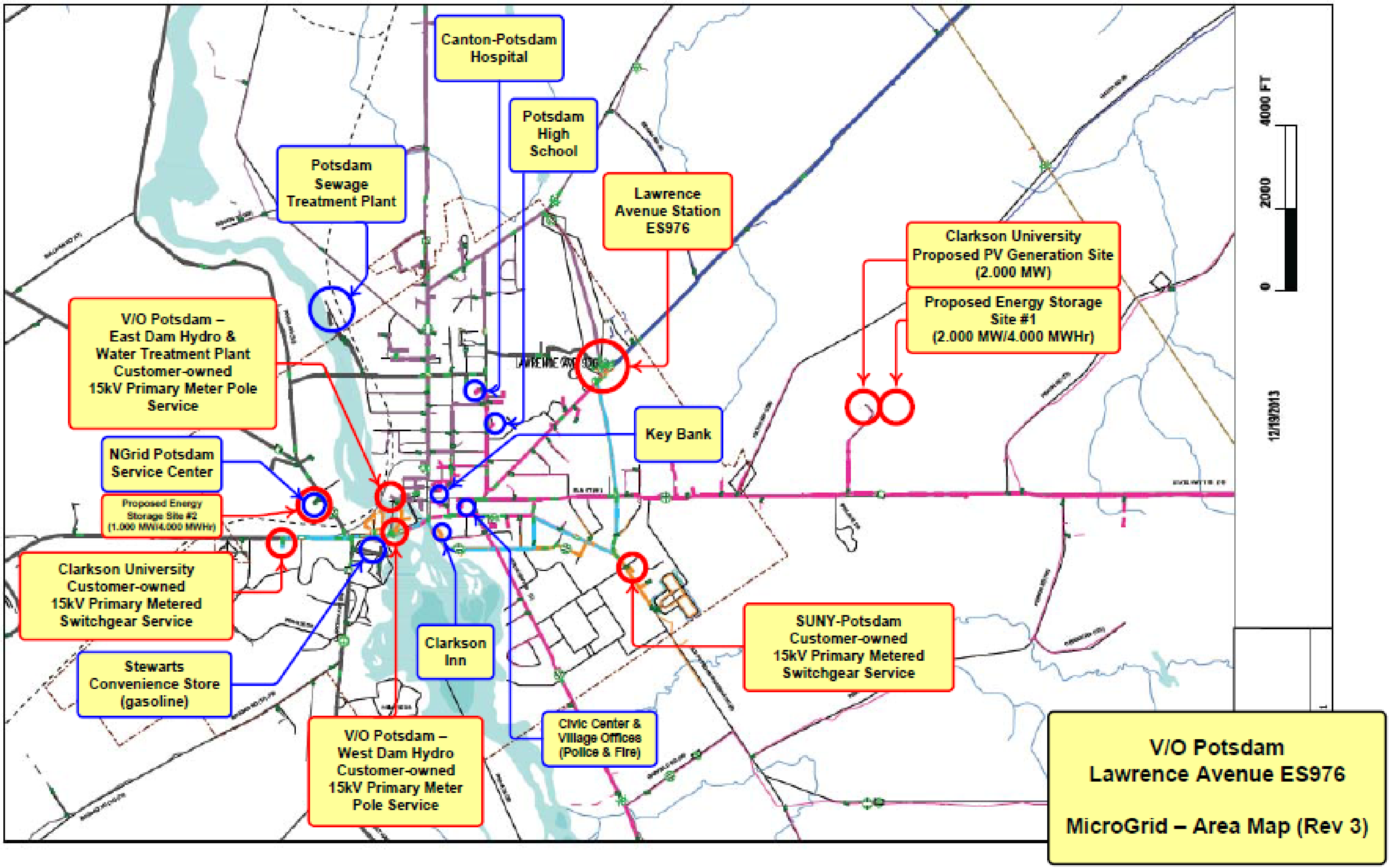


Figure 4. Preliminary Microgrid One-Line Diagram (Preliminary Representation)

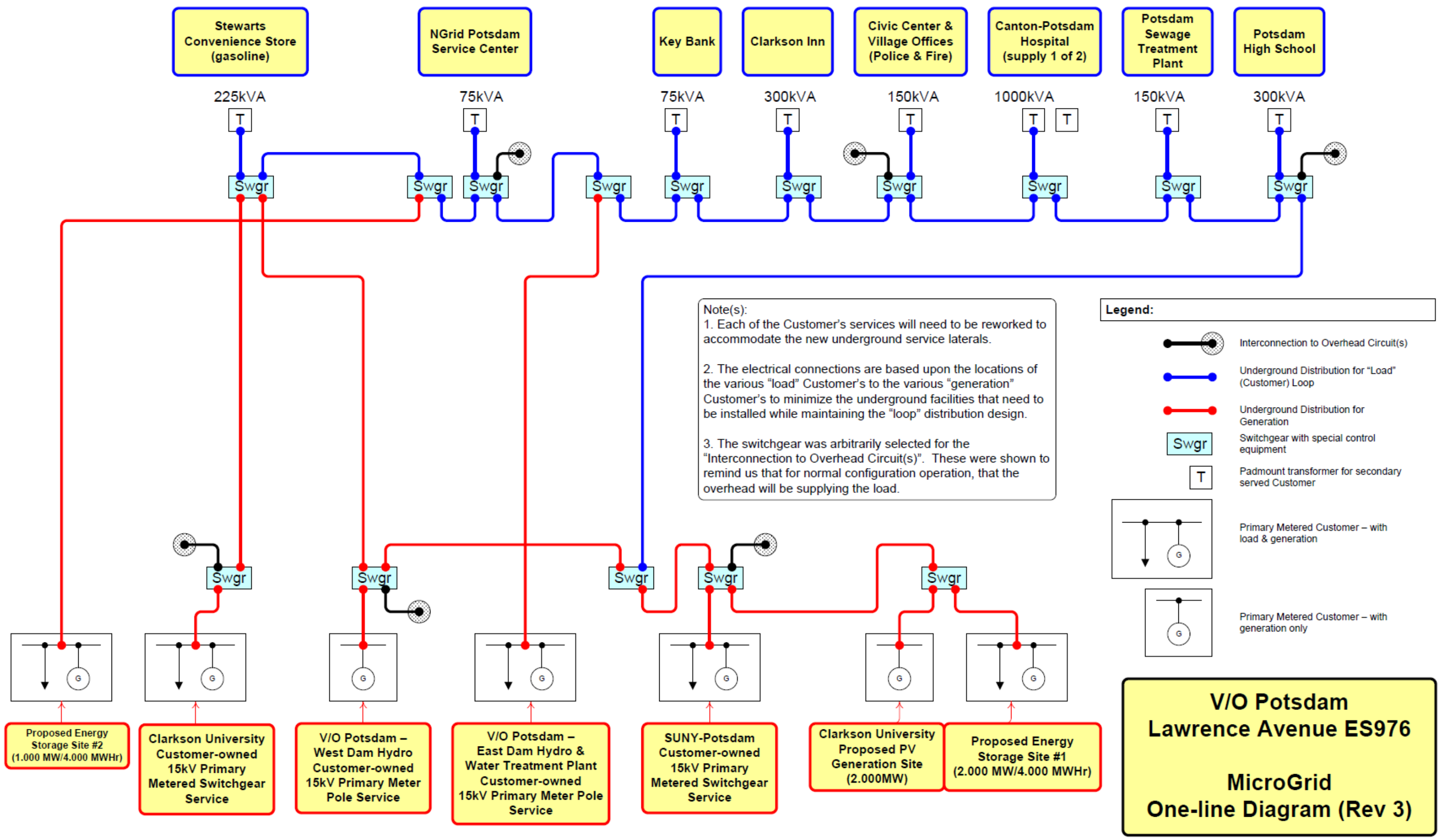
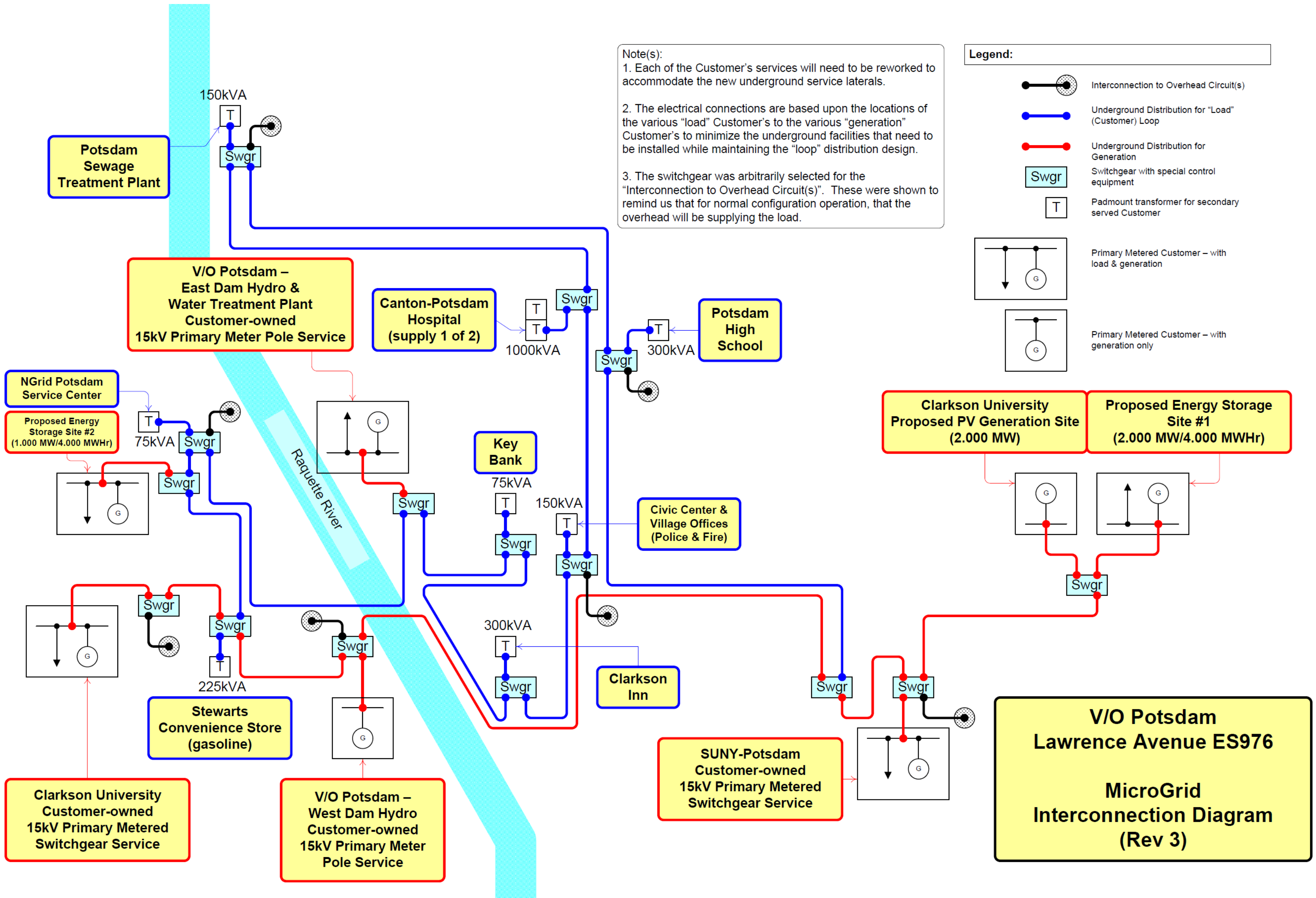


Figure 5. Potsdam Microgrid Interconnection Diagram (Preliminary Representation)



2.3 Feasibility Study Methodology

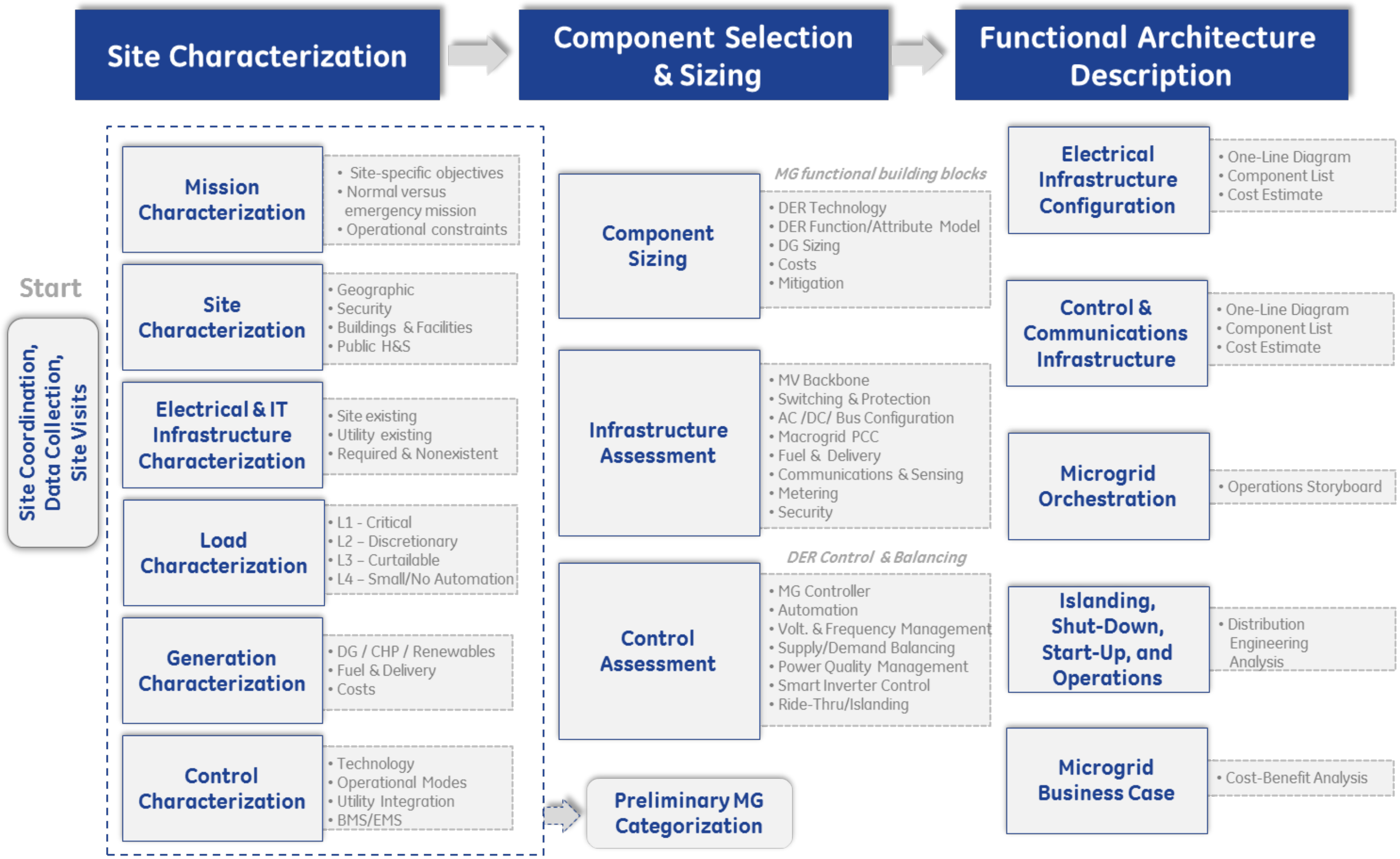
2.3.1 Microgrid Configurations

Microgrids can be categorized across several classes of size and configuration. As the scale of the different microgrid classes grows, the grids increase in power capacity and include increasingly more grid-connection functions that require more sophisticated control and management platforms. The different microgrid classes are categorized in the following list and use criteria from three important feature sets:

- Capacity: Inherent load demand, generation types and scale, self-sustainability timelines, etc.
- Grid Connection Criteria: Whether the microgrid is grid connected and what grid-connection features are required (e.g., stand-alone microgrid, grid connected with island/black-start features, connected with utility control interoperability, connected with dispatch ability and support for ancillary services or market interfaces, new or existing infrastructure requirements, security requirement, etc.).
- Management, Control, and System Attributes: Microgrid control functions and modes, sensors and building management systems, fuel delivery requirements, load classification, load prioritization and load shedding modes, reliability requirements, public health and safety requirements, maintenance, testing, hardening, and redundancy.

Figure 6 provides the general process for microgrid assessment and the task workflow that the GE team followed.

Figure 6. Microgrid Assessment and Task Workflow



2.3.2 Microgrid Reference Architecture

Grid modernization projects have become increasingly more sophisticated and include multiple technologies from both the electrical and information technology domains. Grid management systems can include numerous interacting components, representing core generation and distribution functions, which address a variety of dynamic load types and grid conditions that are all connected and monitored with advanced sensing, control, and communications technologies. Developing an intricate and integrated grid management system of this type requires the application of system architecture-based methods and design processes to ensure a robust assessment of complex operational objectives and a methodical decomposition of a system's technical requirements into an integrated suite of technology components.

The microgrid assessment for the New York State locations required the project team to consider operational objectives that stem from the core technical requirements of power generation, critical load, and electrical distribution infrastructure. The locations operate at different supply and demand scales, each with a variety of critical load characteristics and specific geographic and physical infrastructure constraints. These factors combine to create unique characteristics of resiliency during contingency periods that may trigger isolation from the macrogrid and operation of microgrid components. The GE team applied its Microgrid Reference Architecture to ensure an optimized assessment and configuration of an individual microgrid design for each of the sites. Using the Microgrid Reference Architecture and supporting systems engineering processes, the approach provides a reasonably optimized design at the component level (e.g., Generation/Load/Storage/Electrical/IT) and captures economies of scale from the reuse of common operational processes across the individual sites. The resulting microgrids, if implemented, should also offer efficiencies from operational coordination with the broader grid.

GE's unique approach incorporates a multifaceted, systems-level perspective when designing the microgrid configuration. This includes methods for selecting the individual components and cross-ranking and weighting their functional and performance attributes. The Microgrid Reference Architecture provides constructs and analysis process flows for guiding design activities, including optimally selecting scale and technology type of generation components, managing cost efficiency by balancing the application of redundancy and hardening, and defining a weighted set of metrics used to classify and rank the criticality of loads.

Within the microgrid system design process, multiple site requirements and operational objectives are assessed at multiple levels. First, requirements and system functions are correlated and understood at the enterprise level as well as the site level to ensure an optimized site configuration that is also “grid-aware.” Taking this perspective allows the design to consider the grid-level macro operational objectives and inherent grid-infrastructure constraints and effects, while optimally addressing a site’s critical performance, sustainability, infrastructure, and cost attributes.

Next, using the Microgrid Reference Architecture, the individual site-level functional and performance requirements and unique physical infrastructure constraints are organized as a single, system-level microgrid platform. In this step, the functional and performance requirements are allocated to the component-level constructs defined in the Microgrid Reference Architecture. Through this decomposition process, the functional and performance requirements are assigned across an optimized set of Generation/Load/Storage/Electrical/IT components and specifically sized and configured for an individual site.

Finally, within the context of each site and specific microgrid system architecture decomposition, the individual microgrid components and their specific function/performance/benefit/cost aspects are identified. This systems-level and top-down methodology to the microgrid architecture and component design is layered across all the feasibility assessment activities in the study tasks.

2.3.3 Project Questionnaire

The project team performed a microgrid feasibility study for each site that included the following steps.

Discovery and Data Collection:

- The team distributed a questionnaire to representatives of each facility within the microgrid to collect information that would help with characterization of each site.
- The team visited each site and met with facility representatives and the National Grid representative.
- The team made additional contacts with each site representative who provided additional site information.

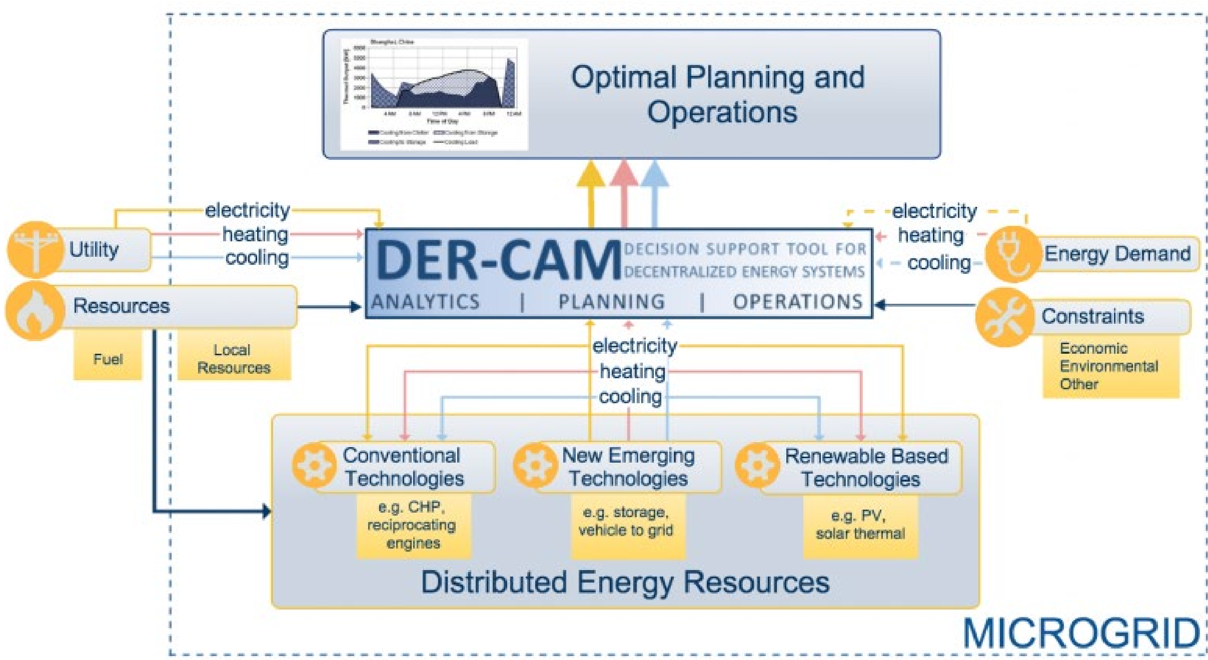
2.3.4 Microgrid System Simulation Model

GE performed a detailed supply and demand study for the Potsdam Microgrid using DER-CAM[4] (Figure 7).

DER-CAM is an economic and environmental model of customer DER adoption. This model has been in development at Lawrence Berkeley National Laboratory (LBNL) since 2000 under funding from the DOE. The objective of the model is to minimize the cost of operating on-site DG and combined heat and power (CHP) systems, either for individual customer sites or a microgrid.

GE Energy Consulting is a partner with LBNL in utilizing and testing the DER-CAM and providing feedback for further improvement of the model.

Figure 7. Microgrid Load and Supply Analysis: DER-CAM Schematic



2.3.5 Modeling Assumptions and Data

The modeling task included the following activities.

Modeled dispatch of the system's power sources to serve the primary load at the least total cost at each time step, within system constraints:

- Modeled cost includes capital costs, fixed operations and maintenance (FOM) costs, fuel, and variable operation and maintenance (VOM).
- Balance of energy calculations were performed across the load profile, generation alternatives, load curtailment, and other scenarios.

2.3.6 Electric Load Profiles

The DER-CAM model accepts load data in the form of a 12 x 24 (12 months by 24 hours) table. Each row represents a typical day in the month. Hour one of month one can be either average of all the hour one loads in the month, averaged across the days, or the maximum load at hour one across all the days of the month.

Since the Potsdam Microgrid should be able to operate in islanded mode for at least two weeks of the year, the team decided to represent the maximum load in each hour instead of the average load.

The load data was defined for the following day types:

- Weekdays (interconnected mode)
- Weekends (interconnected mode)
- Emergency weekdays (islanded mode)
- Emergency weekends (islanded mode)

In addition to supply-side resources, the modeling also considered potential demand-side resources in the form of load curtailment, such as 2,000 kW across a defined number of hours in the year.

The following facilities provided actual/historical hourly load covering almost a year of electricity consumption. Some adjustments were made to cover the gaps in the data.

- Clarkson University
- SUNY Potsdam
- Potsdam Canton Hospital
- Water Treatment Plant

The following facilities provided monthly billing statements.

- Sewage Treatment Plant
- Potsdam Central School
- IGA Grocery
- Stewart's Shop and Gas Station
- Kinney Drugs
- Potsdam Civic Center (Town Hall and Fire Station)

The resulting hourly electric load of the Potsdam Microgrid was adjusted or reduced by subtracting the hourly generation from the following non-thermal generation within the Potsdam Microgrid:

- Clarkson PV Plant
- East Dam (hydropower plant)
- West Dam (hydropower plant)

For the facilities with monthly statements only, the project team accessed the available DER-CAM database to select example daily-load profiles (for similar facilities) and develop the 12 x 24 load tables. The weekday and weekend load net electric load profiles are shown in Figures 8 to 9. The same profiles were used to represent the emergency weekday and emergency weekend profiles.

A following section will describe the process used to develop the PV plant hourly load profile. Hourly generation for the East and West Dams were available.

Figure 8. Potsdam Microgrid Weekday Electric Load Profile

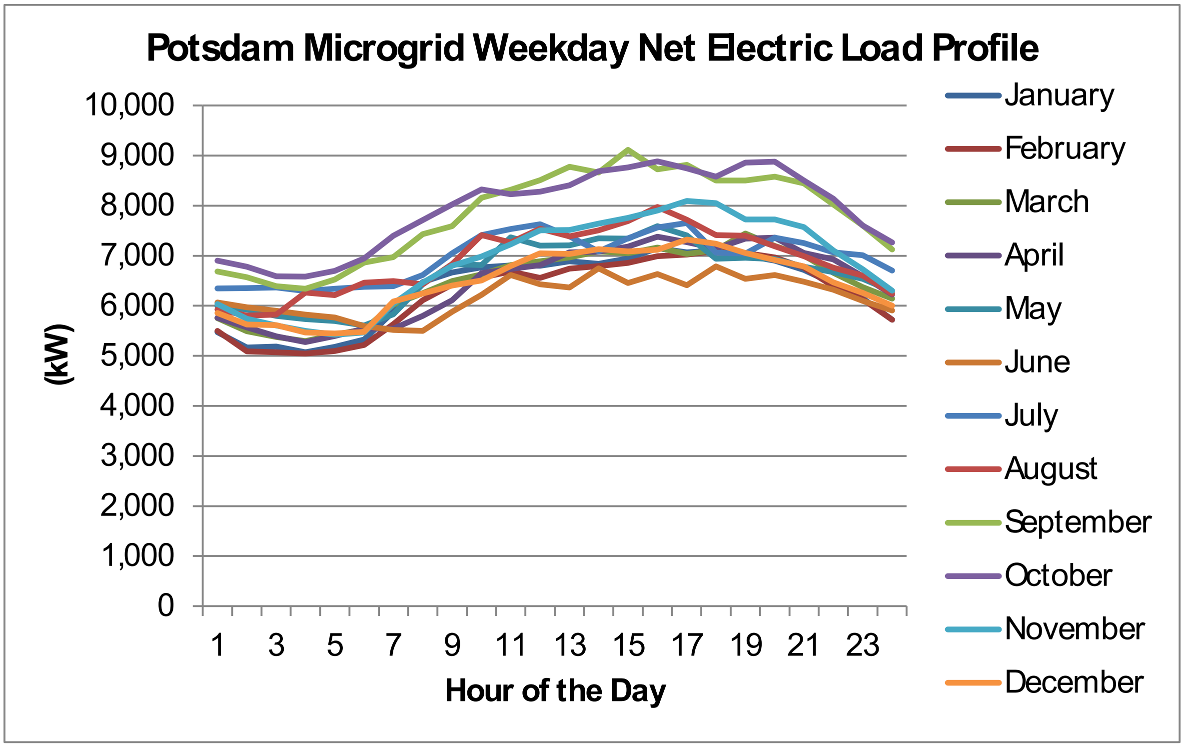
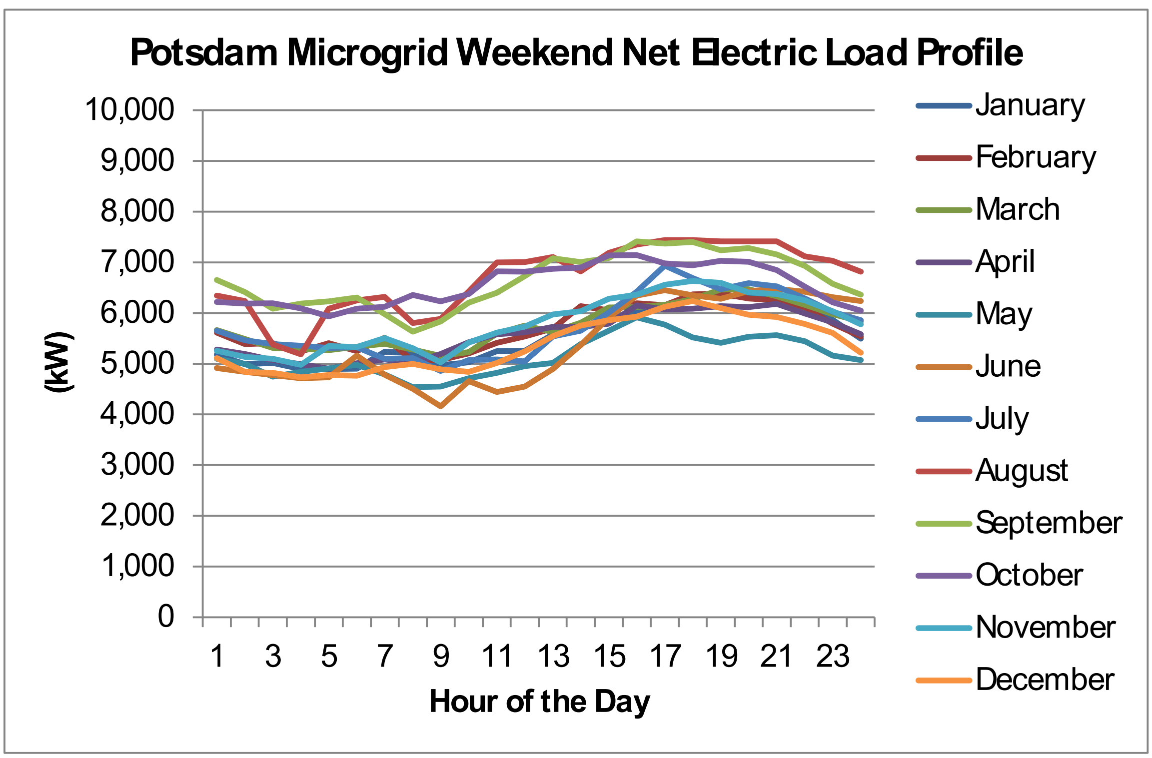


Figure 9. Potsdam Microgrid Weekend Electric Load Profile



2.3.7 Thermal Load Profile

Most of the facilities within the Potsdam Microgrid have existing systems that provide the thermal needs of those facilities.

The only facility that provided thermal load data was the Potsdam Central School in the form of monthly thermal load in units of therms. The team assumed that the Potsdam Central School could be a candidate for installation of a CHP system. The DER-CAM has the capability of including CHP in its analysis when thermal loads are also provided to the model.

A representative daily thermal load profile of a school in cold climates was used to define the 12 x 24 thermal profiles of the Potsdam Central School. Figures 10 to 13 depict the monthly and daily thermal load profiles of the Potsdam Central School.

Although the inclusion of a CHP to meet the thermal load of the Potsdam Central School was considered, the team determined that the small size of this thermal load did not justify consideration of a CHP in the microgrid. However, CHP would be an option to consider if other facilities in the microgrid, such as Clarkson University, considered replacing their existing boiler-based heating and hot water system with CHPs.

Figure 10. Potsdam Central School Monthly Thermal Load Profile (in units of Therm)

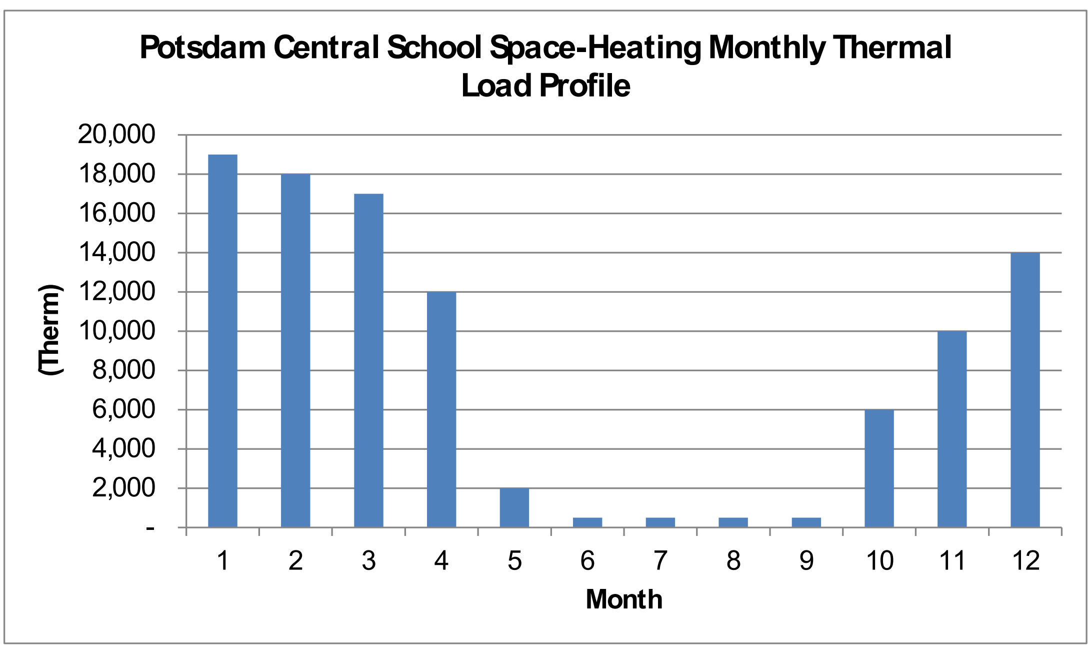


Figure 11. Potsdam Central School Monthly Thermal Load Profile (in units of kWh)

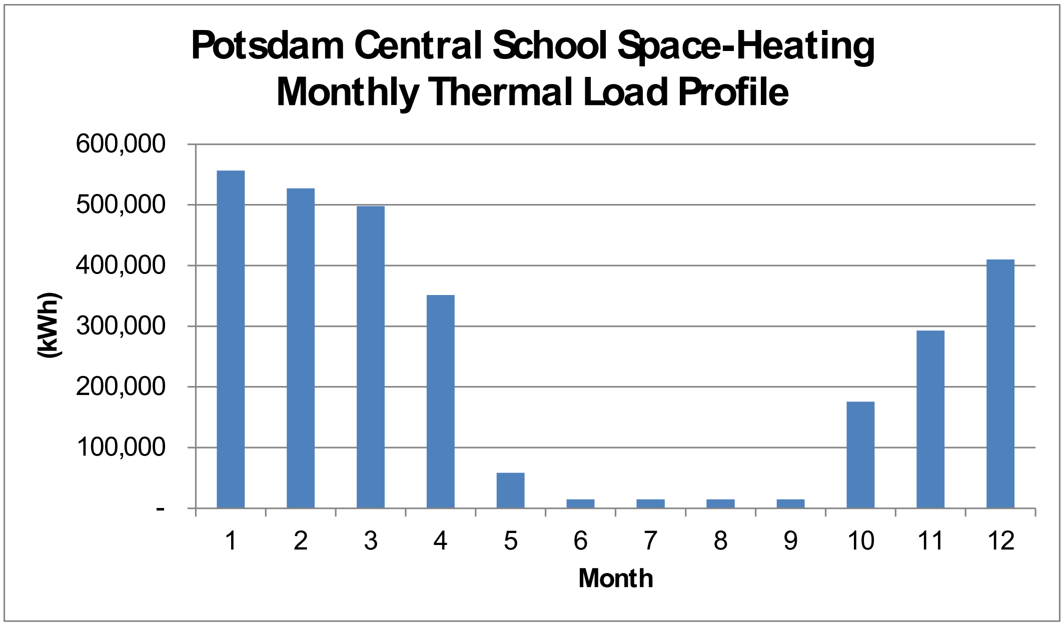


Figure 12. Potsdam Central School Weekday Daily Thermal Load Profile

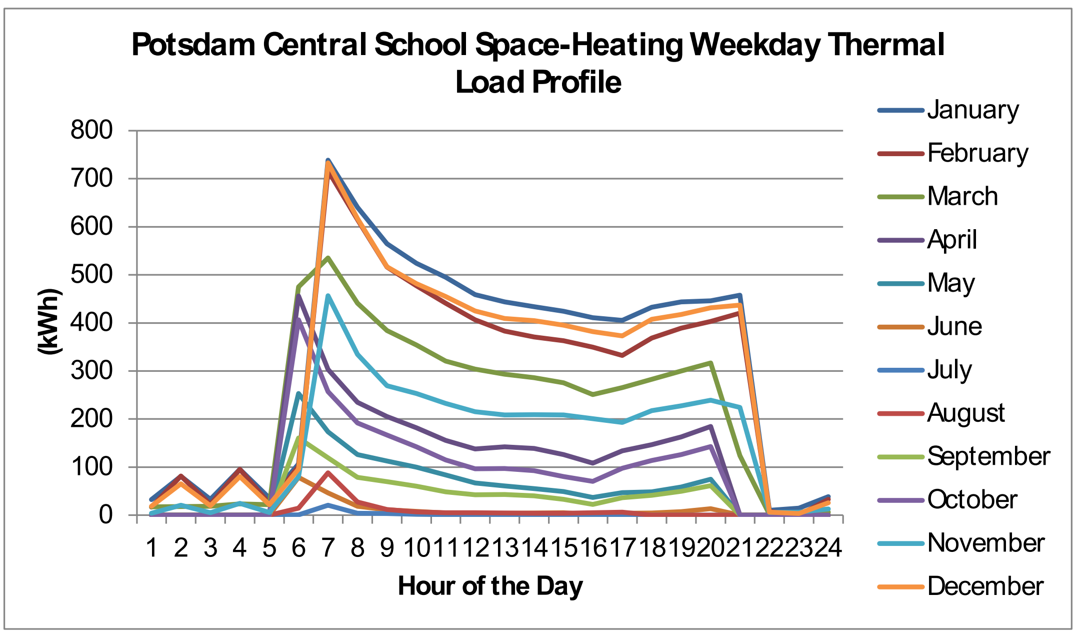
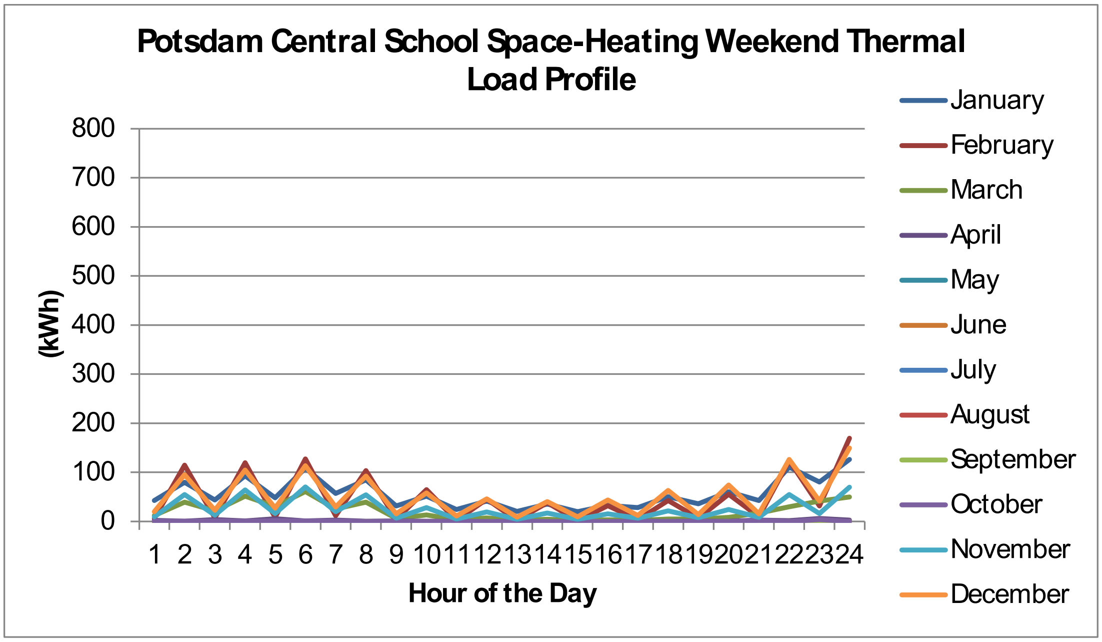


Figure 13. Potsdam Central School Weekend Daily Thermal Load Profile



2.3.8 Solar Generation

Clarkson University's 2000 kW nameplate PV plant started operation in December 2014 with only half of the solar panels producing electricity. At the start of the project, two months of actual power generation data were provided to the project team. During most of this period, only half of the project was online.

To generate a full year of data, the online PVWatts™ Calculator[5] developed by the National Renewable Energy Laboratory (NREL) was used to estimate the solar power generation at Potsdam. PVWatts™ uses the approximate location, module type, array type, and other information to estimate the monthly and hourly energy production of grid-connected PV energy. The solar station nearest to Potsdam, NY is in Massena, NY. The input assumptions used in the PVWatts™ model are summarized in Table 1.

Table 1. PVWatts™ Model Input Assumptions

PVWatts™ Input Assumptions	
Requested Location:	Potsdam, NY
Nearest Location with Solar Data:	Massena, NY
Latitude (degrees N):	44.93
Longitude (degrees W):	74.85
Elevation (m):	63
DC System Size (kW):	2000
Module Type:	Standard
Array Type:	Fixed (open rack)
Array Tilt (degrees):	45
Array Azimuth (degrees):	135
System Losses:	14%
Invert Efficiency:	96%
DC to AC Size Ratio:	1.1

AC = alternating current, DC = direct current

Results of the PVWatts™ model, based on the specified assumptions, are provided in Table 2.

Table 2. PVWatts™ Projection of Monthly Solar Generation

Month	Solar Radiation (kWh / m2 / day)	AC Energy (kWh)
January	2.57	144,877
February	3.54	175,920
March	4.33	234,713
April	4.88	248,606
May	5.00	258,776
June	5.64	273,618
July	5.60	278,584
August	4.95	243,720
September	4.11	200,293
October	3.22	166,301
November	2.12	109,588
December	1.95	107,878
Annual	3.99	2,442,874

In addition to the monthly results, PVWatts™ also produced a full year of hourly projections.

The actual two months of data from the Clarkson PV plant was used to adjust the PVWatts™ data using the ratio of the actual to the PVWatts™ projection.

The two months of actual operations were compared to the PVWatts™ projections (Table 3). The team assumed that after initial start-up, the Clarkson PV plant would operate with all its PV solar panels. Therefore, the actual observations were multiplied by a factor of two. The hourly PVWatts™ solar generation estimates were then multiplied by 0.94 to project the hourly Clarkson PV plant generation.

Table 3. Comparison of Two Months of PVWatts™ Generation to Actual Generation

	1/2 Actual (kWh)	Full Actual (kWh)	PVWatts ™ (kWh)	Actual / PVWatts™
MIN	0	0	1,066	0.00
AVG	1,919	3,837	4,077	0.94
MAX	8,005	16,010	8,524	1.88
SUM	118,948	237,896	252,755	**0.94**

2.3.9 Utility Rates and Fuel Prices

DER-CAM requires the electric and gas utility rates and DG natural gas and diesel fuel prices to determine the least-cost generation mix of the microgrid under both interconnected and islanded operational modes.

Tables 4 to 5 summarize the utility rate and fuel price assumptions used in the DER-CAM model. The values used are based on assumed National Grid rates applicable to medium to large commercial customers.

Applicable electric utility and supplier rates are:

- National Grid SC-3A (Large Commercial Customers, such as Clarkson University)
- National Grid SC-7 (Customers with internal distributed generation, such as SUNY Potsdam)

Our base case modeling assumption is that without any distributed generation in operation (and no outages) the SC-3A will be the applicable electric rate schedule. But with operational distributed generation and buy and sell with the larger grid, SC-7 would be the applicable electric rate schedule. The microgrid is assumed to be a primary class customer (2.2 to 15 kV).

Table 4. National Grid SC-3A Electric Rate Schedule

Service Classification	Monthly Customer Charge	Monthly Demand Charge	Miscellaneous Other Charges	Average On-Peak Hourly Supplier Price	Average Off-Peak Hourly Supplier Price	Daily On-Peak Demand Charge
	($)	($/kW-Month)	($/kWh)	($/kWh)	($/kWh)	($/kW-Day)
SC-3A	1,000.00	9.18	0.0200	0.0415	0.0284	N/A

Table 5. National Grid SC-7 Electric Rate Schedule

Service Classification	Monthly Customer Charge	Contract Demand Charge	Miscellaneous Other Charges	Average On-Peak Hourly Supplier Price	Average Off-Peak Hourly Supplier Price	Daily On-Peak Demand Charge
	($)	($/kW-Month)	($/kWh)	($/kWh)	($/kWh)	($/kW-Day)
SC-7	1,000.00	3.71	0.0200	0.0415	0.0284	0.2691

Natural gas prices are from Enbridge St. Lawrence Gas—PSC No.3 Gas, Service Classification No. 10, Distributed Generation—Non-Residential. Diesel prices are taken from the NYSERDA website[6].

Table 6 shows the price of natural gas is for the fuel used for operation of DG units fueled by natural gas, including any back-up generators, internal combustion/reciprocating engines, gas turbines, steam turbines, and CHP units.

The price of diesel is for fuel used for operation of backup generation units. Please note the almost 5 to 1 ratio of diesel price to natural gas price.

Table 6. Natural Gas and Diesel Prices

Fuel Category	Price	Price	Price
	NG ($/Therm) Diesel ($/Gallon)	($/kWh Equivalent)	($/MMBtu Equivalent)
NG - Summer DG Rate			
(April - October)			
Demand Charge	0.444200		
Commodity Charge	0.005090		
Effective Summer Rate	0.449290	0.015334	4.49
NG - Winter DG Rate			
(November - March)			
Demand Charge	0.444200		
Commodity Charge	0.006446		
Effective Summer Rate	0.450646	0.015380	4.51
Diesel	3.11	0.076344	22.37

DG, distributed generation; NG, natural gas.

2.3.10 Candidate Non-Renewable DG for Inclusion in the Microgrid

Table 7 lists the candidate new generation units considered for inclusion in the microgrid and modeled in DER-CAM. The main scenarios considered include only Gas Turbine (GT), Reciprocating Engine/ Internal Combustion Units (RE/IC) and CHP units driven by RE/IC units.

For comparison, Appendix C presents selected data on distributed generation characteristics that helped formulate our assumptions (but are not used directly).

In Table 7, the capital costs in dollars/kW are installed costs and include emission control systems. For instance, installed cost of a 2000 kW reciprocating engine is $800/kW. We have assumed an additional $300/kW in emissions control cost, leading to a total of $1,100/kW.

Table 7. List of Candidate New Thermal Units under Consideration

ID	Name	Type	Fuel	Maximum Capacity (kW)	Capital Cost ($/kW)	Fixed O&M Cost ($/kW-Year)	Variable O&M Cost ($/kWh)	Electrical Efficiency	Heat to Power Ratio	Availability	Start-Up Time
1	GT-NG-250	GT	NG	250	1200	10.0	0.013	0.24	0.00	93-96%	10 Mn - 1 hr
2	GT-NG-500	GT	NG	500	1100	15.0	0.012	0.28	0.00	93-96%	10 Mn - 1 hr
3	GT-NG-1000	GT	NG	1000	1000	20.0	0.011	0.32	0.00	93-96%	10 Mn - 1 hr
4	GT-NG-2000	GT	NG	2000	900	40.0	0.010	0.36	0.00	93-96%	10 Mn - 1 hr
5	RE-NG-250	RE/IC	NG	250	1400	10.0	0.023	0.27	0.00	96-98%	10 Sec
6	RE-NG-500	RE/IC	NG	500	1300	15.0	0.021	0.32	0.00	96-98%	10 Sec
7	RE-NG-1000	RE/IC	NG	1000	1200	20.0	0.019	0.36	0.00	96-98%	10 Sec
8	RE-NG-2000	RE/IC	NG	2000	1100	40.0	0.017	0.41	0.00	96-98%	10 Sec
9	RE-DS-250	RE/IC	Diesel	250	1400	10.0	0.023	0.27	0.00	96-98%	10 Sec
10	RE-DS-500	RE/IC	Diesel	500	1300	15.0	0.021	0.32	0.00	96-98%	10 Sec
11	RE-DS-1000	RE/IC	Diesel	1000	1200	20.0	0.019	0.36	0.00	96-98%	10 Sec
12	RE-DS-2000	RE/IC	Diesel	2000	1100	40.0	0.017	0.41	0.00	96-98%	10 Sec
13	CHP-RE-NG-250	CHP	NG	250	3200	10.0	0.023	0.27	1.96	96-98%	10 Sec
14	CHP-RE-NG-500	CHP	NG	500	3100	15.0	0.021	0.32	1.50	96-98%	10 Sec
15	CHP-RE-NG-1000	CHP	NG	1000	2700	20.0	0.019	0.36	1.22	96-98%	10 Sec
16	CHP-RE-NG-2000	CHP	NG	2000	2400	40.0	0.017	0.41	0.95	96-98%	10 Sec
17	CHP-RE-DS-250	CHP	Diesel	250	3200	10.0	0.023	0.27	1.96	96-98%	10 Sec
18	CHP-RE-DS-500	CHP	Diesel	500	3100	15.0	0.021	0.32	1.50	96-98%	10 Sec
19	CHP-RE-DS-1000	CHP	Diesel	1000	2700	20.0	0.019	0.36	1.22	96-98%	10 Sec
20	CHP-RE-DS-2000	CHP	Diesel	2000	2400	40.0	0.017	0.41	0.95	96-98%	10 Sec

CHP = combined heat and power, DS = diesel, GT = gas turbine, NG = natural gas, O&M = operations and maintenance, RE/IC = reciprocating engine/internal combustion engine

2.3.10.1 CHP Assumptions

The heat to power ratios of the CHP units are calculated assuming 80% total energy efficiency (i.e., combined electricity and thermal generation), based on the following relationship:

$$\text{Electrical Efficiency } X\ (1 + \text{Heat/Power Ratio}) = 80\%$$

Or

$$\text{Heat/Power Ratio} = (80\%/\text{Electrical Efficiency}) - 1$$

Because of their long start-up time, the GT units are not suitable for a resilient microgrid, as almost immediate start-up is required to enable smooth and uninterrupted transition from interconnected to islanded mode of operation. However, the GT units were kept in the model for future consideration of energy storage units that may close the gap in start-up time. Other unit types where not considered at this stage due to their high cost. These include microturbines and fuel cells.

2.3.11 Existing Thermal Generation

Table 8 lists the existing thermal generation units (i.e., backup generators) currently available in the facilities included in the microgrid.

Most of the existing units are stand-alone and used as backup generators for individual buildings within the facilities. The two CHP units at SUNY Potsdam are grid interconnected and participate in the New York Independent System Operator (NYISO) wholesale markets. Two units at Clarkson are also capable of grid-interconnected operation and are included in the microgrid-base generation.

The team decided that interconnecting the generators smaller than 250 kW and the diesel generators would be neither technically nor economically feasible. Hospital units were also excluded from interconnection to the microgrid because of the higher criticality of the hospital electric load. Existing backup generators that are excluded from interconnection to the microgrid network will still be part of the overall system but as stand-alone units that can operate as secondary back up to the microgrid. In Table 8, the highlighted rows are the existing generators selected to be integrated into the microgrid network.

Table 8. List of Existing Thermal Units

ID	Name	Type	Fuel	Maximum Capacity (kW)	Capital Cost ($/kW)	Fixed O&M Cost ($/kW-Year)	Variable O&M Cost ($/kWh)	Electrical Efficiency	Heat to Power Ratio	Availability	Start-Up Time
21	GEN Clarkson A	RE/IC	NG	290	0	11.0	0.023	0.26	0.00	96-98%	10 Sec
22	GEN Clarkson B	RE/IC	NG	195	0	10.0	0.025	0.24	0.00	96-98%	10 Sec
23	GEN Clarkson C	RE/IC	NG	370	0	13.0	0.022	0.27	0.00	96-98%	10 Sec
24	GEN Clarkson D Small NG	RE/IC	NG	211	0	10.0	0.024	0.25	0.00	96-98%	10 Sec
25	GEN Hospital B	RE/IC	Diesel	600	0	16.0	0.021	0.33	0.00	96-98%	10 Sec
26	GEN Hospital C	RE/IC	Diesel	60	0	10.0	0.028	0.21	0.00	96-98%	10 Sec
27	GEN SUNY CHP A	CHP	NG	1400	0	28.0	0.018	0.38	1.11	96-98%	10 Sec
28	GEN SUNY CHP B	CHP	NG	1400	0	28.0	0.018	0.38	1.11	96-98%	10 Sec
29	GEN SUNY Bowman Hall	RE/IC	Diesel	500	0	15.0	0.021	0.32	0.00	96-98%	10 Sec
30	GEN SUNY Portable Gen A	RE/IC	Diesel	350	0	12.0	0.022	0.27	0.00	96-98%	10 Sec
31	GEN SUNY Performing Art Center	RE/IC	Diesel	250	0	10.0	0.023	0.26	0.00	96-98%	10 Sec
32	GEN SUNY Portable Gen B	RE/IC	Diesel	230	0	10.0	0.024	0.25	0.00	96-98%	10 Sec
33	GEN SUNY Maxy Hall	RE/IC	Diesel	125	0	10.0	0.026	0.23	0.00	96-98%	10 Sec
34	GEN SUNY Kellas Hall	RE/IC	Diesel	100	0	10.0	0.027	0.22	0.00	96-98%	10 Sec
35	GEN SUNY Small NG	RE/IC	Diesel	280	0	10.0	0.023	0.26	0.00	96-98%	10 Sec
36	GEN SUNY Small DS	RE/IC	NG	40	0	10.0	0.029	0.20	0.00	96-98%	10 Sec
37	GEN VIL A	RE/IC	Diesel	60	0	10.0	0.028	0.21	0.00	96-98%	10 Sec
38	GEN VIL B	RE/IC	Diesel	500	0	15.0	0.021	0.32	0.00	96-98%	10 Sec
39	GEN VIL C	RE/IC	NG	125	0	10.0	0.026	0.23	0.00	96-98%	10 Sec
40	GEN VIL D	RE/IC	NG	40	0	10.0	0.029	0.20	0.00	96-98%	10 Sec
Total Existing Units										7126	kW
Total in Microgrid Base (Shaded – Natural Gas Units)										3460	kW
NG units less than 250 kW, diesel units, and hospital units are not included in the microgrid network—but will act as backup to the microgrid.										3666	kW

2.3.12 Fuel Accessibility

Based on historical experience, as communicated by facility managers, the team determined that natural gas would be readily available, without loss of accessibility or major drop in pressure, during emergencies. Furthermore, even if diesel fuel storage is limited to a handful of hours to days, the historical experience indicates that fuel trucks were always available during emergency conditions with trucks making regular rounds to refuel backup generators.

2.4 Load and Supply Analysis Modeling Results

2.4.1 Introduction

The DER-CAM was used to analyze many scenarios and sensitivities and compared them to a baseline scenario covering a full year.

The main metric for comparison was the annualized cost of operation of the microgrid.

The annualized cost includes the following:

- Annual utility power purchase cost (during interconnected mode of operation)
- Annualized capital cost of new dg units
- Annual total cost of fuel consumed to operate DG units
- Annual total FOM cost of DG operations
- Annual total VOM cost of DG operations

Modeling also considered CHP options, but the small size of the Potsdam Central School thermal load did not justify inclusion of CHP. Cost of fuel to meet the thermal load of the school was therefore ignored.

The baseline scenario assumed no outages, no load curtailments, and no internal generation (whether existing or new) to meet the annual load of the microgrid. The baseline scenario assumes that all electricity is purchased, and all Potsdam Central School thermal needs are met by boiler thermal generation with purchased natural gas (which is at a different rate compared to the natural gas used by distributed generation and CHP).

The baseline does not represent the existing mode of operation, since—at least in the case of SUNY Potsdam—the CHP units are currently participating in the NYISO wholesale market and dispatched accordingly.

The modeling also compared the total annual carbon dioxide (CO_2) emissions to meet the microgrid load, which includes CO_2 emissions of the purchased utility power and the CO_2 emissions of the internal microgrid generation. For the utility purchased power, an average grid-wide CO_2 emission in tons/kWh was assumed.

However, it should be noted that CO_2 emission values are subject to change based on future planned detailed GE Multi-Area Production Simulation (MAPS) modeling of the NYISO with and without the microgrid.

Each scenario and sensitivity results in a minimum cost configuration in terms of the recommended new DG units by type, size, and numbers. In addition, for each scenario, the model provided the following information (not a complete list):

- DG electrical generation kWh
- DG thermal generation kWh
- Utility purchased power kWh
- Annualized cost of capital
- Cost of DG operations (fuel, FOM, and VOM)
- Cost of purchased electricity from the utility (energy and demand charges)
- Cost of fuel purchased to meet thermal load, excluding CHP operations based on the natural gas prices applied to non-DG-based consumption
- CO_2 emissions

2.4.2 Scenarios and Sensitivities Considered

Table 9 lists the scenarios and sensitivities evaluated using DER-CAM. The numbering system is used to track past, on-going, and future multiple-model runs.

Table 9. List of Scenarios and Sensitivities

51A	Baseline: No Outage, No Load Curtailment, Electric Service Rate: SC-3A, Utility Purchase Only (i.e., other than existing PV and Hydro generation, no other internal generation)
52A	2 Weeks of Outage, 2 Weeks of 2000 kW Load Curtailment, Electric Service Rate: SC-3A, All Existing Generation Available, No New Distributed Generation
53A	Same as 52A, Exception: Only Partial Existing Generation Available, Candidate New Distributed Generation <= 2000 kW, WACC set at 8.3%, 15 Year Lifetime of New DG
54A	Based on 53A, Exception: with Electric Service Rate SC-7
55A	Based on 54A, Exception: New DG Size Limit set to 1000 kW
56A	Based on 54A, Exception: $300/kW added to Capital Costs
57A	Based on 54A, Exception: $600/kW added to Capital Costs
58A	Based on 54A, Exception: WACC set at 5.0%
59A	Based on 54A, Exception: WACC set at 12.0%
60A	Based on 54A, Exception: 20% Higher Eclectic Supply Prices
61A	Based on 54A, Exception: 20% Higher Natural Gas Prices

2.4.3 Least-Cost Selection of Additional Microgrid Generation

Results of the DER-CAM modeling are summarized in Table 10.

Scenario 51A assumed no internal generation and no outages and, other than existing solar and hydro generation, no additional internal generation to be relied on. Therefore, the net load (load minus solar and hydro generation) is met by purchased utility power.

Scenario 52A accounts for two weeks of larger grid outage and assumes availability of two weeks of 2000 kW load curtailment. It also allows utilization of all renewable and non-renewable internal generation. Two weeks in September was assumed to be the outage period, simply because September is a high-load month.

Scenarios 53A and 54A represent the same microgrid features, except for the electric rate schedule applied to the microgrid, and are presented next to each other to compare the impact of the SC-3A versus SC-7 rate schedules on operation and costs as well as CO_2 emissions. The base scenarios assume an 8.3% weighted average cost of capital (WACC) and a 15-year lifetime. The maximum size of the DG considered is limited to 2000 kW. However, scenario 54A is more realistic since the microgrid will more likely be subject to rate SC-7 instead of SC-3A when operational—if the current rate structures remain in effect. Therefore, scenario 54A represents the recommended new DG to be installed (i.e., two natural gas-based reciprocating engines of 2000 kW each; sizes are approximate since actual units may not be available in exactly 2000 kW sizes). Based on discussion with the microgrid stakeholders, the team determined that one unit will be located at the Clarkson University Campus and the other unit at the SUNY Potsdam Campus.

Scenario 55A considers the annualized costs and CO_2 emissions based on a maximum DG size limited to 1000 kW. As shown in Table 10, DER-CAM selects four units of 1000 kW each. Costs and emission are higher compared to scenario 54A because smaller units cost more and are less efficient. However, upon further analysis, four units of 1000 kW each may be preferred over two units of 2000 kW each in the microgrid, given the overall reliability of four smaller units versus two larger units.

Scenarios 56A and 57A are sensitivities that consider higher capital costs for the new generation compared to scenario 54A, namely an additional \$300/kW and \$600/kW, respectively.

Scenarios 58A and 59A are sensitivities that consider a lower (i.e., 5%) and a higher (i.e., 12%) WACC compared to scenario 54A.

Scenarios 60A and 61A are sensitivities that consider 20% higher electric supply prices and 20% higher natural gas prices relative to scenario 54A.

It should be noted that additional scenarios and sensitivities will be run throughout the project to provide a full spectrum of results. We may also consider additional Base Scenarios for comparison. For instance, Scenarios 60A and 61A should be benchmarked and compared to a base case of utility purchased power only—but similar increases in electric and gas supply prices—instead of being compared to scenario 51A, which has a different electric and gas price assumptions.

Table 10. Summary of Results for Subset of Scenarios Most Representative of the Eventual Microgrid

Scenario	Description	New DG Capacity (kW)	Number of New DG Units	Utility Purchase (MWh)	DG Generation (MWh)	Annualized Cost ($K)	Annual CO2 Emissions (Tons)	Annualized Cost Change from Baseline ($K)	Annual CO2 Emissions Change from Baseline (Tons)
51A	Baseline: No Outage + No DR Electric Service Rate: SC-3A Utility Purchase Only - No Internal Generation Updated Util Rates + Cap Costs $300/kW More	0	0	57,001	0	4,247	34,146	0	0
52A	2 Wk Outage + 2 Wk 2000 kW DR Electric Service Rate: SC-3A All Existing DG + No New DG	0	0	33,817	22,513	4,038	31,835	-209	-2,311
53A	2 Wk Outage + 2 Wk 2000 kW DR Electric Service Rate: SC-3A Partial Existing DG + New DG <= 2000 kW WACC set at 8.3%	2000	2	3,801	52,720	3,946	26,877	-301	-7,269
54A	Based on 53A Exception: with Electric Service Rate SC-7	2000	2	26,994	29,527	4,236	30,112	-10	-4,033
55A	Based on 54A Exception: New DG Size Limit set to 1000 kW	1000	4	27,209	29,120	4,321	31,058	74	-3,088
56A	Based on 54A Exception: $300/kW added to Capital Costs	2000	2	26,915	29,415	4,348	30,017	101	-4,129
57A	Based on 54A Exception: $600/kW added to Capital Costs	2000	2	26,994	29,527	4,486	30,112	240	-4,033
58A	Based on 54A Exception: WACC set at 5.0%	2000	2	26,994	29,527	4,131	30,112	-116	-4,033
59A	Based on 54A Exception: WACC set at 12.0%	2000	2	26,915	29,415	4,354	30,017	107	-4,129
60A	Based on 54A Exception: 20% Higher Eclectic Supply Prices	2000	2	1,149	55,373	4,334	26,679	88	-7,467
61A	Based on 54A Exception: 20% Higher Natural Gas Prices	2000	2	27,344	28,985	4,455	30,041	208	-4,104

2.5 Load and Supply Study Conclusions

2.5.1 Recommended Microgrid Generation Configuration

Based on the results of the Load and Supply Analysis using DER-CAM, the recommended microgrid has the following features:

- Of the total 7,126 kW of existing fossil-fuel fired generation and backup units, 3460 kW are to be integrated into the microgrid network.
- NG units less than 250 kW, diesel units, and Hospital units are not included in the microgrid network due to expected costs and complexity of network integration, but they will act as backup to the microgrid.
- Includes the existing 2,000 kW solar PVs and the existing East and West Hydropower generation.
- Includes at least 2,000 kW of load curtailment/demand response (DR) available during an emergency.
- Based on DER-CAM modeling of many scenarios and sensitivities, the recommended least-cost, new generation additions would be two 2000-kW gas-fired reciprocating (internal combustion) units.

2.5.2 Impact of Different Electric Rate Schedules

As scenarios 53A and 54A demonstrate, different electric rate schedules will have different impacts on the microgrid's operations and economics. Figures 14–18 depict a one-day profile of microgrid operation (i.e., internal generation and external power purchase) under the SC-3A and SC-7 rate schedules.

In Figures 14–15, the power purchased from the utility has a flat profile during both weekdays and weekends. The main reason is that rate SC-3A has a high Monthly Demand Charge applied to the peak demand, which keeps the microgrid purchases from the utility at a relatively constant rate to avoid setting a high peak during the month.

Figure 14. Microgrid Load and Supply Profile—Normal Weekday under SC-3A Rate Schedule

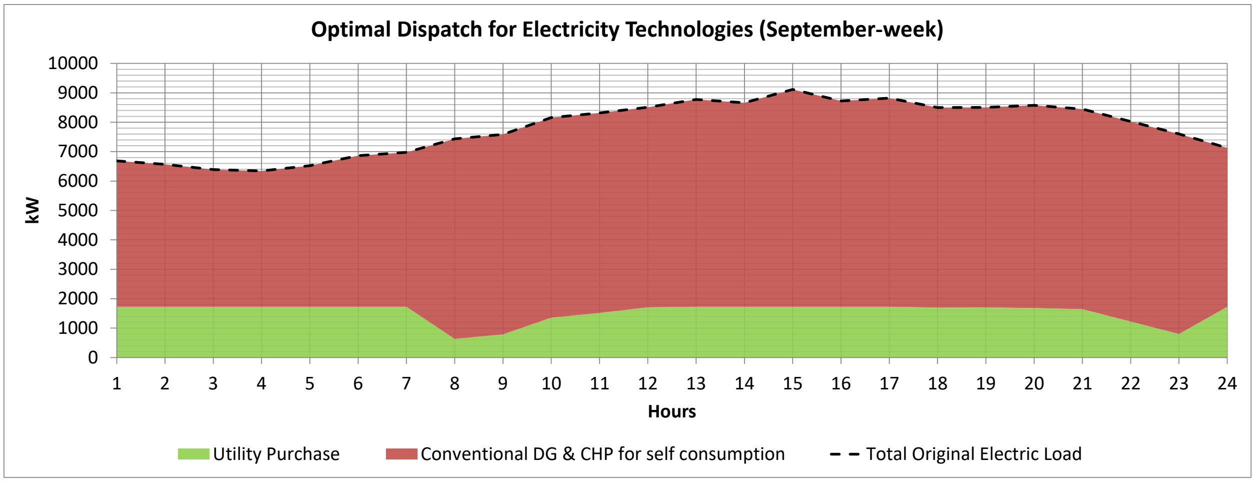
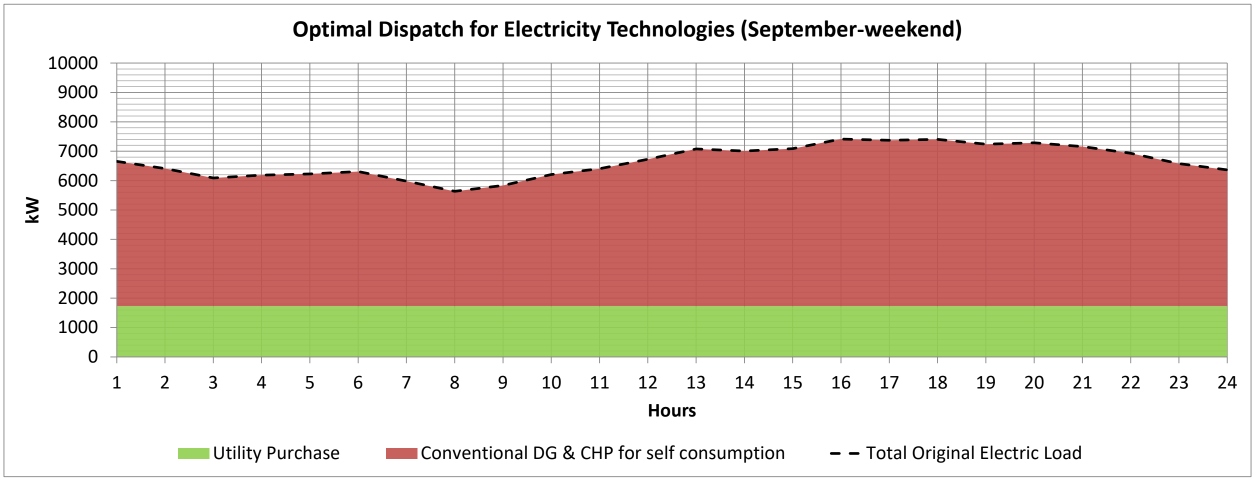


Figure 15. Microgrid Load and Supply Profile—Normal Weekend under SC-3A Rate Schedule



In contrast, Figure 16 shows that power purchased from the utility is high during off-peak periods and low during on-peak periods during a typical weekday. The main reason is that the SC-7 rate has a high Daily On-Peak Demand Charge. Therefore, power purchases during on-peak periods are kept at a minimum. Figure 17 shows the microgrid load and supply profile for a normal weekend under the SC-7 rate schedule, where the daily on-peak demand charge is not applied since weekends are considered off-peak. It therefore costs less to purchase power from the utility compared to producing power internally.

Figure 16. Microgrid Load and Supply Profile—Normal Weekday under SC-7 Rate Schedule

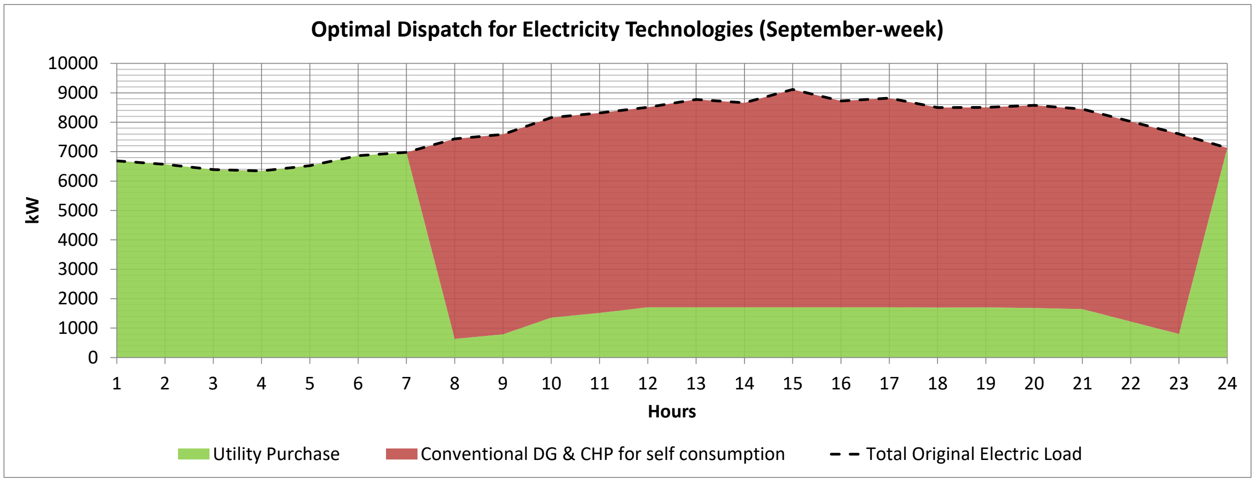


Figure 17. Microgrid Load and Supply Profile—Normal Weekend under SC-7 Rate Schedule

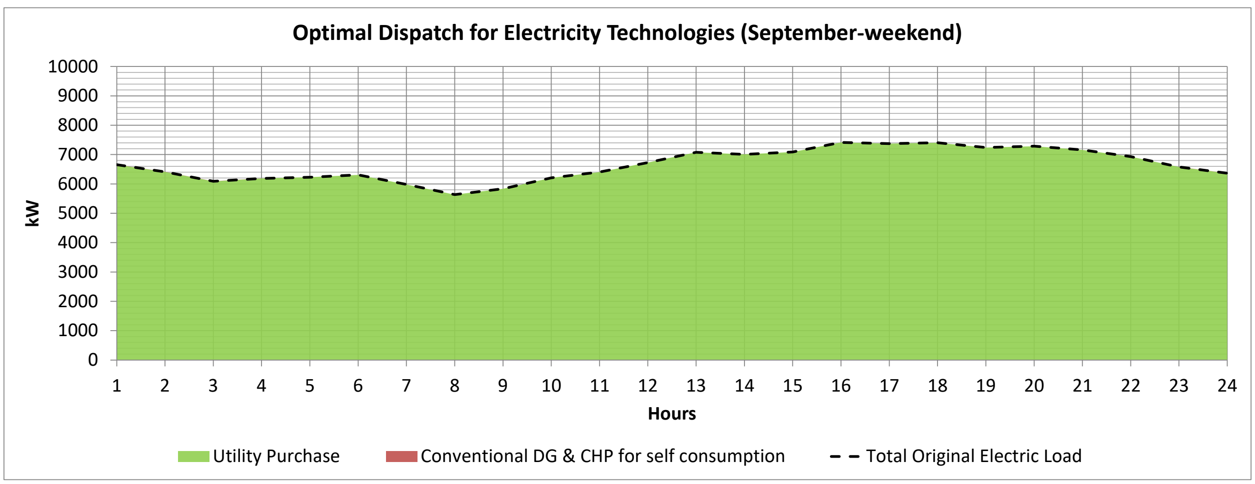
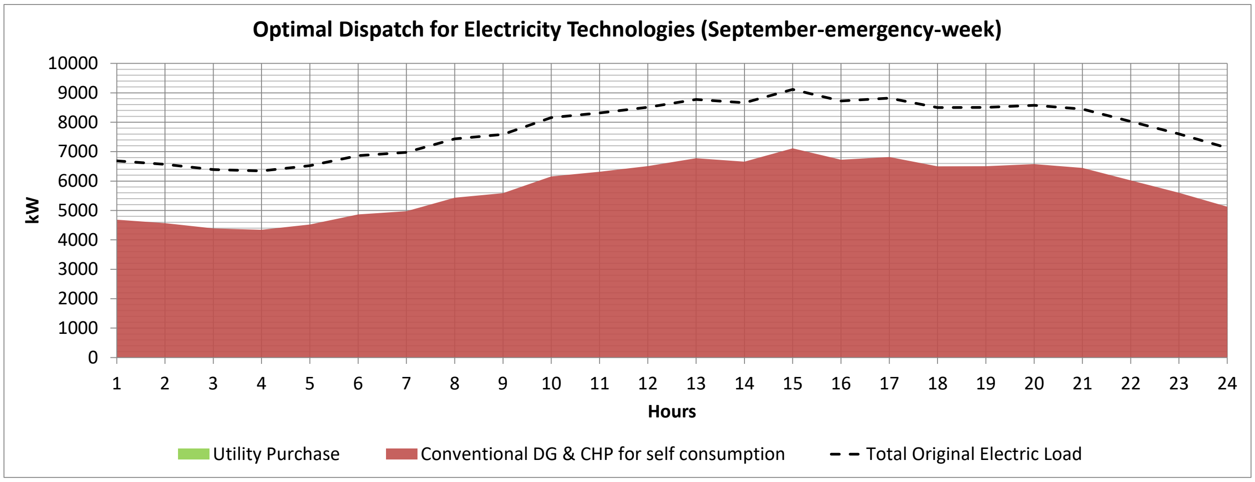


Figure 18 depicts microgrid operations during a weekday emergency period (i.e., a period of larger grid and utility blackout). In this situation, power is produced internally with the 2000-kW load curtailment (gap between dotted line and solid area) helping to reduce internal power generation.

Figure 18. Microgrid Load and Supply Profile—Emergency Weekday under Both Rate Schedules



3 Microgrid Design

The Potsdam Microgrid is being designed and developed as a resilient microgrid that will provide the continuity of power to select entities within the village of Potsdam in the event of a main electrical grid failure during extreme weather conditions. The electrical design of the Potsdam Microgrid includes both the steady-state and the short-circuit analysis in grid-connected and microgrid (islanded) modes, building upon the results of the economic and Load and Supply analyses (section 2) and accounting for the transient and grounding analysis provided by Nova Energy Specialists (section 5). GE Energy Consulting conducted this portion of the study.

The Potsdam Microgrid design consists of an underground distribution grid linking the included entities together on a dedicated ring. While more expensive than a standard overhead distribution grid, the underground grid, as the primary service for all selected entities, will be less susceptible to weather related outages and should provide the microgrid with an increased level of reliability over an overheard grid.

A combination of DG assets, including hydropower, solar power, and single or dual-fuel (natural gas/diesel fuel) generators will power the microgrid. The varying nature of the generation assets and their locations will help to provide a greater level of redundancy and reliability than any single type or location.

The microgrid will operate in both grid-connected mode and islanded mode. When in grid-connected mode, the DG assets will supply power to both the microgrid and any excess power to the larger grid. The microgrid will be served by one primary connection to the larger grid. The primary connection to the larger grid will be through the existing overhead feeder serving the Clarkson University Campus, National Grid feeder 97651. This feeder was identified by National Grid as the primary connection, indicating that reinforcement will most likely be needed prior to use. Should this feeder not be available, there are five other secondary overhead connections that would allow the microgrid to operate in a grid-connected mode; however, if the primary feeder is not available, a combination of two feeders (with the microgrid split) will need to be used due to feeder thermal limitations.

When in islanded mode, with the underground microgrid disconnected from the overhead grid, the connected entities can be fully served by the DG assets of the microgrid. However, during islanded mode a certain amount of load reduction is assumed during peak loading as described in section 2.

Figure 19 is a high-level, one-line diagram of the microgrid.

3.1 Study Methodology

The Potsdam Microgrid was modeled and studied using two different simulation software packages.

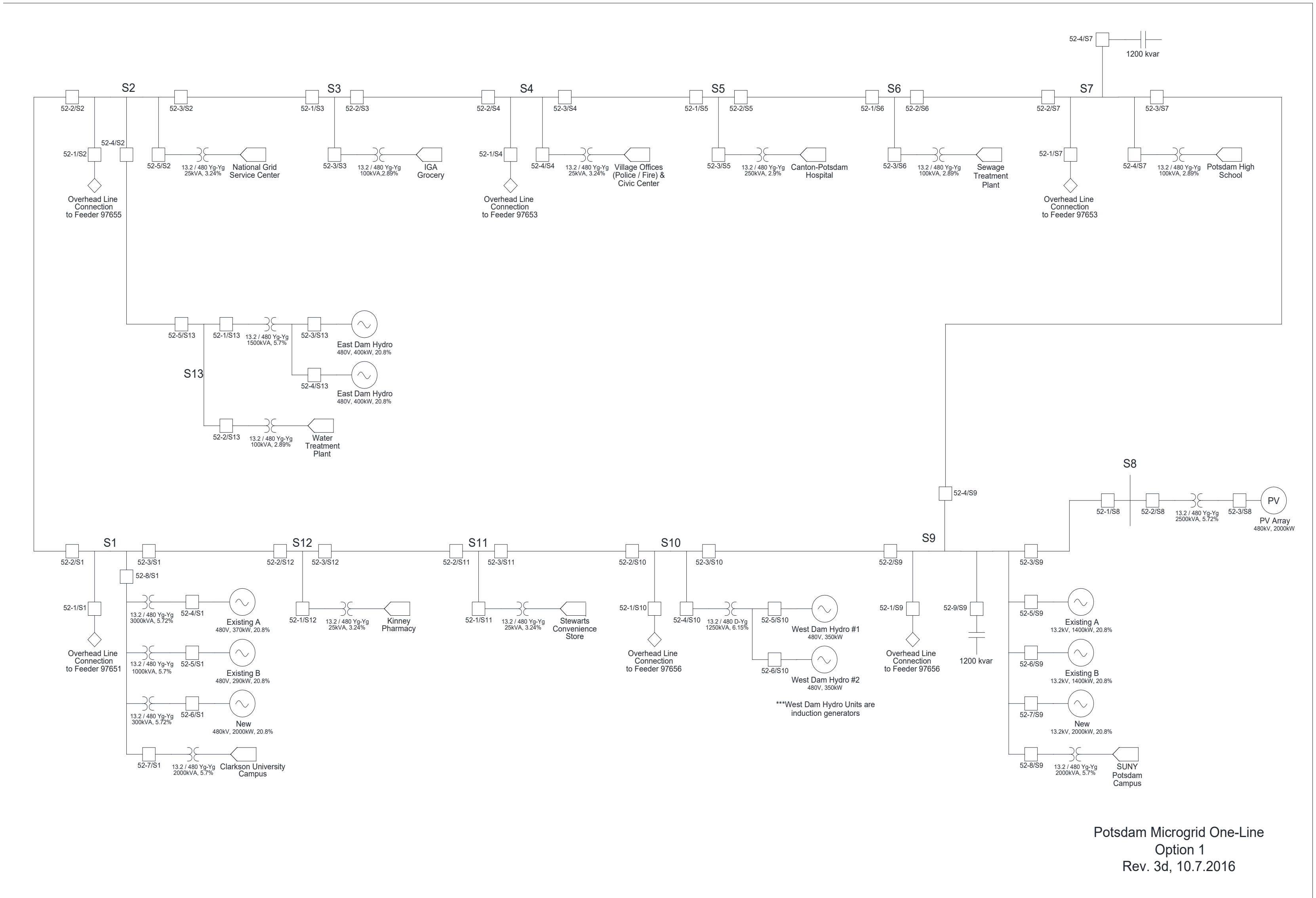
CYME Distribution System Analysis (CYMDIST) software was used for all steady-state modeling. This software is a distribution modeling package that allows the user to model the various components of the distribution grid and then simulate various conditions and contingencies.

Electrical Transient and Analysis Program's (ETAP®) electrical power system analysis and operation software were used for the short-circuit analysis, breaker rating, and protection design. This software is a PC-based power system analysis tool that allows the engineer to model the system and study it under various fault types and locations. The results of the model can then be used to size and rate the breakers and to develop the protection design.

Once modeled, the system was studied in both grid-connected and in islanded modes. The modeled parameters were selected from various sources. If known, the parameters of existing equipment were taken directly from the nameplates. If not known, the parameters of existing equipment were estimated based on typical or similar equipment. For all new equipment, the parameters were also derived from typical or similar equipment.

The load parameters were taken from the values used in the economic and load and supply analyses (section 2). These values were based on actual values if determined through site surveys or estimated based on similar load types.

Figure 19. Potsdam Microgrid One-Line—Design Option 1



3.2 Steady-State Analysis

Steady-state analysis was performed to determine design values for the microgrid electrical infrastructure and to ensure the voltage and thermal limits are not violated when in grid-connected or islanded mode. To facilitate this evaluation, the one-line diagram shown in Figure 19 was constructed in CYMDIST.

For the steady-state analysis, load and generation values were set according to the DER-CAM peak load point determined in the economic study and Load and Supply Analysis. Generation and load values used in the model are shown in Table 11. Hydro generators behind the same transformer are represented as a single unit in the steady-state model.

Table 11. Generation and Load Values for Grid-Connected Mode

Load	kW	power factor (+ = absorbing VARs)		Generator	kW	power factor (+ = supplying VARs)
Hospital	560	0.85		**West Dam Hydro(s)**	193*	-0.9
Civic Center/ Village Office	54	0.85		**East Dam Hydro(s)**	398*	0.9
Clarkson	4,866	0.85		**Clarkson Existing A**	370	0.9
IGA Grocery	144	0.85		**Clarkson Existing B**	290	0.9
Kinney Drugs	48	0.85		**Clarkson New**	2,000	1.0
NG Service Center	48	0.85		**SUNY Potsdam Existing A**	1,400	0.9
Potsdam High School	142	0.85		**SUNY Potsdam Existing B**	1,400	0.9
Sewage Treatment Plant	122	0.85		**SUNY Potsdam New**	2,000	0.9
Stewarts	48	0.85		**PV Array**	552*	1.0
SUNY Potsdam	4,166	0.85				
Water Treatment Plant	83	0.85				

* Hydro units and PV array are scheduled based on DER-CAM calculation and correspond to hourly output during the system peak. Refer to Table 19 for nominal generator ratings

While transformers are included, the impact of secondary lines and cables are generally not included in the steady-state model due to lack of information for infrastructure beyond the transformer. All generation and loads are balanced three-phase circuits.

3.2.1 Grid-Connected Mode

The microgrid was evaluated in five different configurations when in grid-connected mode. These cases are described in Table 12. For each case, the microgrid was evaluated with generation and load at the DER-CAM prescribed values for the peak system load. The microgrid was also evaluated without the generation to make sure voltage and thermal limits were not violated in the non-generation state.

Table 12. Grid-Connected Configurations

Case	OHL Connection(s) In Service, Others Out of Service	Microgrid Ring Status
1	• Feeder 97651 at Clarkson	Full Ring
2	• Feeder 97656 at West Dam Hydro feeding half ring towards Clarkson • Feeder 97653 at the Village Offices/Civic Center feeding half ring towards Hospital and SUNY Potsdam	Split at West Dam Hydro and Village Offices/Civic Center Breakers 52-3/S10, 52-2/S9, 52-2/S3, and 52-2/S4 open
3	• Feeder 97656 at SUNY Potsdam feeding half ring towards High School • Feeder 97653 at the Village Offices/Civic Center feeding half ring towards Clarkson	Split at SUNY Potsdam and Village Offices/Civic Center Breakers 52-3/S10, 52-2/S9, 52-3/S4, and 52-1/S5 open
4	• Feeder 97653 at Potsdam High School feeding half ring including SUNY Potsdam and Hospital • Feeder 97655 at the National Grid Service Center feeding half ring including Clarkson and NG Service Center	Split at West Dam Hydro and Village Offices/Civic Center Breakers 52-2/S3, 52-2/S4, 52-3/S10, and 52-2/S9 open
5	• Feeder 97656 at West Dam Hydro feeding half ring towards SUNY Potsdam • Feeder 97655 at the National Grid Service Center feeding half ring including Clarkson and NG Service Center	Split at West Dam Hydro and Village Offices/Civic Center Breakers 52-3/S13, 52-2/S10, 52-3/S4, and 52-1/S5 open

The results of the simulations show that the voltage limits for the microgrid were not violated in any of the cases. Figures 20 and 21 show the voltage range for the grid-connected cases with and without generation, respectively. The minimum voltage across all cases was 0.964 per unit, and the maximum voltage across all cases was 1.036 per unit.

Figure 20. Voltage Range, Grid-Connected with Generation

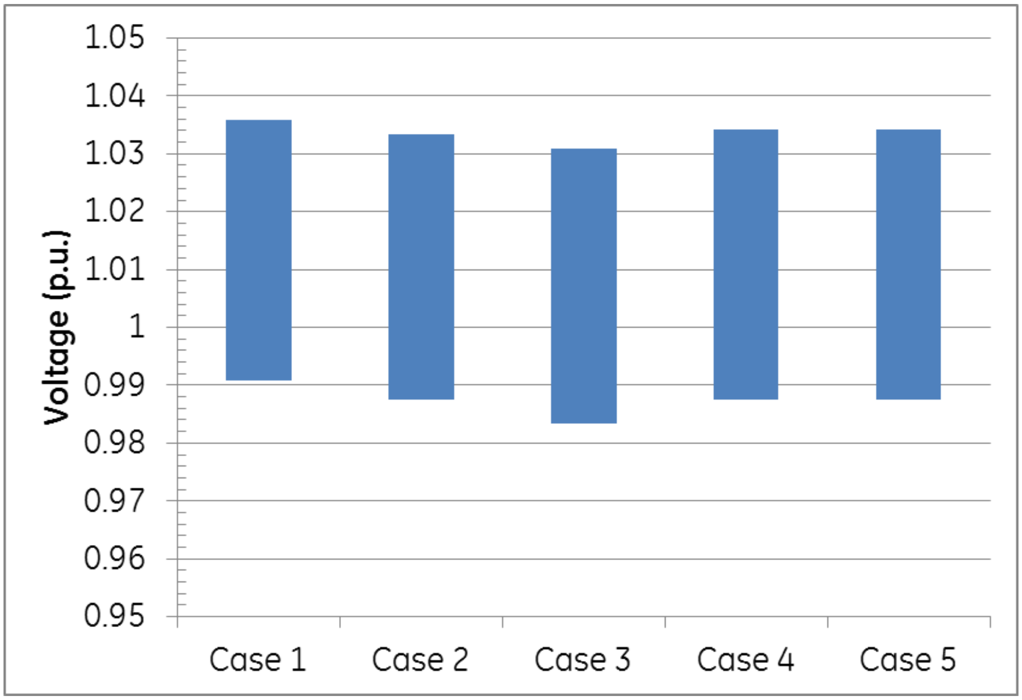


Figure 21. Voltage Range, Grid-Connected without Generation

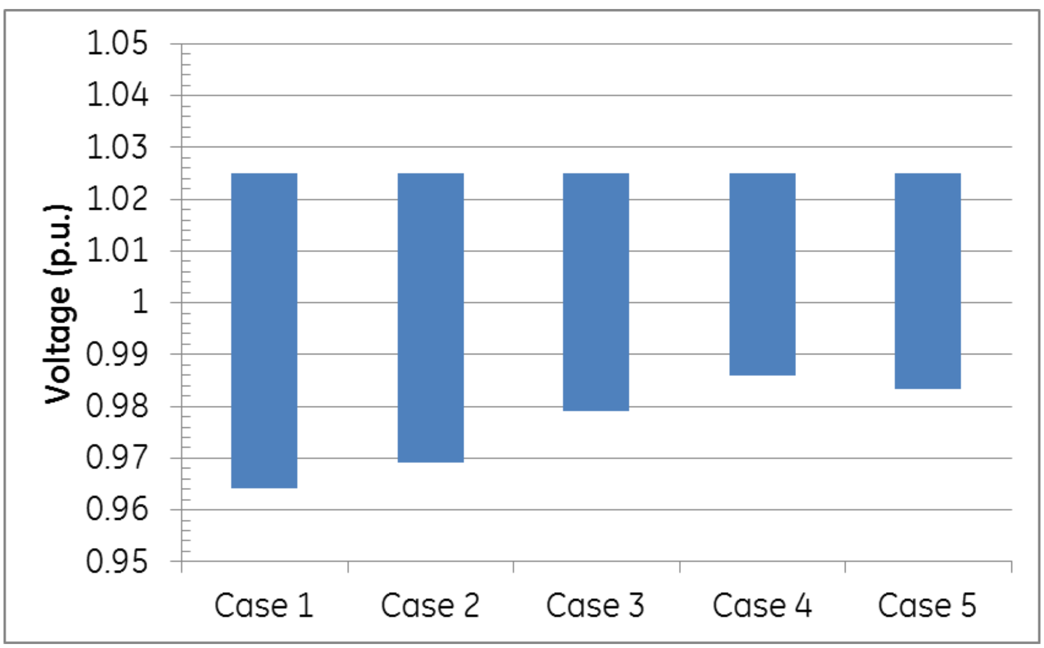
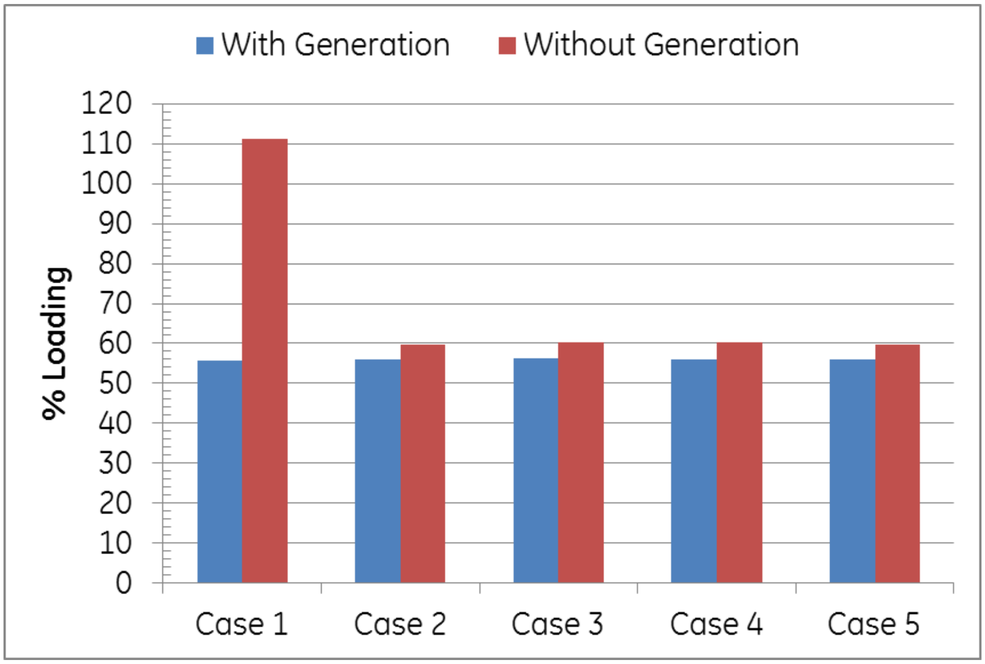


Figure 22 shows the maximum loading for any cable in the microgrid for each of the grid-connected cases (with and without generation). The simulation results indicate that for case 1, with no generation on the microgrid, the maximum loading exceeds the normal rating of the selected conductor by 11.2%.

Figure 22. Max Loading, Grid-Connected



For the overloaded case, the only overloaded cable on the system was between the Clarkson utility interconnection point and the isolation switch (Figure 19). Since this cable was only overloaded in the maximum-load case where no generation is use and the overloaded value was likely within the emergency rating of the cable, a larger cable was not modeled. However, if a larger 750-MCM cable[7] is used in place of the selected 500-MCM cable, the loading on the cable decreases to 92% with minimal impact on rest of the system.

A thorough evaluation of the electrical infrastructure surrounding the microgrid was beyond the scope of the project. In each case, the voltage at the point of interconnection was assumed to be 103% of nominal. To help quantify the impact of the microgrid on the local utility infrastructure, the interconnection flows for each case are listed in Table 13.

It should be noted that some of the flows shown in Table 13 are negative, indicating that power is flowing from the microgrid back to the utility system. While this power will likely be consumed by loads near the point of utility interconnection, special care should be taken to ensure the local utility system can handle this backflow.

Table 13. Grid-Connected Interconnection Point Flows

Overhead Connection Location	Case 1				Case 2				Case 3				Case 4				Case 5			
	Gen		No Gen		Gen		No Gen		Gen		No Gen		Gen		No Gen		Gen		No Gen	
	kW	kVAR	kW	kVAR	kW	kVAR	kW	kVAR	kW	kVAR	kW	kVAR	kW	kVAR	kW	kVAR	kW	kVAR	kW	kVAR
Clarkson	908	3,971	10,195	5,255																
West Dam Hydro					1,313	3,346	5,025	3,066									-1,259	1,009	4,895	3,005
Village Offices/Civic Center					-410	620	5,163	3,362	1,378	3,326	5,245	3,363								
SUNY Potsdam									-468	657	4,883	2,975								
Potsdam High School													-1,254	1,013	4,909	2,940				
National Grid Service Center													2,161	2,960	5,220	3,398	2,161	2,960	5,164	3,364

3.2.2 Islanded Mode

In islanded mode, the microgrid load is served entirely from sources on the microgrid. To satisfy the load/generation balance and to allow for some generation margin, approximately 2 MW of load will be curtailed from the grid-connected scenario. To simplify control and communication requirements for load control, the curtailed load is taken only from Clarkson University, SUNY Potsdam, and the hospital. The curtailed load values are shown in Table 14.

Table 14. Microgrid Load Details

Location	Original (kW)	Curtailed Load (kW)	Curtailed %	Microgrid Load (kW)
Clarkson	4,886	1,049	22%	3,837
SUNY Potsdam	4,166	895	22%	3,271
Hospital	560	56	10%	504

When transitioning to islanded mode, the following changes were made to the grid-connected system:

- Disconnected all utility sources by opening breakers
- Switched the new 2-MW Generator located at SUNY Potsdam to “swing generator” control mode (load-following mode with voltage control) with the voltage control set point of 100% of nominal
- Changed the power factor set point for the new 2-MW Generator located at Clarkson to 0.9 (supplying VARs)
- Removed all curtailable load from the system

The control modes listed above may not be the actual control utilized by the microgrid. The above configuration is intended to test the adequacy of the microgrid resources to maintain the load/generation balance under worst-case conditions.

To support reactive power demands during islanded mode, two 1,200 kilovolt amp reactive (kVar) switched shunt capacitors were added to the microgrid (Figure 19). These capacitors were included in the simulations for grid-connected mode above.

Table 15 shows the simulation results for the islanded system. The results indicate that the microgrid generation assets can support both the real and reactive demands in islanded mode at peak load and meet voltage and thermal criteria. Additionally, the microgrid was simulated in islanded mode without PV to ensure there was enough generation margin and voltage support in the event of unexpected cloud cover (Table 16).

Table 15. Microgrid Simulation Results

	PV	No PV
Min Voltage per unit	0.9567	0.9567
Max Voltage per unit	1.0075	1.0075
Max Conductor Loading	46.9%	46.9%
Swing Generator Real Power	1,196 kW	1,748 kW
Swing Generator Real Power Margin	804 kW	252 kW
Swing Generator Reactive Power	430 kVar	422 kVar

Table 16. Microgrid Generation Results

Generator	With PV		Without PV	
	kW	kVar	kW	kVar
West Dam Hydro(s)	193	-387	800	-387
East Dam Hydro(s)	398	193	398	193
Clarkson Existing A	370	179	370	179
Clarkson Existing B	290	140	290	140
Clarkson New	2,000	969	2,000	969
SUNY Potsdam Existing A	1,400	678	1,400	678
SUNY Potsdam Existing B	1,400	678	1,400	678
SUNY Potsdam New	1,196	430	1,748	422
PV Array	552	0	0	0

3.2.3 Design Values Summary

Table 17. Cable Summary

Cable Description	Cable Type	Length (ft.)	Max Loading
CAB_CIVIC_CENTER_CP_HOSPITAL	500 MCM	3,350	56.5%
CAB_CLARKSON_NG_SERVICE	500 MCM	3,100	57.0%
CAB_CP_HOSPITAL_SEWAGE_TRTMT	500 MCM	4,350	50.3%
CAB_IGA_GROC_CIVIC_CENTER	500 MCM	125	59.8%
CAB_KINNEY_DRUGS_CLARKSON	500 MCM	1,950	58.7%
CAB_NEW_SUNY_GEN	500 MCM	100	21.6%
CAB_NG_SERVICE_CENTER	500 MCM	100	5.5%
CAB_NG_SERVICE_EAST_DAM	500 MCM	4,150	3.6%
CAB_NG_SERVICE_IGA_GROCERY	500 MCM	4150	58.1%
CAB_OHL_CIVIC_CENTER	500 MCM	62.9	60.4%
CAB_OHL_CLARKSON	500 MCM	110	111.2%
CAB_OHL_CLARKSON (alternate)*	750 MCM	110	92.0%
CAB_OHL_EAST_DAM	500 MCM	55	60.4%
CAB_OHL_POTSDAM_HIGH	500 MCM	55	55.5%
CAB_OHL_SUNY POTSDAM _Potsdam	500 MCM	90	55.5%
CAB_OHL_WEST_DAM	500 MCM	70	59.8%
CAB_ POTSDAM_HS_SUNY_POTSDAM	500 MCM	7,025	47.6%
CAB_SEWAGE_TRTMT_POTSDAM_HS	500 MCM	5,425	49.0%
CAB_STEWARTS_KINNEY_DRUGS	500 MCM	400	59.2%
CAB_SUNY_GEN_A	500 MCM	100	15.5%
CAB_SUNY_GEN_B	500 MCM	100	30.9%
CAB_SUNY_POTSDAM_PV_GEN	500 MCM	8,100	5.4%
CAB_SUNY_POTSDAM_WEST_DAM	500 MCM	8,200	56.5%
CAB_WEST_DAM_GEN	500 MCM	100	8.9%
CAB_WEST_DAM_STEWARTS	500 MCM	375	59.8%

* The alternate cable for the overhead line connection at Clarkson was selected to ensure the max loading was within the ratings of the cable for all cases.

Table 18. 500-MCM Cable Specifications

Rated Voltage:	7.62 kV
Nominal Ampacity:	440 A
Type:	3-core cable with grounded conductor
Conductor Material:	copper
Conductor Size:	500 kcmil
Positive Sequence Resistance:	0.1558 Ω/mi
Zero Sequence Resistance:	0.8216 Ω/mi
Positive Sequence Reactance:	0.1927 Ω/mi
Zero Sequence Reactance:	0.3876 Ω/mi
Positive Sequence Susceptance:	253.54 μS/mi
Zero Sequence Susceptance:	253.54 μS/mi

Table 19. Generator Summary

Generator	Rated Power (kW)	Nominal Voltage (kV)	Impedance (%)
GEN_CLARKSON_NG	2000	0.48	20.8
GEN_CLARKSON_GEN_A	370	0.48	20.8
GEN_CLARKSON_GEN_B	290	0.48	20.8
GEN_SUNY_NEW	2000	13.2	20.8
GEN_SUNY_GEN_A	1400	13.2	20.8
GEN_SUNY_GEN_B	1400	13.2	20.8
GEN_EAST_DAM_HYDRO	2 x 400	0.48	20.8
GEN_WEST_DAM_HYDRO	2 x 350	0.48	NA
GEN_PV_PLANT	2000	0.48	NA

Table 20. Capacitor Summary

Capacitor	Nominal Rating (kVar)	Nominal Voltage (kV)
CAP_SUNY	1200	13.2
CAP_POTSDAM_HIGH	1200	13.2

Table 21. Transformer Summary

Transformer	Cap Nom (kVA)	Prim Volt (kV L-L)	Sec Volt (kV L-L)	Z1 (%)
TR_NG_SERVICE_CENTER	3 × 25.00	13.20	0.48	3.24
TR_WATER_TREATEMENT_PLANT	3 × 100.00	13.20	0.48	2.89
TR_IGA_GROCERY	3 × 100.00	13.20	0.48	2.89
TR_CIVIC_CENTER_VILLAGE_OFFICE	3 × 25.00	13.20	0.48	3.24
TR_SEWAGE_TREATMENT_PLANT	3 × 100.00	13.20	0.48	2.89
TR_POTSDAM_HIGH_SCHOOL	3 × 100.00	13.20	0.48	2.89
TR_SUNY_LOAD	3 × 2000.00	13.20	0.48	5.70
TR_CANTON_POTSDAM_HOSPITAL	3 × 2500.00	13.20	0.48	2.90
TR_KINNEY_DRUGS	3 ×2 5.00	13.20	0.48	3.24
TR_STEWARTS	3 × 25.00	13.20	0.48	3.24
TR_CLARKSON_LOAD	3 × 2000.00	13.20	0.48	5.70
TR_CLARKSON_NEWGEN	3000.00	13.20	0.48	5.72
TR_CLARKSON_GEN_A	3000.00	13.20	0.48	5.72
TR_CLARKSON_GEN_B	1000.00	13.20	0.48	5.70
TR_WEST_DAM_HYDRO	1250.00	13.20	0.48	6.15
TR_EAST_DAM_HYDRO	1500.00	13.20	0.48	5.70
TR_PV_GEN	2500.00	13.20	0.48	5.72

Note: All load serving transformers are assumed to be three single-phase transformers and all generator step up (GSU) transformers are assumed to be three-phase transformers.

3.2.4 Conclusions and Future Work

The steady-state analysis showed that the proposed microgrid design is adequate in both grid-connected and islanded modes. Five different configurations were tested to ensure the microgrid could serve load reliability in grid-connected mode. In each case, the voltage was within acceptable limits. The single thermal violation (case 1, no generation) was minor and unlikely to occur; therefore, alteration of the design was not warranted. However, a higher capacity cable could be substituted with minimal design and cost impact.

With appropriate load curtailment, the proposed generation assets were sufficient to meet the real power demands of the peak system loads with some margin. Two capacitors were added to the microgrid to facilitate reactive power balance in the islanded mode. With curtailed loads and the added capacitors, no voltage or thermal violations were recorded at peak load.

To verify that the local utility system can support the microgrid in grid-connected mode, steady-state models of the local utility system should be evaluated. Table 13 provides a list of interconnection flows at the point of interconnection with the local utility. To analyze the impact of the microgrid on voltage and thermal limits, these flows can be attached to a utility model at the interconnection points as a load or generator.

It is possible that the Microgrid will have an unbalanced three-phase load leading to unbalanced currents in generators. The capability of a generator to withstand such unbalance is specified by Institute of Electrical and Electronics Engineers (IEEE) Standards C50.12 and C50.13, IEC Standard 60034-1 and IEEE Standard C37.102. Typical generators of the size proposed for this microgrid are capable of withstanding 8% to 10% continuous current unbalance when the generator is within the rated kilovolt amp (kVA) and the maximum current does not exceed 105% of rated current in any phase.[8] Similarly, the short time current imbalance capability is expressed in square of per unit of rated current and time in seconds (I^2t), and the typical value is $I^2t = 10$. For a more comprehensive design evaluation, unbalanced time-varying load and generation profiles should be simulated. Significant voltage unbalance on a system can cause generation sources to drop off line, which could impact the ability of the microgrid to reliably serve loads. Additionally, time-varying loads should be evaluated along with local utility models to ensure the local system can handle excess generation supplied by the microgrid.

3.3 Short-Circuit Analysis and Circuit Breaker Ratings

A short circuit anlysis was performed to determine design values for the microgrid electrical infrastructure and select appropriately sized breakers for the 13.2 kV and 480-V systems. To facilitate this evaluation, the one-line diagram shown in Figure 19 was modeled in ETAP® (Figure 23).

New 13.2 kV and 480-V circuit breakers will be required to meet the operational requirements of the microgrid, allow changes in the electrical configuration, and clear disturbances and faults.

3.3.1 Short-Circuit Analysis

Using ETAP®, the cases described in Table 22 were set up and evaluated. For each case, faults were run at each bus and the short-circuit levels recorded. The worst-case fault level at each location was then summarized on the one-line diagrams in Appendix **C**. The values in red on the one-line diagrams summarize the highest fault level at each location from the series of faults run for each case and allow for a quick comparison between the different cases.

Table 22. ETAP Cases

Case	Description
MG Only	• Microgrid Ring complete, in-service • All OHL sources out of service (OOS)
1	• OHL_SRC1 Source In-service Only, all others OOS • Clarkson New Generator (Swing) • Microgrid Ring with all cable sections in-service
2	• OHL_SRC3 and OHL_SRC6 Sources In-service, all others OOS • Clarkson New Generator (Swing) • Microgrid Ring complete, all in-service
2A	• OHL_SRC3 and OHL_SRC6 Sources In-service, all others OOS • Microgrid Ring broken into 2 Sub-systems • Clarkson and SUNY Potsdam New Generators set both for Swing operation mode
3	• OHL_SRC3 and OHL_SRC5 Sources In-service, all others OOS. • Clarkson New Generator (Swing) • Microgrid Ring complete, all in-service
3A	• OHL_SRC3 and OHL_SRC5 Sources In-service, all others OOS • Microgrid Ring broken into 2 Sub-systems • Clarkson and SUNY Potsdam New Generators set both for Swing operation mode
4	• OHL_SRC2 and OHL_SRC4 Sources In-service, all others OOS • Clarkson New Generator (Swing) • Microgrid Ring complete, all in-service
4A	• OHL_SRC2 and OHL_SRC4 Sources In-service, all others OOS • Microgrid Ring broken into 2 Sub-systems • Clarkson and SUNY Potsdam New Generators set both for Swing operation mode
5	• OHL_SRC2 and OHL_SRC6 Sources In-service, all others OOS • Clarkson New Generator (Swing) • Microgrid Ring complete, all in-service
5A	• OHL_SRC2 and OHL_SRC6 Sources In-service, all others OOS • Microgrid Ring broken into 2 Sub-systems • Clarkson and SUNY Potsdam New Generators set both for Swing operation mode

3.3.2 Breaker Ratings

The circuit breakers selected for the 13.2 kV distribution system are 15 kV class breakers based on IEEE Std. C37.06-2009. The minimum available rated continuous current capability for 15 kV distribution class circuit breakers is 1200 A. This continuous current rating was used for all 15 kV circuit breakers defined within the Potsdam Microgrid system model, as all operational scenarios evaluated in the study showed that the maximum continuous current flow through each associated 15 kV circuit was well below 1200 A.

Rated continuous current ratings for the 480-V circuit breakers defined within the Potsdam Microgrid system model were selected based upon the maximum observed continuous current flow that could result from maximum load and/or maximum expected generation. In general, either 800 A or 4000 A circuit breakers were selected for application in the 480-V microgrid distribution system depending upon maximum continuous current requirements. These continuous current ratings represent standard frame sizes for low-voltage power circuit breakers.

Based on the short-circuit evaluation, the maximum available fault current levels in the 15-kilovolts (kV_ distribution system were found to be lower than 20 kilo amps (kA) root mean square (RMS), the minimum available rated short-circuit interrupting current capability for 15 kV-distribution class circuit breakers as defined in IEEE Std. C37.06-2009. Therefore, an interrupting current rating of 20 kA was selected for all 15-kV breakers associated with the microgrid distribution system.

The interrupting capability of each of the 480-V circuit breakers was selected based upon the available short-circuit fault levels observed when simulating faults on both sides of each circuit breaker (transformer/bus side versus generator/load side). In general, a published interrupting current rating of 65 kA RMS symmetrical was selected for all 800 A frame circuit breakers, while a published interrupting current rating of 100 kA RMS symmetrical was selected for all 4000 A circuit breakers proposed for installation in the 480-V microgrid distribution system. These ratings represent standard available interrupting current ratings for 800 A and 4000 A frame low-voltage, power circuit breakers. These 480-V circuit breakers will operate and isolate the faulted or overloaded sections of the distribution system via the use of the trip units included with each 480-V circuit breaker. A complete list of breakers and the selected ratings are included in Tables 23–35.

Table 23. Breaker Ratings—Switchgear Lineup 1

BKR ID	KV, System Nominal	KV, BKR Class	A, Ratings (Continuous)	kA, Ratings (Interrupting)
52-1/S1	13.2	15	1200	20
52-2/S1	13.2	15	1200	20
52-3/S1	13.2	15	1200	20
52-4/S1	0.48	0.48	800	65
52-5/S1	0.48	0.48	800	65
52-6/S1	0.48	0.48	4000	100
52-7/S1	13.2	15	1200	20
52-8/S1	13.2	15	1200	20

Table 24. Breaker Ratings—Switchgear Lineup 2

BKR ID	KV, System Nominal	KV, BKR Class	A, Ratings (Continuous)	kA, Ratings (Interrupting)
52-1/S2	**13.2**	**15**	**1200**	**20**
52-2/S2	**13.2**	**15**	**1200**	**20**
52-3/S2	**13.2**	**15**	**1200**	**20**
52-4/S2	**13.2**	**15**	**1200**	**20**
52-5/S2	**13.2**	**15**	**1200**	**20**

Table 25. Breaker Ratings—Switchgear Lineup 3

BKR ID	KV, System Nominal	KV, BKR Class	A, Ratings (Continuous)	kA, Ratings (Interrupting)
52-1/S3	13.2	15	1200	20
52-2/S3	13.2	15	1200	20
52-3/S3	13.2	15	1200	20

Table 26. Breaker Ratings—Switchgear Lineup 4

BKR ID	KV, System Nominal	KV, BKR Class	A, Ratings (Continuous)	kA, Ratings (Interrupting)
52-1/S4	13.2	15	1200	20
52-2/S4	13.2	15	1200	20
52-3/S4	13.2	15	1200	20
52-4/S4	13.2	15	1200	20

Table 27. Breaker Ratings—Switchgear Lineup 5

BKR ID	KV, System Nominal	KV, BKR Class	A, Ratings (Continuous)	kA, Ratings (Interrupting)
52-1/S5	13.2	15	1200	20
52-2/S5	13.2	15	1200	20
52-3/S5	13.2	15	1200	20

Table 28. Breaker Ratings—Switchgear Lineup 6

BKR ID	KV, System Nominal	KV, BKR Class	A, Ratings (Continuous)	kA, Ratings (Interrupting)
52-1/S6	13.2	15	1200	20
52-2/S6	13.2	15	1200	20
52-3/S6	13.2	15	1200	20

Table 29. Breaker Ratings—Switchgear Lineup 7

BKR ID	KV, System Nominal	KV, BKR Class	A, Ratings (Continuous)	kA, Ratings (Interrupting)
52-1/S7	13.2	15	1200	20
52-2/S7	13.2	15	1200	20
52-3/S7	13.2	15	1200	20
52-4/S7	13.2	15	1200	20
52-5/S7	13.2	15	1200	20

Table 30. Breaker Ratings—Switchgear Lineup 8

BKR ID	KV, System Nominal	KV, BKR Class	A, Ratings (Continuous)	kA, Ratings (Interrupting)
52-1/S8	13.2	15	1200	20
52-2/S8	13.2	15	1200	20
52-3/S8	0.48	0.48	4000	100

Table 31. Breaker Ratings—Switchgear Lineup 9

BKR ID	KV, System Nominal	KV, BKR Class	A, Ratings (Continuous)	kA, Ratings (Interrupting)
52-1/S9	13.2	15	1200	20
52-2/S9	13.2	15	1200	20
52-3/S9	13.2	15	1200	20
52-4/S9	13.2	15	1200	20
52-5/S9	13.2	15	1200	20
52-6/S9	13.2	15	1200	20
52-7/S9	13.2	15	1200	20
52-8/S9	13.2	15	1200	20
52-9/S9	13.2	15	1200	20

Table 32. Breaker Ratings—Switchgear Lineup 10

BKR ID	KV, System Nominal	KV, BKR Class	A, Ratings (Continuous)	kA, Ratings (Interrupting)
52-1/S10	13.2	15	1200	20
52-2/S10	13.2	15	1200	20
52-3/S10	13.2	15	1200	20
52-4/S10	13.2	15	1200	20
52-5/S10	0.48	0.48	800	65
52-6/S10	0.48	0.48	800	65

Table 33. Breaker Ratings—Switchgear Lineup 11

BKR ID	KV, System Nominal	KV, BKR Class	A, Ratings (Continuous)	kA, Ratings (Interrupting)
52-1/S11	13.2	15	1200	20
52-2/S11	13.2	15	1200	20
52-3/S11	13.2	15	1200	20

Table 34. Breaker Ratings—Switchgear Lineup 12

BKR ID	KV, System Nominal	KV, BKR Class	A, Ratings (Continuous)	kA, Ratings (Interrupting)
52-1/S12	13.2	15	1200	20
52-2/S12	13.2	15	1200	20
52-3/S12	13.2	15	1200	20

Table 35. Breaker Ratings—Switchgear Lineup 13

BKR ID	KV, System Nominal	KV, BKR Class	A, Ratings (Continuous)	kA, Ratings (Interrupting)
52-1/S13	13.2	15	1200	20
52-2/S13	13.2	15	1200	20
52-3/S13	0.48	0.48	800	65
52-4/S13	0.48	0.48	800	65
52-5/S13	13.2	15	1200	20

3.3.3 Alternate Breaker and Switch/Fuse Design

The breakers and breaker locations presented in sections 3.1 to 3.3 and in Figure 19 were selected to maximize the reliability and resiliency of the microgrid, especially when operating in islanded mode. The breaker positions maximize the divisibility of the microgrid, allowing for faults to be quickly isolated and cleared and minimizing the effect on the overall microgrid. They also allow for automatic rapid re-closure, which minimizes downtime. However, these benefits come at a higher equipment cost.

Two alternate design options were considered. The fundamental protection philosophy and relay selections presented in sections 3.1 to 3.3 remain the same for the proposed alternatives, except for a potential reduction in the number of relays if breakers are removed and loss of the rapid reclose functionality where fused disconnects are used. Figures 24–25 are high-level, one-line diagrams of the microgrid for each option.

3.3.3.1 Design Option 2

An alternative to using breakers at each position indicated in Figure 19 would be to use a fused disconnect switch at some of the locations in place of the breaker (Figure 24). Fused disconnects have similar capabilities to divide and section the microgrid during faults, assuming the fuse characteristics are properly selected; however, they do not have the ability for automatic rapid reclose. Should a fuse blow while clearing a fault, it will need to be manually replaced prior to re-energizing the faulted section. This will potentially increase the amount of downtime and decrease the resiliency of the microgrid. If used, the ratings of the fused disconnects would be similar to the breaker ratings presented in Tables 23–35.

The following breakers have been selected as potential candidates for replacement with a suitability sized fused disconnect or for removal as noted (refer to Figure 19 for breaker numbers).

Secondary microgrid to overhead line connections (52-1/S2, 52-1/S4, 52-1/S7, 52-1/S9, and 52-1/S10): The secondary overhead line connections are only intended to be used if the primary overheard line connection, 52-1/S1, at Clarkson University is unavailable. Changing these locations will cause the microgrid to lose some resiliency, as a fault could lead to a prolonged outage, especially if some of the generation on the microgrid is also out of service. However, these are N-2 or greater contingencies.[9]

All load-only serving breakers (52-7/S1, 52-2/S2, 52-3/S3, 52-4/S4, 52-3/S5, 52-3/S6, 52-4/S7, 52-8/S9, 52-1/S11, 52-1/S12, and 52-2/S13): Changing these locations may cause the downtime after faults to increase due to lack of rapid reclose. However, the impact on the overall microgrid will be small, as all other loads and generation are maintained.

PV breaker (52-2/S8): This breaker could be considered redundant to 52-1/S8 as they are in series, have no other connection between them, and could be removed. Removing this breaker would have no impact on the operation or resiliency of the microgrid. However, it may increase the cost of any future connections at this point as it would lack a bus for connection.

Combination and removal of connections that are physically close into a single switchgear lineup: For example, the physical distance between the Stewarts and the Kinney Pharmacy located on Maple Street is less than 1000 feet and could be served from a centrally located switchgear lineup, allowing for the removal of breakers 52-2/S12 and 52-2/S11.

3.3.3.2 Design Option 3

Another alternative is a more basic protection scheme using a combination of fuses, fused disconnects, and reclosers in place of many of the breaker locations, and removing many of the breakers proposed in Option 1. Option 3 (Figure 25) provides for the protection of the underground primary distribution network, while sacrificing a significant amount of the flexibility and automatic restoration capability that is provided with Option 1(Figure 19) or Option 2 (Figure 24) but at a much lower cost.

3.3.4 Conclusions and Future Work

The breaker and/or fused disconnect switch ratings have been examined and selected through a short-circuit analysis. Breaker locations have been selected to maximize reliability and resiliency of the microgrid when operating in both grid-connected and islanded modes. Alternatives to the breaker-only design were also discussed, allowing for the substitution or direct removal of redundant or combined breakers. The alternative designs allow for a lower overall cost at the potential loss of some functionality and resiliency. Once an approach has been selected, appropriately sized equipment will need to be obtained.

Figure 23. ETAP Circuit Model

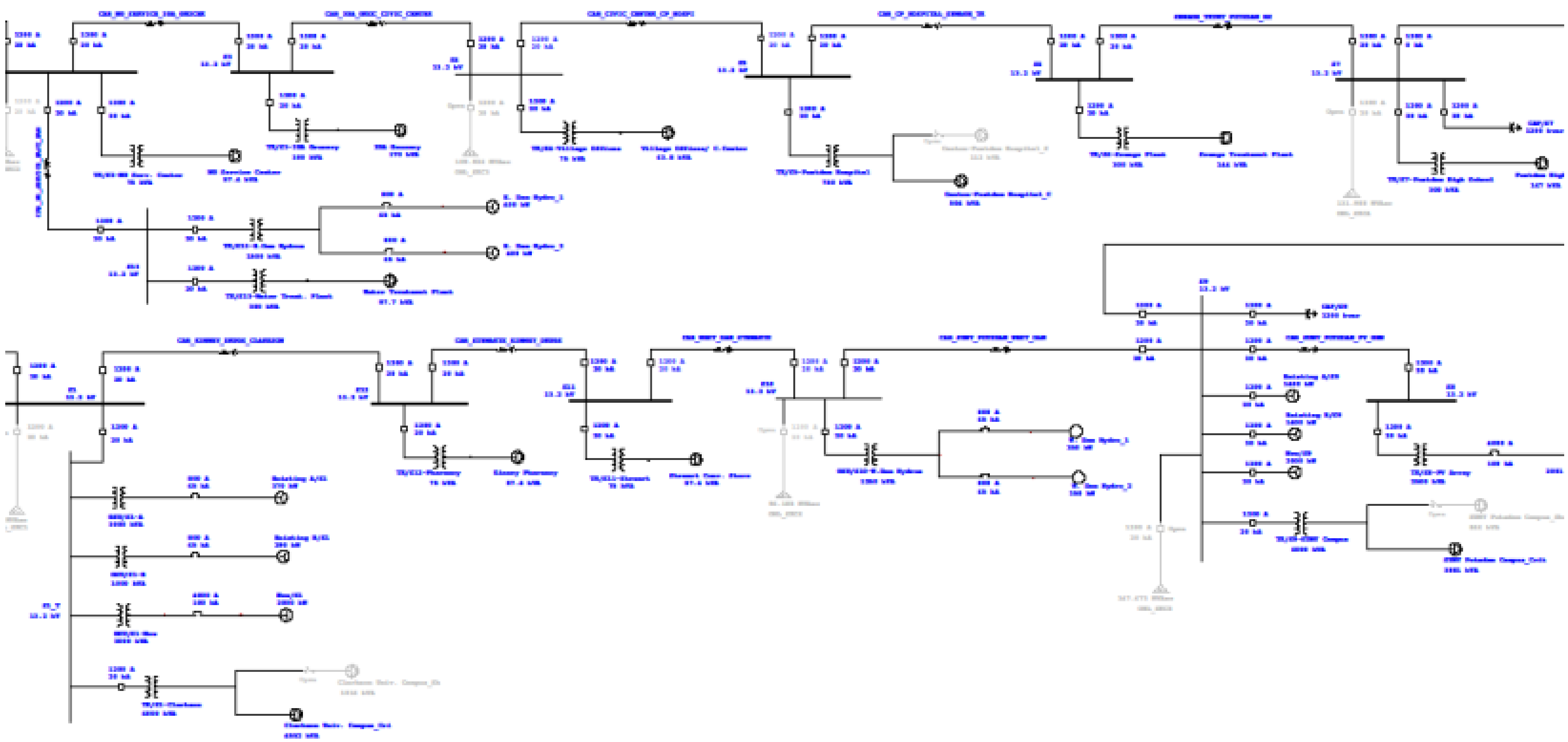


Figure 24. Potsdam Microgrid One-Line—Option 2

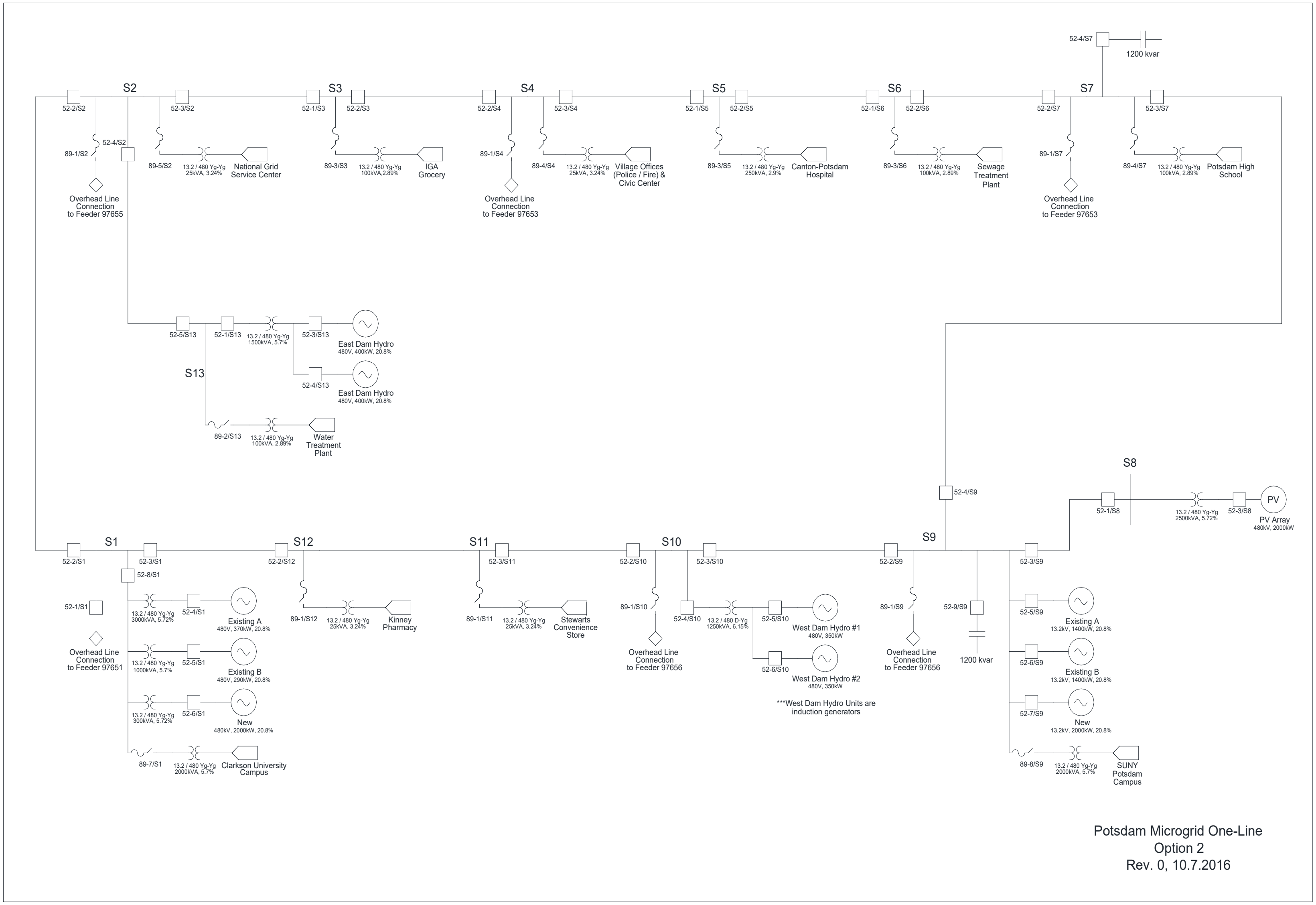
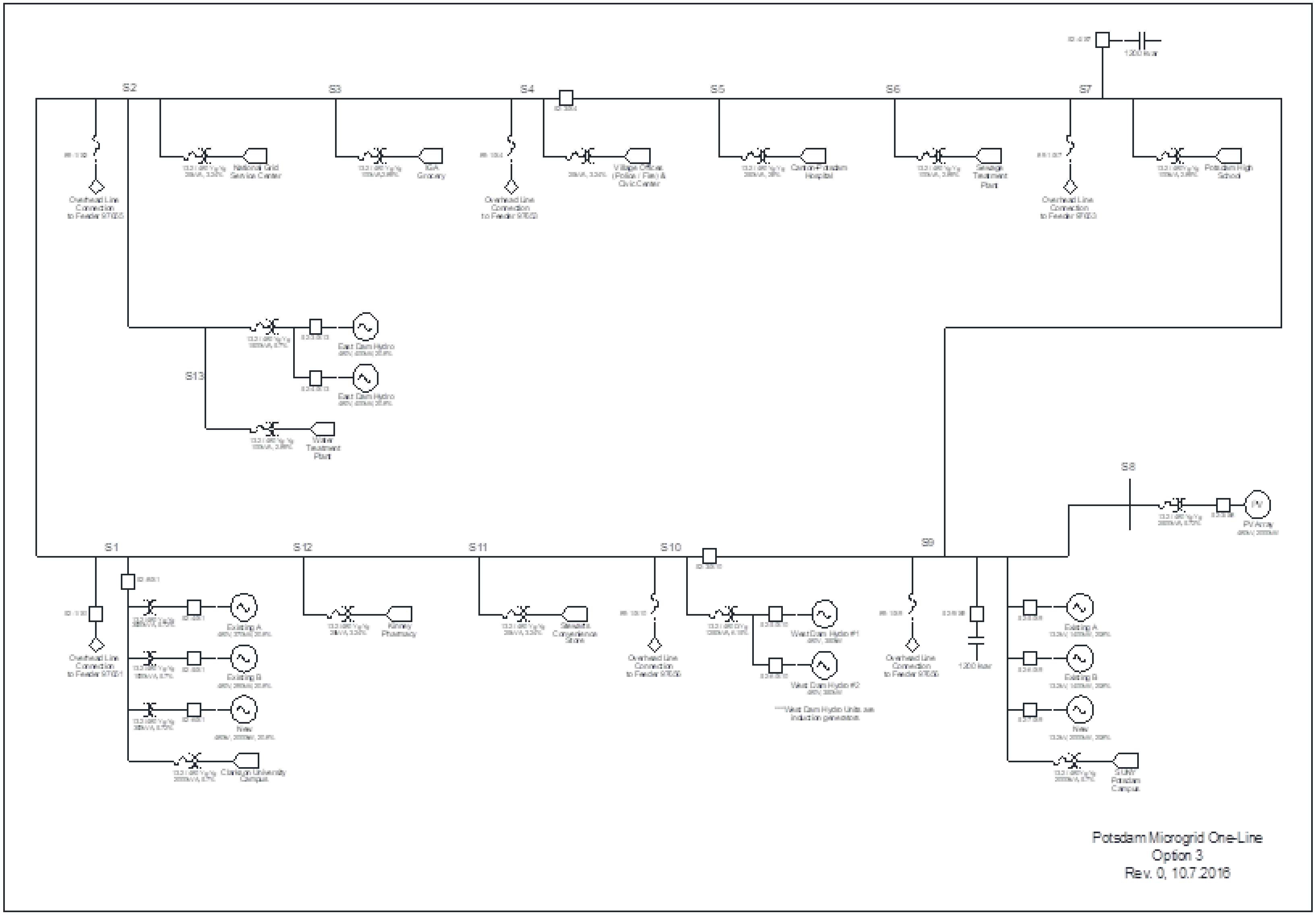


Figure 25. Potsdam Microgrid One-Line—Option 3



3.4 Protection and Control/Monitoring Scheme

The proposed microgrid will include 13 switchgear lineups interconnected via underground transmission lines (Figure 19). Four of these switchgear lineups connect combustion/hydro generation into the microgrid, while a fifth switchgear lineup connects a PV solar array. Each of the 13 switchgear lineups supports commercial, hospital, or campus loads.

3.4.1 Overall Design and Operating Philosophy

To implement the proposed protection and control/monitoring scheme, new protection panels will be installed at each of the 13 switchgear lineups. These protection panels include new GE Multilin UR relays and will provide the following features/functions:

- Primary high-speed differential and backup phase and ground overcurrent protection to each of the 13 interconnecting transmission lines in the microgrid distribution system.
- Primary high-speed differential protection to each of the 13 switchgear lineups in the microgrid distribution system. If desired, backup phase overcurrent protection for each of the feeder and tie circuits associated with each switchgear bus in the microgrid distribution system can also be provided.
- Stator and rotor protection to each of the critical generators in the microgrid distribution system.
- Phase and ground overcurrent, under/over-voltage and capacitor unbalance protection, as well as operational control for each of the capacitor banks proposed for installation in the microgrid distribution system.
- The ability to monitor analog and digital data items through the Supervisory Control and Data Acquisition/Human Machine Interface (SCADA/HMI) system via Ethernet switches and optical fiber circuits.
- If desired, the ability to remotely trip and close each switchgear bus feeder and tie circuit breaker from the SCADA/HMI system.

3.4.2 Components of the Protection and Communications Architecture

The proposed protection and control/monitoring scheme will include the following components:

- GE Multilin UR L90 Line Protection System relays will be used to provide primary high-speed differential and backup phase and ground overcurrent protection to each of the 13 interconnecting transmission lines in the microgrid distribution system. Two UR L90 relays will be installed in conjunction with each interconnecting transmission line, and one relay will be installed at each end of the protected line. Each L90 relay pair will be interconnected via redundant single-mode optical fiber cable pairs to allow exchange of current flow information and determine if a disturbance (fault) has occurred on the protected line. These redundant L90 relay to L90 relay optical fiber communications circuits are used exclusively in and dedicated to each transmission line protection scheme.

- GE Multilin UR B30 Bus Differential System relays will be used to provide primary high-speed differential protection to each of the switchgear lineups containing five or less feeder/tie circuit breakers in the microgrid distribution system. Each B30 relay can also be used to provide backup phase overcurrent protection for each of the feeder and tie circuits associated with each switchgear bus. One UR B30 relay will be installed in conjunction with each switchgear lineup.
- GE Multilin UR B90 Bus Differential System relays will be used to provide primary high-speed differential protection to each of the switchgear lineups containing six or more feeder/tie circuit breakers in the microgrid distribution system. Each B90 relay can also be used to provide backup phase overcurrent protection for each of the feeder and tie circuits associated with each switchgear bus. Up to three UR B90 relays will be installed in conjunction with each switchgear lineup, depending upon the number of feeder/tie circuit breakers that need to be accommodated in the protection scheme.
- One GE Multilin UR F35 Feeder Management System relay will be installed in conjunction with each of the 13 switchgear lineups in the microgrid distribution system. Each F35 relay will be used to monitor the following analog and digital data items associated with the switchgear lineup:
  - Phase Current (IA, IB, IC) flows through each switchgear bus feeder and tie circuit.
  - Active power (P), reactive power (Q) and apparent power (S) flows through each switchgear bus feeder and tie circuit.
  - Phase-to-Phase Voltages (VAB, VBC, VCA) at each switchgear bus.
  - Status (open or closed) information for each switchgear bus feeder and tie circuit breaker.
- GE Multilin UR G30 Generator Protection System relays will be used to provide stator and rotor protection to each of the critical generators in the microgrid distribution system. Two UR G30 relays will be installed in conjunction with each critical generator.
- GE Multilin UR F60 Feeder Protection System relays will be used to provide primary phase and ground overcurrent, under/over-voltage and capacitor unbalance protection to each of the capacitor banks proposed for installation in the microgrid distribution system. These UR F60 relays will also be used to control when each capacitor bank is in service or out of service based upon distribution system operating requirements. One UR F60 relay will be installed in conjunction with each capacitor bank.
- GE Multilin ML 3001 Ethernet Switches will be used to interconnect each of the UR L90, UR B30/B90, UR G30 and UR F35/F60 relays and connect each of these relays to the central SCADA/HMI system. One ML 3001 Ethernet Switch will be installed in conjunction with each switchgear lineup and will be connected to the associated relays via redundant multimode optical fiber cable pairs. These 13 ML 3001 Switches will also be connected via redundant single-mode optical fiber cables, creating redundant “ring” type communication networks. This will allow each relay in each switchgear lineup to communicate and exchange the required analog and digital information with the other Multilin UR relays installed in conjunction with the microgrid and provide (as required) analog and digital data to the central SCADA/HMI system. For the F35 relays, this will also provide the ability to remotely trip and close each switchgear bus feeder and tie circuit breaker from the SCADA/HMI system.

- Two GE Multilin MultiSync 100 Clocks and related accessory packages will be installed in the microgrid protection and control scheme. One MultiSync 100 Clock/Accessory Package will be installed in conjunction with the Clarkson Campus switchgear lineup. The second (redundant) MultiSync 100 Clock/Accessory Package will be installed in conjunction with the SUNY Potsdam Campus switchgear lineup.

  These MultiSync 100 Clocks will be connected to the Ethernet switches installed in the protection panels associated with the switchgear lineups. The MultiSync 100 clocks will be used to provide a precise time reference, via the ML 3001 Ethernet Switches and the optical fiber interconnections, to each of the Multilin UR L90, UR B30/B90, UR G30 and UR F35/F60 relays.

3.4.3 Conclusions and Future Work

The Protection and Control/Monitoring design proposed for the Potsdam Microgrid will provide adequate protection and monitoring in both grid-connected and islanded modes. There is also a high degree of flexibility and sectionalism in the design to ensure that the microgrid will remain operational in the event of a fault or disturbance.

Detailed protection studies will be needed to both select the final protection set points and validate the final design.

3.5 Control System Functional Design

3.5.1 Functional Description of Controls

The Potsdam Microgrid control system is expected to provide the following primary functions:

- **Forecasting:** Historical demand data, including daily, weekly, and annual load profiles, are used to forecast microgrid load on a 24-hour time horizon. Advanced features will include the forecasts of solar power production at the Clarkson PV plant.
- **Unit Commitment:** The optimization engine of the controller periodically determines a combination of generation units to keep or bring on to minimize the cost of operation and ensure that microgrid load requirements are satisfied. The electricity tariffs and fuel costs are provided as inputs to the engine on a periodic basis, ideally in real-time. The default time horizon of optimization is 24 hours. Optimization that includes heating operation (e.g., if CHP is added to the microgrid) will be an advanced feature of the controller.
- **Dispatch:** The controller issues start/stop and proper isochronous status commands to the microgrid generation units. The optimal set point, typically for real and reactive power, is sent to each unit. Generators are operated with sufficient spinning reserves to accommodate for load fluctuations. The solar panel inverters at the Clarkson PV plant should be controllable (i.e., able to be turned on or off to avoid incidents of reverse power and to reduce maintenance issues).

- **Disconnect** (in grid-connected mode): In the case of an unexpected loss of grid due to an outage or poor power quality, the controller should initiate a sequence of steps and transition to the unintentional islanding state. If any generation is running and exceeds load at this time, power quality or load interruption should last a few cycles at most. If no generation is running, the load shedding sequence should be performed. In this case, the load is rapidly shed (i.e., individual or groups of controllable loads are switched off to reduce the duration of grid disruptions).
  Preemptive disconnection (i.e., intentional islanding) should be conducted if a power outage on the main grid is anticipated (e.g., in the case of a forthcoming storm) or at the planned time and duration. In this case, generation units not running should be turned on and synchronized, and load management should be configured before islanding.
- **Voltage, Frequency, and VAR Control:** In islanded mode, the primary function of the microgrid is to maintain voltage and frequency as defined by American National Standards Institute (e.g., ANSI C84.1). Droop control with adequate operating characteristics together with the management of isochronous generators is necessary. In addition, since two capacitors provide local voltage control, the controller will have to coordinate their state by ensuring they are on when the microgrid transitions to islanded mode.
- **Resynchronization** (in islanded mode): This controlled operation occurs only after grid synchronization (i.e., after voltage and frequency of the grid are stable and within acceptable ranges as defined by IEEE 1547). The synchronization mechanism could be active or passive (droop).

3.5.2 Control and Communications Infrastructure

The control and communications architecture were designed to include devices that support multiple protocols and enable interoperability with existing generation units and loads.

3.5.2.1 Controls

The proposed microgrid control architecture consists of four control device types:

- **Microgrid Energy Management System** (MG EMS) (one per microgrid)
  The MG EMS serves as the master control application which orchestrates all control actions and provides the utility interface. This could include integration of existing control platforms and new system-level control services. The data historian, and possibly other databases, are stored in MG EMS, which also provides analytics applications. MG EMS also serves as a main microgrid configuration and dashboard station (e.g., a station operator could provide scheduling policies through its web interface).
- **Microgrid Master Control Station** (one per microgrid)
  Master Control Station is a hardened computer that hosts critical real-time monitoring and control services. It performs forecasting, optimization and dispatch functions. A dual redundant configuration may be preferable.

- **Microgrid Facility Control Node** (one per facility)
  Facility Control Node coordinates control across multiple buildings of a specific facility. This controller abstraction is also utilized for any building in the microgrid with local control functions [i.e., a building that hosts a generation unit or a building energy management system (BEMS)]. Most facility control nodes would also be hardened industrial computers.
- **Microgrid Edge Control Node** (one per facility)
  Edge Control Node is an automation controller or a feeder management relay with a direct switching interface to loads in a building. This is typically a multifunction controller/Intelligent Electronic Device (IED) providing automation and physical interface to switchgear and sensors.

All hardware control devices, classified according to this control hierarchy, are shown in Figure 26 as an overlay of the electrical one-line diagram. The software components of the proposed control architecture together with communication protocols are shown in Figure 27.

Figure 26. One-Line Diagram with Control and Communications Overlay

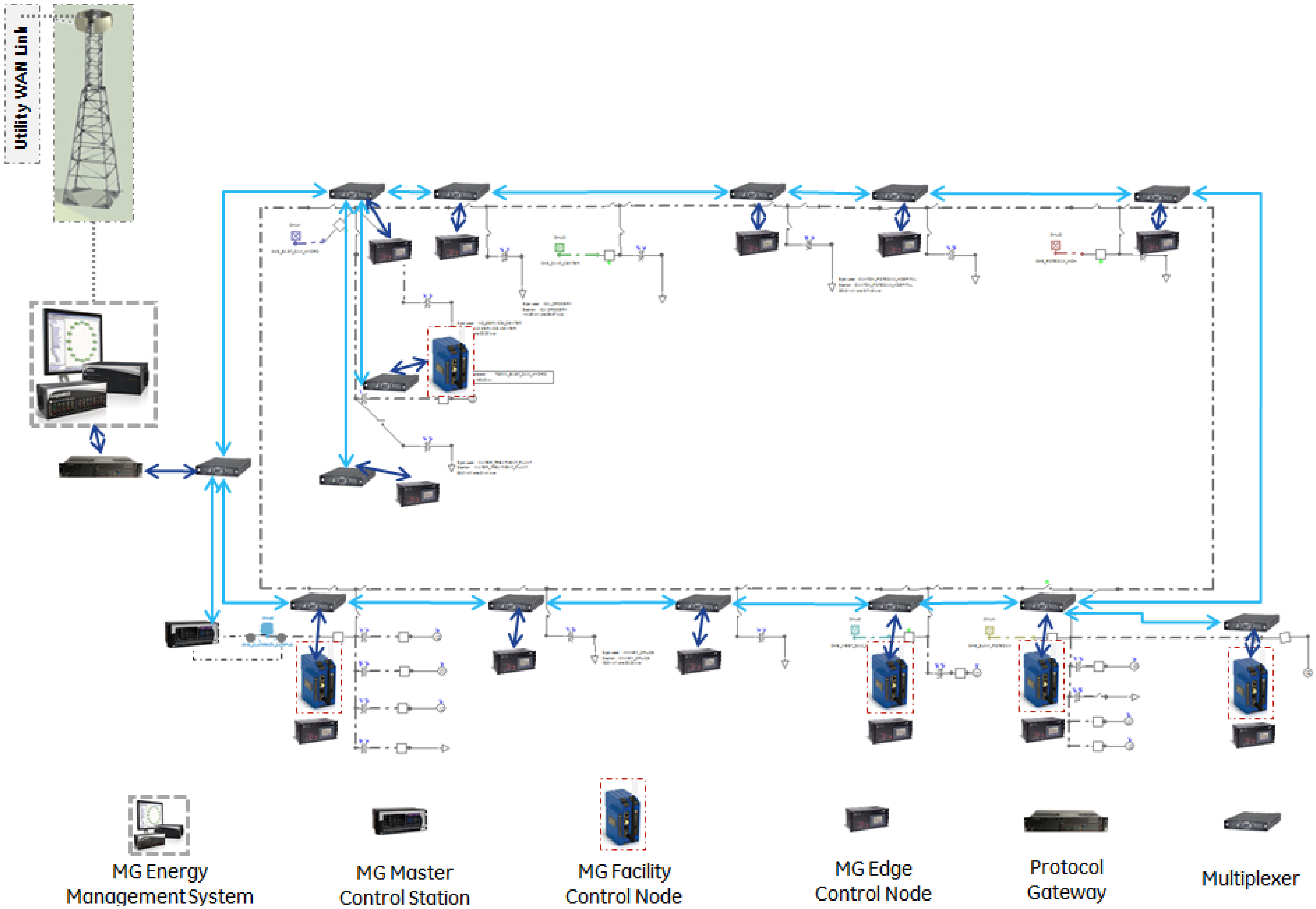
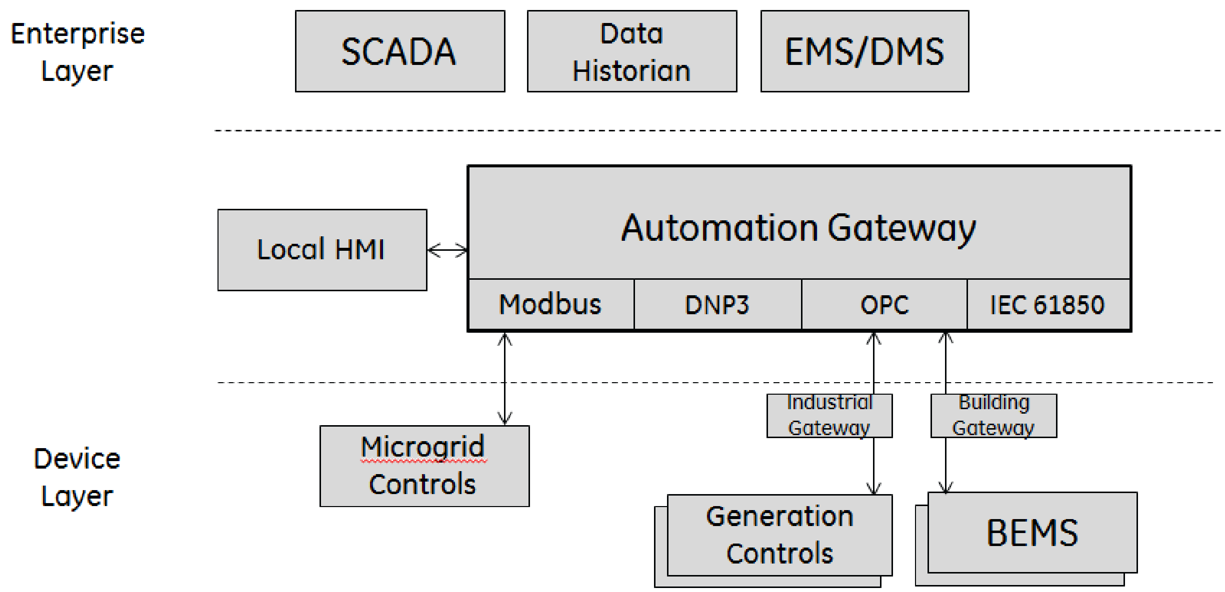


Figure 27. Software Components of the Control Architecture



The loads of the microgrid could be divided into control load zones: curtailable/shedable, discretionary, and critical loads. After a more detailed analysis of loads is conducted, a precise characterization of required controller types for each facility can be provided. For instance, at this point, it is not clear what buildings have BEMS and how these will be controlled by the microgrid controller. In addition, some of the buildings are equipped with heating, ventilation, and air conditioning (HVAC) units and some with direct digital control (DDC) technologies; therefore, for interoperability with the controller, a translation layer will be required (Figure 27).

3.5.2.2 Communications

The new underground electrical infrastructure suggests a dedicated fiber-optic network solution for communications that yields highest performance when it comes to bandwidth and reliability, although at a potentially high-cost commitment for the microgrid owners. All communications within the microgrid will be conducted over this network, which will provide at least 100 Mbit/s Ethernet—a speed that is expected to be sufficient for a network of this size. Network traffic will include communication with the back-end servers and security workstations.

Figure 26 shows fiber links between multiplexers in light blue. When the length between the microgrid facilities is considered, all links satisfy the length requirements of the single mode fiber cables. For links shorter than 300 meters, typically within data centers, more efficient multimode fiber cables can be used.

The suggested ring network design implies redundancy in communications (i.e., in the event that a fiber link is broken, the traffic can be redirected). To build a fault tolerant network of a higher degree (no single point of failure) requires two fiber rings. The devices should be enclosed in rugged aluminum chassis tested for shock and vibration according to military standards. In addition, the standard industrial-grade control and communication devices can withstand extreme operational temperature range of -40°C to 70°C.

For external communications, the MG EMS communicates to the utility-wide area network through 3G/4G, WiMax, or 900 MHz communication links. When the lack of communication signals from the utility is set as an abnormal condition, the microgrid can isolate from the utility and thus operate when there is a loss in communications with the utility. From that moment, the local generation and load devices are under the control of the microgrid controller.

3.5.2.3 Protocols

Depending on the protocols used by the deployed edge devices (e.g., IEDs, Programmable Logic Controllers [PLC], switchgear, relay, sensors, meters, etc.) the microgrid should be able to translate between at least DNP3, Modbus (both Serial and Ethernet) and Open Platform Communication (OPC) protocols, in addition to building communication protocols (e.g., BACNET). To enable the broadest support of interfaces for current and future devices, the underlying data model of the microgrid should be IEC 61850, the de facto industry standard for distribution system communications.

In terms of communication topology, the MG EMS and the Microgrid Master Control Station should act as both client and server (i.e., be able to both initiate and respond to communication).

A preliminary list of hardware and software components is included in Table 36.

Table 36. List of Control and Communications Hardware and Software Components

Description	Notes	Example	QTY
MG Controls			
Microgrid Energy Management System	Hardened computer with processor/communication /interface expansion ports. Rack system. Racks, Displays, Peripherals. SQL Server DBMS.	Dell PowerEdge R270 Rackmount Server	1
HMI/SCADA	Server-based HMI/SCADA software solution framework providing event/alarm monitoring, logging, and SCADA configuration tools.	GE Cimplicity	1
MG Master Control Station	MG Generation Controller. Forecasting and optimal dispatch functions.	GE Multilin U90+ (includes MG controller software)	1
MG Configuration Utility	MG controller HMI and configuration app	GE EnerVista Engineer/Maintenance/Monitoring/Integrator	1
MG Facility Control Node	Hardened computer with processor/communication /interface expansion ports. BEMS I/F.	Dell PowerEdge R270 Rackmount Server.	5
Microgrid Edge Control Node	Multifunction IED for MG control nodes (1 control node per facility - or building if widely distributed). General controller, multi-protocol I/F to MG components.	GE D25 Multifunction Controller	13
Power Metering	Smart meter monitors main facility load. BEMS I/F provides detailed monitoring.	GE Smart Meter	13
MG Communications			
MG Energy Management System Network Access Point	Wireless access point for MG EMS. Use 900Mhz or 3G/4G as needed for linking to utility field network.	GE MDS orbit - MCR-4G access point	1
Protocol Gateway	Multifunction intelligent gateway (interface and data collection from protection, control, monitoring, RTU, IEDs).	GE D400 (includes programming environment LogicX)	1
Fiber-Optic Transceiver	Network switching for reliable operation in industrial and extreme weather conditions. Local or Remote Configuration.	JungleMUX T1 Multiplexer	14

3.5.3 Recommendations for Future Work

For a more detailed evaluation of controls design, a study using a tool that allows simulation of grid islanding and switch supervisory control strategies (e.g., ETAP or Gridlab-D) is recommended. Similarly, for validation of communications performance requirements, a network simulation tool (e.g., ns-2) is recommended.

3.6 Microgrid Design Conclusions

The initial design of the Potsdam Microgrid has been assessed, with preliminary analysis of the steady-state operation of the system and the short-circuit requirements of the equipment. Initial Protection and Control/Monitoring System design and Control System function have also been reviewed.

Based on our findings, the initial plan and design of the Potsdam Microgrid is adequate and meets the Project Objectives, as detailed in the project's statement of work. Further work will be required to finalize the design, equipment ratings, and layout of the microgrid.

4 Costs

Building a microgrid requires a significant investment in equipment. After assessing the results of the economic and load and supply analysis (section 2) and the microgrid design (section 3), the major equipment items needed for the microgrid, general equipment ratings and specifications, and associated costs have been determined. These data inform the overall benefit-cost analysis (BCA) of the proposed microgrid approaches. GE Energy Consulting conducted this portion of the study.

4.1 Potsdam Microgrid Overview

The Potsdam Microgrid is designed as a resilient microgrid to provide select entities within the Village of Potsdam continuity of power in the event of a loss of the main electrical grid during extreme weather conditions. The microgrid will be powered by a combination of DG assets, including hydropower, solar power, and either single or dual-fuel (natural gas/diesel fuel) generators and will be able to operate in both grid-connected and islanded modes.

In grid-connected mode, DG assets will supply power to the microgrid and any excess power will be supplied to the larger grid. In islanded mode, with the underground microgrid disconnected from the overhead grid, the connected entities can be fully served by the microgrid's DG assets; however, a modest amount of load reduction is assumed during peak loading.

Three protection schemes for the microgrid were considered. Option 1 (Figure 28) is dominated by full breaker and relay protections at each node of the microgrid and offers the maximum protection, sectionalizing, and automatic restoration capability. Option 1 provides the most overall resiliency for the microgrid; however, is also the most complex and expensive. Option 2 (Figure 29) has been designed with a combination of both fused disconnects and breaker/relay protections. Option 2 provides a high degree of resiliency, sectionalizing, and protection capabilities; however, it sacrifices some resiliency and automatic restoration capability and has a lower cost compared with Option 1. Protection option 3 (Figure 30) is a more basic protection scheme using a combination of breakers, relays, fuses, fused disconnects, and reclosers. Option 3 provides the minimum amount of protection while sacrificing a significant amount of the resiliency and automatic restoration capability and has a much lower cost when compared with options 1 or 2. See section 3 for detailed descriptions for protection options 1 and 2.

Figure 28. Potsdam Microgrid One-Line—Option 1

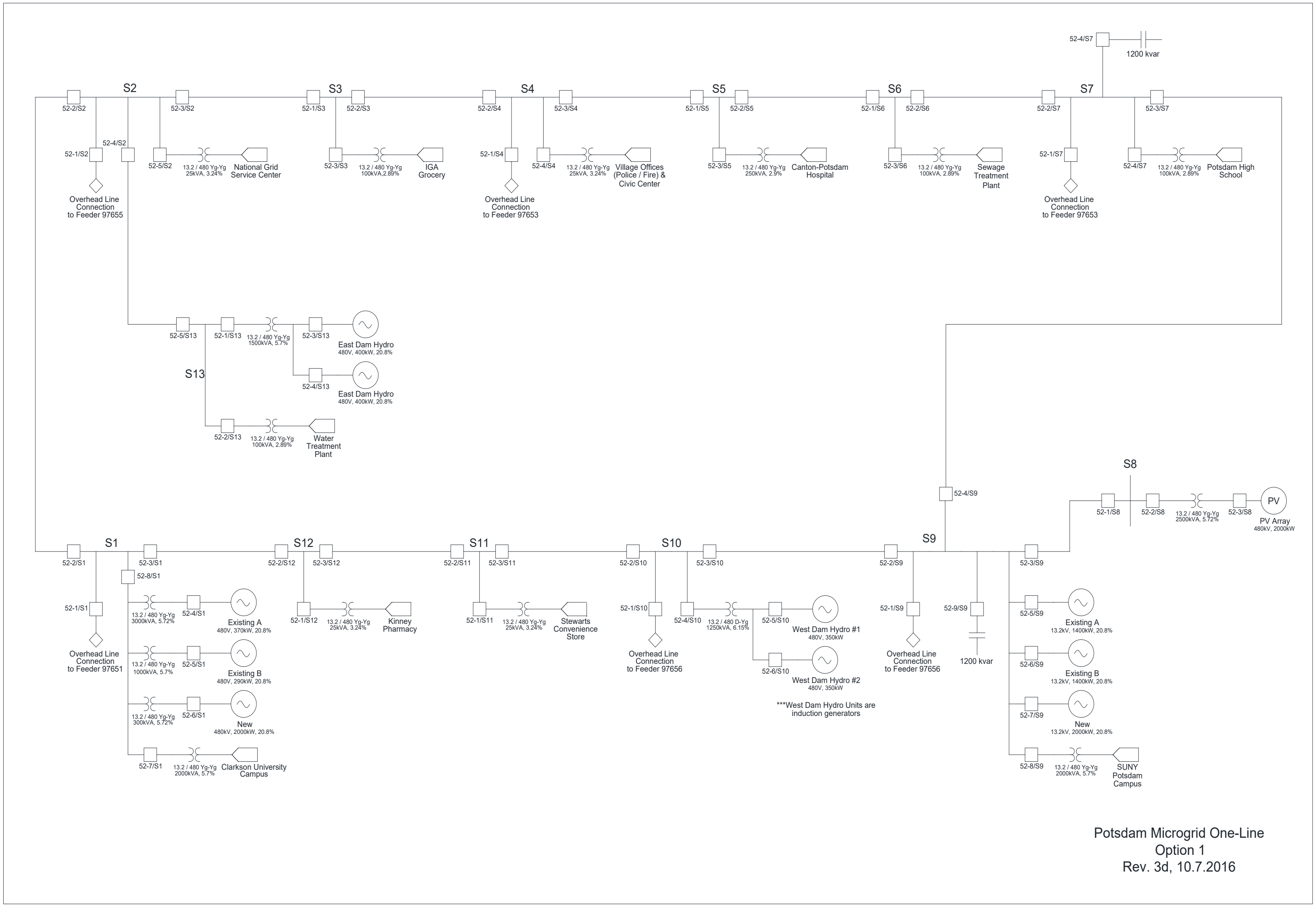


Figure 29. Potsdam Microgrid One-Line—Option 2

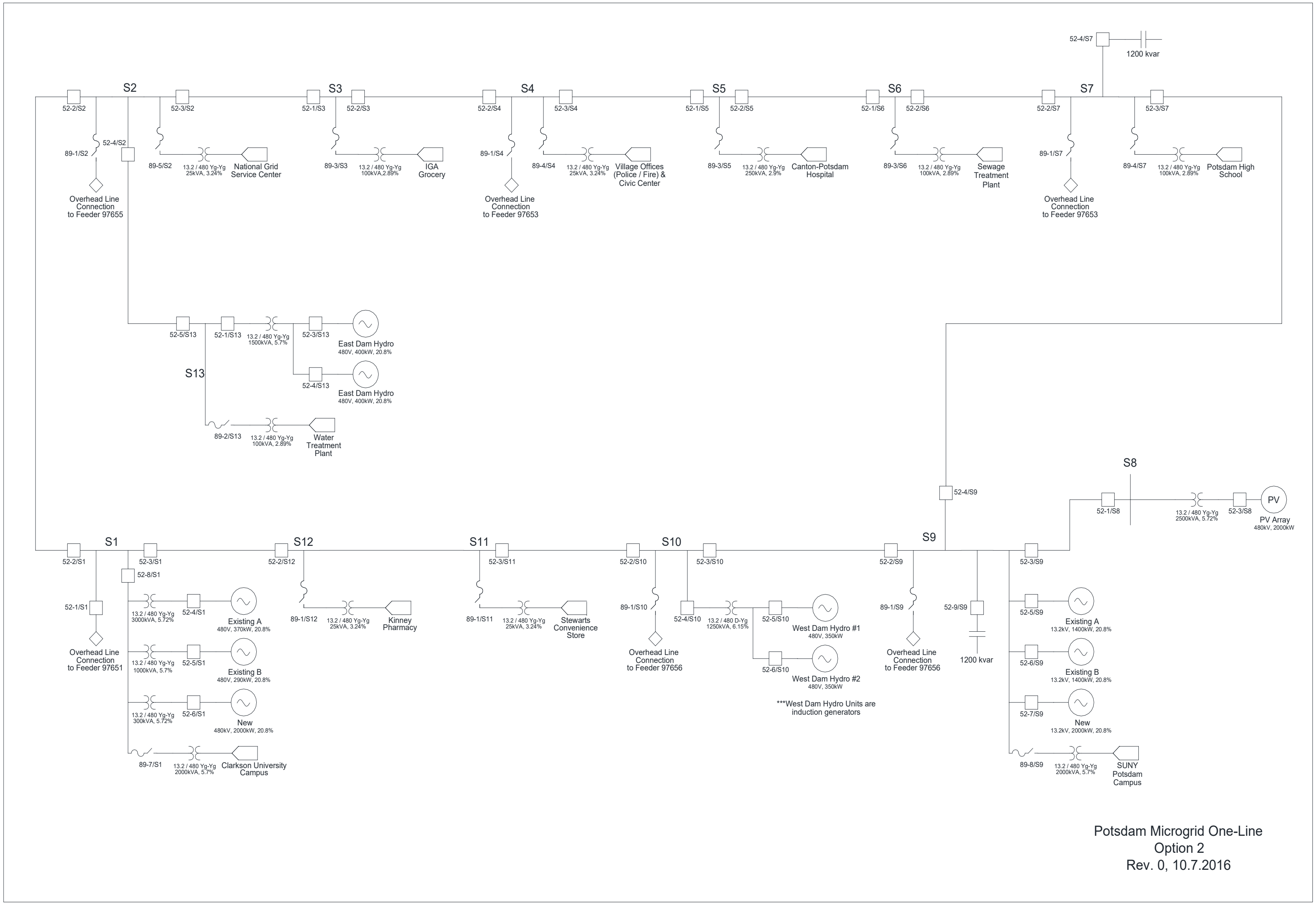
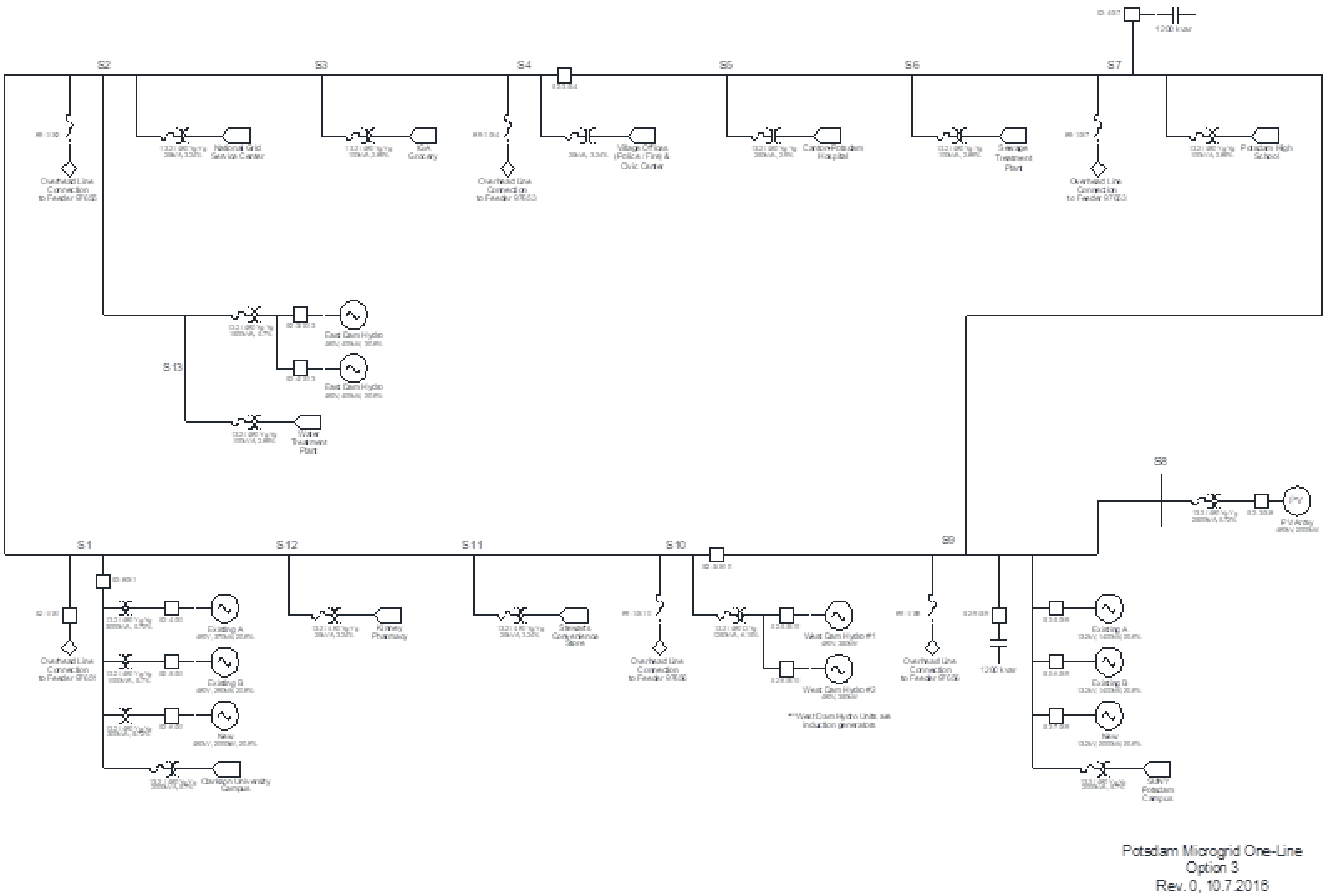


Figure 30. Potsdam Microgrid One-Line—Option 3



4.2 Material List and Cost Information

4.2.1 Generic Material List

The material list (Table 37) was developed based on the proposed microgrid design documented in section 3. Only new equipment needed for the microgrid is included. In most cases, actual suppliers and/or equipment part numbers were used for estimation of costs for "typical" or "example" parts that would meet the requirements. Actual products used for cost estimation are not intended to represent any specific brand; therefore, alternative suppliers and parts could be considered.

Cost estimates have been developed from actual equipment quotes, historical pricing, or raw estimations, and are intended to capture only the major equipment items; minor items have not been included and have been lumped into the miscellaneous cost total.

Table 37. Potsdam Microgrid Generic Material List

Item Number	Quantity	Description and Specification
Generation Equipment		
1	1	Option 1 – 2 MW Dual-Fuel (Natural Gas/Diesel Fuel) Engine and 480 V Generating Set
2	1	Option 1 – 2 MW Dual-Fuel (Natural Gas/Diesel Fuel) Engine and 13.2kV Generating Set
3	1	Option 2 – 2 MW Natural Gas Engine and 480 V Generating Set
4	1	Option 2 – 2 MW Natural Gas Engine and 13.2 kV Generating Set
5	1	Option 3 – 2 MW Hybrid (Fuel Cell/Natural Gas) Engine and 480 V Generating Set
6	1	Option 3 – 2 MW Hybrid (Fuel Cell/Natural Gas) Engine and 13.2 kV Generating Set
Distribution Equipment		
1	12	25kVA, 13.2 / 480 Yg-Yg, Transformer
2	12	100kVA, 13.2 / 480 Yg-Yg, Transformer
3	1	250kVA, 13.2 / 480 Yg-Yg, Transformer
4	1	300kVA, 13.2 / 480 Yg-Yg, Transformer
5	1	1000kVA, 13.2 / 480 Yg-Yg, Transformer
6	1	1250kVA, 13.2 / 480 Yg-Yg, Transformer
7	1	1500kVA, 13.2 / 480 Yg-Yg, Transformer
8	2	2000kVA, 13.2 / 480 Yg-Yg, Transformer
9	3	2500kVA, 13.2 / 480 Yg-Yg, Transformer
10	3	3000kVA, 13.2 / 480 Yg-Yg, Transformer
11	~58,000 ft.	500-MCM Cable
12	~110 ft.	750-MCM Cable

Table 37 (continued)

Item Number	Quantity	Description and Specification
13	As Needed	Buried Ductwork for Cables with Manholes
14	2	13.2kV, 1200kVar, Shunt Capacitor Bank
15	49	Option 1 – 15kV Class Breaker, 1200A continuous, 20kA interrupting
16	30	Option 2 – 15kV Class Breaker, 1200A continuous, 20kA interrupting
17	2	Option 3 – 15kV Class Breaker, 1200A continuous, 20kA interrupting
18	7	480 V Class Breaker, 800A continuous, 65kA interrupting
19	19	Option 2 - 15kV Class Motor-Operated Fused Switch, 600A continuous, 20kA interrupting
20	5	Option 3 - 15kV Class Motor-Operated Fused Switch, 600A continuous, 20kA interrupting
21	2	Option 3 – 15kV Class Recloser, 600A continuous, 12kA interrupting
22	2	Option 3 – 15kV Class Capacitor Switcher, 400 continuous, 13.5kA interrupting
23	12	Control, Protection, and Switchgear Enclosure
Protection Equipment—Options 1 and 2		
1	32	Line Protection System relays: Used to provide primary high-speed Differential and backup Phase and Ground Overcurrent protection to each of the 13 interconnecting transmission lines
2	14	Bus Differential System relays: Used to provide primary high-speed Differential protection to each of the 13.2 kV Switchgear Lineups containing five or less feeder/tie circuit breakers
3	2	Bus Differential System relays: Used to provide primary high-speed Differential protection to each of the 13.2 kV Switchgear Lineups containing six or more feeder/tie circuit breakers
4	15	Feeder Management System relays: Used to provide monitoring and control functions/capabilities for each of the fourteen 13.2 kV Switchgear Lineups. Also used to provide Phase and Ground Overcurrent protection for selected 13.2 kV feeder circuits supplied from each switchgear lineup
5	2	Generator Protection System relays: Used to provide Stator and Rotor protection to the 2000 kW Generators connected to 13.2 kV Switchgear Lineups S1-T and S8
6	2	Capacitor Bank Protection and Control System relays: Used to provide Primary Phase and Ground Overcurrent, Under/Over-Voltage and Can Unbalance protection to the 13.2 kV Capacitor Banks connected to 13.2 kV Switchgear Lineups S7 and S9
7	13	Managed Ethernet Switch
8	2	GPS Clock
9	14	Lockout Switch
Protection Equipment—Option 3		
1	1	Line Protection System relays: Used to provide primary high-speed Differential and backup Phase and Ground Overcurrent protection to the primary interconnecting transmission line
2	2	Bus Differential System relays: Used to provide primary high-speed Differential protection to each of the 13.2 kV Switchgear Lineups containing five or less feeder/tie circuit breakers

Table 37 (continued)

Item Number	Quantity	Description and Specification
3	2	Feeder Management System relays: Used to provide monitoring and control functions/capabilities for each of the 13.2 kV Switchgear Lineups. Also used to provide Phase and Ground Overcurrent protection for selected 13.2 kV feeder circuits supplied from each switchgear lineup
4	2	Generator Protection System relays: Used to provide Stator and Rotor protection to the 2000 kW Generators connected to 13.2 kV Switchgear Lineups S1-T and S8
5	2	Capacitor Bank Protection and Control System relays: Used to provide Primary Phase and Ground Overcurrent, Under/Over-Voltage and Can Unbalance protection to the 13.2 kV Capacitor Banks connected to 13.2 kV Switchgear Lineups S7 and S9
6	2	Managed Ethernet Switch
7	2	GPS Clock
8	14	Lockout Switch
Control and Communications Equipment		
1	1	Microgrid Master Control Station
1.1	1	Microgrid Master Station Computer
1.2	1	Microgrid Configuration Utility
1.3	1	Microgrid Maintenance Utility
1.4	1	Microgrid Monitoring Utility
1.5	1	Microgrid Device Integration
1.6	1	HMI and SCADA framework providing event and alarm monitoring, logging, and SCADA configuration tools
1.7	1	Microgrid Generation Controller/Optimizer
1.8	1	DC-AC Inverter
1.9	1	Advanced Protocol Gateway
2	2	Microgrid Facility Control Node (with BEMS Integration)
2.1	2	Application Host Computer
2.2	2	Load Metering
2.3	2	Load and Generation control and monitoring: IED serving as a general controller, PLC, IED gateway, and fault event recorder
2.4	2	DC-AC Inverter
3	3	Microgrid Facility Control Node (without BEMS)
3.1	3	Application Host Computer
3.2	3	Load Metering
3.3	3	Load and Generation control and monitoring: IED serving as a general controller, PLC, IED gateway, and fault event recorder
3.4	3	DC-AC Inverter
4	8	Microgrid Edge Control Node
4.1	8	Load and Generation control and monitoring: IED serving as a general controller, PLC, IED gateway, and fault event recorder
5	7	Synchronization Equipment
5.1	7	Auto-synchronization of Generation onto the Power System

Table 37 (continued)

Item Number	Quantity	Description and Specification
6	1	Microgrid Communications Network
6.1	1	Microgrid Energy Management System network access point providing wireless access point for the microgrid Energy Management System. A hybrid communication platform providing support for a variety of network interfaces and transport protocols using 900Mhz Mesh or 3G/4G as needed for linking to utility field network and using 900Mhz mesh to microgrid control nodes at buildings.
6.2	1	Redundant fiber-optic network connecting each of the microgrid nodes using bidirectional, single mode fiber-optic cable
6.3	13	Redundant 125Vdc Battery and Charger Systems
Energy Storage Equipment		
1		Storage Equipment (Batteries, Capacitors, and other parts)
2		Connection Equipment
3		Protection Equipment
4		Control Equipment

4.2.2 Estimated Cost Information

Table 38. Potsdam Microgrid Estimated Cost Information

Category	Equipment Costs	Installation Costs	Total
Generation			
Option 1 (Dual-Fuel Option)	$4,000,000[1]	$1,500,000	$5,500,000
Option 2 (Natural Gas Only Option)	$2,700,000	$1,500,000	$4,200,000
Option 3 (GE Hybrid Fuel Cell/Natural Gas Option)	$25,000,000[2]	$3,500,000	$28,500,000
Distribution System (Includes Interconnection Cable, Breakers, and Switches)			
Option 1 Total	$12,013,000	$11,855,000	$23,867,000
Transformer Total	$535,388	$514,500	$1,049,888
Underground Cable System Total	$5,813,300	$6,770,000	$12,583,300
Capacitor Bank Total	$54,000	$30,000	$84,000
Switchgear Total	$5,609,900	$4,540,000	$10,149,900
Option 2 Total	$11,577,000	$11,475,000	$23,051,000
Transformer Total	$535,388	$514,500	$1,049,888
Underground Cable System Total	$5,813,300	$6,770,000	$12,583,300
Capacitor Bank Total	$54,000	$30,000	$84,000

Table 38 (continued)

Category	Equipment Costs	Installation Costs	Total
Switchgear Total	$5,174,000	$4,160,000	$9,334,000
Option 3 Total	$7,460,000	$8,115,000	$15,474,000
Transformer Total	$535,388	$514,500	$1,049,888
Underground Cable System Total	$5,813,300	$6,770,000	$12,583,300
Capacitor Bank Total	$54,000	$30,000	$84,000
Switchgear Total	$957,000	$800,000	$1,757,000
Protection System			
Options 1 and 2	$1,964,000	$630,000	$2,571,000
Option 3	$312,000	$105,000	$393,000
Control and Communications	$2,783,000	$1,450,000	$4,233,000
Energy Storage Equipment Option	TBD	TBD	TBD
Gas Extension and Connections	n/a	n/a	$150,000
Gas Extension, Diesel Storage, and Connections	n/a	n/a	$200,000
Miscellaneous Equipment	n/a	n/a	$750,000
Engineering and Design	n/a	n/a	$1,000,000
Testing and Commissioning	n/a	n/a	$250,000

1 Dual-Fuel Engine cost is an estimate, since no quotes were received from suppliers.

2 Hybrid Fuel Cell-Natural Gas Engines are in development and the cost developed here is an estimate.

Table 39. Potsdam Microgrid Estimated Project Totals

Estimated Project Totals	
Dual-Fuel Engine with Option 1 Protection	$38,390,000[1]
Dual-Fuel Engine with Option 2 Protection	$37,580000[1]
Dual-Fuel Engine with Option 3 Protection	$27,820,000[1]
Natural Gas Engine only with Option 1 Protection	$37,040,000
Natural Gas Engine only with Option 2 Protection	$36,230,000
Natural Gas Engine only with Option 3 Protection	$26,470,000
Hybrid Fuel Cell-Natural Gas with Option 1 Protection	$61,340,000[2]
Hybrid Fuel Cell-Natural Gas with Option 2 Protection	$60,530,000[2]
Hybrid Fuel Cell-Natural Gas with Option 3 Protection	$50,770,000
Energy Storage Option Adder	TBD

1 Dual-Fuel Engine cost is an estimate only due to no quote received from supplier.

2 Hybrid Fuel Cell-Natural Gas Engine is in development and cost is an estimate.

4.3 Societal Benefit-Cost Analysis

The benefit cost assessment is based on the NY Prize Stage 1 methodology, utilizing the BCA model of Industrial Economics, Inc. (IEc). NYSERDA retained IEc to provide a uniform methodology and platform for comparing the benefits and costs of different NY Prize Stage 1 projects.

The reason for considering societal benefits and costs rather than a business case from a private investor's perspective is that the NY Prize-based microgrids, like the Potsdam Microgrid, are intended to be resilient microgrids and serve the interests of the general public. Therefore, any public expenditure towards the development of the microgrid would need to be justified based on the societal net benefits (i.e., to be cost-effective from the society's perspective).

The model does not consider the distribution of costs and benefits among individual stakeholders, which include developers, customers, and utilities. Instead, the model estimates the costs and benefits of a microgrid from the perspective of society, considering the benefits of maintaining operations at the facilities served by the microgrid in the event of a prolonged emergency (i.e., the larger grid outage).

4.3.1 Analysis Approach

4.3.1.1 BCA Model: Industrial Economics, Inc.

The project team collected the information for the BCA model via two questionnaires (one for facilities, and one for the microgrid) that were developed by IEc and used in the NY Prize Stage 1. The cost estimates and site and generation characteristics were input into the IEc BCA model to determine the present value of the benefits and costs and the resulting benefit to cost ratio of the proposed Potsdam Microgrid. The BCA model results are provided in the final part of this section.

In NY Prize Stage 1 and based on the original scope of the Potsdam project, estimation of the costs and benefits should be accurate within +/- 30%. In the NY Prize projects, emphasis of the analysis at Stage 1 was on establishing a reasonable basis for competing for funding for a detailed, audit-grade engineering and business case analysis at Stage 2 of the NY Prize Community Grid Competition.

The following were the main steps in evaluating the societal benefits/costs of the Potsdam Microgrid:

- Running DER-CAM to determine the hourly dispatch of the DER assets in Potsdam.
- Using the DER dispatch results and other information in the BCA model to determine the net present value of benefits to costs ratio (B/C) and the project's internal rate of return (IRR).

In consultation with the project stakeholders, the team decided the BCA of the Potsdam Microgrid should be based on the same methodology as the one used in the NY Prize Stage 1 projects to enable comparison between projects.

The BCA methodology involves an Excel-based spreadsheet program and model that uses a consistent set of underlying assumptions and electricity and fuel prices. However, the data input into the model reflects the particular characteristics of each microgrid site. Description of the general approach and BCA model is based mainly on the NY Prize project related documents developed by IEc.

The economic viability of a microgrid is evaluated by the BCA model based on estimated microgrid costs, design and operating characteristics, and the facilities and services the microgrid is designed to support. The model only analyzes a specified operating scenario, which, for Potsdam, is based on a year's worth of hourly dispatch (i.e., generation profiles) of the microgrid's DER assets, as determined by the DER-CAM model. The model does not determine an optimal project design or operating strategy.

The BCA model analyzes the costs and benefits of the microgrid over a 20-year time horizon. Initial design and planning costs are assumed to occur in 2016, and the results reported (in both a discounted present value and an annualized basis) are in 2014 dollars. The model applies conventional discounting techniques to calculate the present value of costs and benefits, employing an annual discount rate that can be set (the Model assumes a default value of 7%).[10] After the model evaluates the microgrid's cumulative benefits and costs, it then calculates the ratio of microgrid's present value of benefits to its present value of costs. The model also calculates the project's IRR, which indicates the discount rate at which the project's net present value (NPV) becomes equal to zero (i.e., the present value of benefits becomes equal to the present value of costs). All dollar values are adjusted for inflation and expressed in 2014 dollars.

4.3.1.2 BCA Input Data

The following is a list of input data used in the IEc's BCA model based on the NY Prize Stage 1 statement of work. All the items required by the NY Prize are listed, even though some items do not apply to the Potsdam Microgrid.

- Facility and Customer Description
  - Facilities' utility rate class (i.e., residential, small commercial/industrial, and large commercial/industrial).
  - Economic sector to which the facility belongs (e.g., manufacturing, wholesale and retail trade, etc.).

- Whether multiple ratepayers are present at the facility (e.g., multifamily apartment buildings).
- Facility's average annual electricity demand (MWh) and peak electricity demand (MW). For facilities with multiple ratepayers: Average annual and peak demand per customer, rather than for the facility as a whole.
- Percentage of the facility's average demand the microgrid would be designed to support during a major power outage.
- In the event of a multiday outage, the number of hours per day, on average, the facility would require electricity from the microgrid.

- Characterization of Distributed Energy Resources
  - Energy/fuel source.
  - Nameplate capacity.
  - Estimated average annual production (MWh) under normal operating conditions.
  - Average daily production (MWh/day) in the event of a major power outage.
  - For fuel-based DER, fuel consumption per MWh generated (MMBtu/MWh).

- Capacity Impacts and Ancillary Services
  - The impact of the expected provision of peak load support on generating capacity requirements (MW/year).
  - Capacity (MW/year) of demand response that would be available by each facility the microgrid would serve.
  - Associated impact (deferral or avoidance) on transmission capacity requirements (MW/year).
  - Associated impact (deferral or avoidance) on distribution capacity requirements (MW/year).
  - Ancillary services to the local utility (e.g., frequency or real power support, voltage or reactive power support, black start or system restoration support).
  - Estimates of the projected annual energy savings from development of a new CHP system relative to the current heating system and current type of fuel being used by such system.
  - Environmental regulations mandating the purchase of emissions allowances for the microgrid (e.g., due to system size thresholds).
  - Emission rates of the microgrid for CO_2, SO_2, NO_x, and particulate matter (emissions/MWh).

- Project Costs
  - Fully installed costs and engineering life span of all capital equipment.
  - Initial planning and design costs.
  - FOM costs (dollars/year).
  - VOM costs, excluding fuel costs (dollars/MWh).
  - The maximum amount of time each DER would be able to operate in islanded mode without replenishing its fuel supply.
  - Amount of fuel the DER would consume during the islanded period.

- Costs to Maintain Service During a Power Outage
  - Fuel/energy source of each existing backup generator.

- Nameplate capacity of each existing backup generator.
- The percentage of nameplate capacity at which each backup generator is likely to operate during an extended power outage.
- Average daily electricity production (MWh/day) for each generator in the event of a major power outage, and the associated amount of fuel (MMBtu/day) needed to generate that electricity.
- Any one-time costs (e.g., labor or contract service costs) associated with connecting and starting each backup generator.
- Any daily costs (dollars/day) (e.g., maintenance costs) associated with operating each backup generator, excluding fuel costs.
- Assuming a widespread power outage (i.e., a total loss of power in the surrounding area), estimates of the costs of any emergency measures that would be necessary for each facility to maintain operations, preserve property, and/or protect the health and safety of workers, residents, or the public. These costs should be specified for two scenarios: (1) when the facility is operating on backup power, if applicable, and (2) when backup power is not available, and should include:
  - Costs for one-time measures (e.g., total costs for connecting backup power)
  - Any ongoing measures (expressed in terms of average costs per day)

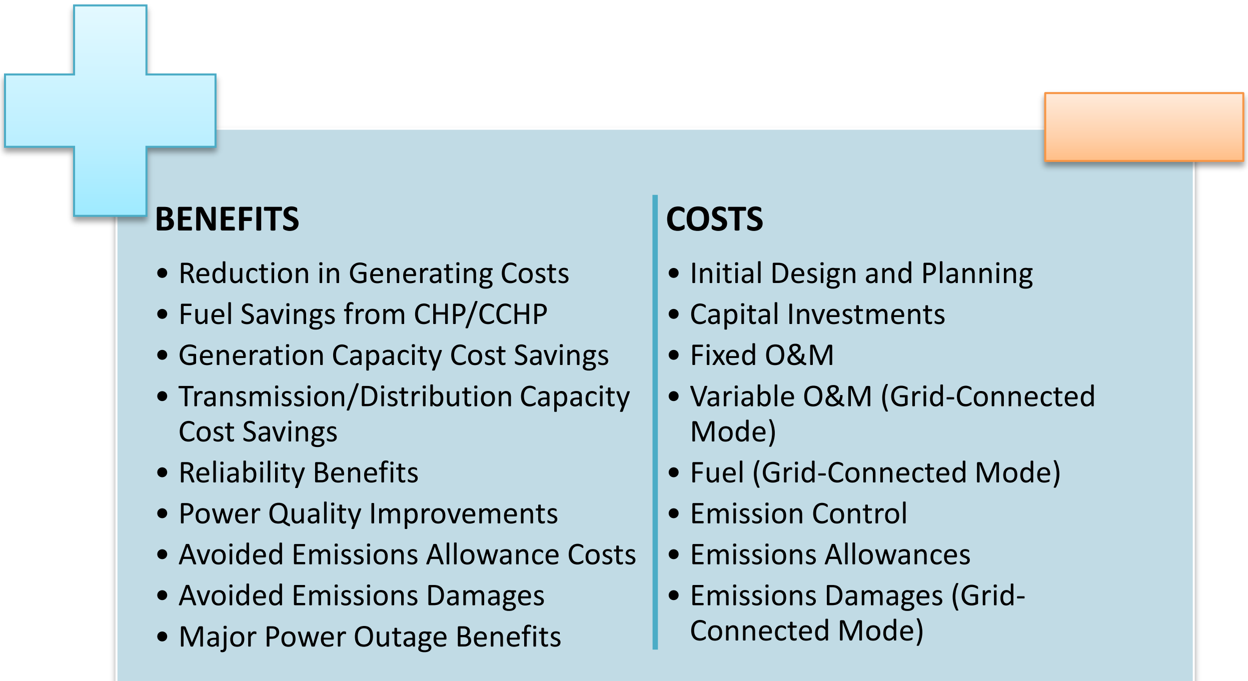
- Services Supported by the Microgrid
  - Estimate of the population served by each facility.
  - Estimate of the percentage loss in the facility's ability to serve its population during a power outage relative to normal operations (e.g., 20% service loss during a power outage), both when the facility is operating on backup power and when backup power is not available.

- For Residential Facilities
  - The type of housing the facility provides (e.g., group housing, apartments, dormitory, nursing home, assisted living, etc.).
  - Estimate of the number of residents that would be left without power during a power outage.

4.3.2 Benefit and Cost Components

The main components of societal benefits and costs are summarized in Figure 31.

Figure 31. Societal Benefits and Costs



4.3.2.1 Cost Components

- Initial Design and Planning: Includes costs of project design, building and development permits, and other initial general and administrative costs.
- Capital Investments: Includes capital investments (equipment and installation) associated with power generation, other DER assets, and costs associated with acquisition and installation of microgrid network infrastructure and interconnections.
- FOM: Includes FOM costs that do not vary with amount of electricity generated.
- VOM: Includes costs, other than fuel costs that vary with amount of electricity generated
- Fuel: Includes cost of fuel to power DER assets. The IEc BCA model's estimates of fuel costs are based on forecasts of petroleum distillate and natural gas prices (dollars/MMBtu) developed for the Draft 2013 State Energy Plan (SEP).
- Environmental Costs: Include costs associated with abatement of, or contribution to, air pollutions, such as emission control equipment, emission allowances, and emission damages.

4.3.2.2 Benefit Components

- Reduction in Generating Costs: Includes avoided costs of grid-based generation based on NYISO forecasts of energy prices by zone.
- Fuel Savings from CHP/CCHP (not applicable to the Potsdam Microgrid): Includes savings from CHP/CCHP system-based estimate of annual fuel savings, such as natural gas used in boilers for heating and electricity used for central chilling.

- Capacity Cost Savings: Includes cost savings in deferment of investment in expansion of generation, transmission, and distribution system, based on microgrid's anticipated peak load support or offering of demand response resources.
    - Generation Capacity Cost savings: Values of impacts on generation capacity are based on NY DPS forecasts of capacity prices by zone.
    - Transmission/Distribution Capacity Cost Savings: Values of impact on distribution capacity are based on the prices of distribution capacity by area as reported by NY PSC (2009) and Con Edison (2013).
- Reliability Benefits: Includes avoided interruption cost due to reduction in routine outages (and reliability metrics such as SAIFI, CAIDI, MAIDI, etc.), based on the DOE's Interruption Cost Estimate (ICE) Calculator.
- Power Quality Benefits: Based on impact on baseline cost of power quality events for different categories of customer types, with the baseline cost estimate based on frequency of power quality events, and cost of power quality events for average customer in each rate class, and the number of customers in each class. Annual benefits are based on the percentage of power quality events the microgrid would prevent.
- Environmental Benefits: Include reductions in emissions (and hence emission allowance costs) from grid-based generation due to their displacement by the microgrid generation and also displacement of other fuel sources within the microgrid due to installation of CHP/CCHP systems.
- Major Power Outage Benefits: Based on maintaining critical services that reduce damages attributable to outages caused by extreme weather and other natural or man-made disasters.
    - Benefits of a particular project depend on the likelihood and severity of outages and the specific services that the microgrid helps to maintain.
    - IEc's BCA model has detailed assumptions regarding "Value of Lost Services" for different categories of critical services, such as fire service, emergency medical service, hospital service, police service, wastewater service, water service, and others.

Both costs and benefits are measured relative to a common baseline. The baseline is meeting the microgrid's loads without the microgrid's DER assets (i.e., a "without project" scenario). Then the BCA considers only those costs and benefits that are incremental to the baseline if the microgrid project is implemented.

Detailed Potsdam Microgrid site information used in the BCA model is provided in the appendices to this report section in the form of two questionnaires based on the same templates used in the Stage 1 projects.

4.3.3 Industrial Economics BCA Model Results

Benefit-Cost Analyses were performed for the following nine cases:

1. Generation Option 1 and Distribution Option 1
2. Generation Option 1 and Distribution Option 2
3. Generation Option 1 and Distribution Option 3
4. Generation Option 2 and Distribution Option 1
5. Generation Option 2 and Distribution Option 2
6. Generation Option 2 and Distribution Option 3
7. Generation Option 3 and Distribution Option 1
8. Generation Option 3 and Distribution Option 2
9. Generation Option 3 and Distribution Option 3

There are two principal scenarios to be considered in each case using the BCA model.

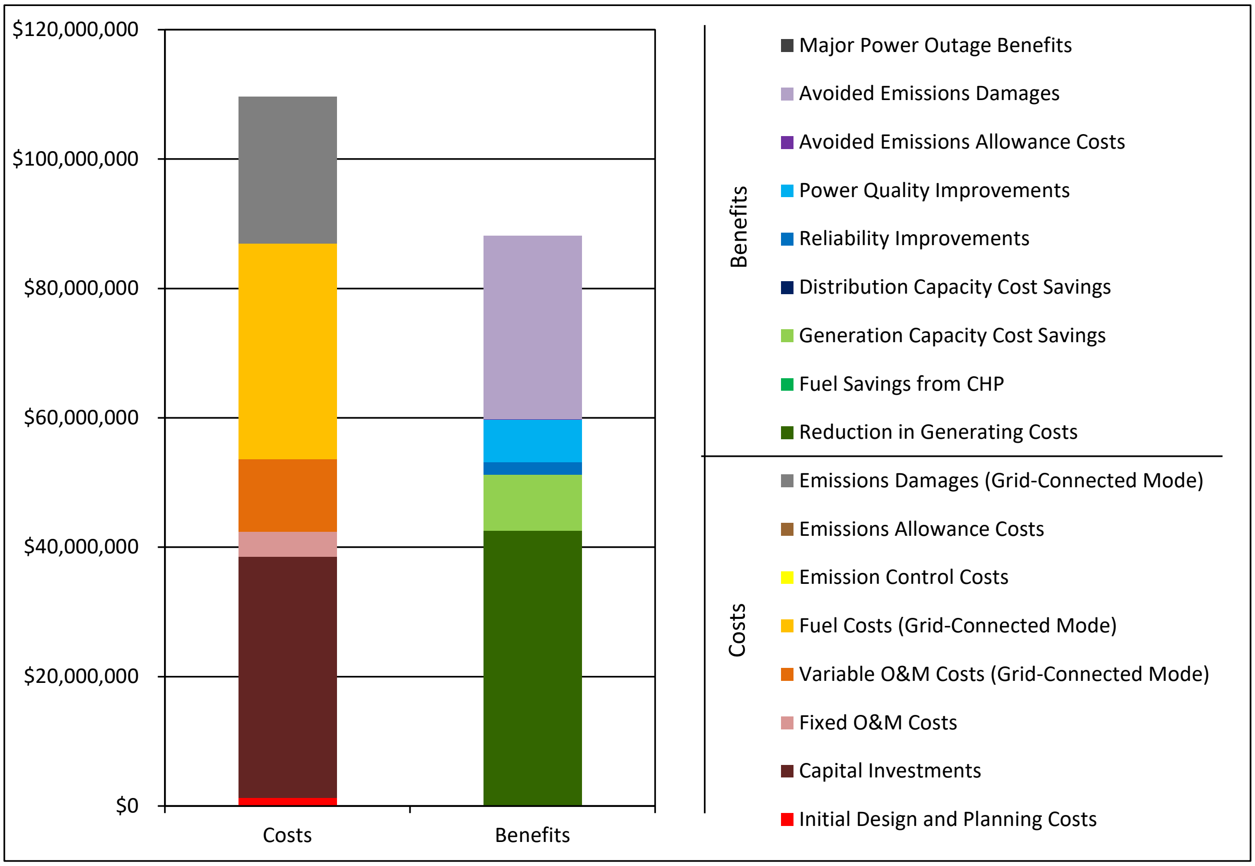
- Scenario 1: No major power outages over the assumed 20-year operating period (i.e., normal operating conditions in normal/blue sky days).
- Scenario 2: The average annual duration of "major power outages" (i.e., days of outage in the year) required for project benefits to equal costs, if benefits do not exceed costs under scenario 1.

The results of scenario 1 analysis for case 1 are provided in Table 40 and displayed in Figure 32. The BCA model results indicate that, under current assumptions, using high-level analysis and assuming no major power outages (only normal blue-sky days) during a 20-year time horizon, the Potsdam Microgrid's societal present value of costs would exceed its present value of benefits, resulting in a societal benefit to cost ratio of 0.80.

Table 40. Potsdam Societal BCA Results (with No Annual Major Power Outages)

Cost/Benefit Category	Present Value Over 20 Years (2014$)	Annualized Value (2014$)
Costs		
Initial Design and Planning	$1,250,000	$110,272
Capital Investments	$37,271,000	$2,807,043
Fixed O&M	$3,926,650	$346,400
Variable O&M (Grid-Connected Mode)	$11,160,556	$984,558
Fuel (Grid-Connected Mode)	$33,362,340	$2,943,148
Emission Control	$0	$0
Emissions Allowances	$0	$0
Emissions Damages (Grid-Connected Mode)	$22,697,293	$1,481,179
Total Costs	**$109,667,838**	**$8,672,601**
Benefits		
Reduction in Generating Costs	$42,525,428	$3,751,495
Fuel Savings from CHP	$0	$0
Generation Capacity Cost Savings	$8,690,644	$766,668
Distribution Capacity Cost Savings	$0	$0
Reliability Improvements	$1,878,695	$165,845
Power Quality Improvements	$6,666,383	$588,093
Avoided Emissions Allowance Costs	$19,071	$1,682
Avoided Emissions Damages	$28,334,071	$1,849,024
Major Power Outage Benefits	$0	$0
Total Benefits	**$88,114,291**	**$7,122,807**
Net Benefits	**-$21,553,547**	**-$1,549,794**
Benefit/Cost Ratio	**0.80**	

Figure 32. Potsdam Microgrid Societal BCA Results with No Annual Major Power Outages



The BCA model classifies outages caused by major storms or other events beyond a utility's control as "major power outages."[11] The Potsdam Microgrid is intended to be a resilient microgrid that would provide electric power to the microgrid's critical facilities in the event of a major power outage for an extended period. As expected, avoidance of outages through microgrid energy distribution would increase the societal benefits of the microgrid by lowering the interruption costs incurred by the microgrid serviced facilities. The BCA model includes detailed bench marked data on which to base evaluation of the accrued benefits of avoided outages for various types of facilities such as hospitals, police stations, fire stations, water pumping stations, waste water facilities, etc.

By incrementally adding fractions of major power outage days to the BCA model for case 1, the team determined that with an annual 0.75 days of outage per year, the Potsdam Microgrid with achieve a Societal Benefit to Cost Ratio of 1.

The results of scenario 2 analysis for case 1 are provided in Table 41 and displayed in Figure 33.

Table 41. Potsdam Societal BCA Results with 0.73 Days of Annual Major Power Outages

Cost/Benefit Category	Present Value Over 20 Years (2014$)	Annualized Value (2014$)
Costs		
Initial Design and Planning	$1,250,000	$110,272
Capital Investments	$37,271,000	$2,807,043
Fixed O&M	$3,926,650	$346,400
Variable O&M (Grid-Connected Mode)	$11,160,556	$984,558
Fuel (Grid-Connected Mode)	$33,362,340	$2,943,148
Emission Control	$0	$0
Emissions Allowances	$0	$0
Emissions Damages (Grid-Connected Mode)	$22,697,293	$1,481,179
Total Costs	**$109,667,838**	**$8,672,601**
		Benefits
Reduction in Generating Costs	$42,525,428	$3,751,495
Fuel Savings from CHP	$0	$0
Generation Capacity Cost Savings	$8,690,644	$766,668
Distribution Capacity Cost Savings	$0	$0
Reliability Improvements	$1,878,695	$165,845
Power Quality Improvements	$6,666,383	$588,093
Avoided Emissions Allowance Costs	$19,071	$1,682
Avoided Emissions Damages	$28,334,071	$1,849,024
Major Power Outage Benefits	$21,727,455	$1,918,118
Total Benefits	**$109,841,746**	**$9,040,925**
Net Benefits	**$173,907**	**$368,324**
Benefit/Cost Ratio	**1.00**	

Figure 33. Potsdam Societal BCA Results with 0.73 Days of Annual Major Power Outages

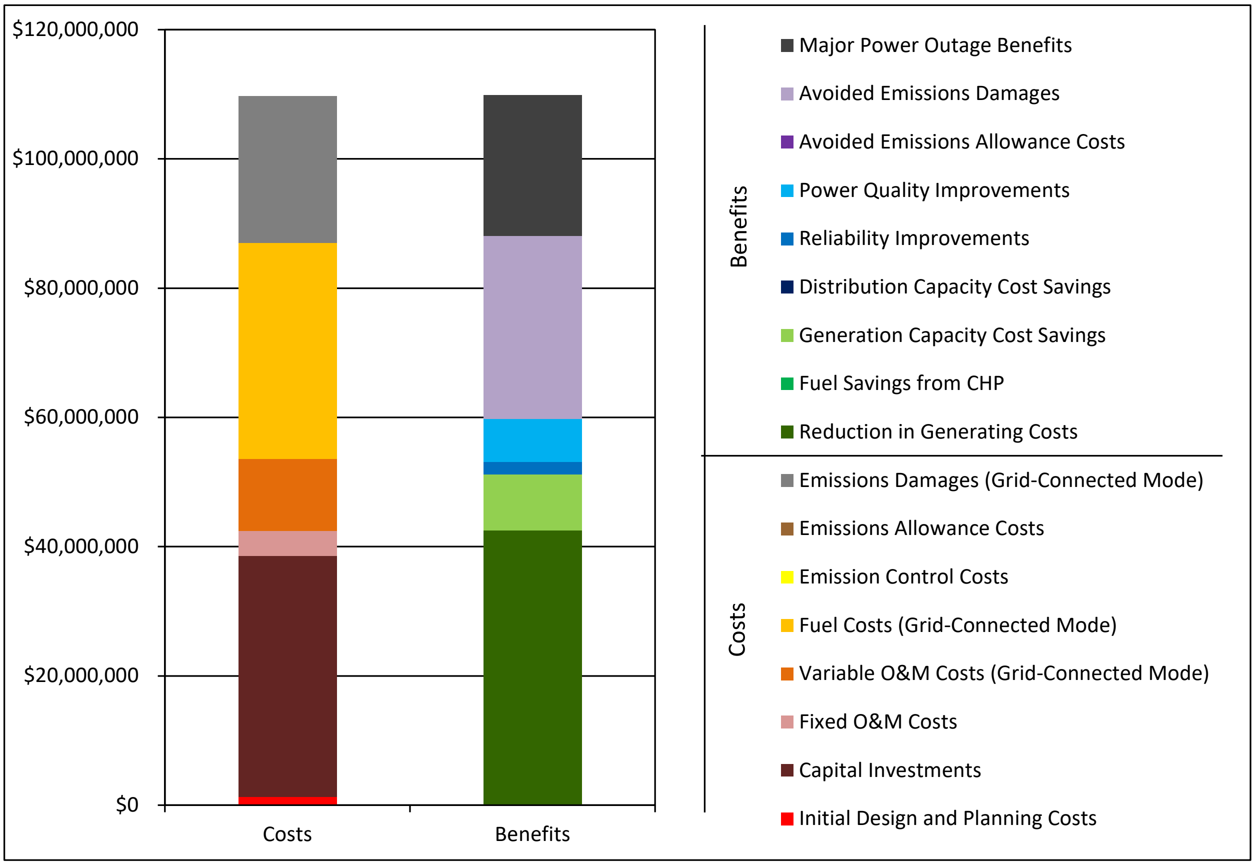


Table 42 provides the BCA results for all nine cases.

Table 42. Potsdam Societal BCA Results for all Nine Cases

	Generation Option 1 Distribution Option 1	Generation Option 1 Distribution Option 2	Generation Option 1 Distribution Option 3	Generation Option 2 Distribution Option 1	Generation Option 2 Distribution Option 2	Generation Option 2 Distribution Option 3	Generation Option 3 Distribution Option 1	Generation Option 3 Distribution Option 2	Generation Option 3 Distribution Option 3
NPV of Total Costs ($M)	109.67	108.85	99.10	108.37	107.55	97.80	132.67	131.85	122.10
NPV of Total Benefits ($M)	88.11	88.11	88.11	88.11	88.11	88.11	88.11	88.11	88.11
NPV of Net Benefits ($M)	-21.55	-20.74	-10.98	-20.25	-19.44	-9.68	-44.55	-43.74	-33.98
Annualized Costs ($M)	8.67	8.61	7.88	8.57	8.51	7.78	10.40	10.34	9.61
Annualized Benefits ($M)	7.12	7.12	7.12	7.12	7.12	7.12	7.12	7.12	7.12
Annualized Net Benefits ($M)	-1.55	-1.49	-0.75	-1.45	-1.39	-0.66	-3.28	-3.22	-2.49
Benefit/Cost Ratio	**0.80**	**0.81**	**0.89**	**0.81**	**0.82**	**0.90**	**0.66**	**0.67**	**0.72**
Outage Days/Year Needed for B/C=1	**0.75**	**0.72**	**0.38**	**0.70**	**0.67**	**0.33**	**1.56**	**1.53**	**1.19**

4.4 Microgrid Components and Costs Conclusions

4.4.1 Analysis Notes

4.4.1.1 Use of Average Versus Hourly Prices

DER-CAM and IEc's BCA model results do not provide the full scope of the microgrid's benefits due to the high-level nature of the analysis and the limits to modeling capability.

Both the DER-CAM and the BCA models use average monthly rather than hourly NYISO prices. This results in underestimating the benefits of the microgrid and in limiting the hourly dispatch options of the microgrid's DER assets. A more detailed analysis requires dispatch of the DER assets subject to "hourly" prices, such as NYISO's day-ahead and real-time locational marginal pricing (LMP).

The lack of hourly dispatch capability of the DER-CAM results in a simplified simulation of the microgrid in terms of self-generation versus power purchase from grid options, and therefore a less accurate representation of expected actual operations. In actual operations, where hourly prices exhibit a higher degree of variability, there would be a greater potential for the dispatch of DER assets during high-priced hours; this has been smoothed over in the monthly prices used in the current analysis. Therefore, the benefit cost results presented here may be notably different from an analysis of actual operations using alternate pricing assumptions (hourly, peak, etc.).

In the next stage, to evaluate the impact of microgrid dispatch under hourly prices, the project team will develop an hourly dispatch model to simulate the microgrid operations under historical NYISO day-ahead and real-time prices (and projected prices, if available).

4.4.1.2 Displacement of Grid Generation by Microgrid

The types of generation that might be displaced by the microgrid operation at any hour during normal "blue sky" days would depend on the type of generator that would be on the margin in the NYISO market at that hour.

Since the marginal unit at most hours is a fossil-fired generator, the displaced generator would most likely be a fossil-fired generator in NYISO. To balance the load and supply during times of low-demand and high-supply in typical NYISO (and other ISO) operations, it is usually the generators with highest operational costs that are displaced first, which in most hours happen to be fossil-based fuels. Only after all other options have been exhausted would ISOs require curtailment of renewable generation (in industry parlance, conventional fossil-based generation gets "displaced," and the renewable energy such as solar, wind, hydro, gets "curtailed").

Grid losses and transmission congestion also influence which generator is displaced by the operation of the microgrid; for instance, the costliest generator in ISO may not be displaced if it is in a load pocket. However, in general, during low-demand or high-supply periods, the high-variable cost units, such as fossil-fuel based generators, are displaced before curtailment of low-variable cost units, such as hydro and wind resources.

The type and level of displacement of fossil-fuel based generation and curtailment of renewable resources can be evaluated by running a security-constrained, production-costing model, such as the GE Multi Area Production Simulation (MAPS) model.

4.4.1.3 Carbon Emissions

The carbon emission results from the IEc BCA model are based on two sets of numbers:

- Annual carbon emission rates, which are based on the total CO_2 produced by all the generators in the microgrid during one full year of normal day operations. Units are in Metric Tons/MWh (the MWh includes both fossil-fuel-burning and renewable generation).
- IEc BCA models default values for the average Grid-ISO CO_2 generation.

The primary carbon emissions savings depend on multiple factors, such as the following:

- Efficiency of microgrid generation relative to the grid-based generation.
- Type of fuel used by the microgrid.
- Mix of generation in the microgrid, particularly the proportion of clean/ renewable energy.

4.4.1.4 Ancillary Services

The BCA did not consider potential benefits from the ancillary services/operating reserve offerings under utility programs or NYISO markets. Assuming microgrid DER assets (including both demand and supply side resources) meet the qualifying requirements, potential offerings by the microgrid may include Volt/Var support, frequency control, regulation, and even longer time spinning and non-spinning reserves.

In the next phase, the project evaluates additional potential ancillary services revenues for the Potsdam Microgrid through participation in National Grid programs and/or NYISO markets.

4.4.2 Overall Findings

The cost details presented in this section were developed from the proposed microgrid design presented in section 3. Costs are based on actual budgetary information received from potential suppliers, historical pricing details, and/or raw cost estimations. Not all the technical details have been engineered, so the cost totals are subject to change. Similarly, if the design changes from that proposed in section 3, the cost totals may also change.

IEc's BCA Model was used to perform a societal BCA for the Potsdam Microgrid project. The following are the findings:

- With No Major Power Outages: Under current assumptions the high-level analysis, assuming no major power outages within a 20-year time horizon (i.e., microgrid operation under only normal blue-sky days), the Potsdam Microgrid has a Societal Benefit to Cost Ratio of 0.81.
- However, the Societal Benefit to Cost Ratio can increase if the larger grid in Potsdam experiences outages. By increasing the number of major power outage days per year in the IEc BCA model, the team determined that with 0.73 major outage days per year, the Potsdam Microgrid would achieve a Societal Benefit to Cost Ratio of 1.

4.4.3 Recommendations for Further Analysis

Recommendations for further analysis in the next phase of the project include the following:

- Perform a more detailed analysis by considering unique characteristics of the Potsdam Microgrid, such as DER asset lifespan, hours of continuous operation, etc.
- Use the new multinodal version of DER-CAM with power flow capability for improved analysis.
- Develop a model to dispatch the microgrid DER assets against hourly day-ahead and real-time NYISO prices and evaluate, in more detail, the following:
    - Hourly scheduling and generation by the DER assets
    - Hourly purchase from the grid/ISO
    - Hourly sales to the grid/ISO
- Model NYISO with GE MAPS to determine which fossil-fuel units are displaced and which renewable resources are curtailed due to the operation of the Potsdam Microgrid on normal days.
- Perform sensitivity analysis on principal drivers, such as electricity prices, fuel prices, capital costs, DER efficiency, etc.

5 Dynamic Studies and Power Quality Analysis

This section discusses the findings of dynamic and power quality analysis for the preliminary design of a Resilient Underground Microgrid in Potsdam, NY. It is to be used in conjunction with other results to define the overall nature and characteristics of the proposed microgrid for Potsdam. Nova Energy Specialists conducted this portion of the study.

As discussed in section 2.2, the proposed microgrid will link together several existing National Grid customers in the Town of Potsdam, NY on a 13.2-kV primary feeder underground loop. These customers are to be supplied electric power that will be resilient to ice storms, lightning, wind storms, and other factors that cause electric power outages on conventional overhead power systems. Because the microgrid will have its own power generation of sufficient capacity to supply the planned loading, even the loss of the bulk supply source coming in from the local National Grid substation (known as Lawrence Avenue Substation) will not prevent the microgrid from continuing to serve customers.

Several of the listed customers already operate their own generation within the grounds of their facility to offset some of their load. A few of the listed entities above (such as Clarkson University PV Array and the East and West Hydropower Dams) are not part of physical customer load sites but are instead dedicated power generation sites that will likely participate in the microgrid.

Most of the conventional generation is to be coordinated via a central microgrid controller to supply the needed generation capacity during periods of “islanded” operation and to provide other generation dispatch coordination as needed to fulfill any microgrid ancillary functions. Load shedding of the less important loads within buildings will be used abundantly to allow the microgrid to meet major operational objectives even though the total generation capacity will at times be less than the total peak demand of all coincident loads combined. GE performed a load analysis with load curtailment up to and exceeding 20% of the total load to meet objectives.

As a general operating plan, under normal conditions (the vast majority of the time) the microgrid will operate in parallel with the bulk National Grid power system source. During conditions where the conventional supply is compromised (such as ice storms, wind storms, natural disasters, etc.) the microgrid transitions to an “islanded condition” (meaning separated from the main utility source) and continues to provide service for connected customers. The microgrid may be required to operate in an islanded state up to about two weeks at a time in a worst-case scenario involving the loss of the National Grid bulk power source. However, more typically, most severe ice storms and other types of catastrophic outage events would be expected to be of significantly less duration ranging from many hours up to a few days.

The microgrid transition to an island status from a grid-parallel status is not intended to provide a seamless transfer in the event the bulk power supply is lost. “Seamless” in power quality terminology means that the 60 Hz waveform has no noticeable load disrupting waveform characteristics present during the transition from the grid-parallel state to the islanded state of condition. Such a feature would come at greater cost and complexity and is not deemed necessary in this case due to the nature of the loads present. The objective of the microgrid in this case is to provide “backup generation grade power” and not “uninterruptible power supply (UPS) grade power” to those loads. Any critical functions of a specific portion of the customer load on the microgrid requiring seamless transfer would necessarily have their own local smaller UPS systems running off the microgrid to obtain localized seamless power for those selected loads where necessary.

During the transition to an island mode (due to an unplanned outage event) will not be seamless, and the power interruptions are expected to be on the order of several minutes up to perhaps a bit over 20 minutes as the grid is automatically and/or manually reconfigured for islanded microgrid operation. Even though seamless operation for unplanned outages is not a planned part of this grid design, the topic is explored later in more detail to explain the pros and cons and the type of equipment that would be needed if such a feature were ever desired. It should be noted that for various planned utility source outage events, the transfer can easily be seamless as discussed in section 5.6.

5.1 Key Topics

This section reviews key electrical operating considerations of the microgrid in both grid-parallel mode and in microgrid mode (islanded mode). Topics covered in the analysis include fault calculations, generator protection requirements, voltage regulation analysis, grounding, ferro-resonance, harmonic distortion influence and other critical areas.

Keep in mind that the microgrid-based generators are meant to operate both in parallel with the National Grid power system as well as in an "intentionally islanded microgrid state." Each of these modes of operation are substantially different requiring different control settings, reconfigured system switch positions, neutral grounding provisions, and other changes that are discussed in this report.

For the analysis presented here, the scenarios are based on a total generation capacity of up to about 10 MW of connected natural gas fueled, hydroelectric and PV type generation. The generation level at any given time will vary depending on the status of the connected units. Some generators may not be available at certain times. For example, solar PV generation is obviously greatly impacted by time of day, cloudiness conditions and seasonal factors. The hydro-generation varies significantly depending on weather conditions and seasonal river flow factors. Natural gas fueled generation may not always be available either due to scheduled maintenance of units or other factors; however, it serves as the bedrock of the microgrid in this case and is intended to have high-dispatch reliability. In most situations, anywhere between a minimum of roughly 5 MW and a maximum of about 10 MW of dispatch equivalent generation capacity is expected to be available depending on these factors. The load of all the customers will in many cases exceed available generation and some load shedding on the order of up to 20% to 25% is therefore required at sometimes, as has been discussed in the earlier GE reports.

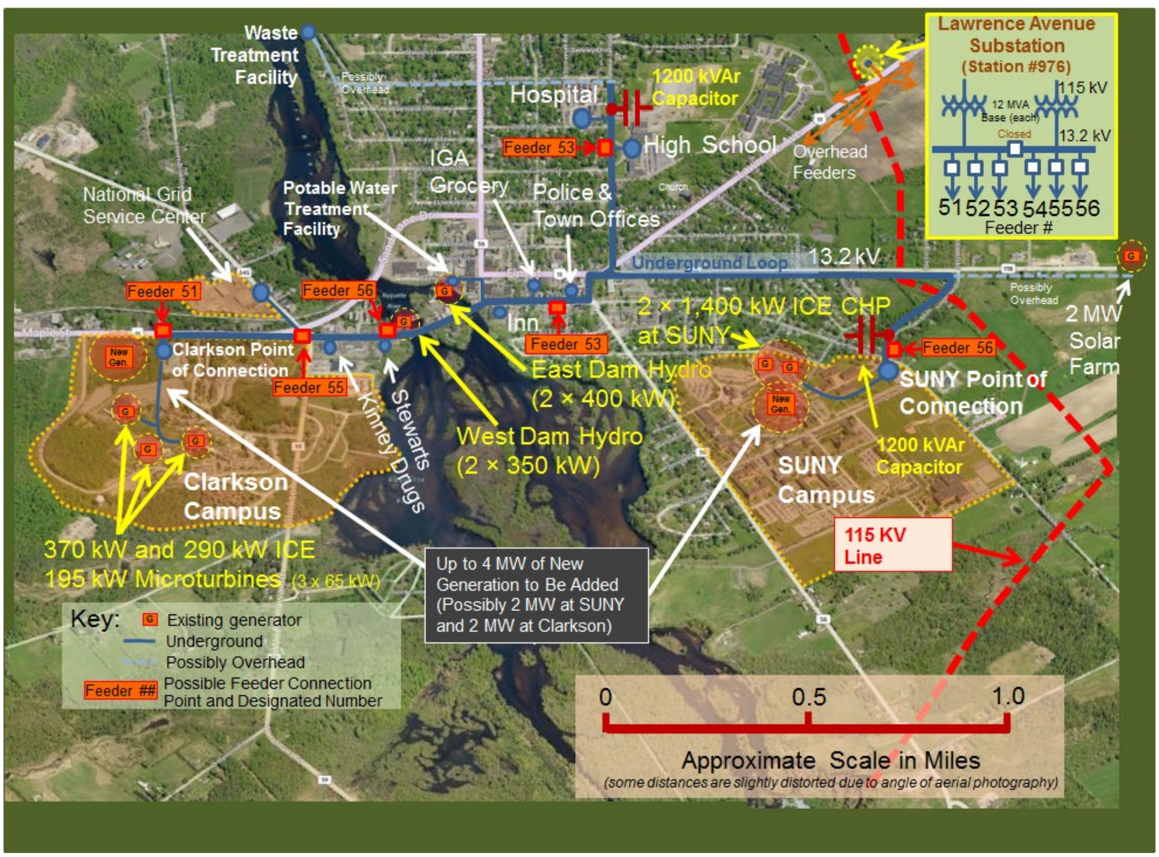
The material of this report is divided into several key sections. Section 2 focuses on the basic configurations of the microgrid—including the layout of the system, customer loads, and generator locations. Section 3 discusses the power quality metrics that the grid must operate within. Section 4 discusses the modeling techniques and tools that are employed. Section 5 focuses on the power system impact and interconnection issues associated with grid-parallel operation. Section 6 deals with the issues associated with islanded (microgrid) generator operation, such as island start-up and restoration to grid, voltage regulation, frequency regulation, harmonics, load-sharing, fault levels and system stability and power quality during transient events. And finally, section 7, the summary and conclusion, wraps up with a list of the key recommendations/findings.

5.2 Potsdam Microgrid Configuration

5.2.1 Microgrid Layout

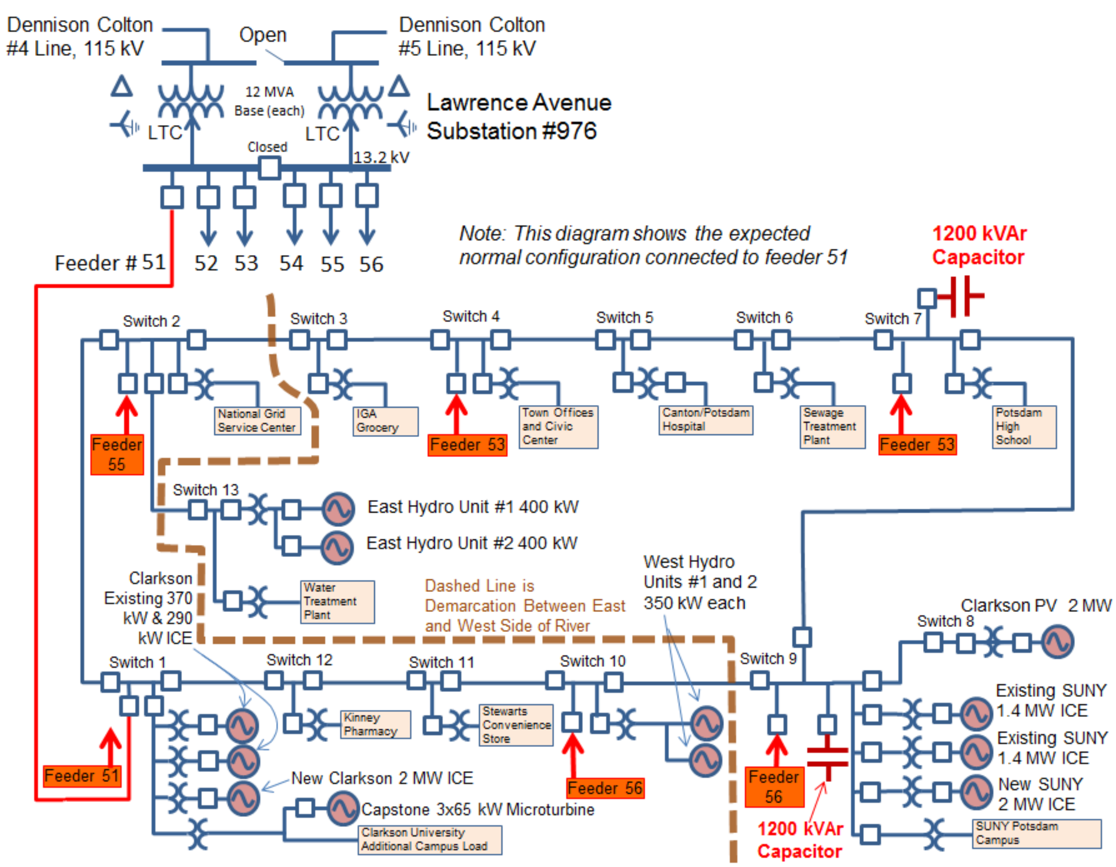
The Potsdam Microgrid spans a physical distance of about two miles east to west and one mile north to south. Figure 34 shows the overall layout of the microgrid with the underground 13.2 kV cable paths (solid blue lines) superimposed on an aerial image of the Town of Potsdam. The microgrid will serve the Clarkson University and SUNY Potsdam campuses as well as the hospital, high school, police, water facilities and several other key municipal loads and commercial loads in the Town of Potsdam. The cables are buried in ducts and in an arrangement that allows a looped feeder configuration. With multiple switching vaults/cabinets present along the loop path, it is possible to create a redundant underground loop scheme that can be operated either as an open-loop or closed-loop depending on various factors. A failed section can be sectionalized out of the system as needed to insure continuity of service to most or all loads.

Figure 34. General Layout of the Microgrid Superimposed on Aerial Photograph



National Grid's Lawrence Avenue Substation is the connection path to the bulk utility system source. The orange feeder labels (e.g., "Feeder 51" or "Feeder 53," etc.) that are shown in Figure 34 represent possible alternative tie points to the conventional bulk power system by any of several possible feeders that connect to the Lawrence Avenue substation. It is expected that Feeder 51, which is currently a dedicated express feeder that serves Clarkson University, is to be the typical key connection point. The overall microgrid with the configuration of the looped scheme and positions of key switches and breakers is shown in a one-line diagram format in Figure 35. As mentioned previously, for this particular arrangement, the focus is on Feeder 51 as the normal feed point from the substation. During isolated microgrid operation the bulk power system would be separated by the opening of the breaker (or recloser) at switch position 1 that connects Feeder 51 to the microgrid. As already stated, there are other possible feed points and the microgrid can also be split in half if desired with a feed point to each side. A natural splitting demarcation line is that of the Raquette River as shown in the diagram by the brown dashed line.

Figure 35. General Schematic Layout of the Full-Microgrid Loop Showing Key National Grid Feed Points, Switches, Customers, and Generation Sites



5.2.2 Lawrence Avenue Substation Details

Lawrence Avenue Substation is the key source of bulk utility system power and will interact with the DG of the microgrid during normal system conditions when the microgrid is operated in parallel with the utility system. The substation characteristics play a large part in defining this interaction.

The station is a two-transformer design with six feeders (designated by National Grid feeder numbers 97651 through 97656). Each transformer is base rated at 12 MVA and 22.4 MVA with all stages of cooling activated. There are two 13.2-kV busses with three feeders on each; however, the bus tie switch is normally closed such that all feeders operate as if they are on one common bus with both transformers operated in parallel.

The effective impedance of the power system at the 13.2-kV bus (with the tie switch closed) is 3.89% on a 12 megavolt ampere (MVA) base. This makes the substation bus fault currents contributed by the utility system higher than average at about 13,507A for a three-phase fault and 14,087A for a line to ground (L-G) fault. The substation's LTCs are set at 123V and the line-drop compensation is not activated. The lack of line-drop compensation along with the relatively low-impedance of power system at this bus (because both transformers are paralleled) makes the bus relatively insensitive to voltage changes caused by distributed generation current fluctuations. For example, fluctuations from the 2 MW of PV on this system when in parallel with the bulk National Grid source would be inconsequential as discussed later in this report.

The minimum loading at the substation (with both transformers combined since they are operated in parallel) is about 3 to 4 MW. During minimum load periods, if much of the planned generation is operating at or near rated capacity, the substation might export energy into the 115-kV transmission system. On the other hand, the peak loading at both transformers combined is about 30 to 33 MW and the available DG is at maximum at roughly 10 MW (see list of units later in report) which is about one-third of the substation peak load. While power exported into the sub-transmission is unlikely much of the time, it is important to recognize that export is still a possibility if a large amount of DG were to be operated during minimum load periods. Provisions may be needed to handle this condition as discussed later in the report. The substation has no capacitor banks present, according to data provided by National Grid. A summary of the substation characteristics is shown in Table 43.

Table 43. Characteristics of Lawrence Avenue Substation

Item	Details
High Voltage Bus (Nominal Rating)	115 kV (Source is Dennison/Colten no. 4 and no.5 lines)
Low Voltage Bus (Nominal Rating)	13.2 KV
Substation Transformers	Two Transformer Units Normally Operated in Parallel: Delta High Side to Wye-Ground Low side Each is LTC Equipped. Each unit rated at 12 MVA OA and up to 22.4 MVA FA/FOA
LTC Settings	Set Voltage = 123V, Band Width = ±2V Time Delay = 45 seconds Line-drop compensation = None
Bus Configuration	2 buses with three feeders per bus. (A normally closed tie switch connects the two buses.)
Station Capacitors	None in this Station
Feeder Circuit Breaker Reclosing Scheme for the Six Circuits	Conventional Overhead Feeders: 3 reclosing attempts with 15, 30, 45 second dead times Clarkson Feeder 97651 with Aerial cable: 1 Reclosing attempt with a 20 second dead time
Impedance at the 13.2 kV Bus	3.89% on a 12 MVA Base. (Impedance with both transformers running in parallel. This value includes the 115kV sub-transmission system impedance.)
Feeder Loading	Max 97651: (5.0MW, 2.9MVAR, 5.8MVA) Min 97651: (0.6MW, 0.5MVAR, 0.8MVA) Max 97652: (5.5MW, 1.4MVAR, 5.7MVA) Min 97652: (0.7MW, 0.1MVAR, 0.7MVA) Max 97653: (4.3MW, 0.1MVAR, 4.3MVA) Min 97653: (0.4MW, 0.1MVAR, 0.4MVA) Max 97654: (4.2MW, 0.2MVAR, 4.2MVA) Min 97654: (0.2MW, 0.1MVAR, 0.2MVA) Max 97655: (5.2MW, 1.5MVAR, 5.4MVA) Min 97655: (1.2MW, 0.7MVAR, 1.6MVA) Max 97656: (6.7MW, 0.2MVAR, 6.7MVA) Min 97656: (0.3MW, 1.1MVAR, 1.1MVA)
Transformer Loadings at the Substation	Max Transformer 1: (18.2MW, 6.5MVAR, 19.3MVA) Min Transformer1: (1.6MW, 0.7MVAR, 1.8MVA) Max Transformer 2: (14.5MW, 3.6MVAR, 15.0MVA) Min Transformer 2: (1.4MW, 1.4MVAR, 2.0MVA)

5.2.3 Distributed Generation Units Planned for Microgrid

For the planned microgrid there are several existing generators already located at customer sites, as well as new ones that will be added so that the microgrid has sufficient generating capacity to operate under the expected loading scenarios.

The generator characteristics used for this study are detailed in Table 44. The generator characteristics are based on typical values for rotating machine generators (for both the existing and new planned units.) The characteristic values provided include the positive, negative, and zero sequence impedances as well as transient and sub-transient time constants, and other characteristics.

The characteristics also include the step-up transformers either in use for existing units or likely to be used for future units. The zero sequence impedances shown assume that effective neutral grounding practices will be used for this project (although currently some large units such as the SUNY Potsdam generators and others don't follow these practices). The effective grounding will be achieved either by a suitable generator interface transformer for the largest units or by means of an adjacent grounding transformer bank that emulates effective grounding of the generator itself. Because of the type of distribution system (four-wire, multi-grounded neutral system) the microgrid must be suitably effectively grounded when operating isolated from the utility source (as discussed later in this report.)

Taken as a whole, the generator and transformer characteristics of Table 44 give a reasonable approximation of the overall expected characteristics of the units as a group, even though for any particular specific generator these are not necessarily the exact specifications since complete detailed data was not available for many existing units and, in the case of the proposed new ones, the unit type and model/configuration has not been finalized yet so a presumed typical value is used in this preliminary study. Later in Phase II of the study more precise specifications may be available for the generators.

Table 44. Electrical Characteristics of Generators to be Used on the Microgrid

Generators (all are synchronous rotating type except West Dam hydro induction units, 2 MW PV and Capstone which are inverters)	Generator Impedance Parameters						Total Zero Sequence Reactance (X0) of the Generation Source. (see note 1)	Total Zero Sequence Resistance (R0) of the Generation Source. (see Note 2)	Inertia Value (H) [units are in kW·sec/KVA of machine rating]	Step Up Transformer Characteristics			Generator Connecting Cables (208 or 480 V cables)		T' Machine Short-Circuit Time Constant (seconds)	T" Machine Short-Circuit Time Constant (seconds)
	R_{stator}	X1	X1'	X1"	X0	X2				Size Rating & Winding	Reactance (X1, X2, and X0) *Note 3*	Resistance (R1, R2 and R0) *Note 3*	X1 and X2 [X0 = twice these values] Note 3	R1 and R2 [R0= twice these values] Note 3		
Clarkson New: 2000 kW, 2500 kVA at 0.8 power factor rating	1.30%	250%	20.8%	16%	3%	19.5%	37%	5%	1.5	3000 kVA, grnd-wye to grnd-wye	5.72%	0.61%	2.00%	1.00%	0.6	0.05
Clarkson Existing A: 370 kW, 463 kVA at 0.8 PF rating.	1.30%	250%	20.8%	16%	3%	19.5%	37%	5%	1.5	3000 kVA, grnd-wye to grnd-wye	5.72%	0.61%	2.00%	1.00%	0.6	0.05
Clarkson Existing B: 290 kW, 363 kVA at 0.8 PF rating	1.30%	250%	20.8%	16%	3%	19.5%	37%	5%	1.5	1000 kVA, grnd-wye to grnd-wye	5.70%	1.20%	2.00%	1.00%	0.6	0.05
SUNY Potsdam New: 2000 kW, 2500 kVA at 0.8 PF rating	1.30%	250%	20.8%	16%	3%	19.5%	37%	5%	1.5	2500 kVA, grnd-wye to grnd-wye	5.70%	1.20%	2.00%	1.00%	0.6	0.05
SUNY Potsdam Existing A: 1400 kW, 1750 kVA at 0.8 PF rating	1.30%	250%	20.8%	16%	3%	19.5%	37%	5%	1.5	Direct Connect (no transformer or low voltage cables)					0.6	0.05
SUNY Potsdam Existing B: 1400 kW, 1750 kVA at 0.8 PF rating.	1.30%	250%	20.8%	16%	3%	19.5%	37%	5%	1.5	Direct Connect (no transformer or low voltage cables)					0.6	0.05
East Dam Hydro: 2 units x 400 kW each (2 x 500 kVA each at 0.8 PF rating)	1.30%	250%	20.8%	16%	3%	19.5%	Infinite (ungrounded interface) [at primary point of connection]		3.0	1500 kVA, grnd-wye to grnd-wye	5.70%	0.72%	2.00%	1.00%	0.6	0.05
West Dam Hydro: 2 x 350 kW each (2 x 389 kVA each at 0.9 PF consuming VARs) [these units are induction generators]	1.30%	NA	NA	16%	3%	19.5%	Infinite (ungrounded neutral interface) [at primary point of connection]		3.0	1250 KVA, grnd-wye to delta on utility side	6.15%	1.40%	2.00%	1.00%	NA	0.05
2 MW PV Site (estimated inverter capacity at unity PF so KVA rating = KW rating)	Assume balanced fault current contribution limited to 1.3 per unit or less (similar to having a generation impedance of 77% or higher.)						Assumed Non-Effectively grounded Neutral (ungrounded)		?	2500 kVA, grnd-wye to grnd-wye	5.72%	0.61%	2.00%	1.00%	PV contributes for less than 10 cycles during bolted fault.	
Clarkson Capstone C-65 Microturbines (3 units x 65 kW each). Capstones inverters are rated at unity PF such that KVA = KW.	Assume balanced fault current contribution limited to 1.3 per unit or less (similar to having a generation impedance of 77% or higher.)						Assumed Non-Effectively grounded Neutral (ungrounded)		?	1500 kVA, grnd-wye to grnd-wye	5.70%	0.72%	2.00%	1.00%	Capstone Inverter contributes for less than 10 cycles during bolted fault.	

Note 1: Generator total Zero Sequence Reactance (X0). Includes effect of any neutral grounding impedance or adjacent grounding transformer to be added later. Values are with respect to terminals of machine or where otherwise noted
Note 2: Generator total Zero Sequence Resistance (R0). Includes effect of any neutral grounding impedance or adjacent grounding transformer to be added later. Values are with respect to terminals of machine or where otherwise noted.
Note 3: Percent impedance on base rating of the of the step-up transformer

Table 45 describes the power ratings of the generators used for the project. This includes the full nominal rated power (kVA) under ideal conditions as well as a reduced rating for some of the units based on a weighted output due to the variability of the energy resource. In particular, the photovoltaic system and the hydroelectric units have a much lower weighted average output than the full-nominal, nameplate-rated output would indicate. The weighted output as shown here is per the GE load flow study and is similar to but not quite the same thing as a capacity factor. It is a number that has been adjusted to account for the coincidence of the energy resource with the expected demand cycle and load duration curves of the microgrid loads. It can be thought of as something akin to an "effective load carrying capacity" of that resource that can be expected for planning purposes.

Table 45. Power Ratings of Generators in the Project

Full-nominal and average where applicable.

Generator	kW Rating Used in GE Steady-State Load Flow	Full-Nominal kW Rating Based on Generator Maximum Capability	Full-Nominal kVA Rating of Generator
West Dam Hydro(s)	193 (water flow weighted)	700 (2 × 350 kW)	778
East Dam Hydro(s)	398 (water flow weighted) *	800 (2 × 400 kW)	1000
Clarkson Existing A	370	370	463
Clarkson Existing B	290	290	363
Clarkson New*	2,000	2,000	2500
SUNY Potsdam Existing A	1,400	1,400	1750
SUNY Potsdam Existing B	1,400	1,400	1750
SUNY Potsdam New*	2,000	2,000	2500
PV Array	552 (sun resource weighted)	2,000	2000 (unity PF inverter)
Capstone Microturbine	195	195	195 (unity PF inverter)

5.2.4 Microgrid Loading

The majority of the microgrid load (over 80%) is due to the SUNY Potsdam and Clarkson campuses. A breakdown of the peak loads on the microgrid per the early Phase I project data analysis as used by GE in the GE load-flow report is provided in Table 46. The maximum loading on the microgrid without load shedding is in the range 9-10 MW. The minimum load on the microgrid which occurs in the middle of the night is on the order of 3 to 5 MW. These are preliminary estimates and more detailed data has become available recently and will be discussed in Phase II of the project.

Table 46. Customer Loads Used for Phase I Analysis and Load-Flow Report

Peak Load	kW	PF (absorbing VARs)
Hospital	560	0.85
Civic Center / Village Office	54	0.85
Clarkson	4,866	0.85
IGA Grocery	144	0.85
Kinney Drugs	48	0.85
NG Service Center	48	0.85
Potsdam High School	142	0.85
Sewage Treatment Plant	122	0.85
Stewarts	48	0.85
SUNY Potsdam	4,166	0.85
Water Treatment Plant	83	0.85

5.3 Power Quality Parameters

Power quality parameters that relate to the operation of the microgrid considered in this report are as follows:

- Voltage regulation (RMS voltage steady-state conditions with time frame of roughly a minute or longer. This includes both the absolute limits on any phase for high- and low-voltage relative to nominal as well as the balance [difference] of voltage between phases).
- Voltage flicker and short duration excursions above or below ANSI limits (RMS voltage changes of this nature are usually caused by load and/or generation current changes with time frames of roughly one minute down to a few cycles duration).
- Temporary overvoltage (short duration severe overvoltage typically due to neutral shift, load rejection or ferro-resonance usually lasting anywhere from ½ cycle up to many seconds—and sometimes longer. This is often called a transient over voltage, but technically temporary overvoltage is a better term.)
- Transient overvoltage (lightning or switching voltage transients that are impulsive or ringing in nature with frequency much higher than 60 Hz. Often these are confused with temporary overvoltage. This term is often misused to refer to temporary overvoltage).
- Harmonic distortion (a waveform with non-fundamental frequency components that are multiples of the 60 Hz frequency, typically caused by non-linear loads and/or generation sources).
- Frequency Regulation (pertaining to deviations above or below the nominal system frequency of 60 Hz).

For electric utilities there are requirements for each of the above parameters that utilities should achieve for their customers to assure satisfactory and safe operation of customer loads. Table 47 lists some key parameters and IEEE standards for electric operations under normal service conditions and suggests some possible relaxed allowances during islanded microgrid mode.

While a desirable operating objective is to satisfy the normal IEEE and ANSI bulk system requirements for power quality, it must be understood that the practical limitations of the generation equipment when operating within an islanded microgrid are such that a relaxed level of voltage quality may at times be necessary. The microgrid has less generator inertia with respect to the size of load steps and a higher effective source impedance than the bulk grid system; therefore, it is more susceptible to load-step induced frequency variations, load-step related voltage dips, and harmonic distortion caused by load non-linearity. In islanded microgrid mode, we can expect a certain amount of degradation of the voltage regulation, frequency regulation and harmonic distortion due to the effects of loads on such weaker systems. The microgrid does not necessarily need to provide quite the same level of voltage quality as is provided by the utility under normal conditions since such conditions are not permanent.

Given the prior discussion, what should the operating voltage quality objectives be for the islanded microgrid mode of operation? The following points are worth considering:

- Steady-state voltage should not be so low that excessive heating of motor devices or low voltage related cycling of UPS devices occurs.
- Steady-state voltage must not be allowed to get too high that it causes overheating of resistive devices, failures of surge arresters due to too much leakage current, or saturation (overheating) of magnetic core devices such as motors/generators and transformers, or high voltage related cycling of UPS devices.
- Steady-state voltage unbalance should not become too high as to cause overheating of three-phase motors/generators (due to negative sequence currents induced on rotors by unbalance).
- Frequency variations (the absolute limits and rates of change of the microgrid frequency) must not be so great as to cause UPS systems to cycle, magnetic devices to saturate excessively, or generator frequency relays to operate.
- Harmonic distortion must not be so high that it excites problematic resonances and/or overheats devices or triggers the malfunction of devices.

There is precedent for relaxing the allowable power quality for short periods of time. For example, under today's existing ANSI standards the voltage regulation limits on regular utility systems are often relaxed to allow occasional excursions outside of the ANSI C84.1 Range A and into the broader Range B limits. A higher degree of flicker is also allowable per IEEE 1453 if the conditions is not permanent and only lasts a few days or up to perhaps a few weeks in emergency conditions. Table 47 contrasts the conditions expected in bulk grid-parallel mode versus some possible relaxed conditions that could be allowable in an islanded microgrid mode for short periods. These are discussed in more detail following the Table 47.

Table 47. Summary of Power Quality Criteria for Microgrid Operation

Type of Power Quality Concern	Applicable Standard or Method	Utility Supplied Grid with Parallel DG (this is the normal mode)	Islanded Microgrid Mode (Up to 2 Weeks)
Voltage Regulation (steady-state)	ANSI Standard C84.1	Typical Utility Practice: Regulate voltage to *Range A Service Voltage* (±5%). Allow occasional excursions into Range B (roughly +6% and-8%)	Range-A is still desirable, but Range-B may be allowable given the infrequent and limited nature of islanded mode.
Voltage Flicker, Variations and Brief Duration Excursions	▪ **Flicker:** IEEE 1453 P_{st}, P_{lt} Flicker Criteria (Or IEEE 141 or 519) **Excursions/Variations:** Tap Changer Cycling, Load Process Sensitivity Screen Test	▪ Limit voltage flicker to the *Borderline of Visibility* For LTC cycling and load process sensitivity, employ relatively strict screens for excess tap changer operations and load process dropouts or problems.	▪ Borderline of Irritation rather than visibility? ▪ Allow deeper dips on motor starts? ▪ Use "1% of time" IEEE-1453 violation criteria evaluated over annual basis? Relaxed sensitivity screen for tap changers and load process?
TOV: *Ground Fault and Load Rejection Overvoltage*	ITIC Curve, IEEE C62.92, Surge Arrester TOV Curves	Temporary overvoltage not recommended to exceed about 1.31 per unit for typical fault durations.	Consider a blend of the ITIC and the 1.31 per unit TOV requirements based on IEEE COG of 72%.
Harmonics	IEEE 519 and IEEE 1547 Guidelines	**Voltage harmonic**: Voltage THD up to 5% and individual voltage harmonic up to 3% **Current Harmonics:** DG Use I_{sc}/I_{load} < 20 for current harmonics. Loads can have higher values at higher I_{sc}/I_{load} ratios (per IEEE 519 and 1547).	**Voltage harmonic**: Voltage THD up to 5% and individual voltage harmonic up to 3% **Current Harmonics:** Both loads and DG should use the most strict I_{sc}/I_{load} < 20 allowances for current harmonics.
Frequency Regulation Range (Hertz)	Transformer and Motor Saturation Limits, etc. (for motor loads see NEMA MG1)	Typically, less than ±0.5% deviation from 60 Hz nominal occurs for large scale utility grid systems.	Aim for ±3 but up to ±5% may be allowable for short periods depending on UPS responses, critical processes, transformer and machine saturation curves.

5.3.1 Voltage Regulation Guidelines

On the normally operating bulk grid system it is required that the steady-state voltage regulation (voltage conditions of about 1 to 2 minutes or longer duration) should be within the ANSI C84.1-1995 Range A voltage limits. These limits are shown in Table 48 and represent the voltage delivered to the customer. The “service voltage” part of the requirement is the delivered voltage at the customer’s point of common coupling (PCC) and the utility should normally meet the limits specified for service voltage. Utilization voltage is the voltage at end-user devices deep within customer buildings or facilities—and is outside the responsibility of the utility as long as adequate service voltage is provided to the customer. The utility also must provide proper voltage balance within 3% at all customer service connection points. Too much voltage unbalance can overheat motors and cause other problems.

Table 48. ANSI C84.1 Voltage Limits (Shown on a 120-Volt Base as well as in Percent of Nominal)

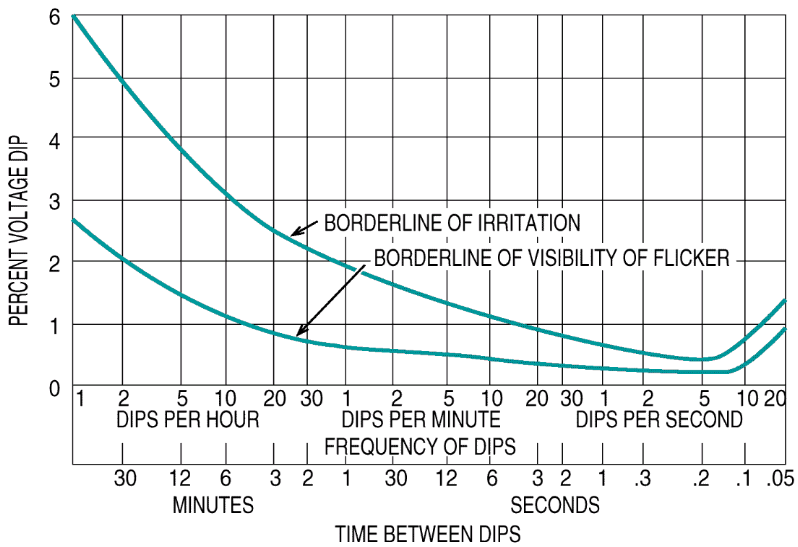
Allowable Voltage Limits for Systems with Service Voltages Less than 600 Volts (limits shown on a 120 volt base and in percent of nominal)		
Classification	***Range A***	***Range B***
Service Voltage	(114-126 Volts) (95-105%)	(110-127 Volts) (91.7-105.8%)
Utilization Voltage	(110-125 Volts) (91.7-104.2%)	(106-127 Volts) (88.3-105.8%)
The standard also specifies that voltage between phases shall be balanced to within 3% at service entrance under no-load conditions		

The Range-B voltage limits in the above table are intended to be allowable only for infrequent conditions and with limited duration. When operating in the islanded microgrid mode this type of operation also fits the “infrequent and limited duration” definition well. Therefore, a reasonable interpretation of the ANSI C84.1 standard when used for an islanded microgrid is that while Range-A is still the desired objective, Range-B conditions are allowable as long as the islanded mode is utilized infrequently.

5.3.2 Flicker Guidelines

The second major voltage regulation concern is lamp flicker. Lamp flicker is an objectionable variation in the output of lighting systems caused by rapid variations in voltage. We call these variations “voltage flicker.” Flicker is a subjective phenomenon and some people are more sensitive than others to a given level of flicker. Based on research projects done in the 1930s by GE, Westinghouse and others, the electric utility industry developed guidelines that help determine when voltage flicker becomes noticeable on the system. For a long time, the IEEE 519-1992 voltage flicker curves, which are based on the 1930s GE studies, were the most commonly used approach at many U.S. utilities (Figure 36). The flicker curves shown are for 60-watt incandescent light sources which are 2 to 3 times more sensitive to flicker than many types of LEDs and fluorescent bulbs. These two curves show the threshold of visibility (the level where customers begin to notice) and the threshold of objection (the level where customers become irritated or uncomfortable with the flicker). The Potsdam Microgrid must be operated in a manner during grid-parallel mode that can keep the voltage flicker below the borderline of visibility—and if not below that curve at least significantly below the borderline of irritation. For islanded operation of a few days or hours each year, the condition is so infrequent it is possible to relax the flicker standard somewhat. But there are no published guidelines on what may be considered “acceptable” for such short periods of a few days each year when done as an emergency condition once every year or so to avoid an outage. However, IEEE 1453 does have statistical methods that allow flicker limits to be exceeded 1% of the time which may be a good approach in this case.

Figure 36. Flicker Curve Limit per IEEE Standard 519-1992



Even though the IEEE 519-1992 curve is still widely used in the industry because of its legacy familiarity and ease of use, it is no longer the most up-to-date flicker standard. A more modern flicker standard that has superseded the IEEE-519 is the IEEE 1453 standard (Table 49). This is a more complex method of evaluating flicker that involves mathematical weighting models of the eye-brain response, light source characteristics, and envelop variation rates and shapes. While complex, the method has the advantage in its capacity to handle a wide range of RMS voltage envelop conditions as well as light source types. Additionally, it can provide an appropriate flicker measurement for complex situations not easily handled by the old IEEE-519 method. That older method was only suitable for 60-watt incandescent bulbs and relatively rectangular modulations (step-changes) of the RMS voltage envelope. The IEEE 1453 method has two measures of flicker—the short-term (P_{st}) and the long-term (P_{lt}) flicker parameters. A P_{st} and/or P_{lt} Value =1.0 is considered the borderline of irritation. There are two measurements—short-term flicker (P_{st}) and long-term flicker (P_{lt}.). Flicker compatibility levels are intended for compliance of existing systems/equipment and planning levels are for new systems being designed and built, and therefore are more conservative. (The use of the letter "P" comes from the word "Papilloter" meaning "flicker" in French as the guideline was originally created in Europe using the French language as IEC 61000-4-15 was developed and later adopted by IEEE as Standard 1453.)

Table 49. IEEE 1453 Flicker Guidelines (for Grid-Parallel Mode)

Type of Flicker	Compatibility Levels	Planning Levels (not to exceed >1% of time)	
	LV and MV Applications	MV	HV and EHV
Pst (10-minute interval)	1.0	0.9	0.8
Plt (2-hour interval)	0.8	0.7	0.6

Even with the more modern IEEE 1453 flicker standard, the same issue with the old GE curve IEEE 519 method holds true when it comes to applying flicker studies to emergency islanding conditions (i.e., microgrid mode). That is, it is not entirely clear how much the P_{st} and P_{lt} values could be relaxed and still be considered acceptable for the islanded mode of operation when used infrequently. As a general guideline for conventional power systems, IEEE 1453 recommends that P_{st} and P_{lt} should not exceed the planning levels more than 1% of the time (99% probability level). Considered over an *annual basis,* this recommendation might be interpreted as flicker violation are allowable several days each year as long as the rest of the year is well within limits. It makes sense to use this approach for the microgrid, but the question still remains as to how much of a violation above the limits in the table could be allowable during such periods. As an educated suggestion, an increase in the allowable flicker P_{st} and P_{lt} thresholds (or allowable GE curves) by 25% to 50% above the regular values could be suitable for the microgrid during the violation period.

5.3.3 Temporary Overvoltage Guidelines

Temporary overvoltage (TOV) conditions are those that involve short duration overvoltage lasting many tens of seconds in duration down to about half-cycle duration. These may be due to ground fault overvoltage or load rejection overvoltage due to DG or other causes. In modern usage, these conditions are also sometimes referred to as *transient* overvoltage conditions; however, that term has traditionally been used to refer mainly to lightning or switches surges rather than 60-Hz RMS waveform overvoltage conditions.

A curve that represents the ability of information technology loads to survive short-term overvoltage conditions is the Information Technology Industry Council (ITIC) voltage tolerance curve (Figure 37). The ITIC voltage tolerance curve shows a range of voltages that are suitable for such loads. It provides not only a high-side boundary for withstanding damage but also a lower boundary of the ability of loads to handle voltage sags without dropout. The upper bound of the curve is felt to be quite conservative by many experts. In reality, many loads and devices in most cases can handle some increased voltage without damage.

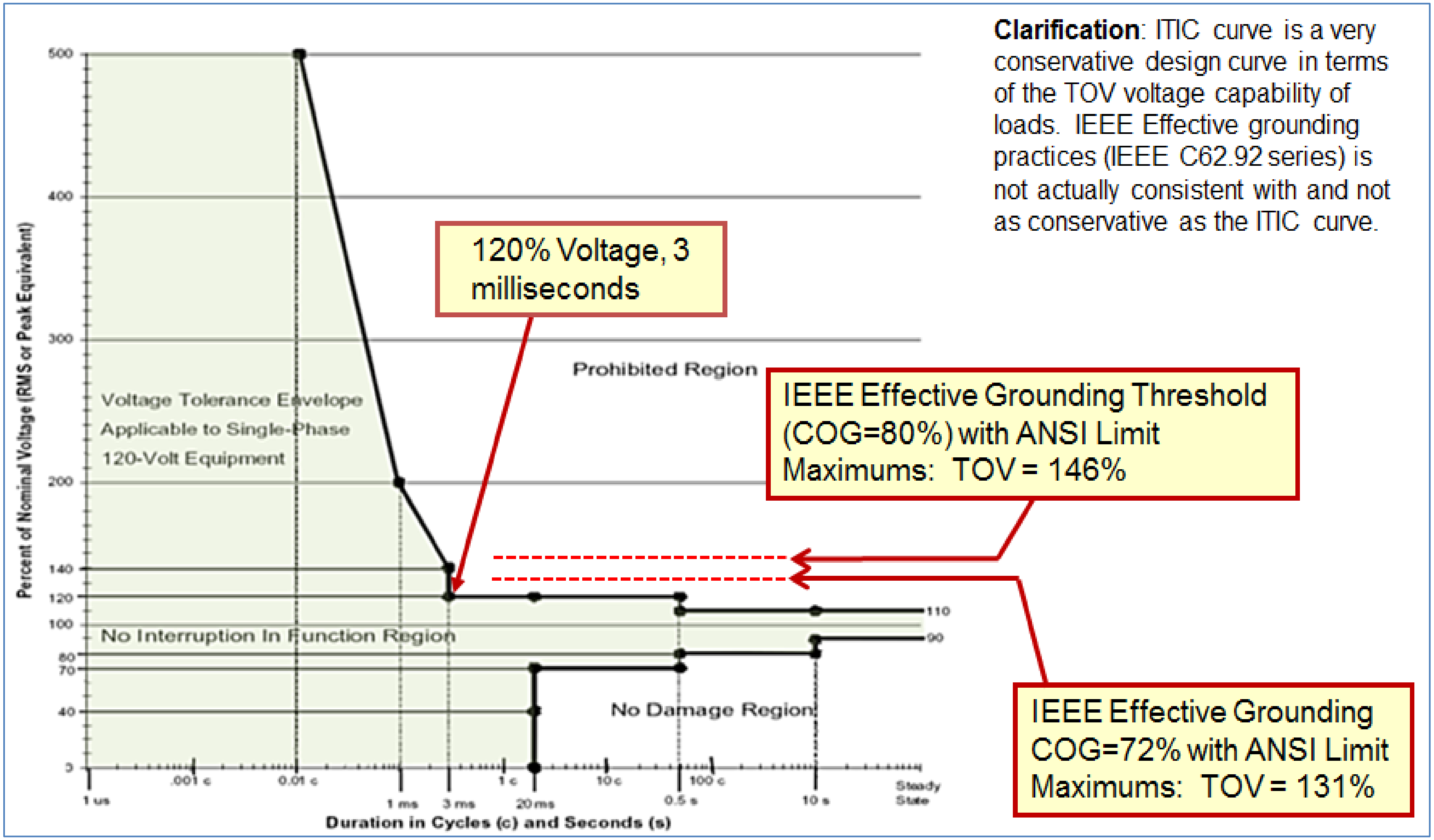
Another standard that can apply to temporary overvoltage limits is the IEEE effective grounding feeder design standard. This is aimed at limiting ground fault overvoltage due to neutral shift as specified in IEEE C62.92 parts one through four. A key parameter is what is known as the coefficient of grounding (COG). The applicable standard for four-wire, multigrounded neutral distribution systems recommends that the COG be 72% or less on systems servicing line-to-neutral loads.

The COG value is the level of line-to-neutral voltage of the system during a ground fault on the un-faulted phases in relation to the line-to-line voltage. A COG of 72% means that the line-to-neutral voltage rises to 72% of the line-to-line voltage on the un-faulted phases during a ground fault on the faulted phase—or put more concisely, the line-to-neutral voltage rises to about 125% of the pre-fault line-to-neutral voltage. If we factor in an extra 1.05 per unit to account for the ANSI C84.1 voltage regulation window, the COG requirement of 72% will suggest a TOV limit of about 131% for short periods (seconds or less) on typical systems.

Another type of overvoltage defining criteria is what is known as the “TOV capability curve” for surge arresters. This curve defines the voltage the arrester can withstand for short periods (from a few cycles duration up to several minutes) without being damaged. All surge arresters (whether utility company applied, or consumer/customer applied) have known TOV capability curves that can be obtained from the manufacturer. No standard curve for all arresters exists, since there are a huge variety of surge arrester products, types, sizes, and applications in use. However, these TOV curves under most situations would be expected to be significantly higher than the ITIC curve or the voltages possible with COG of 72%. In fact, most, if not all utility arresters in use could easily withstand a COG of 80% as long as the duration were ten seconds or less. The weakest link in the ability to withstand overvoltage is likely to be on the consumer load-side devices and not with the utility company devices. A COG of 80% is in this author’s opinion a bit high for load devices due to both consumer arrester TOV limits as well as electronic elements in the consumer appliance power supply devices.

It would be ideal if the microgrid could satisfy the ITIC curve, but in practice even regular utility systems are not designed to meet the stringent nature of ITIC. For the microgrid an overvoltage limit that blends some parts of the ITIC curve with the COG=72% IEEE standard makes the most sense. This could consist of 125% for 2 to 10 seconds, 131% for 2 cycles to 2 seconds, 146% voltage for 2 cycles to 0.5 cycles—and then merging with the ITIC boundary for anything shorter than 2 milliseconds.

Figure 37. Information Technology Industry Council Voltage Tolerance Curve with IEEE Effective Grounding Criteria Added



5.3.4 Disruptive Under Voltage Events

The ITIC curve of the earlier section can also be used to define the short duration under the voltage boundary that may result in dropouts of sensitive devices. For example, 90% for 10 seconds or longer, 80% voltage for a half second to 10 seconds, and 70% voltage for about one cycle to up to a half second. While short duration under voltage events due to motor starts, inrush, and load steps should be limited to an amount that does not cause unreasonable voltage flicker, it is also important that voltage dip variations should not cause disruption to operating devices on the microgrid as per the lower bound of the ITIC curve. A short duration under voltage can cause disruption by tripping out protective relays that control generators or load devices, for example, by dropping out motor, lighting, or process control contactors and by a deficiency of energy needed for stable operation of electronic power supplies of load devices. It is noteworthy that some devices may be more sensitive than the ITIC under voltage curve if they are equipped with protection relays. In particular, distributed generation devices, UPS systems and motors with under voltage protection relays, or contactors may be affected. While operating in microgrid mode these device relay settings will need to either be coordinated with the expected voltage dips or the severe dips (if any)—limited such that they are not disruptive to microgrid operation.

5.3.5 Harmonics

The applicable standards for harmonics are IEEE 519 and IEEE 1547. The first standard applies broadly to power systems. The second standard applies specifically to DG (Table 50) applied on the system. The limits are for when the DG is serving balanced linear loads. These standards also specify that voltage distortion on the distribution system should not exceed 5% total harmonic distortion (THD).

For the purposes of the microgrid, while in grid-parallel mode, the harmonic levels need to satisfy both the IEEE 1547 table and any respective IEEE 519 tables per the ratio of short circuit current to load current that exists in that mode. The DG harmonic limits of IEEE 1547 are coordinated with the IEEE 519 limits for the case where the ratio of short-circuit current to load current is less than 20 (meaning the I_{sc}/I_{load} ratio). However, during the islanded microgrid mode, a suitable target for harmonic limits can be based solely on the existing IEEE 1547 table (which is based on a 20:1 ratio of short-circuit to load current).

Table 50. IEEE 1547 Requirements for DG Harmonics

Harmonic Order	Allowed Harmonic Current Level Relative to Fundamental Current (Odd Harmonics only. See notes 1 and 2)
h < 11th	4.0%
11th ≤ h <17th	2.0%
17th ≤ h < 23rd	1.5%
23rd ≤ h <35th	0.6%
35th or greater	0.3%
Total Harmonic Current Distortion	5%

Notes:

- The greater of the maximum-load current integrated demand (15 or 30 minutes) at PCC without DG unit or the DG unit current capacity at PCC.
- Harmonics are limited to 25% of odd harmonic values.

There may be some room for relaxation of the harmonic criteria owing to the infrequent nature of operation and limited duration of operation in islanded microgrid mode. However, further study is needed to define how much relaxation could be allowed. Severe harmonics can cause disruption of customer load and generation devices in two main ways: misoperation of devices due to the waveform distortion and/or additional heating in wires, cables, and rotating machinery. From a heating perspective, limited duration of moderate violations of the harmonic criteria may be allowable since the effect of heating tends to be a gradual cumulative effect over time (meaning a gradual equipment-life shortening factor for each hour operated above rated temperature) and may not be a severe issue for short periods. On the other hand, from a waveform disruption perspective (for example, misoperating relays caused by peak waveform and zero crossing distortion) the onset of effects could occur almost immediately and so more care would be needed in those cases.

5.3.6 Frequency Variations

The bulk power system normally operates with tight frequency tolerances well within ±0.5 Hz of the 60 Hz nominal frequency. Once the system has transitioned to microgrid mode, frequency variations will be larger. The question is how large can these variations be before they pose a risk to loads and equipment, and what should be the target range when operating in an islanded mode?

There are a number of factors that determine the frequency variations that are allowable on a microgrid from the perspective of customer loads and equipment. A key limiting factor on the low side is that lower than normal frequency may cause some magnetic core containing devices such as transformers and motors to saturate. In general, a ±5% frequency deviation, while not ideal is tolerable most of the time for magnetic core devices as long as the voltage is not higher than about +5% above nominal. However, in some cases the combination of higher voltage (near the top end of ANSI window) and low frequency (near -5%) can saturate and overheat devices with magnetic cores if they are heavily loaded, so care must be exercised in evaluating the combination of higher-than-nominal voltage and lower-than-nominal frequency together.

Another factor of concern is that if the frequency is off nominal, motors may run at a speed that is either higher-than-normal (due to high frequency) or lower-than-normal (due to low frequency). This can change the loading on fans, pumps, etc. If any motor processes are highly sensitive to frequency in this manner, then a tighter tolerance than ±5% may be desirable. Some clocks and timing devices are also impacted by changes in the system frequency, since they use the system frequency as their actual time reference. Error is accumulated in the time keeping device as the integral of the "off-nominal" frequency condition. For example, a continuous high frequency of +5% over the course 24 hours would advance some clocks by over one hour. To avoid time error on AC clocks that derive their reference from the grid frequency, the microgrid would need to regulate excursions of high- and low-frequency so as not to accumulate (integrate) unacceptable errors over time.

With regards to frequency, The National Electrical Equipment Manufacturers Association (NEMA) has several standards that may be applicable or helpful for the microgrid limits.
The NEMA MG-1 standards deal with motors and specifies up to ±5% frequency for motors as long as voltage is within the normal ANSI limits, although its states performance may be degraded. NEMA also has a standard for UPS called NEMA PE 1-2012 that indicates a much tighter range (± 0.5% for systems above 2 kVA) for the output of UPS systems. This tight range would be expected since a UPS is generally a premium power device intended to offer a higher grade of power than needed for regular microgrid condition. However, such a tight range suggests that some UPS architectures, such as line interactive type UPS or line preferred UPS systems, could have difficulty dealing with a broad frequency regulation range on the microgrid if they

were still required to maintain their output frequency standard. This might result in the UPS architectures cycling back and forth between battery operating mode and grid-supplied mode. It is noteworthy that the UPS standard also suggests a maximum rate of change of frequency (a slew rate) of no more than 1 Hz per second allowable on the output of a UPS system.

Overall, based on the characteristics of loads, a targeted frequency range of ±3% when operating in islanded mode is a reasonable goal for the preferred operating frequency range for the microgrid that should not pose issues with the exceptions that certain types of UPS systems and DG equipment with tight protective relay settings might be upset by the broader frequency swings. Those devices may need to have tripping settings coordinated with the broader range of the microgrid.

5.3.7 IEEE 1547.4-2011

IEEE Guide for Design, Operation, and Integration of Distributed Resource Island Systems with Electric Power Systems is intended to offer guidance on various engineering factors that apply to islanded microgrids. This would include power quality standards such as voltage, frequency, TOV transients, etc. However, the specific guidance offered in that document is limited in detail compared to the information presented here in this report. Nonetheless, it offers background material for the various factors that must be considered in an islanded DG operating mode.

5.4 Methods and Modeling Tools

5.4.1 Modeling Tools

This study employed two primary tools for analyzing the impact of DG on the power system. The first tool was direct calculations using a spreadsheet-based analysis approach which is used for many of the key calculations and screenings. This direct calculation approach is suitable for many elements of the analysis including calculating voltage changes with various generation fluctuations and general fault levels. For the more challenging aspects of the analysis, such as determining waveforms associated with faults, ground fault overvoltage plots in the time domain, ferro-resonance and stability analysis, as well as checking the accuracy of some of the direct calculations, the Electro-Magnetic Transients Program (EMTP) was utilized. Specifically, a commercial version of the software known as EMTP-RV was employed.

EMTP-RV is a comprehensive tool in transient power system analysis. The software package is a sophisticated program for the simulation of electromagnetic, electromechanical, and control systems transients in multiphase electric power systems. It features a wide variety of modeling capabilities encompassing electromagnetic and electromechanical oscillations ranging in duration from microseconds to seconds and features a state-of-the-art graphical user interface (GUI). Typical applications include switching and lightning surge analysis, insulation coordination, shaft-torsional oscillations, power system stability, ferro-resonance, power electronics applications, and many other types of analysis suitable for DG applications on power systems.

5.4.2 EMTP Simulation Options

EMTP-RV accepts several simulation options which are performed for arbitrary network configurations. All options are applicable to all devices within documented rules of device behavior:

- Frequency scans.
- Steady-state solutions: linear harmonic steady-state solution, non-linear harmonic steady-state solution and three-phase power flow.
- Time domain solutions: fixed time-step trapezoidal with/without back Ward Euler method, automatic initialization from steady state, start up from manual initial conditions and special option for power electronics instantaneous switching conditions within a time-step.
- Statistical/systematic analysis.

For the microgrid project, time domain solutions and steady-state solutions were the predominant type of simulation used for islanding analysis, ground fault overvoltage analysis, stability analysis, and fault analysis. Some frequency scans were performed for harmonic analysis.

The models include the equivalent Lawrence Avenue Substation source impedance of the 115-kV transmission system and transformers (data provided by National Grid), the impedance characteristics of the main connecting feeder (67851), and the characteristics of the distribution system underground feeders. The system is modeled as a three-phase, four-wire, multigrounded neutral type of system. The individual impedances of each feeder and/or underground cable system were modeled as PI sections which represent the series X and R (reactance and resistance) as well as the shunt capacitance (C) of the cable systems. Power factor correction capacitors (1200 kVar banks) are also provided in the model and can be seen as roughly 18 microfarad capacitors on the model.

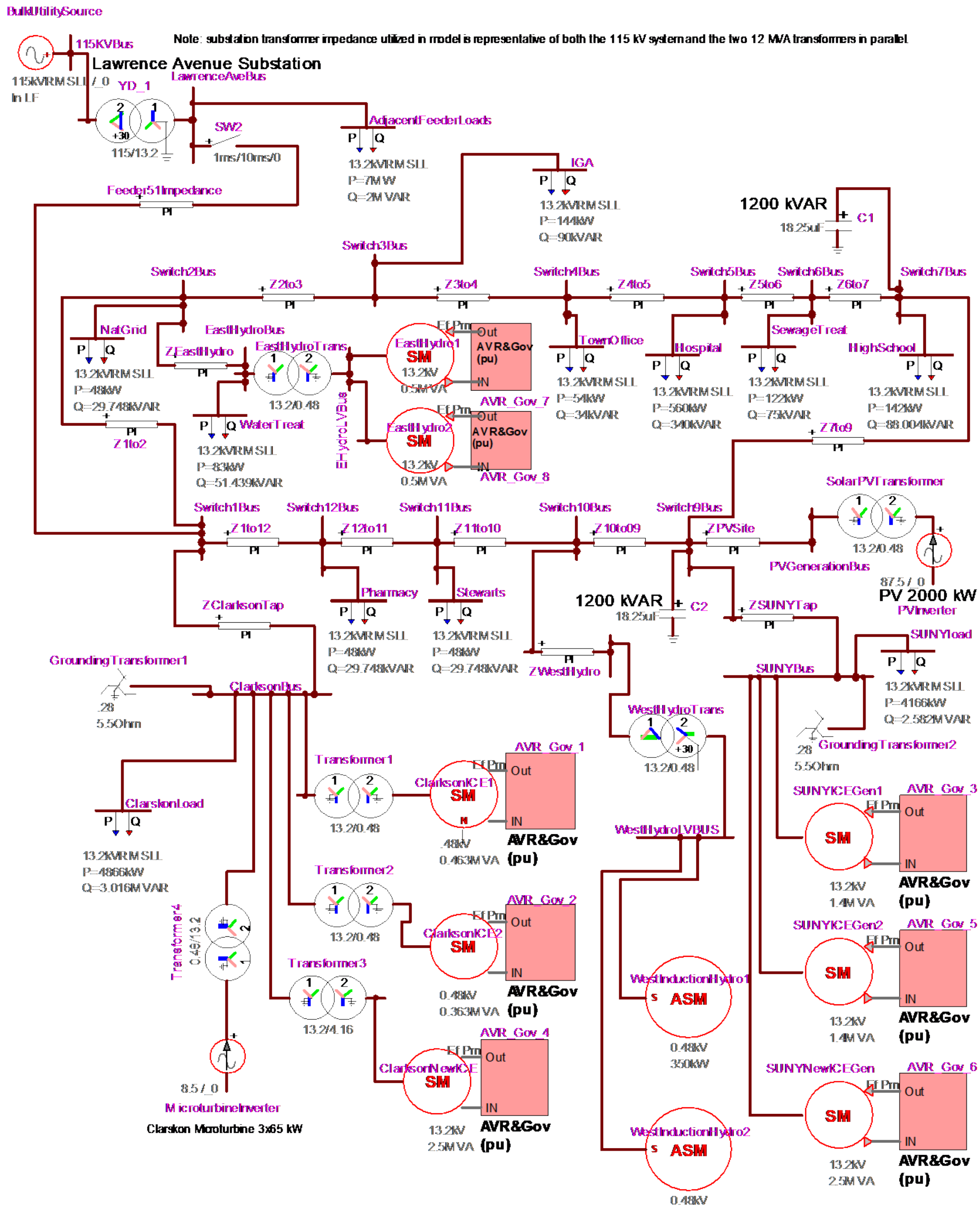
The distributed generation plants located on the system were modeled using the previously described parameters (section 5.1.3, Table 44). Each synchronous generator has an exciter model and a governor control representing the internal combustion engine (ICE) response. The machine data is based upon the typical time constants of response expected for ICE units operating on natural gas. There are also inverters present, modeled as current sources and induction machines modeled as asynchronous generators with slip.

The large SUNY Potsdam ICE generators are modeled as direct connected units (connected directly at 13.2 kV without step-up transformer) and other units are modeled as being interfaced by means of step-up transformers either from 480 V or 4.16 kV generator voltage up to 13.2 kV. The winding arrangements and generator neutral grounding are set to provide the neutral grounding conditions needed for each mode of operation. For example, there are two grounding transformers which are sized to provide effective grounding per IEEE standards with a COG well within effective grounding limits.

For the loads in the model, these values are based on the data provided for the various microgrid customers that will be on the system and can be adjusted based on the scenario simulated. A real and reactive component of load is provided. This characteristic was particularly important in cases involving islanding analysis and ground fault overvoltage analysis where there is a need to properly characterize the load on the system to facilitate the effectiveness of the islanding protection and the level of ground fault overvoltage during faults on certain types of generation islands that could impact the 115-kV system.

Figure 38 shows an example of EMTP system model used to simulate various types of grid-parallel and islanded conditions. The EMTP model used single- and three-phase switches triggered at certain times during the simulation to simulate various conditions. For example, the switch SW2 in the diagram can be opened to represent islanding. However, other switches (not shown in the figure) can be added and triggered as needed to simulate load steps, faults, and other conditions. Simulations were run out to anywhere from one to 10 seconds duration depending on the type of analysis and with step times of about 100-200 microseconds. This step time is sufficient to accurately calculate 60 Hz waveforms and pertinent harmonics associated with system conditions.

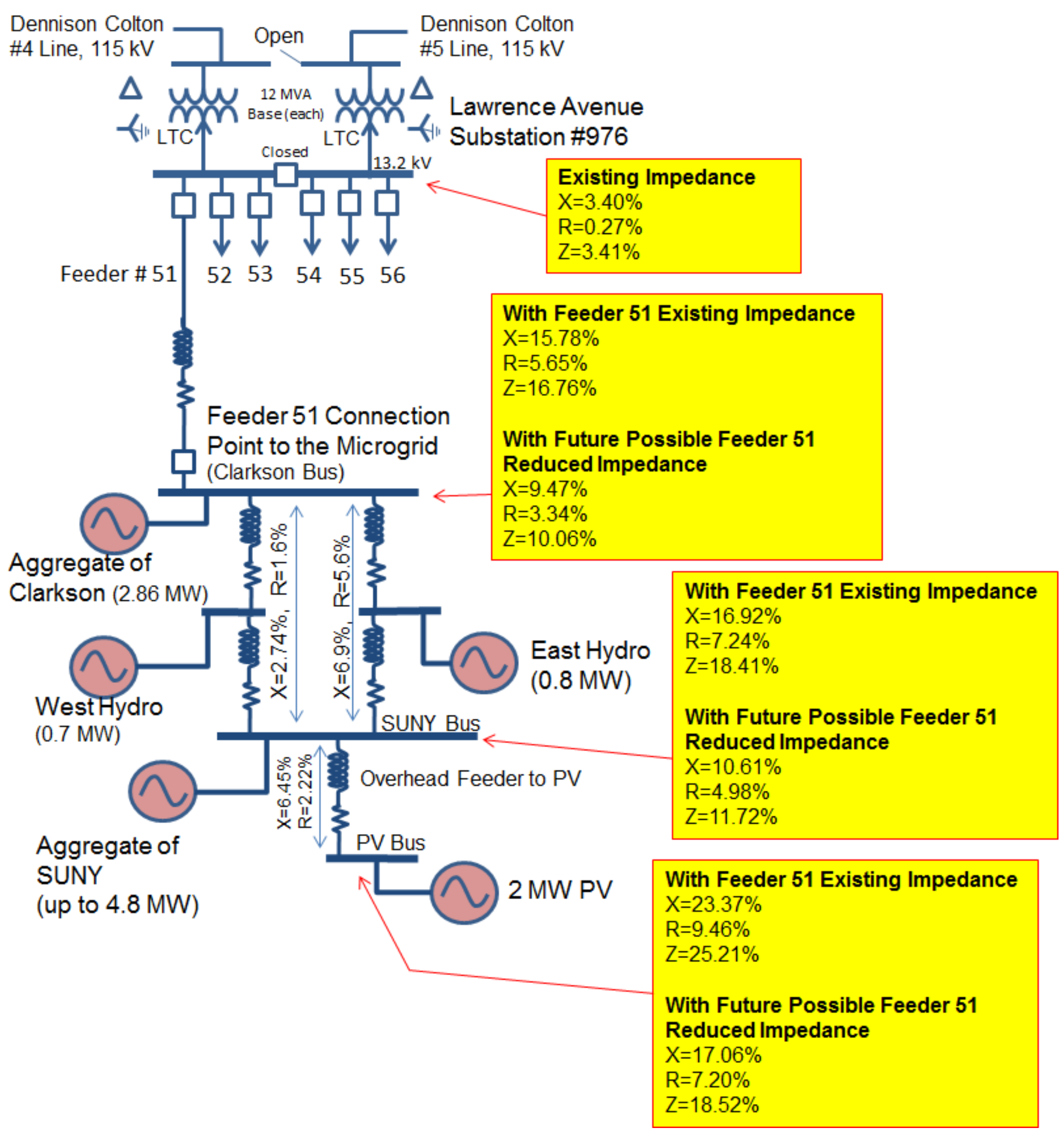
Figure 38. Example of the Typical EMTP Model Used for Simulation of the Potsdam Microgrid



5.4.3 Simplified Spreadsheet Model Calculations

For many of the calculations, a more simplified model was useful for screening purposes and voltage sensitivity analysis, etc. One such model is the simplified model of the impedances of the system at Lawrence Avenue Substation, the Clarkson point of common coupling, the SUNY Potsdam bus, and PV system bus (Figure 39). This model includes some basic locations of the various generation sources and is quite useful and intuitive for calculating voltage changes with various step changes in current levels as discussed in section 5.4.

Figure 39. Simplified Impedance Model of the Microgrid with Connection to the Bulk Power System—Impedances on 12 MVA Base



5.5 System Impacts of the Microgrid when Operating in Grid-Parallel Mode

5.5.1 Overview

The microgrid generators will operate in two major modes—either as grid-parallel generation with the bulk power system acting as classical DG resources (individually or as a group) or in an intentionally islanded mode (as a group of generators) to function as a stand-alone microgrid for "emergency" generation service to the loads on the microgrid in case of a bulk power outage. For each of these two roles the generator settings and operating characteristics are configured somewhat differently, causing the units to behave differently for each mode. As a result, it is best to discuss the results of the analysis in separate sections of this report. This section focuses on the grid-parallel mode of the operation (the classical DG role), while section 5.5 focuses on the islanded mode of the operation.

Even though this is a microgrid project, the grid-parallel role is still important because more than 99% of the time the microgrid generation will be operating in this manner. Proper operation in this mode facilitates the ability to capture the classical DG economic benefits of localized power generation, transmission and distribution support, and bulk system ancillary services (such as bidding into ISO markets) that can help economically justify the presence of a microgrid for the rare times it is needed in an islanded mode. In aggregate the microgrid will have up to about 10 MW of total generation capacity. This is a large capacity for a distribution circuit at 13.2 kV rating and so the grid-parallel impacts must be considered in this mode of operation. Some key topics that relate to grid-parallel operation include the following:

- Voltage regulation and flicker influence
- Fault levels
- Protection coordination
- Anti-islanding protection
- Generator protection
- Ground fault overvoltage and grounding
- Dynamic behavior
- Power quality and harmonics

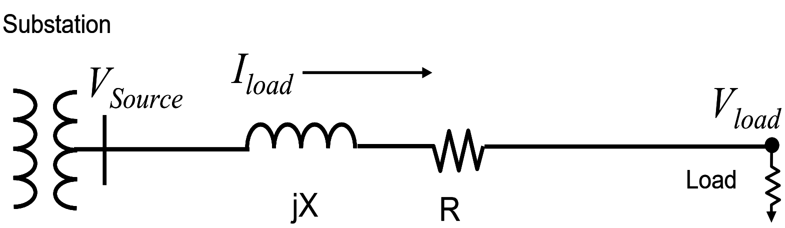
5.5.2 Voltage Regulation (Grid-Parallel Mode)

When the microgrid generation is operated in grid-parallel mode as a distributed generation resource, the generators will influence power flow on the system, which will cause changes in voltage on the system and directional changes in the power flow. It is important to screen the application to make sure that any voltage changes occurring during normal operation of the generators are within the proper ANSI C84.1 steady-state operating guidelines discussed earlier in section 5.2 and will not subject customers to objectionable voltage flicker.

5.5.2.1 Calculating Voltage Change due to DG (Grid-Parallel Mode)

The voltage change due to current flow (I) at an angle (θ) can be intuitively understood using the vector methodology shown in Figure 40. Starting with a load current example, it is evident that the load current at angle θ creates a resistive voltage drop vector and reactive drop vector (shown in red as IR and IX). These are subtracted from the voltage source vector to give the resultant voltage at the load (V_{load}). The R and X values are the resistance and reactance of the system at the load connection point. The voltage drop can be approximated by using trigonometric functions to project to the horizontal axis the components of the voltage drop. These are the components IXSin(θ) and IRCos(θ) shown in Figure 41. There is little error in this example compared to the actual voltage drop if the angle between the source voltage vector and load voltage vector is relatively small (under 10 degrees.) Equation 1 is the formula used to approximate the voltage change (a drop or rise) when the current is pulled or pushed through the system impedance. The approach will calculate voltage change when DG operates on the power system (but DG acts like a negative load pushing current into the system).

Figure 40. Vectors of Voltage Drop due to a Non-Unity Power Factor Load Consuming Watts and VARs



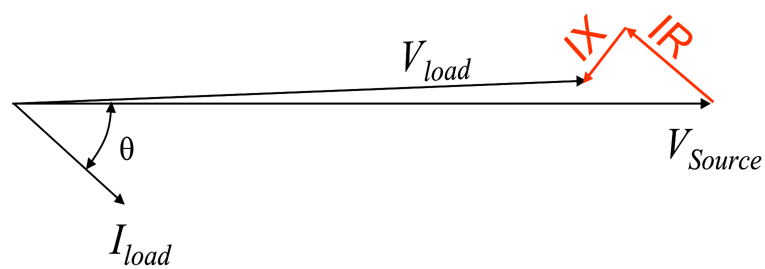
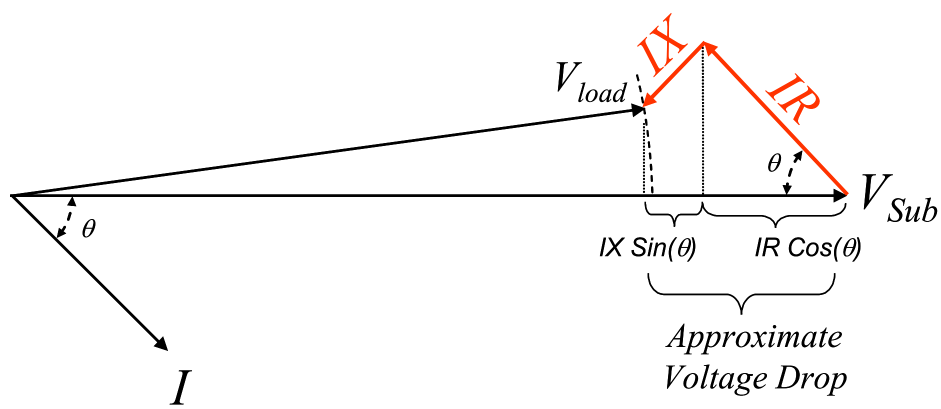


Figure 41. Components of Voltage Drop Projected to the Horizontal Axis to Give the Approximate Voltage Drop

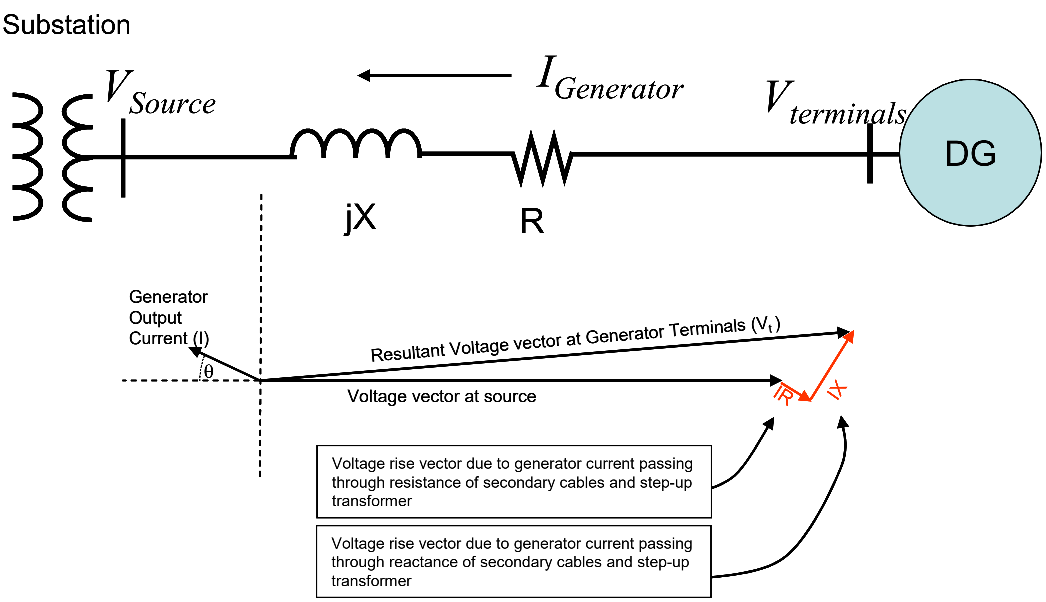


Equation 1. Voltage Change (Drop or Rise) Approximation

$$Voltage\,Change \approx I\left(X\,Sin(\theta) + R\,Cos(\theta)\right)$$

Distributed generation acts as a negative load. The change in current on the line results in a voltage change due to current pushed into the feed point impedance (X and R). Because it is a negative load the voltage change vectors are in the opposite direction and will cause a voltage rise rather than a drop. Figure 42 shows the vector situation for DG injected current for the case where it is producing real watts and producing reactive power.

Figure 42. Voltage Rise due to DG Injected Current into the System Impedance Producing Watts and VARs



Based on the preceding discussion and vector diagram, the voltage rise on the power system is calculated in much the same way as the voltage drop due to a load. The following equation is the formula used:

Equation 2. Voltage Rise on Power System

$$\Delta V \approx I_{DG}\left(X\,Sin(\theta) + R\,Cos(\theta)\right)$$

In the above formula ΔV is the change in voltage on the system; I_{DG} is the current injected by the DG, and θ is the angle between the current and voltage. R and X are the impedances of the system at the feed point. The power factor of the generator plays a big role. Note that if a generator is producing only watts (unity power factor [PF]), it will create a certain amount of voltage rise on the system due only to the product of I and R. If it is also producing VARs, the reactive current associated with it will causes an additional rise. On the other hand, if it is consuming VARs, the reactive current causes a drop. The generation situation that creates the greatest voltage change is one where the unit creates both real watts and produces VARs. In many locations on the power system, the X/R ratio of impedance is often much greater than one; therefore, the voltage sensitivity of the system to a given number of VARs is greater than it is to the same amount of watts produced by a generator.

5.5.2.2 Voltage Sensitivity Test (Grid-Parallel Mode of Operation)

Using the above approach, the voltage sensitivity of the Potsdam Microgrid can be calculated at the intended normal point of common coupling (the Feeder 97651 interface point near Clarkson) due to the expected maximum current production of the generators feeding into the impedance of the system—the value obtained is important to understand both the steady-state and dynamic behavior of the system at the point of microgrid connection. A small value of a couple percent or less means there is not much to worry about and a large value means that the system is sensitive to the amount of DG being connected and may need to be upgraded to reduce sensitivity. As part of the voltage sensitivity examination, it is worthwhile to evaluate the voltage change that occurs at the Lawrence Avenue Substation bus because that gives an indication of the broader area effects on multiple feeders emanating from that substation.

The maximum injected power from all DG sources of the microgrid is roughly 10 MW and not likely to exceed 11.1 MVA (if we assume operation at 0.9 PF). For the sensitivity test the simplified system schematic of Figure 43 shows the impedance of the Lawrence Avenue Substation bus as well as the impedance of the Feeder 51 connection point at Clarkson. In this test the generation has been collected in a representative mass at the PCC. The calculated voltage change at Lawrence Avenue and the Clarkson service point due to a ΔP equivalent to 10 MW at unity PF and at 0.9 PF producing VARs is shown in Table 51. Notice that the specific load value of the microgrid does not matter for this voltage sensitivity test, since the test is concerned with the *change in voltage* due to generation for dynamics purposes. However, the specific load value of the microgrid matters in order to calculate actual specific level.

Figure 43. Voltage Sensitivity Test Based on Feed Point Impedances at Lawrence Avenue Bus and Clarkson Service Point of Feeder 51

(Impedance Shown on a Base of 12 MVA)

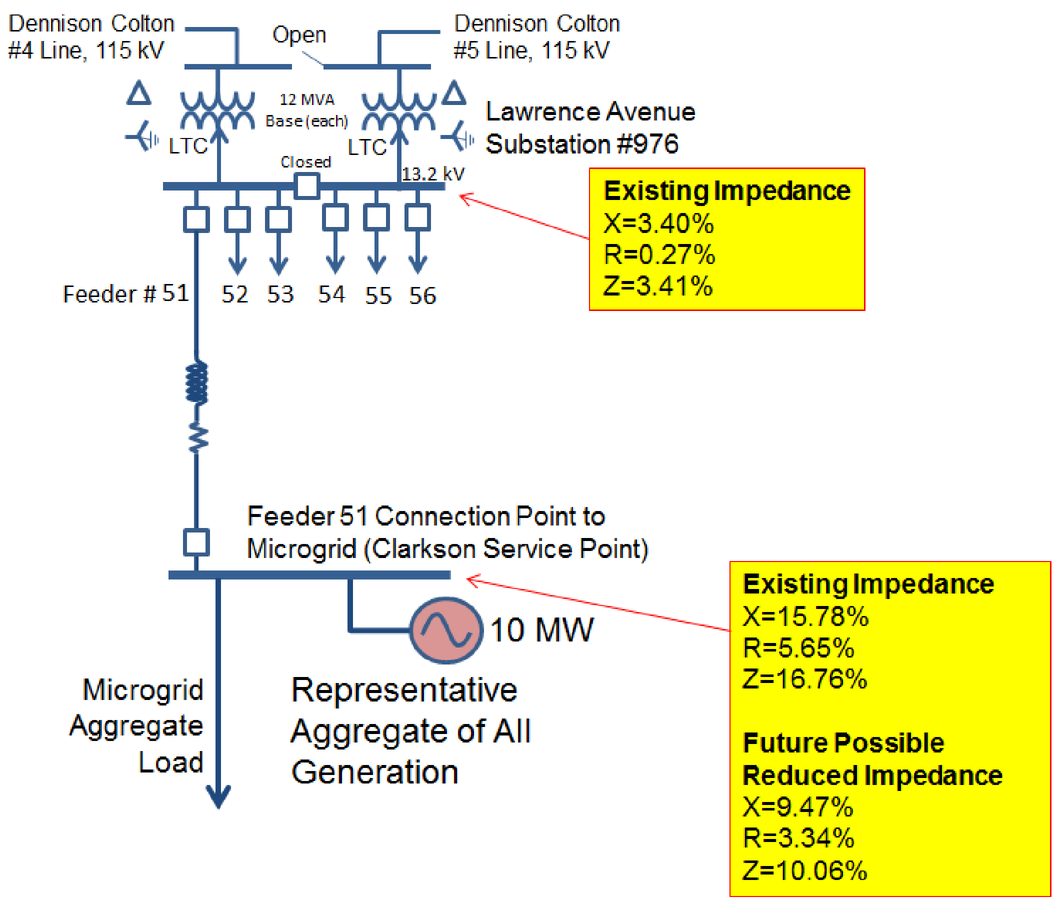


Table 51. Voltage Change Effects for a 10 MW Step Change in Power

Location	Voltage Change Calculation Results (using existing impedance of Feeder 51)	
	Calculated Voltage Change (ΔP=10 MW Unity PF)	***Calculated Voltage Change (ΔP=10 MW at 0.9 PF Producing VARs)***
At the Lawrence Avenue Substation Bus	0.22%	1.60%
At the Clarkson PCC Service Point (Existing Impedance of Feeder)	4.69%	11.08%
At the Clarkson PCC Service Point (Upgraded Feeder with Lower Impedance)	2.82%	6.65%

In Table 51, the voltage change sensitivity results are displayed in three rows. The first-row results show the voltage change at Lawrence Avenue Substation bus with existing impedance values of the overhead feeder and a 10 MW power step. The second row is the voltage change at the Clarkson PCC using the existing impedance of overhead Feeder 51. The third row is the result with Feeder 51 reduced impedance that could be achieved through a combination of conductor impedance reduction approaches (such as made possible by undergrounding, larger wires, etc.). These upgrades can be part of system upgrades performed at the time the microgrid is built. It is this analyst's opinion that the upgrades will be needed if the feeder is required to carry the entire load of the microgrid. As an alternative, one of the other feeders with lower impedance could be used (such as Feeder 53 or 56) as is discussed later in this report.

The calculation shows that the substation bus voltage change is insignificant (0.22%) even with a large sudden ΔP=10 MW at unity PF. Even at 0.9 PF producing VARs, the voltage change is still limited to only 1.6% at that bus. This shows that the substation is sufficiently stiff (acts as a low-impedance feed point) such that even with relatively large changes in current and considerable reactive current injection, only a small voltage change occurs. This characteristic combined with the fact that the line-drop compensation is not enabled at the substation LTC controller means that 10 MW of DG does not pose an issue at the substation level from a steady-state voltage regulation or dynamics perspective. A caveat is that the LTC controller must be set to handle reverse power flow into the 115-kV system by setting the mode of the regulation controller to always regulate in the forward direction no matter the direction of the power flow. Note that some voltage regulation controllers can be set to either lock the tap changer or reverse the direction of regulation if reverse power flow occurs. However, this type of function would not be appropriate in this case.

As mentioned previously, the voltage change sensitivity at the Clarkson PCC is fairly large. For a 10 MW step, it is 4.69% at unity power factor and 11.08% at 0.9 power factor generating VARs. This is nearly half the ±5% ANSI C84.1 allowable range window at unity PF and more than the entire ANSI window if generation is at 0.9 PF (producing VARs). The extra impedance of the existing overhead feeder to the Clarkson PCC is a key factor that increases the voltage sensitivity at this location compared to the voltage sensitivity at the substation bus. This suggests that a sudden step-power change (or power swings) of the generation all at once could cause voltage excursions outside the ANSI limits. It also suggests that keeping the whole feeder and microgrid within the ANSI C84.1 limits, even under steady-state conditions, will be difficult without special provisions. It should be noted that the problem is not just with the generation. The problem is also that in order to build the microgrid as planned and put all loads (SUNY Potsdam, Clarkson, and others, etc.) onto the single feeder (no. 97651), puts too much load on the feeder for its impedance. Keep in mind that prior to putting all loads on one feeder, the SUNY Potsdam load, in particular, was formerly on a different feeder and closer to the substation. In the new arrangement, the SUNY Potsdam campus load now must travel twice the distance, as it travels across the river back to Clarkson, and then back to Lawrence Avenue via Feeder 51. The effective electrical distance is much higher along with and the loading. Feeder 51 with its existing impedance simply does not have the voltage regulation capacity to carry all loads on the microgrid without an upgrade.

The reduction of the feeder impedance by means of increased size conductors and partial undergrounding to obtain lower impedance to the microgrid PCC will be necessary. It is understood that this reduction is already part of the plan for this project, although the specific final configuration is still being decided as part of the next phase. If the feeder 97651 impedance is reduced (Table 51, row 3), we can see that the voltage change for the 10-MW power step becomes much less. The change is 2.82% at unity PF and 6.65% at the microgrid PCC point. This is a more manageable voltage sensitivity factor.

There is no single 10-MW generator associated with the microgrid. However, 10 MW was used for the sensitivity test because it represented a possible power swing condition that can occur under some situations between all generation running and all generation offline. The largest single ICE generation unit is in blocks of up to about 2 MW and the largest planned ICE generator "stepping online" could create a 2-MW power ramp over several tens of seconds or a few minutes. The voltage sensitivity test calculation was therefore also done for a 2-MW generator at unity PF and 0.9 PF to observe the possible effect of this size of generation step (Table 52). The voltage swings due to 2-MW step at 0.9 PF that produce VARs could be as great as 2.21% with the existing feeder impedance at the Clarkson point of common coupling and existing feeder impedance. With the reduced impedance feeder, the voltage change would be only 1.33%. At the substation bus the voltage change is insignificant at 0.32%.

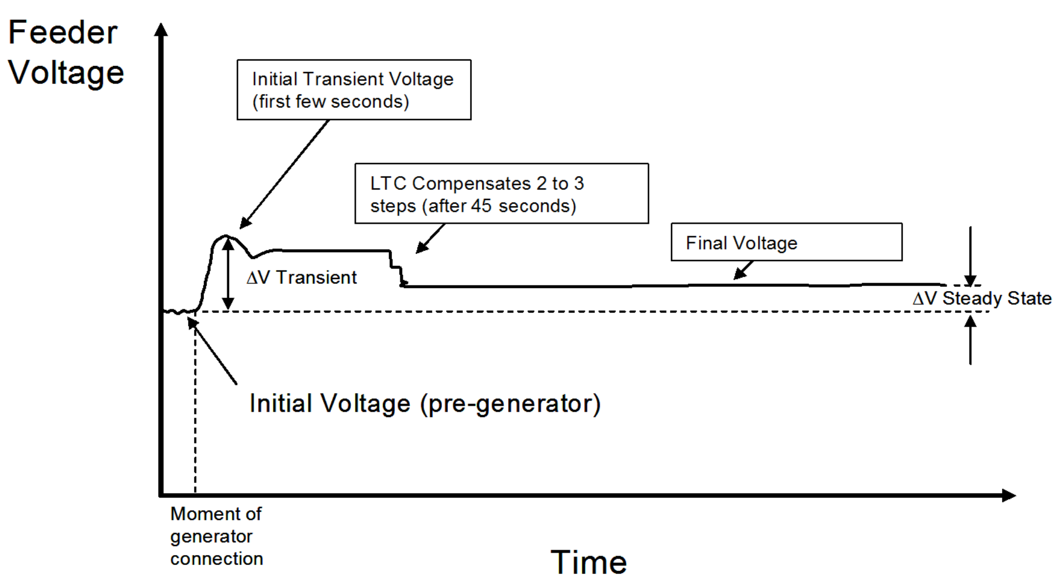
Table 52. Calculated Voltage Change due to 2 MW of Generation (Rapid On/Off Step)

Location	Voltage Change Calculation Results 2-MW Step	
	Calculated Voltage Change (2 MW Unity PF)	***Calculated Voltage Change (2 MW at 0.9 PF Producing VARs)***
At the Lawrence Avenue Substation Bus	0.046%	0.32%
At the Clarkson PCC Service Point (Existing Impedance of Feeder)	0.944%	2.21%
At the Clarkson PCC Service Point (Upgraded Feeder with Lower Impedance)	0.566%	1.33%

5.5.2.3 Substation Load Tap Changer Response and Feeder Regulator as a Solution

From the voltage sensitivity results in the previous section, it is evident that if the DG plants are "stepped on suddenly" or have fast dynamic swings in power over the 10-MW range, a large voltage change on the system is created at the PCC of the microgrid. This voltage change is solely due to the feed point impedance effect and occurs before the load tap changer (LTC) controller responds. After 30 seconds, the LTC begins to respond and will change its tap setting to compensate for any observed voltage change on the substation bus. Because the tap changer voltage controller is not currently set to use line-drop compensation, the effect of the tap changer controller on the voltage at the Clarkson PCC would be minimal since most of the voltage change occurs across the Feeder 51 impedance and is not at the Lawrence Avenue Substation bus. By using line-drop compensation at Lawrence Avenue, the LTC could be made to compensate somewhat more for the voltage change due to the Feeder 97651 impedance. However, this approach would not work well since the amount of compensation needed would adversely influence the adjacent feeders. A better choice, since Feeder 51 is an express feeder, might be to add a 1 MVA supplementary voltage regulator bank at the microgrid PCC (near Clarkson) and use it to manage the voltage changes that occur during grid-parallel DG operation. When used in that manner, a sudden step of 10 MW of generation (or the smaller 2 MW we discussed) creates a voltage rise initially, but after the time delay of the controller elapses it should correct that voltage rise to a lesser value or even entirely, as shown in Figure 44. If a slowed ramp rate is utilized for stepping in ICE generation, the slowed rate should allow the regulator time to correct the voltage change even for 10 MW of generation. While the regulator option can correct for slower "steady-state" variations of many minutes or longer it would not be a suitable fix to correct for the voltage change due to fast dynamics (power angle swings), etc. A better approach is still to reduce the impedance of Feeder 51, although this could be done in combination with a regulator bank added to produce a better overall solution.

Figure 44. Typical Voltage Change on Sudden Start (Without Ramp-Up) of a DG Plant Showing the Effect of the Feeder Regulator Over Time

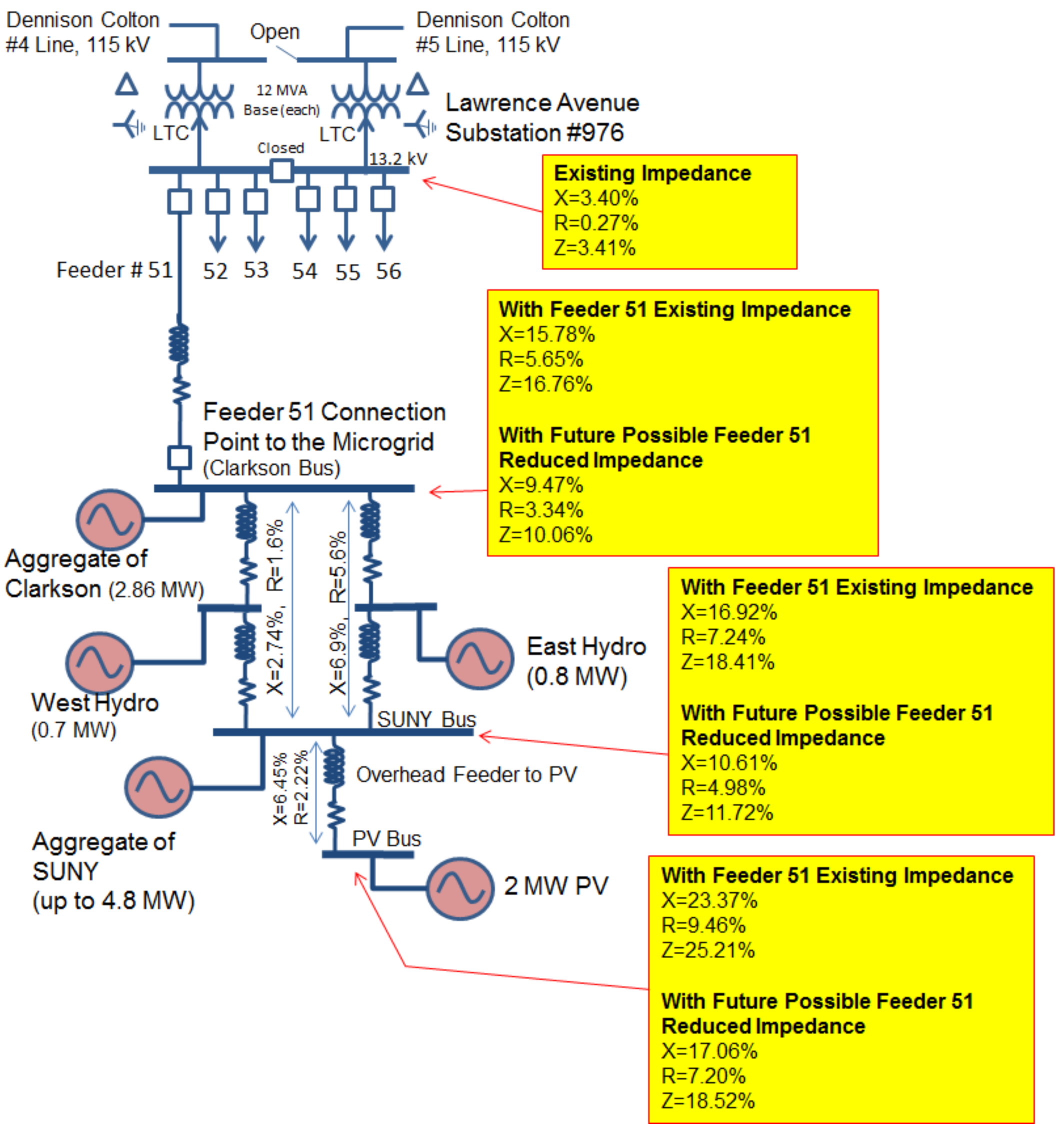


5.5.2.4 Voltage Change Deeper within the Microgrid

The voltage sensitivity test discussed so far was for the point of common coupling of the Feeder 51 with the microgrid. A lumped quantity of generation was used for that case to represent the voltage change for the worst-case step of all generation (10 MW) and for a more typical step (2 MW). However, there are many generators scattered around the microgrid that are electrically further away from the point of common coupling. These generators will have some additional impedance feeding that create additional voltage changes at their locations. The impedances on the primary (13.2 kV level) within the microgrid are as shown in Figure 45.

Figure 45. Impedance at Key Bus Points Within Microgrid

(Shown on 12 MVA Base)



The impedance between locations within the microgrid is determined by the underground cable characteristics. Compared to the Feeder 51 Clarkson PCC impedance, the intra-microgrid impedance is relatively low owing to the use of large copper 500-MCM underground cables which have both low reactance and resistance. This keeps the voltage drops along the cables relatively modest. Whereas, the existing overhead Feeder 51 feed point connection to Clarkson has higher impedance between it and the Lawrence Avenue Substation Clarkson is chiefly an overhead line with higher X and R and has a meandering physical path to Lawrence Avenue Substation, which increases the distance. While the impedance of the Feeder 51 connection is expected to be reduced in the future to facilitate operation of the microgrid during the buildout, it will nevertheless represent a large fraction of impedance, even when upgraded, that both the operating loads and DG must contend with while operating in grid-parallel mode. The impedances marked “Future Possible Feeder 51 Reduced Impedance” on the diagram are the ones that are most appropriate in our analysis. It is recommended to reduce the Feeder 51 impedance as part of the project and these estimates seem reasonable for what could likely be obtained.

The amount of additional voltage drop or rise within and across the microgrid during generation steps and dynamic swings while in grid-parallel mode depends on which generating units are stepping/changing their power levels. The worst-case location is the PV system feed point since it is electrically the farthest from the Feeder 51 connection point and so has the highest feed point impedance with the source as far back as Lawrence Avenue. The PV system, if it becomes part of the microgrid, is to be connected by an overhead connection near the SUNY Potsdam bus (as shown on the model) and will have a total X = 17.06% and R = 7.2% (on 12-MVA base) at its 13.2 kV feeder feed point. This does not include the impedance of the PV step-up transformer since the interests lies in primary side voltage changes affecting the feeder and other customers in that region.

A 2-MW variation of power level at the PV feed point would create a voltage change of 1.2% at unity PF and 2.57% producing VARs at 0.9 PF (Table 53). This shows us that operating the PV to produce VARs at as high as 0.9 PF along with real watts could be problematic while in grid-parallel mode, producing more voltage change than is desired on that overhead line section— especially during dynamic power output conditions caused by cloud shading effects. Cloud shading can result in up to nearly 100% swings in power relative to nominal PV rating in a short period of 2 minutes or even faster. The good news is that while the PF settings of the PV plant are not known at this time, it is considered extremely unlikely that it would be set to produce so many VARs as is currently configured. It is more than likely the PV is operating near unity PF or perhaps even absorbing some VARs if it is operating as a typical PV plant. Under those conditions, the calculations show the voltage change is well within reasonable limits and poses no issues for the system in grid-parallel mode. Note also that the calculated variation in voltage at the Feeder 51 feed point (at Clarkson) is not high enough to be problematic regardless of whether the PV operates at unity PF or 0.9 PF producing reactive power.

Table 53. Voltage Change due to 2-MW Step at Clarkson Tie Point and PV Service Feed Point

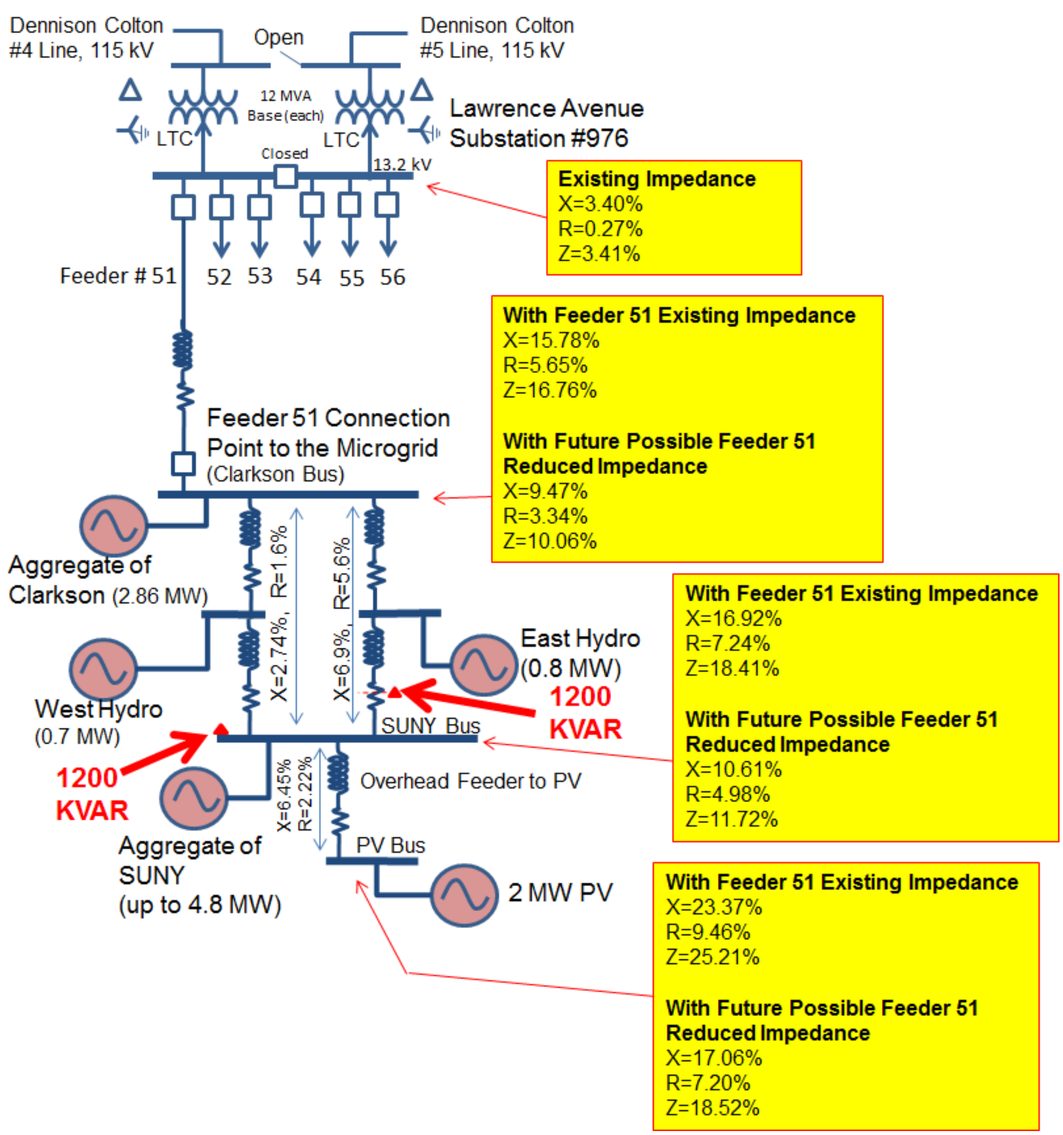
Location	Voltage Change Calculation Results 2 MW Step	
	Calculated Voltage Change (2 MW Unity PF)	Calculated Voltage Change (2 MW at 0.9 PF Producing VARs)
At the Clarkson PCC Service Point (Upgraded Feeder with Lower Impedance)	0.566%	1.33%
At the PV Primary Bus with PV Fed by an Overhead Line	1.20%	2.57%

5.5.2.5 Effect of the Two Proposed 1200 KVAR Capacitors

In section 2, the team recommended that two 1200 kVAR capacitor banks be installed, one near or at the high side of SUNY Potsdam bus in the model and the other one near or at Potsdam High School (which is midway between East Hydro and SUNY Potsdam bus). These are denoted by the red triangles in Figure 46. These capacitors are a good idea and can be helpful to provide reactive current to the system as well as compensate for voltage drop from Lawrence Avenue substation during periods when the generation is mostly offline and when load is high.

The calculated voltage rise due to these capacitor units at the SUNY Potsdam bus is about 3.4% if the existing Feeder 51 impedance is used and about 2.1% with the lowered impedance configuration. It should be noted that if during a period of light microgrid load, it was desirable to export a large amount of real and reactive power for bulk power market sales purposes, the system would then be exporting energy into Feeder 51 toward Lawrence Avenue. The voltage rise across that feeder combined with the additional rise due to the capacitor reactive current could become excessive. It would likely make it necessary to switch off the capacitors to avoid an overvoltage condition—or the generators could also be made to absorb VARs to cancel the voltage rise. For this reason, it may be a good idea to have those capacitors be switchable. The switching could be coordinated with the microgrid controller based on system loading and voltage conditions as well as the desired real and reactive power export for market transactions. Note that having the switching function is important for grid-parallel operating mode as well as for the islanded mode of operation discussed later. As mentioned earlier in the report, a 1 MVA voltage regulator bank could also be added at the Clarkson microgrid PCC for Feeder 51 that could help limit voltage changes and allow more flexibility in the real and reactive power export and loading options through the impedance of Feeder 51.

Figure 46. Approximate Locations of the Two Proposed 1200 kVAR Capacitor Banks on the Impedance Model

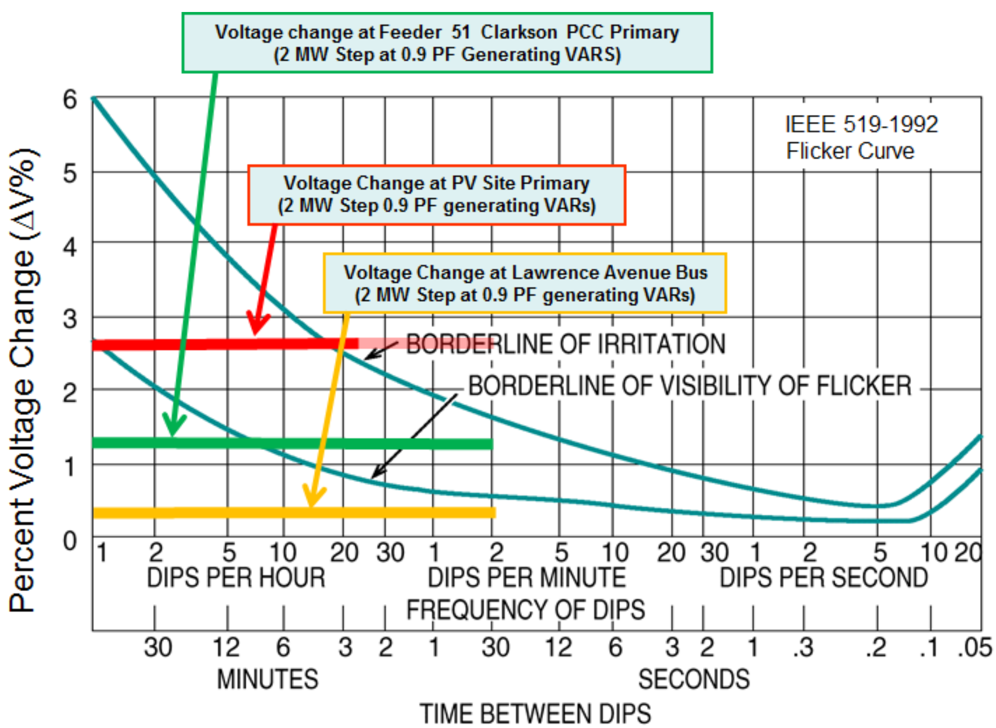


5.5.2.6 Voltage Flicker Conditions (Grid-Parallel Mode)

Rapid voltage changes on the distribution system due to variable generation output conditions (such as the PV system during cloud shading variations) should be limited so that they do not cause objectionable flicker that exceeds the allowable flicker curve limits. From the earlier results (Tables 52–53), we can plot the amount of ΔV at the substation bus, the Clarkson Feeder 51 PCC primary and the PV primary connection point for up to a 2-MW 0.9 PF rapid power step plotted on the IEEE 519 flicker curve (Figure 47). Please note that this curve is for rectangular (step type) voltage changes such as might be seen with a motor starting condition. The PV variations are not "rectangular" and are more gradual in their rise and fall. Therefore, the flicker curves for such gradual variations are at least 1.5 times these bounds. The conclusion is that at the PV primary feeder feed point, irritating flicker might be visible if a rapid 2 MW rectangular step change were to occur and if the change includes a reactive component of output. But if we consider that the PV would be operated near unity PF (causing far less voltage change), the ΔP would be somewhat less than 2 MW and would have a gradual rise and fall of the output; therefore, there would be no risk of visible flicker from the PV site during grid-parallel operations.

Figure 47. Change in Voltage for a 2-MW 0.9 Power Factor Step

On this curve, the 2-MW PV site would not be expected to change at frequency more than roughly two times per minute.



While microgrid ICE generators have the ability to cause flicker during grid-parallel mode, these units do not have uncontrolled running variations as in the case of wind or PV sources. Instead, they generally operate as steady sources over long periods of time or, at the most, are ramped up/down at controlled slow rates per dispatch and/or at load following requirements.

Two general guidelines for the ICEs (especially the largest unit blocks) are to be followed when generators are connected in the grid-parallel mode. The first guideline is to not go outside the bounds of the IEEE 1547 interconnection accuracy guidelines for voltage matching, frequency matching, and phase angle matching at the moment of connection as shown in Table 54 (aggregate amount column is total nameplate capacity of the block of units connecting at a given instant) during the moment of interconnection between bulk grid and the generator unit. This minimizes the interconnection related power flow transients that can cause noticeable voltage flicker. The second guideline is to slowly ramp up larger units when dispatching generators over a two minute or longer period and avoid suddenly increasing the speed to the fastest possible ramp rate. This makes the voltage transition more gradual (less noticeable) as well as allows time for the upstream LTC and voltage regulator tap changers to adjust themselves to minimize the voltage change experienced by the distribution system.

Table 54. IEEE 1547 Interconnection Synchronization Accuracy Recommendations

Aggregate Rating of DG Units (kVA)	Frequency Difference (Δf, Hz)	Voltage Difference (Δ V, %)	Phase Angle Difference ($\Delta\theta$, degrees)
0-500	0.3	10	20
>500-1,500	0.2	5	15
>1,500-10,000	0.1	3	10

5.5.2.7 Voltage Flicker and Voltage Changes on 115 kV Transmission

There is also interest in knowing whether or not when operating in grid-parallel mode if any problematic steady-state or flicker related voltage fluctuations will occur on the 115-kV transmission system due to the DG running and/or connection currents. The answer is absolutely no in this case. Ten megawatts of DG, even if suddenly fully stepped on at 0.9 PF is not able to cause more than a few tenths of a percent of variation in the 115-kV side voltage given the low relative impedance on that side of the system.

5.5.2.8 Unusual Load and DG Interactions that Might Cause Flicker

Starting and stopping of the ICE DG as well as PV type cloud variations are not the only possible sources of DG induced voltage flicker. DG can cause flicker if there are load pulsations and/or ICE misfiring issues that excite certain types of sub-synchronous generator rotor angle oscillations. Such pulsations could be caused by misfiring engines (due to poor fuel or engine ignition control problems) or due to strange interactions between the machine and the system loads/equipment and system voltage sags. These pulsations and oscillations, if any occur, are not typically as severe as the start-and-stop type voltage changes from a ΔV perspective. Rather, since they can occur on a more frequent basis, they can be in a much more sensitive region of the flicker curve where a smaller ΔV, even as small as ½ percent, is visible to the naked eye as light flicker.

For the Potsdam Microgrid the loads at the customers have been characterized and it does not appear that there are any large pulsating loads such as industrial sized motors, rock crushers, cranes, arc furnaces, etc., that would cause issues. The largest motors present on the system (as far as we know) as per the earlier characterization of loads in 2015 indicated that no motors exceed 100 horsepower (hp).

Overall, it does not appear that there are any periodic large stepping loads that would be an issue. In addition, the fueled DGs for this project are to run on high-quality utility grade natural gas so misfiring due to poor gas (which is sometimes a characteristic of bio-digester natural gas fueled DG sites) is not an issue in this project.

5.5.2.9 High-Steady-State Voltage at Generator Terminals

It is important to avoid high-terminal voltage at the generators because high voltage can cause saturation, which leads to additional heating that may damage the generators and require curtailment of output. If high voltage occurs, it may make it difficult to utilize the generator units to their full capability to provide real and reactive marketing services to the bulk power system at all times. This could reduce the economic viability of the project.

The amount of voltage rise a generator can handle depends on many factors including loading, frequency conditions, presence of other heating effects (such as unbalance and harmonics) and ambient temperature conditions. NEMA/ANSI/IEEE standards rate most machines in a manner that allows up to 1.05 per unit steady=-state voltage at the machines nominal rated frequency and power levels.

The impedances of the key feed point (Feeder 51 at Clarkson PCC) and the LTC settings (123 V) used at Lawrence Avenue are such that if the microgrid is lightly loaded and generation is attempting to operate (for bulk market purposes) at or near the full 10 MW level, the microgrid voltage may tend rise to much higher than 1.05 per unit on the primary feeder. In this condition the generator terminal voltages would be even higher due to the additional impedance of the step-up transformer and connecting cables for each generator where applicable. The ANSI Range A and B voltage limits would also be exceeded, causing issues not just for the generators but for loads on the system as well. Overall, this would mean that at certain times of light microgrid loading, the generator activity would need to be limited (curtailed) compared to its full capability. At heavy load the problem disappears due to the voltage drop caused by the load. To avoid this issue of the need for light-load generator curtailment, it is recommended that the impedance of the Feeder 51 circuit as seen at the Clarkson PCC be made lower than its existing value. A voltage regulator may also be needed at that feed point to further enhance the voltage regulation capabilities. As an alternative to the voltage regulator, the generators may need to have reactive power generation limits imposed during periods of light-microgrid load and some may even need to operate in a fixed-power factor mode and absorb reactive power to mitigate voltage rise as discussed in the next section.

5.5.2.10 Operating Mode for Generator Controller (Grid-Parallel)

An important consideration for connected generators is the real/reactive power control operating mode. Choosing the correct mode will help insure proper voltage regulation on the power system and avoid possible problematic interactions with voltage regulation equipment. When the units are operating in grid-parallel mode, they should be operated in a manner in which there is no attempt to directly regulate the voltage via a closed-loop voltage feedback method. Closed loop means measuring voltage and then trying to control it with a corrective action. There are "open-loop" methods of generator operation that do not use the voltage directly as a feedback control and instead simply use the generator's own measured power output as the controlling entity. For grid-parallel DG, an open-loop method of operation is usually better because the substation transformer LTC and other utility system regulation equipment will not be fighting against the settings of the DG voltage control. This is in contrast with DG units operating in an islanded mode, where the major units present can be set in a closed-loop mode to help regulate the voltage if properly coordinated.

For a synchronous generator some possible modes of operation of the DG exciter/governor controller include the following:

- Open-Loop Independent Set Points for Both Real Power (watts) and Reactive Power (VARs): In this mode the operator sets the desired level of "watts" and "reactive power," and the machine holds those values regardless of the measured voltage at the machine terminals.
- Open-Loop Fixed Power Factor Mode: The operator sets the desired value of watts and the value of the power factor (PF). The reactive power produced (or consumed) is a fixed ratio function of the watts produced as follows:

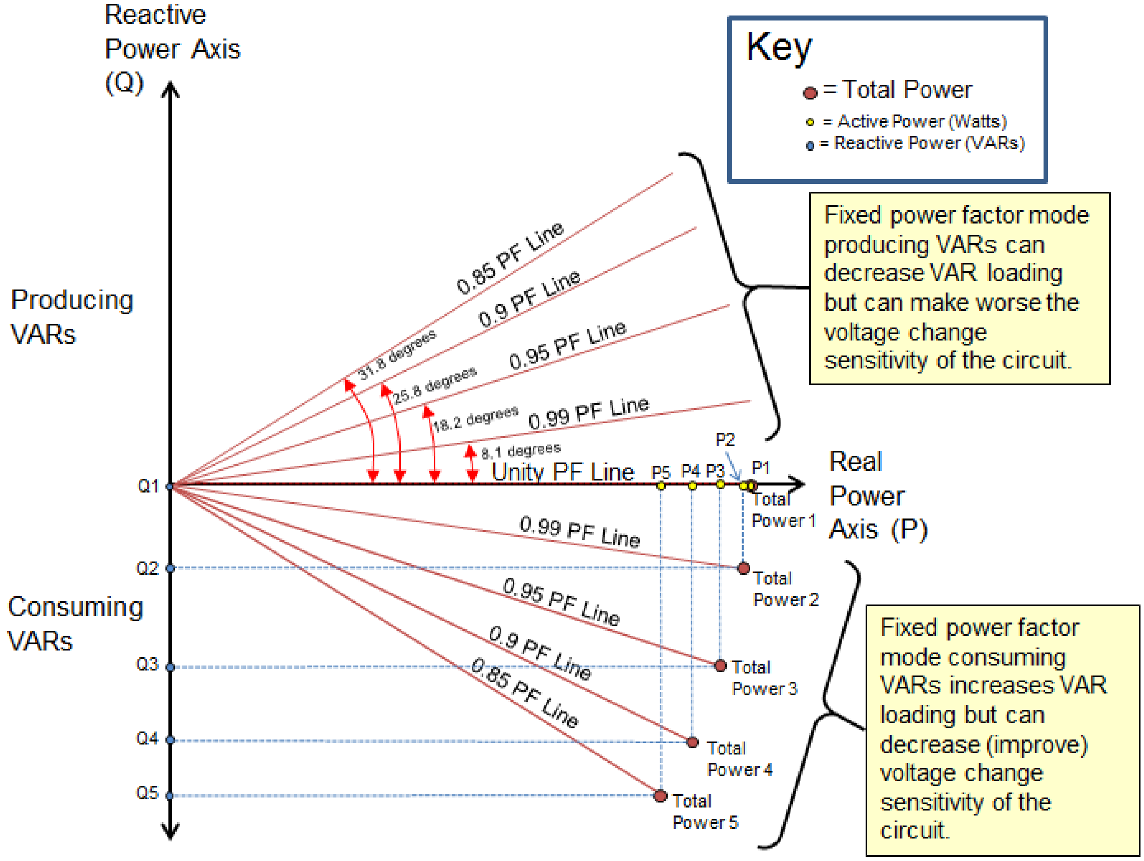
$$\text{Reactive Power} = \tan(\cos^{-1}(PF)) \times Watts$$

- Closed-Loop Voltage Regulating Mode with Independent Real Power: In this mode the machine operates at a real power level set by the operator (independent of voltage measurements) but automatically adjusts its reactive power (VARs) to either leading or lagging as needed to hold the machine terminal voltage to an operator adjusted set point.
- Closed-Loop Voltage Regulating, Load Following and Frequency Regulating Mode: From an exciter standpoint this is similar to the voltage regulating mode above, but the unit follows the real and reactive load demand as well as regulating the voltage at its terminals (this mode is needed for islanded operation discussed in the next section).

In the first two of the above cases the "operator" can be either a locally autonomous power-level action set manually (or automatically) or it might be controlled remotely by an overall generator aggregation controller. The first two modes mentioned make the most sense in classical distributed generation applications with DG connected to the bulk power system (so called grid-parallel mode). Modes 3 or 4 listed above are not recommended for classical grid-parallel DG applications unless special provisions to coordinate the operation with the utility LTC controller and other regulation devices are carefully engineered. Otherwise, this can cause "hunting" between the substation LTC unit and the various generators on the system. In particularly problematic cases, excessive and unpredictable swings in reactive power output from the generators along with excessive tap-changer cycling would be a symptom of trying to operate the units in voltage-regulating mode when they fight the LTC controller or fight each other.

To avoid these hunting problems either the fixed-power factor mode or fixed-independent real and reactive setting can be employed while in a grid-parallel mode of operation. This is the method most used by DG today. It should be noted that when using the fixed-power factor mode, it is possible to operate at a fixed PF that is either unity, leading or lagging. Meaning it is VAR neutral, consuming VARs or producing VARs. When the generator is consuming VARs the voltage tends to fall, and when the generator is producing VARs the voltage tends to rise. In cases where the system is being constrained by high voltage when real power generation is high (which might be the case in the Potsdam Microgrid during period of light load), then backing off on the VAR production or even going as far as consuming VARs can be helpful to keep voltage rise in check. Figure 48 shows examples of fixed-power factor operating lines.

Figure 48. Fixed-Power Factor Operating Lines

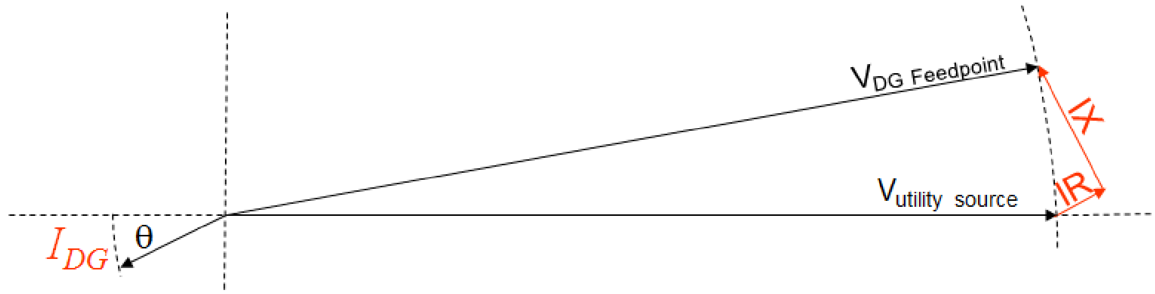


For a given X/R ratio feed-point impedance, there is an ideal single-fixed power setting consuming VARs while producing real watts that mitigates the voltage change feeding into the system impedance. This happens when the following occurs:

$$\boldsymbol{X} \sin \boldsymbol{\theta} + \boldsymbol{R} \cos \boldsymbol{\theta} \;=\; \mathbf{0}$$

Figure 49 shows an example of an ideal fixed-power setting with an operating PF angle where the reactive power voltage drop vector cancels out the real power voltage rise vector, resulting in no change in voltage. Notice that the voltage vector at the feed point is the same length as the source voltage and is therefore unchanged. For the Potsdam Microgrid, these methods may be needed at times to limit the voltage rise, although the drawback of the approaches is that they will increase reactive demand as seen by the bulk utility source.

Figure 49. Example of Ideal Fixed Power Setting



5.5.2.11 Alternative Feeders as the Main Microgrid Tie Point

The results so far show that Feeder 51 (located at the Clarkson main service point) is not the most ideal feeder from an impedance perspective despite the fact that it, as initially designed, has been the preferred microgrid connection. The feeder has more impedance than several other possible feeder connections. While it will work for the project, the recommendation is to reduce the impedance and/or to consider corrective actions such as a supplementary voltage regulator and/or VAR management to reduce the voltage changes. Various combinations of these approaches can solve the issues.

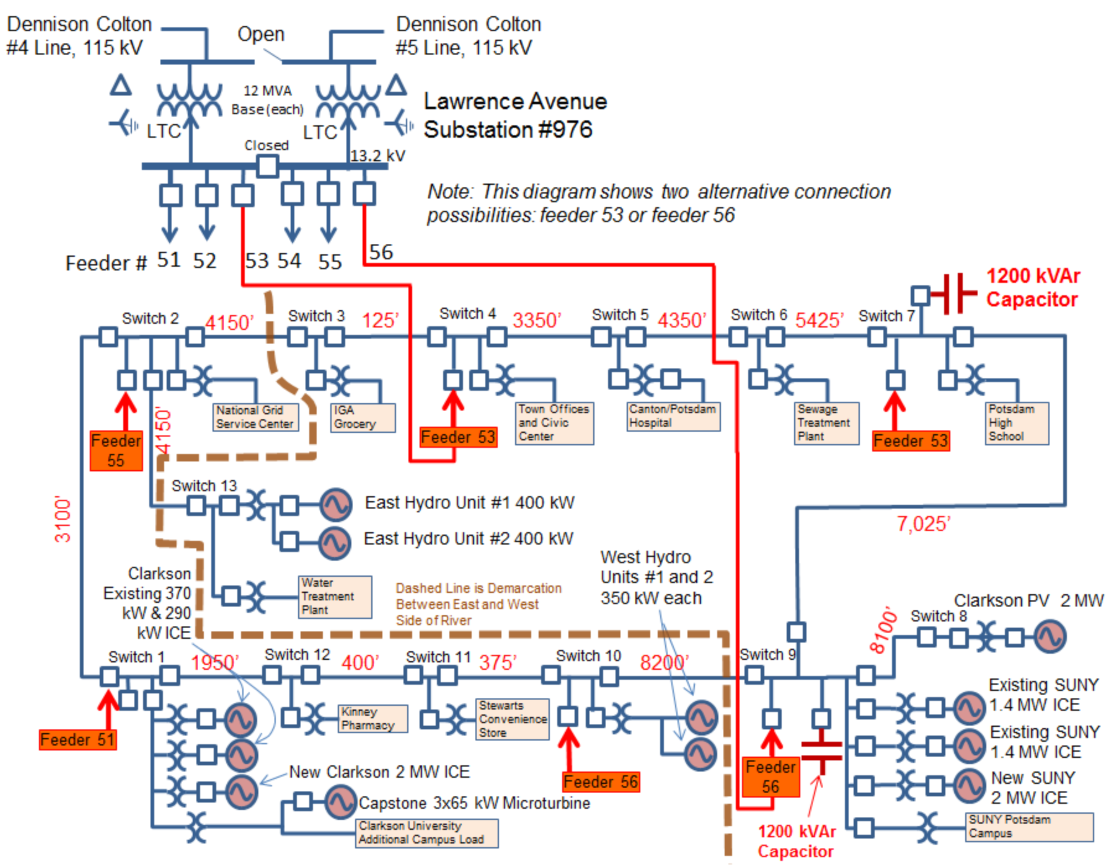
However, another possibility is simply to use an alternative feeder as the connection point for the entire microgrid. The two best possibilities from an impedance perspective given the available data provided by National Grid are Feeder 53 (with an interface point near the police station/civic center) or Feeder 56 (with interface near or at the SUNY Potsdam main service point). Both have about half the impedance of the existing Feeder 51 tie point and therefore will see about half the voltage change for a given amount of current flow change (Table 55). These and other alternative feeder connection possibilities are shown in Figure 50. When comparing the Feeder 53 to Feeder 56 tie points, Feeder 56 proves to be superior for a number of reasons. One reason is that its impedance is slightly lower than Feeder 53. In addition, the tie point is located on the southeast side of the underground microgrid branch at a generation-centric point, which should also help reduce the voltage change within the loop actual impedance due to DG current changes. This location is closest to the large SUNY Potsdam load, the large SUNY Potsdam generation, and the PV generation of all the proposed tie points.

Table 55. Feed Point Impedances of Four Microgrid Tie Points

Location	R	X	Z
Feeder 51 Clarkson Main Service (at Switch 1)	5.65%	15.78%	16.76%
Feeder 55 Near National Grid Service Center (Switch 2)	3.62%	10.86%	11.45%
Feeder 53 Near Police Station/Civic Center (at Switch 4)	2.23%	8.15%	8.45%
Feeder 56 Near SUNY Potsdam Main Service (at Switch 10)	2.08%	7.85%	8.13%
Note: Impedances in percent on 12 MVA base.			

Figure 50. Alternative Feed Points with Lower Existing Impedance than Feeder 51

(Lengths of Feeders 53 and 56 not to scale)



5.5.2.12 Splitting the Microgrid in Half (Grid-Parallel Mode)

If the microgrid is split in half, which is a key part of the plan at certain times, both for reliability and operational flexibility, the natural demarcation would point would be the Raquette River. The approximate location of the river is shown by the dashed brown line on Figure 50. In that case, the best way to tie the utility source on the Clarkson side of river into the microgrid is with either Feeder 55 at Switch 2 or Feeder 51 at Switch 1. When operated in "half-microgrid mode" the generation and load levels are far less demanding. Feeder 55 has somewhat less impedance than Feeder 51. On the SUNY Potsdam side of the river, Feeder 56 at the SUNY Potsdam location remains the best option.

5.5.3 Fault Current Contributions and Protective Relaying Issues Associated with Microgrid DG (Grid-Parallel Operation)

5.5.3.1 Background

This subsection focuses on the fault current and protective relaying issues associated with the application of the DG on the microgrid while it is operating in parallel with the power system. Discussions and topics include the following:

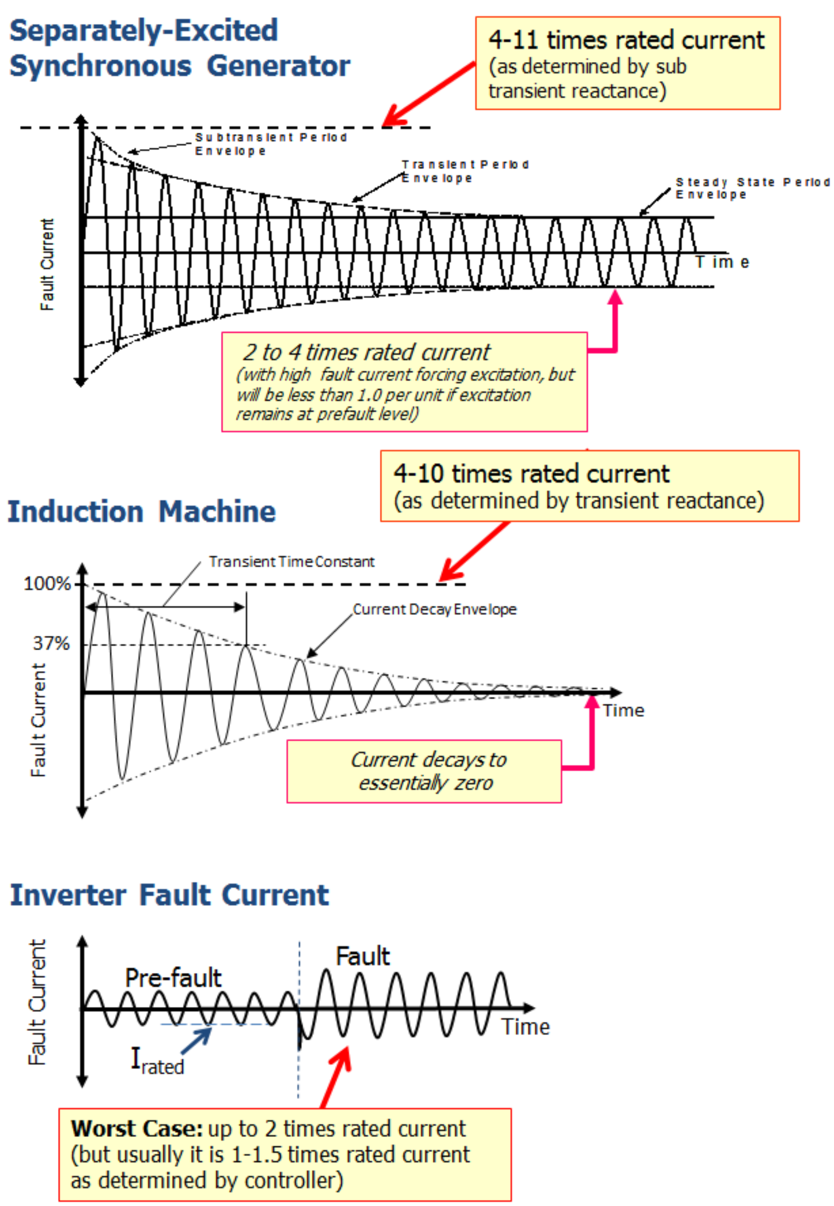
- Machine characteristics (as they related to fault contributions)
- DG fault contribution levels and impact on the microgrid system
- Coordination issues associated with DG and the power system

5.5.3.2 Machine Characteristics and Fault Levels

The DGs will contribute fault current to the power system whenever there is a fault. The level of fault current contributed is a function of the impedance between the fault location and the generator, the ratings of the DG machines operating, the type of fault, and the impedance characteristics of the machines. For synchronous rotating machines, the generator's fault contribution is not constant, but rather it starts out large and decays to a significantly smaller value after many cycles. The generator goes through a period of sub-transient reactance followed by a transient reactance and then synchronous reactance. The initial current for a balanced fault at the machine terminals will be four to 11 times the rated current depending on the machine's sub-transient reactance. The final current depends on the exciter response and synchronous reactance but might be as high as two to four times rated current and, in some cases, it is less than the rated current. Induction machines also have a similar current contribution decay, albeit, the end point of the decay is at essentially zero current because as an induction machine there is no separately derived excitation field present. Inverters contribute fault current up to typically several tens of cycles of time that is typically 1 to 1.5 times the normal rated current of the inverter. An illustration of the fault current levels from all these devices is shown in Figure 51. All three generator types (synchronous machine, induction machine and inverter) with various prime movers are present on the Potsdam Microgrid, but by far internal combustion engine driven synchronous generators will contribute the bulk of the fault current coming from generation devices on the system.

Figure 51. Generator Fault Current for DG Devices

(Number of cycles of contribution shown is for illustration only)



The existing and new planned ICE generators for this project are most likely all separately excited. This means they have their own power source for excitation not derived from the machine's terminals. The separate source is a small permanent magnet generator mounted on the shaft to provide power for the exciter—this supply stays running as long as the shaft is spinning and regardless of what is happening on the main generator terminals. A separately excited generator such as this can continue supplying fault current indefinitely (until tripped for thermal winding protection) because it never loses its source of excitation (magnetic field) during a fault.

The two 350-kW induction machines employed for this project are at the West Dam hydroelectric site and current contributions would have fault contributions decaying in a manner initially similar to a synchronous machine but would quickly decay to zero current due to the lack of excitation. The inverters (both the Capstone microturbines and the PV) can provide an essentially steady-fault current (but small compared to initial magnitude of a rotating machine fault level) until the inverter control algorithm trips it off.

For rotating machines the main machine characteristics that determine the nature of the fault contribution immediately after initiation of the fault are the machine's sub-transient and transient reactance (these are X″ and X′), the sub-transient and transient time constants (T" and T'), and the machine's internally generated electromotive force (EMF)—which is typically at maximum—is no more than 10% to 15% higher than its terminal voltage at rated load depending on excitation level and PF of the load. With these elements known, the machine can be modeled as the internal voltage (this excitation voltage is often referred to as E_{af}) behind the machine's impedance. After a period of a one second or more, the machine transitions to its steady-state fault level as determine by the synchronous reactance of the machine. Since the synchronous reactance of a machine can be well over 100%, the fault current will fall below one per unit unless the exciter is of the type that "forces" higher current by dramatically increasing the excitation level.

5.5.3.3 Generator Fault Contributions at Primary Terminals of Each Respective Generator Interface Transformer

If a bolted three-phase fault occurs near the high-side, step-up transformer terminals of each of the various generators of the microgrid, the impedance seen to the fault (if we ignore R because X/R ratio is high enough to do so) would be the sum of the generator (X″), the secondary connecting cables (X), and the step-up transformer (X). For rotating synchronous machines of this project, the fault current assumes a running loaded generator EMF 10% higher than the nominal terminal voltage. A synchronous machine sub-transient reactance of 16% is used for the calculation. For inverters, they are modeled as current sources and the maximum fault current is about 1.5 per unit of rated current. The actual fault current contribution as calculated will be per those shown in Table 56. For the rotating machines, these are the initial fault current calculations during the first cycle and the current contributions will rapidly decay to much lower values due to the sub-transient and transient decay envelopes.

Table 56. Approximate Generator Fault Contributions to a Three-Phase Bolted Fault on the 13.2-kV Side of the Step-Up Transformer

Impedances shown are on the base rating of each specific generator.

Generator	Nominal kVA Rating of Generator	Generator X" (% reactance at nominal rating)	X of Generator Step-Up Transformer and Cables	Total Impedance of Generator, Transformer and Cables	Amperes Initial Fault Contribution High Side (13.2 kV) of Step-Up Transformer [(a,b,c)]
West Dam Hydro(s)	778	16	5.07	21.07	162
East Dam Hydro(s)	1000	16	5.13	21.13	228
Clarkson Existing A	463	16	1.19	17.19	130
Clarkson Existing B	363	16	0.93	16.93	103
Clarkson New	2500	16	No Transformer Direct Connected Unit	16.00	752
SUNY PotsdamExisting A	1750	16	No Transformer Direct Connected Unit	16.00	526
SUNY Potsdam Existing B	1750	16	No Transformer Direct Connected Unit	16.00	526
SUNY Potsdam New	2500	16	7.70	23.70	508
PV Array	2000	Inverter: 1.5 per unit current source fault model used			131
Capstone Microturbine	195	Inverter: 1.5 per unit current source fault model used			13

Notes:

[a] All machines except for West Dam Hydro and the inverters are Synchronous rotating machines with 16% X″ and 1.1 per unit EMF used as approximation of the EMF under loaded generator condition.

[b] West Dam Hydro Induction machine EMF assumed at 1.0 per unit.

[c] Inverters modeled with 1.5 per unit maximum current model.

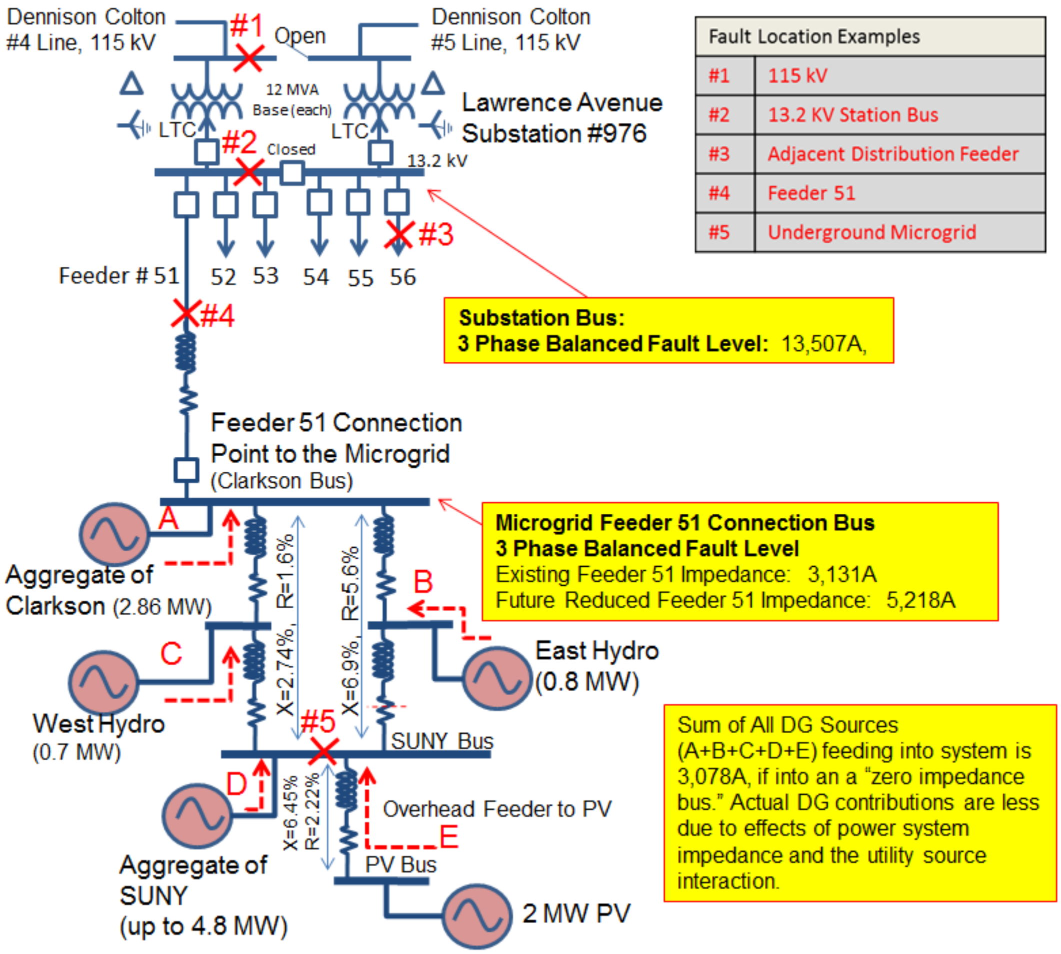
5.5.3.4 DG Fault Contributions Interacting with Utility System

The distributed generator fault contributions discussed individually in the prior section (Table 56) add up to a total value of 3,078 amperes (A) for a three-phase balanced fault. However, the actual contributions of DG to a system fault depending on where it is located are going to add up to less than this value due to the intervening impedance of the power system and the effect of the utility source feeding fault current into the system impedance. The degree of the effect varies greatly depending on fault location. For faults on the underground microgrid loop or Feeder 51, the effect is small and the total fault current injected by all of the DG is not changed more than about 10% to 20% from the sum of the individual units in the prior table. For faults out on adjacent feeders, the effect is more substantial.

Per the impedance data provided by National Grid, the available three-phase fault levels from the utility source alone are as shown in Figure 52. These are 13,507 A at the Lawrence Avenue Substation and 3,131 A at the Feeder 51, Clarkson PCC of the microgrid (fault-level calculated using the existing Feeder 51 impedance). If Feeder 51 impedance is reduced to levels discussed previously, the utility fault level at Clarkson PCC would be increased to 5,281 A.

Figure 52. Fault Levels of the Utility Source Compared to Distributed Generator Maximum Contributions

(115 kV side switches, fuses and breakers are not shown)



As shown in Figure 52, there are several possible locations (number 1 through 5) to consider in relation to faults from the perspective of how DG interacts with the utility system. For faults at the transmission level (location number 1 on the diagram), the injected currents from the DG pass up through the substation transformer and will be up to about 315 A (at 115-kV reference level). This extra 315 A from the DG fed into transmission faults is potentially enough to moderately impact the accuracy of protective relaying that exists on the transmission system. In other words, any zone-based tripping might be adversely affected. Since no data exists concerning the specifics of the 115-kV transmission impedances or the protection settings employed at the 115-kV level, there is no way to know at this stage whether the interaction is problematic and requires relaying adjustment. Based on this analyst’s experience in performing prior DG impact studies over the years, the aggregate amount of DG for the Potsdam Microgrid (which is up to about 10 MW) is enough to warrant study of the 115-kV line effects but probably won't be enough to cause issues. This additional analysis is recommended for the Phase II design study.

At fault location number 2, which is a fault on the Lawrence Avenue Substation bus, the DG contribution will be up to about 2,800 A and will add to the utility current (which is 13,507 A) such that the total current could become slightly over 16,000 A. The bus tie breaker ratings and settings should be investigated in terms of how this extra current impacts the speed of tripping and rating needs for the circuit breakers. The possibility of "sympathetic tripping" of the Feeder 51 circuit breaker and the bus tie circuit breaker also need to be investigated. Backfeed of current from the DG during bus faults could trip the feeder breaker or the tie breaker if the instantaneous pickup and time-overcurrent tripping curve settings are below the contribution level.

At location number 3 (the adjacent feeders), if the fault is very near the substation on any of the adjacent feeders, it would see roughly up to an additional 2,800 A of current from the DG. This would increase the maximum fault level on the feeder to a total of about 16,000 A. The feeder circuit breaker ratings and protection coordination (effect for any time-overcurrent curves, fusing coordination, transformer fusing, etc.) would need to be reviewed to see if adjustments are needed. Once again, sympathetic tripping of the Feeder 51 breaker and bus tie breaker would also need to be investigated to see if backfeed from the DG during adjacent feeder faults could trip these devices.

For faults on Feeder 51 itself (location number 4), the current contribution of the DG comes from the microgrid direction and the utility contribution comes from the substation side. The currents in the wires do not add (except at the arc) and therefore the DG is less likely to interfere with breaker coordination and ratings than an adjacent feeder fault. Since Feeder 51 is an express feeder, there are no known taps or branches that would see a summation effect of the current.

For faults on the underground microgrid itself (location number 5), the contribution of all DG sources combined will be up to about 3,000 A to any specific fault—the exact amount depends on the location. This value excludes the utility current, which adds roughly another 2,500 to 3,000 amperes to the DG current. Thus, in this region, the total (utility + DG) fault levels will be up to about 6,000 A for the locations where the currents are additive from all the sources.

Note that these values are for Feeder 51 with its existing impedance. If the impedance of Feeder 51 is lowered as discussed earlier, the fault level of the DG plus the utility current can be as high as about 8,000 A on certain parts of the underground microgrid. Fault levels can increase at some of the customer sites compared to the existing feeders where they are located, and existing distribution transformer fusing may in some cases need updating to avoid case rupture if the transformers are not already adequately protected with a current limiting fuse (see section on distribution transformer [DT] fusing later in report).

Table 57 summarizes the issues we have discussed here of DG fault contributions that would affect the surrounding National Grid system. This table deals with issues that may arise with existing equipment (not the newly installed microgrid build-out equipment).

Table 57. Grid-Parallel Mode Fault Current Issues Requiring More Study

Fault currents shown are for balanced three-phase faults cases, but issues apply to line-to-ground faults as well.

Fault Location	Maximum DG Fault Contribution with All Generators Running (will be less if all DG are not running)	Possible Fault-Current Issues with Existing Equipment and Recommended Further Study for Phase II[a]
#1 - 115-kV Transmission	Up to about 315 A additional current at 115 kV.	• Evaluate Impact on Zone Tripping Accuracy of 115-kV Line.
#2 - Substation 13.2-kV Bus	Up to about 2,800 A contribution. Roughly a 20% increase compared to utility alone.	• Evaluate Interrupting Capacity of Bus Tie, Feeder Breakers, and other devices. • Coordination Effects on Tripping Times of Bus Tie and Feeder Breakers. • Existing Distribution Transformer Rupture Fuse Check. • Sympathetic Trip Evaluation (feeder breakers and bus tie breaker).
#3 -On Any of the Adjacent Feeders	Up to about 2,800 A contribution. Roughly a 20% increase for faults very near the substation. Much lower contribution with only a few percent increases for faults at end of adjacent feeders.	
#4 - Somewhere on Feeder 51	Up to about 3000 A contribution from the DG but not typically additive with utility current.	• Evaluate Interrupting Capacity of Feeder Breakers and other devices. • Coordination Effects on Relay Tripping Times (if branches present). • Existing Distribution Transformer Rupture Fuse Check.
#5 - Underground 13.2-kV Microgrid	Up to 3000 A DG contribution.	• Existing Distribution Transformer Rupture Fuse Check.

[a] Note: This column of issues relates to the existing devices on the National Grid system that are impacted. Any new equipment that is purposely installed is sized, rated, and specified to avoid issues and is therefore not a focus of this table.

The preceding discussion of fault levels was for balanced three-phase faults. L-G faults will experience the same general issues as discussed for three-phase faults, but the effects will be somewhat less. In this case, the effective zero sequence impedance of the DG sources will be high enough to limit the DG fault contributions to a smaller fraction of the utility L-G fault current than was the case for three-phase faults. As an example, the National Grid fault contribution for a L-G fault at the substation is about 14,087 A, but the DG L-G fault contribution will add less than about 1,500 A to this value—about an 11% increase.

The reason for the smaller increase than for a three-phase fault case is the effect of the higher zero sequence impedance for the DG units. The effective grounding design of the DG units (see the section on effective grounding later in this report for details on the zero-sequence impedance value to be used for effective grounding) will employ grounding transformers that result in about a 2:1 ratio of X_0/X_1.

5.5.3.5 Ground Fault Current Detection Desensitization

An issue concerning DG is that if it acts as a grounding source, the ground source will compete with the utility source as a path for zero-sequence current (i.e., ground/neutral path return current). This could have an adverse impact on current levels for ground-mode protection at devices such as the Feeder 51 circuit breaker. The extra ground sources due to effectively grounded DG will divert some of the zero-sequence fault current to their location rather than allowing it to be available and fully measurable at the substation. The amount of diversion depends on the ratio of the zero-sequence impedance of the DG versus that of the utility source. Grounding transformers are needed on this project for effective grounding; however, they will divert enough current to have a serious impact. This topic is discussed later in the section on ground fault overvoltage and effective grounding.

5.5.3.6 National Grid Fault Levels and Impedances

As part of the project, National Grid provided some fault levels and impedances for various locations on several of the existing circuits emanating from the Lawrence Avenue Substation (Table 58). These were at the primary side of the transformers for the customers that will eventually be moved onto the microgrid as well as at the substation. The data of this table is not only useful for determining the impedances of the existing power system network at the Lawrence Avenue Substation bus and the Clarkson service point of Feeder 51 where the microgrid will be connected, but also gives an idea of what the customer fault levels are now (before the microgrid) for comparison after development of the microgrid. It also provides impedances of several alternative feeders (53, 55, and 56).

While this data serves as the basis for some of the key impedances in this report, keep in mind that the Clarkson feed-point impedance shown is the existing Feeder 51 impedance that will change if the feeder is upgraded to reduced impedance. The National Grid fault levels shown in the table do not include effects of generation.

Table 58. Existing Fault Levels and Impedances (Prior to Microgrid) of Various Sites Provided by National Grid

Fault Location	Pole	Line	Tax District	Feeder	Nominal Voltage	LLL	LLG	LL	LG	R1pu	X1pu	Z1pu	R0pu	X0pu	Z0pu	X/R
Clarkson Univeristy - Main Service	17	44	6302	97651	13,200	3,131	2,889	2,711	2,199	0.4710	1.3154	**1.3972**	1.2892	2.9034	**3.1768**	2.7900
Clarkson Univeristy - PV	5	97	6272	97653	13,200	2,875	2,662	2,490	2,243	0.6101	1.3937	**1.5214**	1.0960	2.5856	**2.8083**	2.2800
Key Bank	6-1	6	6302	97653	13,200	4,392	4,162	3,804	3,696	0.3307	0.9393	**0.9958**	0.5674	1.4523	**1.5592**	2.8400
V/O Potsdam - Civic Center/Fire Department	11	6	6302	97653	13,200	4,808	4,614	4,164	4,178	0.2689	0.8691	**0.9097**	0.4509	1.2428	**1.3221**	3.2300
V/O Potsdam - Rescue Squad/Police/Communit y Room	4	9	6302	97653	13,200	6,266	6,013	5,427	5,313	0.1856	0.6729	**0.6980**	0.3619	1.0124	**1.0751**	3.6300
Canton-Potsdam Hospital - 1 of 2	19-1	12	6302	97653	13,200	5,059	4,729	4,381	3,934	0.2654	0.8228	**0.8645**	0.5730	1.5022	**1.6078**	3.1000
Potsdam High School	13-1	77	6302	97653	13,200	5,773	5,466	4,999	4,682	0.2129	0.7271	**0.7576**	0.4434	1.2102	**1.2889**	3.4100
Stewarts Convenience	3-6	30	6302	97655	13,200	3,508	3,523	3,439	2,893	0.4271	1.1713	**1.2467**	0.9601	2.1278	**2.3344**	2.7400
Ngrid - Potsdam Service Center	9-1	10	6302	97655	13,200	4,264	4,445	4,307	3,792	0.3017	0.9805	**1.0259**	0.6871	1.5612	**1.7057**	3.2500
Potsdam Sewage Treatment Plant	13-1	24	6272	97655	13,200	5,411	5,514	5,387	4,674	0.2661	0.7633	**0.8084**	0.5786	1.2775	**1.4024**	2.8700
V/O Potsdam - West Dam Hydro	5-1	1	6302	97656	13,200	4,207	4,145	3,847	3,261	0.3263	0.9871	**1.0396**	1.0182	1.8025	**2.0702**	3.0300
V/O Potsdam - East Dam Hydro	5A	32	6302	97656	13,200	4,064	4,019	3,730	3,164	0.3399	1.0213	**1.0764**	1.0648	1.8485	**2.1332**	3.0100
SUNY Potsdam - Main Service	50	6	6302	97656	13,200	6,459	6,218	5,773	5,021	0.1736	0.6545	**0.6771**	0.5010	1.2062	**1.3061**	3.7700
Clarkson Inn	SWGR #2-1	4	6302	97656	13,200	4,467	4,365	4,072	3,421	0.2930	0.9343	**0.9792**	0.9136	1.7642	**1.9867**	3.1900
Lawrence Avenue					13,200	13,507	13,840	11,698	14,087	0.0229	0.2832	**0.2841**	0.0187	0.2832	**0.2838**	14.1000

Fault values do not include any contribution from other generation sources

Important note: Per unit impedances shown in this table calculated on a 100 MVA base

5.5.3.7 DG Effect on Distribution Transformer (DT) Tank Rupture

Since the fault levels at some of the Potsdam Microgrid customer sites currently may be at or below fault levels where current limiting fuses may be applied, and since fault levels will rise at some customer sites, there is no guarantee that the existing population of distribution transformers is fused sufficiently to handle the increased fault levels that will be caused by the DG as well as the upgrading of Feeder 51 to a lower impedance. A few of the transformers may need to be fused differently. It is therefore a good idea for National Grid to verify the internal DT fusing policy of the company with regards to rupture protection practices and then to fuse any transformers that may be put at risk by the higher fault levels with the appropriate current limiting fuses.

The background on this issue is that above a specific fault-current level, if a fault occurs inside a DT housing, a standard expulsion fuse cannot necessarily protect the housing from rupture due to sudden internal pressure buildup. This is why some transformers explode (blow their tops) when high-magnitude internal faults occur. To mitigate this problem, utilities typically use a current limiting fuse (CLF) on DT when the units are located close to the substation where fault levels are higher. The exact fault level where such fuses are applied depends on the type and design of the transformer, such as whether it is an overhead CSP (completely self-protected) unit with internal fuses, an overhead unit protected by an external fuse, or a padmount transformer unit with internal fuse. The utility practices also play a role because some utilities are more conservative than others in this regard. In many cases on 13.2 kV circuits, utilities consider adding CLF to overhead DT at the 2500 ampere fault level and above. In other cases, such as with padmount units they add CLF at 3,500 A or even 5,000 A and above. There is not a uniform practice in the industry but there are guidelines offered by ANSI C57.12.20-1998 and there is an excellent Canadian Electrical Association (CEA) report (CEA 288 D247, Application Guide for Distribution Transformer Fusing).

5.5.3.8 Effect on Fault Levels if Feeding the Microgrid with Feeders 53 or 56

While Feeder 51 has been the preferred connection feeder for the microgrid, there are other feeder possibilities that were discussed earlier in the voltage regulation section. For example, by tying the existing feeder (Feeder 56) to the microgrid near the SUNY Potsdam service point, the feeder, with its available fault level of 6,459 A, would serve as a stiffer, less voltage change prone microgrid connection point.

Feeder 53 near the police department in Potsdam if used as a tie point has 6,266 A of fault current, which makes it much stiffer than Feeder 51. If either of these two feeders were used, the total fault level on the underground portion of the microgrid, including all the DG could be up to about 9,000 A. In general, the fault levels with these two stiffer feeders will be a slightly higher than if Feeder 51 were upgraded to a lower impedance, but not enough higher to make a difference—as discussed in conclusions arrived at earlier in the report.

5.5.4 Unintended Islanding Protection (Grid-Parallel Mode)

This section discusses the anti-islanding protection issues associated with DG operation in the grid-parallel mode. During the grid-parallel mode of operation, we want to avoid any unintentional islanding condition lasting for any significant period of time longer than what is considered safe from a reclosing dead-time perspective and a voltage quality perspective.

For the distribution system, the reclosing sequence on Feeder 51 is a one shot (one attempted reclose) process which occurs after 20 seconds of dead time. On the adjacent feeders the reclosing sequence is three shots at 15, 30, and 45 seconds dead time, respectively.

For the 115-kV transmission source the reclosing time and switching scheme are not known at this stage but will be investigated in Phase II of the project.

Regarding the distribution side of the system, since reclosing on any of the Lawrence Avenue distribution circuits is 15 seconds or longer, no matter which circuit is used as a tie to the microgrid, there is a significant amount of time to trip the DG offline before reclosing occurs. Per IEEE 1547, a two-second limit is the required clearing time of the DG for basic default anti-islanding protection. However, a quicker islanding response can be achievable using the various direct transfer trip and relaying methods that are available. The key question is how quickly does the DG island need to be disabled?

In fact, the answer to the question is more complex than just applying the standard two-second IEEE limit. In understanding how fast the DG island needs to be disabled, it is necessary to trip the island offline and the following requirements should be satisfied:

- Satisfy the tripping speed required for deep voltage sags and basic islanding conditions (per IEEE 1547 default values or utility specified values).

- De-energize the island well before utility reclosing occurs.
- De-energize the island before DG fault contributions cause unneeded fault current damage to conductors and other equipment (including the DG themselves).
- Avoid damaging load rejection overvoltage or ground fault overvoltage.

The last point (item four), can require an extremely fast tripping response that clears DG offline before the utility system even separates from the forming island. However, if other means are in place to limit the overvoltage conditions referred to in item four, the last point can be ignored leaving only the first three points to determine the tripping speed required. In the case of the Potsdam Microgrid, the plan is to use effective grounding to limit the overvoltage and its expected load rejection overvoltage will be kept in check by limiting export of energy outside the grid to a suitable level, although this latter point may prove a difficult in certain NYISO market functions that have been discussed—therefore, some operating criteria limits will need to be established.

A superfast trip that clears the DG offline before overvoltage conditions arise due to generator load rejection and/or ground fault overvoltage can be accomplished with a time-coordinated, direct-transfer trip (DTT) that goes beyond an ordinary DTT. This approach uses a fast DTT timed to trip the DG breaker just before the actual separation of the island from the utility system. The approach works by keeping the path to the substation transformer and bulk power system always available while the DG is present (operating). In that case, the "grounding source transformer effect" of the substation transformer is always present until DG is offline; therefore, ground fault overvoltage never has a chance to develop. Similarly, for load rejection, the path to the larger bulk system, where excess generation is sent, is also available until the DG is tripped offline, which also limits load rejection overvoltage.

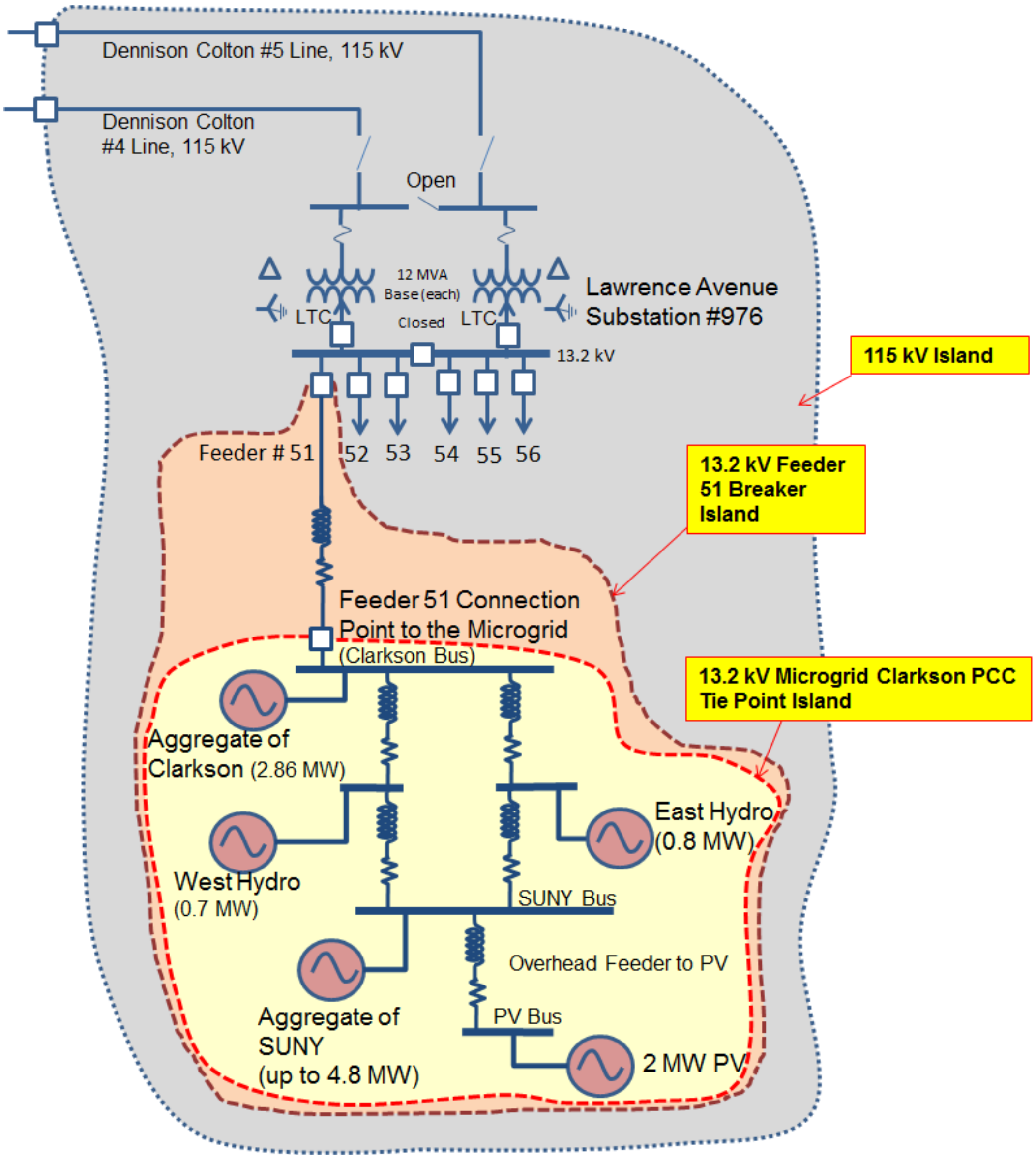
Trips coordinated to de-energize the DG before the feeder breaker opens can be difficult to achieve due to the fast clearing time needed for the devices involved. The strategy on this project will be to try to avoid altogether the need for the fast-time coordinated DTT by using other means to suppress transient and temporary overvoltage. As mentioned earlier, the use of effective grounding (by means of grounding transformers within the microgrid for the DG sources) will eliminate the risk of ground fault overvoltage. For load rejection overvoltage prevention, careful consideration of load to real-time generation ratios, in which operation of the microgrid is allowed, can reduce that risk and meet objectives as long as these limits do not severely conflict with desired power market operating and load support objectives. These approaches should tolerate a slower form of DTT and/or local relay-based islanding prevention approach for grid-parallel operation. In the slower form, many cycles of "islanded" operation are permissible following the formation of the island before the units are tripped (cleared) from the system. In the background, keep in mind that the project may still need to fall back on the fast-time coordinated DTT approach, pending the final outcome of more detailed studies later in Phase II, regarding desired operating modes for power export, etc., but it is hoped this can be avoided.

5.5.4.1 Unintentional Islands of Interest

Whether or not an island is at serious risk of developing depends greatly on the load-to-generation ratio on the island when it forms as well as the types of sources present and the degree of sophistication of the local islanding protection relaying scheme at each generator. If conditions are such that the relays can't be counted on locally, a direct transfer trip may be required. In particular, if a synchronous rotating machine generator is using only passive relay-based islanding protection and if load can at times be balanced to generation on the island, a DTT is likely going to be needed to facilitate tripping. An effective screening approach is to examine the possible islands that can form upon breaker opening to see if minimum load on the island zone might be balanced to generation. If it is closely balanced, there will be danger. As a guideline, if the minimum load is at least twice the generation capacity, there will be minimal danger and even relatively simple relay-based protection should be sufficient.

Potential unintentional islands in grid-parallel mode are shown in Figure 53. As an example, if the Feeder 51 tie breaker at the Clarkson PCC opens, the load data show there could be an island of the microgrid where load is matched to generation. Another example would be if Feeder 51 breaker for the whole feeder at Lawrence Avenue Substation opens. The load in that case could also be matched to generation. An even larger island that might occur includes part of the 115-kV network to the nearest remote source breaker. Whether the load would be matched to generation for an island at that level is not known yet. That case is pending arrival of more load data, generation data, and protection scheme data at that level of the system (Phase II of the project.)

Figure 53. Some Possible Unintentional Islands in Grid-Parallel Mode



In addition to the islands of Figure 53, there are other islands that can occur. However, for the sake of clarity on that drawing, the others are omitted from the diagram. Table 59 is a more comprehensive list of various possible islands that could occur. Keep in mind that even the table is not fully comprehensive as there are plans to have alternative feeds to the microgrid from feeders such as 53, 55 or 56. If those feeders are also used, they too would each have their own set of islands that could be of concern.

Table 59. Unintentional Islands Associated with the Feeder 51 Tie to the Microgrid

Unintentional Island Description (from smallest to largest)	Shown in Figure 53?	Details	Might the Generation Be Closely Matched to Load at Least Some of the Time?
Small Island that is a portion of the underground microgrid.	No	Occurs if only a part of the microgrid separates.	**Yes:** There are many partial microgrid scenarios where operating 2.5-5 MW of generation could be a close match to the load which would be between 2.5 MVA and 6 MVA much of the time.
The full microgrid separated at the Clarkson PCC of Feeder 51.	Yes	Occurs if the circuit breaker at the microgrid point of connection opens (the Clarkson microgrid PCC at Feeder 51).	**Yes:** There are many full-microgrid scenarios where operating 5-10 MW of generation could be a close match to the load which may vary between 5 MVA and 12 MVA much of the time.
The full microgrid separated at Lawrence Avenue Feeder 51 CB.	Yes	Occurs if the circuit breaker at Lawrence Avenue Substation for Feeder 51 opens or if the transformer and tie bus tie breaker open.	**Yes**: Same as above since Feeder 51 is express feeder with no additional load itself above the Clarkson PCC.
Half of Lawrence Avenue Substation and its respective feeders (due to open bus tie and open transformer breaker).	No	Occurs if the fuses melt or switches open on 115 kV side of Lawrence Avenue transformer unit serving Feeder 51 and if the 13.2 kV bus tie is open to the adjacent transformer.	**Yes:** Minimum load on substation transformers is 1.8 and 2.0 MVA Maximum load is 19.3 MVA and 15 MVA. The expected 2.5-5 MW of generation (half of the generation) can match the load some of the time.
The entire substation all feeders (115 kV side switches open).	No	Occurs if all the switches or fuses on the 115-kV side of Lawrence Avenue Substation are open and the 13.2 kV bus tie switch is closed.	**Yes:** On some rare occasions but load is usually enough to suppress. Minimum load at entire station is likely 4 MVA. Maximum load likely exceeds 30 MVA. Generation of 5-10 MW can on rare occasions exceed minimum load.
The entire substation and a portion of the 115-kV transmission to the (115 kV #4 and #5-line breakers open).	Yes	Occurs if the 115-kV source breakers for #4 and #5 Dennison Colton lines are open. (There is a half substation version of this island too, as well as other possible islands.	**Unknown**: must be studied further. Will need load data from National Grid on 115 kV loading to nearest upstream breakers. There is a good chance enough load on other substations to avoid this island.

Notes: Several other islands are possible if feeder 53, 55, or 56 is used to feed the microgrid as an alternative.

As mentioned previously, a solution to the islanding condition is to use direct transfer trips (DTT) to trip the major internal combustion engine DG sites offline, and let the island associated with the remaining smaller generating units collapse due to the local relay-based protection at the other units (Figure 54). To do this we would only need transfer trips added at the two new large units on the system. There are apparently already transfer trips at the existing large SUNY Potsdam units, and the PV might have one as well. If the larger units were tripped, the collapse of the island would occur extremely rapidly due to the massive load-to-generation imbalance that would occur after tripping the larger units. The minimum load-to-generation ratio would be at least 2:1 for the remaining units. A more detailed breakdown of the recommended anti-islanding protection for each generator in grid-parallel mode of operation is shown in Table 60.

Figure 54. Recommended Transfer Trips

Note: 115-kV trips may not be needed pending further analysis of the 115-kV loading and protection scheme.

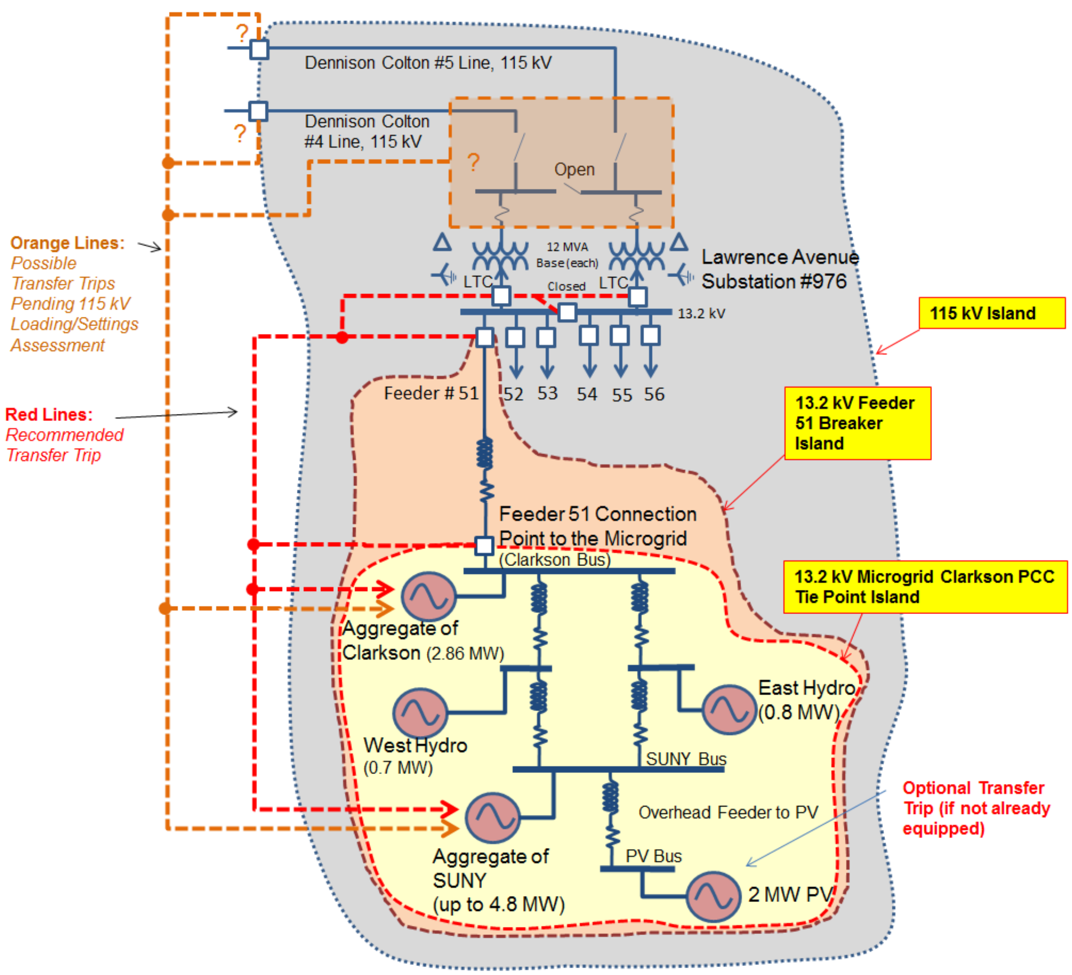


Table 60. Summary of Recommended Anti-Islanding Protection Methods for Each Generator

Generator Name	kW Rating of Gen.	kVA Rating of Gen.	Recommended Anti-Islanding Protection Method	Recommended Transfer Trip Path (Origin Device to Destination Device)			
				Microgrid Tie Breaker to Generator	Substation Low-Side Breakers to Generator	Substation 115-kV Side to Generator	Remote 115-kV Source Breakers to Generator
West Dam Hydro(s)	700 (2 × 350 kW)	778	Passive Local Relays Only				
East Dam Hydro(s)	800 (2 × 400 kW)	1000	Passive Local Relays Only				
Clarkson Existing A	370	463	Passive Local Relays Only				
Clarkson Existing B	290	363	Passive Local Relays Only				
Clarkson New	2,000	2500	DTT	√	√	?	?
SUNY Potsdam Existing A	1,400	1750	DTT[1]	√	√	?	?
SUNY Potsdam Existing B	1,400	1750	DTT[1]	√	√	?	?
SUNY Potsdam New	2,000	2500	DTT	√	√	?	?
PV Array	2,000 (daytime production only)	2000 (unity PF inverter)	Active Inverter UL1741 Algorithm and Local Relay Protection[2]				
Capstone Microturbine	195	195 (unity PF inverter)	Active Inverter UL1741 Algorithm and local relays				

Notes:

1 These units are already equipped with DTT

2 PV site might already be equipped with DTT (need to confirm with National Grid)

"√" Means that DTT is recommended at this system level

"?" Additional data on loads, generation, and switchgear at 115-kV level required to determine if needed.

5.5.4.2 How Fast to Trip the Larger Machines with DTT

As stated earlier in this report, since we will be relying on other means to suppress ground fault overvoltage and load rejection overvoltage, it is not necessary to trip the generators prior to separation of the island from the bulk system (although this would be ideal). However, we also do not want the island to run on for many tens of cycles after it separates due to the ensuing arcing risk and thermal damage to fault conductors, etc. A limit of 5 to 10 cycles of allowable islanding of the DTT controlled generators after separation of the island from the bulk system seems a reasonable goal that will satisfy protection requirements given the fault current contributions the generators are known to produce and the size of the wires and cables on the microgrid. Further study of this is needed in Phase II to finalize a recommendation but the extra current is not likely to adversely raise the risk of conductor meltdown, etc., compared to the existing risk based on utility fault levels.

5.5.4.3 Alternatives to DTT

DTT (even a slow one) is expensive to implement raising question as to whether or not *local DG based relaying* alternatives to DTT are available and can be counted on to trip the larger rotating machine generators in a timely fashion. It would ideal to trip them within no more than 5 to 10 cycles following island separation; however, it can be difficult to implement with just ordinary overvoltage, under-voltage, over-frequency, and under-frequency relaying if load is nearly balanced to generation. There are some more advanced relay functions that could be considered such as special combinations of impedance relays (ANSI device 21), rate of change of frequency (ROCOF), and phase shift and/or synchro-phasor type protection schemes that may be able to trip the larger ICE units fast enough without needing a full-fledged DTT. However, these will probably still be somewhat slower than the DTT in order to measure certain conditions over many cycles to avoid nuisance trips. Two-Way Automatic Communication System (TWACS®) technology using the 60 Hz wave as a “carrier” for tripping may also be worth investigating, as it is a form of DTT but at lower cost because the communication link is the line 60 Hz wave itself. The Phase II study looks more closely at how long the island can run after separation from the main grid to see if longer periods, up to one second, are allowable.

5.5.5 Grid-Parallel Mode Generator Protection Settings

Given what we have already discussed about fault levels and islanding protection in the last few sections, the following question arises: What should the local relays be set at for the project ICE generators? The interconnection protection relay functions will protect the generators from power system conditions that would cause damage to the generator and greatly reduce the risk that the generators impose hazards to the utility system such as unintentional islanding. A list of the recommended protection settings is provided in Table 61. This list is intended for grid-parallel operation only and is only a suggestion to serve as a *starting point* for analysis and discussion of settings to employ. Please be aware that during intentionally islanded operation (i.e., microgrid mode), the values will need to be changed to reflect different requirements during islanded microgrid mode (discussed in a subsequent section).

Table 61. List of Relay Settings for Synchronous Rotating Machine Sites at Potsdam Microgrid

Grid-parallel mode and total clearing times are shown. Settings are for illustration to serve as starting point for final analysis in later phases of project.

<table>
<tr><th rowspan="2">Name of Function</th><th rowspan="2">ANSI Device Number</th><th rowspan="2">Main Purpose of Relay</th><th colspan="6">Settings[1]</th></tr>
<tr><th colspan="2">Tier 1
Pickup Level Time Delay</th><th colspan="2">Tier 2
Pickup Level Time Delay</th><th colspan="2">Tier 3
Pickup Level Time Delay</th></tr>
<tr><td>Phase Undervoltage</td><td>27</td><td>Anti-Islanding/abnormal low voltage</td><td>≤ 88%</td><td>2 seconds</td><td>≤ 60%</td><td>40 cycles</td><td>≤ 45%</td><td>10 cycles</td></tr>
<tr><td>Phase Overvoltage</td><td>59</td><td>Anti-Islanding/abnormal high voltage</td><td>≥ 112%</td><td>1 minute</td><td>≥ 120%</td><td>1 second</td><td>≥ 140%</td><td>10 cycles</td></tr>
<tr><td>Under Frequency</td><td>81 u</td><td>Anti-Islanding/abnormal low frequency</td><td>≤ 59.0 Hz</td><td>UFLS[2] Coordination</td><td>UFLS[2] Coordination</td><td>UFLS[2] Coordination</td><td>≤ 57.0 Hz</td><td>10 cycles</td></tr>
<tr><td>Over Frequency</td><td>81 o</td><td>Anti-Islanding/abnormal high frequency</td><td>≥ 61 Hz</td><td>UFLS[2] Coordination</td><td>UFLS[2] Coordination</td><td>UFLS[2] Coordination</td><td>≥ 62 Hz</td><td>10 cycles</td></tr>
<tr><td rowspan="2">Neutral Overcurrent</td><td rowspan="2">51 N</td><td rowspan="2">Generator Neutral Overcurrent</td><td colspan="3">Pickup (Amperes)</td><td colspan="3">Relay Curve Type</td></tr>
<tr><td colspan="3">15% of generator full-phase current rating</td><td colspan="3">Very Inverse</td></tr>
<tr><td>Phase Overcurrent</td><td>51 V</td><td>Generator Phase Overcurrent</td><td colspan="3">110% of generator full-phase rating</td><td colspan="3">Very Inverse, with voltage restraint activated</td></tr>
<tr><td>Negative Sequence Current</td><td>46</td><td>Generator Negative Sequence Current</td><td colspan="6">Pickup set at 10% of full-load phase current. Maximum time delay 10,000 cycles. Curve type $I^2T=k$.</td></tr>
</table>

Table 61 continued

Name of Function	ANSI Device Number	Main Purpose of Relay	Settings[1]			
			Tier 1		Tier 2	
			Pickup Level	Time delay	Pickup Level	Time delay
Negative Sequence Voltage	47	Generator Negative Sequence Voltage	3%	7200 cycles	8%	120 cycles
Synchronization	25	Synchronize DG to system for connection purposes	Voltage Difference: ∆V=±3% Voltage Window of Proper Relay Operation: 92% to 103% Phase Angle Difference: ±10 degrees Frequency Difference: ∆f=0.1 Hz			
Reverse/Forward Power	32	Avoids Motoring of Generator	Set pickup #1 at negative 0.1 per unit with 90 cycle time delay, 3-phase power mode. Set pickup #2 at positive 1.4 per unit with 20 cycle time delay, 3-phase power mode.			
Loss of Field	40	Detect loss of field	Circle one: offset =-0.098 per unit, diameter = 1.0 per unit, 15 cycle time delay Circle two: offset = -0.098 per unit, diameter = 2.69 per unit, 30 cycle time delay			
Peak Overvoltage	59 I	Detect "harmonic" peaks that are possibly due to ferroresonance	Set at 130% with time delay of 30 cycles			
Ground Overvoltage	59 G	Detect Ground Fault Overvoltage	"3 Vo Protection" may be required for 115-kV side via DTT but not needed for distribution since effective grounding is recommended.			
Reconnection Function	79	Auto-reclosing of DG when system conditions are restored	To be coordinated with Microgrid system controller.			
Direct Transfer Trip (DTT)		Anti-Islanding	Recommended for Larger ICE Generators Above 1 MW rating on Potsdam Microgrid (see discussion in body and other tables/diagrams of this report).			

Notes:

1 These settings are suggestions as a starting point and will need to be finalized in latter phases of the development plan.

2 UFLS = Under Frequency Load Shedding. NYISO UFLS coordination may be needed in this project (see next section of report).

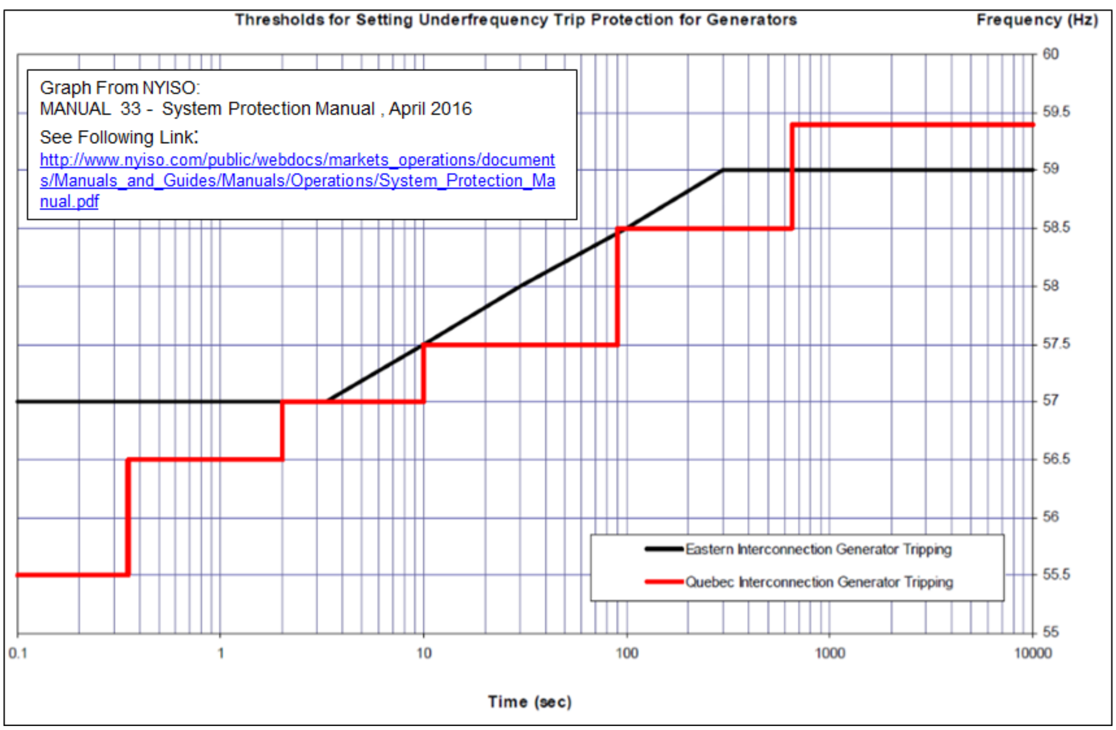
5.5.6 Coordination with Under-Frequency Load Shedding

It is good practice to coordinate the under-frequency tripping of the DG plants with the under-frequency load-shedding (UFLS) scheme of the bulk power system. The fundamental goal of this coordination is to allow the Potsdam Microgrid generation to stay online as long as possible to support bulk system frequency during an under-generation condition where frequency is dropping and yet still protect the generators and local grid from adverse frequency conditions. It is a delicate balancing act between local anti-islanding and PQ (watt and var) requirements of local loads versus the needs of the bulk system per entities such as the NYISO to remain frequency stable (Figure 55). Ideally, the DG should stay online until after the last load block associated with the load shedding scheme trips, but this may or may not be possible depending on various factors. Keep in mind that the Lawrence Avenue Substation likely has existing UFLS settings as well that need to be coordinated.

When operating the generator or motor devices at reduced frequency, it is necessary to be cognizant of the effect of reduced frequency on the equipment. In particular, at reduced frequency if generator/motor terminal voltage were sufficiently high, the magnetic core materials can saturate leading to undue heating stresses within the machine. Also, the speed of operation and reliability of the "under-frequency relay" for anti-islanding protection purposes will be degraded somewhat by use of a broader frequency range.

Figure 55. NYISO Under-Frequency Generation Tripping Requirements

(per NYISO system protection manual April 2016)

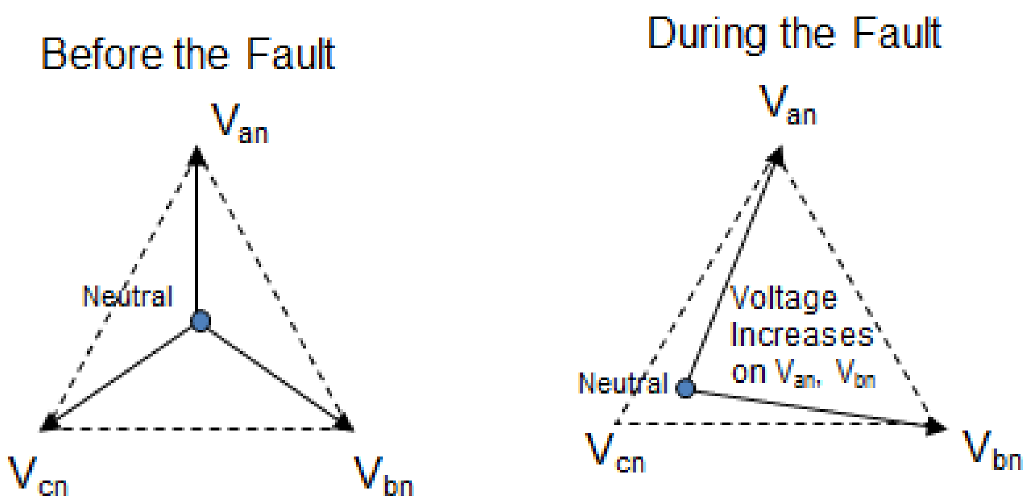


5.5.7 Ground Fault Overvoltage (Grid-Parallel Mode)

Ground fault overvoltage is a condition caused by the neutral potential shifting of its position away from the center of the three-phase voltage triangle toward one corner during a L-G fault (Figure 56). This condition will collapse the voltage on the faulted phase and increases the voltage on the un-faulted phases. The degree to which this neutral shift occurs depends on the ratio the zero-sequence impedance to the positive-sequence impedance of the source—the higher the ratio the greater the shift. In the worst case for a source with no zero-sequence return path (ungrounded connection), the neutral point shifts all the way to one corner of the triangle and the L-G voltages on the un-faulted phases increase to as high as the line-to-line voltage. When the following three conditions are present, the system source characteristic changes from a four-wire effectively grounded system, to a three-wire ungrounded system source causing neutral shift and ground fault overvoltage: a L-G occurs on the distribution system, the utility source breaker opens, and ungrounded DG is present and feeding in.

Figure 56. Neutral Shift During Ground Fault Overvoltage

This example shows a heavily but not fully shifted neutral; in worst case, neutral is fully shifted to one corner.



Overvoltage on the un-faulted phases for a power source with an infinite impedance neutral return path (an open circuit neutral connection) can reach roughly 1.73 per unit of the normal maximum system voltage. That means the total maximum voltage the line might experience is 1.82 per unit as shown in Figure 57 (V_{max} = 1.73 x 1.05 = 1.82 per unit, 1.05 per unit is the top boundary of ANSI C84.1 Range A). If the power system neutral return path is "effectively grounded" as defined by IEEE C62.92, this would mean it has a COG of 80% or less. COG is the ratio of line to neutral voltage divided by line-to-line voltage on the un-faulted phases. The higher the ratio, the greater the neutral shift toward one corner and the higher the L-G overvoltage. Figure 57 shows the voltage levels of the Phase B line-to-neutral voltage for various shifts. The Phase A voltage also rises by a similar amount. Table 62 provides a summary of the voltage conditions with some different levels of neutral grounding.

Figure 57. Neutral Shift with Different Grounding Characteristics

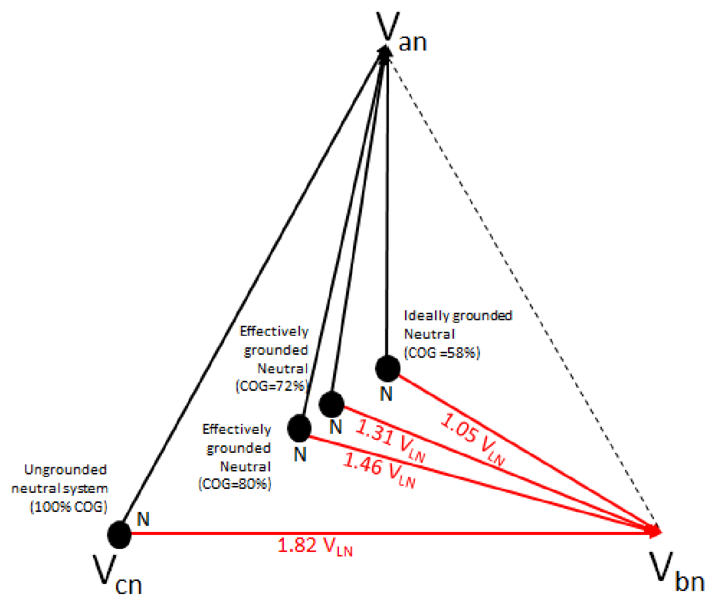


Table 62. Neutral Shift Overvoltage (i.e., Ground Fault Overvoltage) Associated with Various Coefficients of Grounding

Type of Neutral Grounding	COG	Nominal Line-to-Ground Overvoltage Level	Maximum Overvoltage Level (includes ANSI 5% regulation factor)
Ungrounded	100%	1.73	1.82
Barely Effectively Grounded (just barely meets the IEEE definition)	80%	1.39	1.46
More Deeply and Effectively Grounded(recommended good 4-Wire Practice Per IEEE)	≤72%	≤1.25	≤1.31
Ideally Grounded	≤58%	≤1.0	≤1.05

5.5.8 IEEE Effective Grounding

As mentioned in the prior section, a solution to avoid excessively high-ground fault overvoltage in the line-to-neutral mode on power systems is to maintain what is called effective grounding of the system. In this case the ratio of zero-sequence and positive-sequence impedances of the source transformer, wires, cables, etc. are selected in the system design such that a ground fault does not allow much neutral shift. A COG of 80% or less occurs roughly when the ratio of the zero-sequence reactance (Xo) to positive-sequence reactance (X1) as well as the ratio of zero-sequence resistance (Ro) to positive-sequence reactance (X1) of the energy source(s) feeding in meets the following criteria:

$$\frac{X_0}{X_1} \leq 3 \; and \; \frac{R_0}{X_1} < 1$$

An 80% COG is considered good for transmission lines that do not directly serve line-to-neutral loads and only have surge arresters connecting line-to-neutral loads to worry about. Surge arrester ratings can easily be selected to handle the 80% COG voltage levels while still providing adequate surge protection. But at the distribution level because 80% COG still results in a fairly high 1.46 per unit voltage on a line-to-neutral basis (including ANSI 5% factor), any distribution line that serves line-to-neutral loads may need a lower COG for power quality purposes due to the overvoltage sensitivity of the loads.

Even though 80% COG or less is the IEEE definition of the "borderline" of effective grounding, the fine print of IEEE C62.92 design guidelines for 4-wire, multi-grounded neutral distribution systems recommend designing for 72% COG or less; this occurs roughly with $X_0/X_1 \leq 2$ and $R_0/X_1 \leq 0.7$. The lower COG puts the system deeper into effective grounding and limits the maximum overvoltage to a level of about 1.31 per unit line-to-ground voltage during a line-to-ground fault, considering the ANSI 5% factor. A 1.31 per unit overvoltage is unlikely to cause any damage, even to the more sensitive load devices, for the short durations that the overvoltage conditions occur. Typically, these last a few seconds or less until the fault is either cleared by system protection or the power tripped off altogether.

For power systems with distributed generation present the problem is that if a ground fault occurs, the upstream utility source breaker can trip open leaving the DG feeding into the system as the only source(s) for a short period of time until islanding protection trips it offline. During this time, there may be anywhere from a few cycles to a few seconds of overvoltage danger if the "effective grounding path" to the utility source is lost and if there is no alternative zero-sequence ground path on the local island—the COG can become 100% in this scenario. In many cases, the DG neutral does not provide a suitable neutral current path (meaning the DG is not effectively grounded). Provisions need to be made to ensure that the COG remains below 80% (and preferably at or below 72%) during conditions when DG islands occur.

5.5.8.1 Effective Grounding Status of Potsdam DG Sites

A review of the generators on the Potsdam Microgrid reveals that most or all of them are unlikely to be effectively grounded as operating currently with respect to the primary distribution system (Table 63). This is either because the generator interface transformer feeding into the system does not support effective grounding (has a delta high-side winding) or that the neutral of the generation source itself is not connected to the generation source with sufficiently low impedance to be considered effectively grounded. For some units, such as the 2-MW PV site and smaller Clarkson generators the data was not immediately available to determine effective grounding status. Those will be assumed to be non-effectively grounded until data is available. Even though the characteristics of some of the existing sources are not known from an effective grounding perspective, the largest and most powerful sources feeding in from a fault current driving perspective are those that will dominate the effective grounding requirements for the project. Therefore, the smaller and/or weaker sources do not matter that much in driving the requirements for this project. The main sources driving the requirements are the existing large SUNY Potsdam ICE units and the proposed two new large generators (2500 kVA each for SUNY Potsdam and Clarkson) and the hydro units. Since the new units are not installed, there is flexibility in the grounding design for them as the equipment has not yet been ordered.

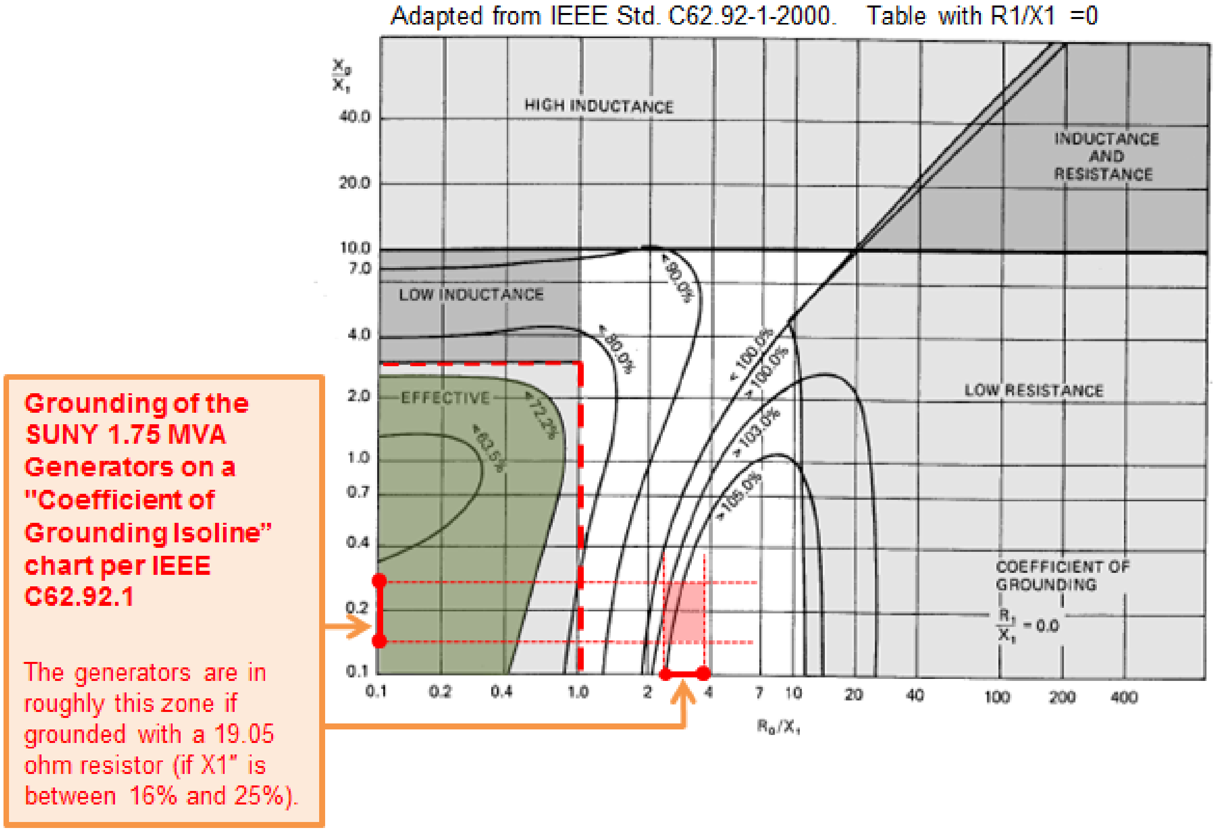
Table 63. Effective Grounding Status of Generators

Generator Name	Full Nominal KVA Rating of Generator	Effective Grounding Status with Respect to 13.2 KV Distribution Level
West Dam Hydro(s)	778	No
East Dam Hydro(s)	1000	No
Clarkson Existing A	463	Not Known (assume no)
Clarkson Existing B	363	Not Known (assume no)
Clarkson New	2500	Generator Not Installed Yet (See Note 1)
SUNY Potsdam Existing A	1750	No (high resistance grounding instead)
SUNY Potsdam Existing B	1750	No (high resistance grounding instead)
SUNY Potsdam New	2500	Generator Not Installed Yet (See Note 1)
PV Array	2000 (unity PF inverter)	Not Known (assume not effectively grounded)
Capstone Microturbine	195 (unity PF inverter)	Not Known (but unlikely to be effectively grounded)

Note 1: The project team recommends that these future units are not only effectively grounded individually but grounded in relation to the whole microgrid system by installing a grounding transformer near or adjacent to each unit.

The two existing SUNY Potsdam units (1750 kVA each) are 13.2-kV rated generators directly interfaced to the primary feeder without a step-up transformer. They are not effectively grounded because they have their neutrals grounded through a 19-ohm resistor. Note that an inserted neutral impedance of this type appears as triple its value mathematically from a zero-sequence perspective. Therefore, the effective value of this resistor is 57 ohms. It is possible to neglect machine resistance since it is normally very small in relation to the 57-ohm value. If the assumed X_1 impedance of the generator is between 16% and 25% (which would be 15.9 to 24.9 ohms on the generator-base ohms) the R_0/X_1 ratio would be between 2.3 and 3.6 for this generator. This R_0/X_1 ratio value is too high for effective grounding as shown in Figure 58. On the other hand, the X_0/X_1 ratio easily meets effective grounding requirements if X_0 is assumed to be in the usual range for the generator's impedance. Overall, the grounding characteristics of the machines will fall roughly in the red shaded zone of Figure 58, and they are not effectively grounded as currently installed.

Figure 58. Coefficient of Grounding for the Two Existing SUNY Potsdam 1.75 MVA Generators

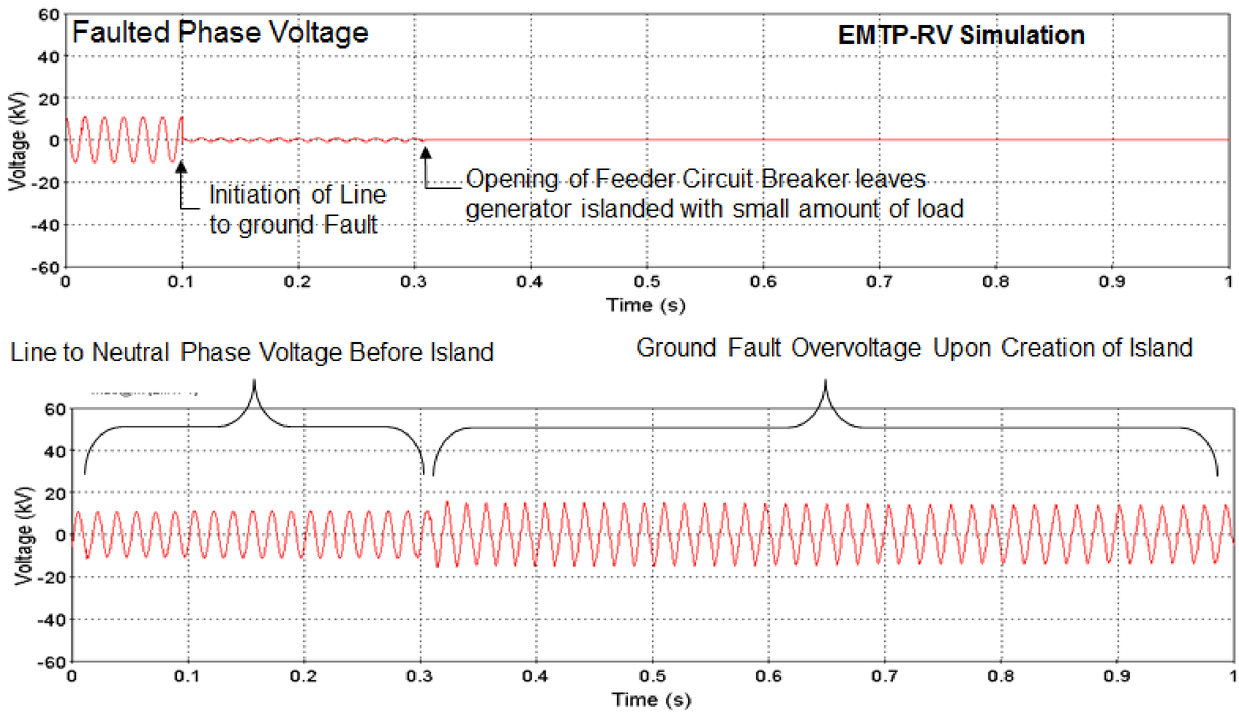


The lack of effective grounding of the Potsdam Microgrid machines does not mean an overvoltage occurs at the instant a L-G fault appears. Since the Lawrence Avenue Substation is composed of two large typical grounding-source type transformers (delta winding on 115 kV side and wye-ground on 13.2 kV side), the 13.2-kV distribution system remains effectively grounded up until the moment the feeder breaker (or any other breaker) opens and isolates those transformers from the microgrid. At that moment, the ground fault overvoltage begins.

Figure 59 shows an EMTP simulation that is representative of a typical ICE generator in the size range of those to be employed in the microgrid project. The DG in this example is barely effectively grounded with COG = 80%. The resulting over voltage is roughly 1.3 to 1.4 per unit. Notice that the overvoltage does not occur until the feeder circuit breaker opens, isolating the utility grounding source transformer from the island. In this case, the overvoltage would not be as severe as a totally ungrounded generator since, in this example, there is a coefficient of grounding of about 80%. In the totally ungrounded case, the voltage would have risen to about 1.73 per unit.

Figure 59. Ground Fault Overvoltage Simulation for a 13.2-kV ICE Generation Source Effectively Grounded to a COG of about 80%

Top trace is the line-to-neutral voltage on the faulted phase and bottom trace is the line-to-neutral voltage on an un-faulted phase.



5.5.8.2 Effective Grounding of DG with Respect to a 115-kV System

Regardless of their grounding status at the distribution system level, none of the generators on the Potsdam Microgrid are effectively grounded with respect to the 115-kV system. This is because the effective grounding reference of the neutral/earth is lost in the pass through from the 13.2 kV side of Lawrence Avenue Substation to the 115-kV side. The high side transformer winding is a delta winding that does not provide a zero-sequence path. This means that if insufficient loading exists to suppress ground fault overvoltage at the 115-kV level, mitigation may be required (see mitigation discussed in next section).

5.5.8.3 Mitigation of Ground Fault Overvoltage

There are four main ways to avoid ground fault overvoltage:

- **High Load to Generation Ratio:** If the DG devices are not effectively grounded in the power system area of concern, the presence of the load by itself may be enough to suppress the condition without any need for effective grounding. In general, a minimum load-to-aggregate generation ratio of five or more within the islanded zone of the DG is enough to suppress ground fault overvoltage from all types of rotating machines (even those with the lowest impedance ratings of about 10%). Rotating machines with impedance at the higher end of the typical range (> 25%) can be adequately suppressed with a minimum load to generation ratio of three or more. Inverter-type generation is far weaker and a load-to-generation ratio of 1.5 or more is usually adequate for those devices. If there is confidence that the minimum loads are known and can be counted on to be present when the faulted condition occurs, the overvoltage will be suppressed even without effective grounding.
- **Effective Grounding of the DG:** Effectively grounding the DG to 72% COG will suppress the overvoltage to a reasonable level by preventing the most severe neutral shift. Keep in mind that the effective grounding of the machine is not transferable upwards to higher system levels through any delta winding; therefore, effective grounding in distribution may not solve a problem at a higher level in transmission. If the DG is effectively grounded at a system level of interest, the presence of load would not be critical enough to suppress ground fault overvoltage at that level. Effective grounding can be achieved at DG units by using the right type of interface transformer and/or the proper type of neutral connection to the DG depending on the specific type of generator.
- **Separate Grounding Transformer:** A separate grounding transformer (not part of the DG itself) located within the “islandable zone” of concern can emulate the same effect as effectively grounding the DG. Even though not directly part of the DG plant, a separate grounding transformer can prevent neutral shift thereby preventing the overvoltage. The grounding transformer needs to be sized and rated according to the total DG in the zone it is attempting to suppress. The power rating of a grounding transformer is roughly 25% of the rating machine capacity being suppressed (i.e., 250 kVA per 1 MVA of machine rating). For PV inverters it is about 5% of the rating—that is, 50 kVA per 1 MVA of PV inverter. The impedance of the transformer is sized to yield a COG of about 72% (or 80% if less conservative design).
- **Time-Coordinated Direct Transfer Trip (DTT):** This method involves a time-coordinated tripping with DTT such that the utility ground source is tripped after the DG is tripped offline. A time-coordinated direct transfer trip can also suppress load rejection overvoltage within the broader island (although it imposes it on the DG site itself once that breaker trips). The EMTP simulation shows how the overvoltage does not occur until the island forms (feeder breaker opens; Figure 59). Thus, if the DG is tripped offline before the island forms, there is no overvoltage.

Considering the four methods (solutions A, B, C or D) for avoiding ground fault overvoltage, the report discusses the best option for Potsdam. In regard to Solution A, the minimum load to generation ratios for the possible islands, the method does not come close to meeting overvoltage suppression criteria discussed earlier in the report. There is not an even a 3:1 ratio much of the time, and in fact some of the time the ratio could be approaching as low as 1:1 or even less if all generation is running during lighter load conditions and power is being exporting out to the bulk system. The loading is insufficient on the underground microgrid zone, the microgrid zone plus the connecting feeder (any of feeders 51, 55, 53 or 56, depending on which one is doing the connecting)—even the substation 13.2-kV bus zone itself at certain times. Overall, the loading solution at the distribution level is not viable for suppression of overvoltage. There may be sufficient loading at the 115-kV transmission level for those possible islands, pending further analysis at that level.

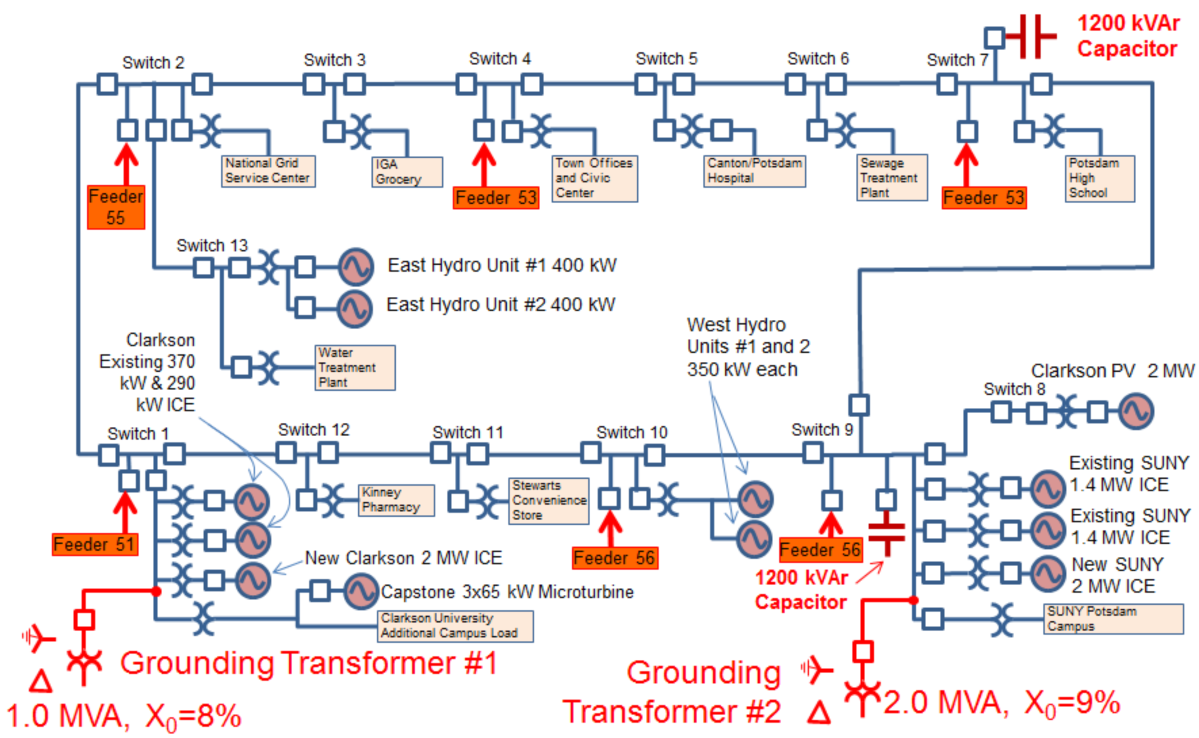
Solution B, which is currently effectively grounding a sufficient number of the DG, could be employed but would require going back to several of the existing large ICE units and retrofitting them with effective grounding. The two new large 2-MW ICEs would also need to be effectively grounded. This approach is workable, but the situation is more complex and difficult when examined closely. For example, the owner of generator installations already running on site may not want to effectively grounded due to ground current flow and retrofit cost issues imposes on their generators. Others may find it more difficulty to change out their interface transformer to provide effective grounding due to the configuration of the loads and busses at their facility. Therefore, a couple of strategically placed grounding transformers as discussed in Solution C may be the best overall approach.

Skipping ahead to Solution D, the Time-Coordinated DTT, as another possible option for ground fault overvoltage, the study found that the method will require a high-speed communication link to trip the DG before or at the same instant the island forms. Further research on the speed of response of the switchgear and relaying scheme is needed to assess the viability of this option. However, the solution does not solve the need for suppressing ground fault overvoltage and providing neutral stability during islanded microgrid mode as well as grid-parallel mode. Only Solution C solves an operating need for both modes of operation.

Solution C—the use of two separate grounding transformer banks—is a workable solution and perhaps the easiest of all. Two grounding transformers (one on each side of the microgrid system in case the system splits in half) would be capable of providing the needed effective grounding for all key generation scenarios and islanding modes (Figure 60). Calculations show a needed rating of about 1 MVA near Clarkson and 2 MVA near SUNY Potsdam each (3 MVA total) which together would be about 25% of the total generation capacity. An X_0 impedance of about 8% at Clarkson on the 1 MVA base rating and 9% at SUNY Potsdam on the 2 MVA base rating would be enough to give an X_0/X_1 ratio that would achieve roughly 72% COG or better. Note that there is more grounding transformer capacity at SUNY Potsdam than at Clarkson due to the larger concentration of generation at that side of the system.

Figure 60. Grounding Transformer Locations Need to Emulate Effective Grounding

These will be useful during both unintentional islands as well as intentional islanded microgrid modes for neutral stabilization and ground fault overvoltage mitigation.

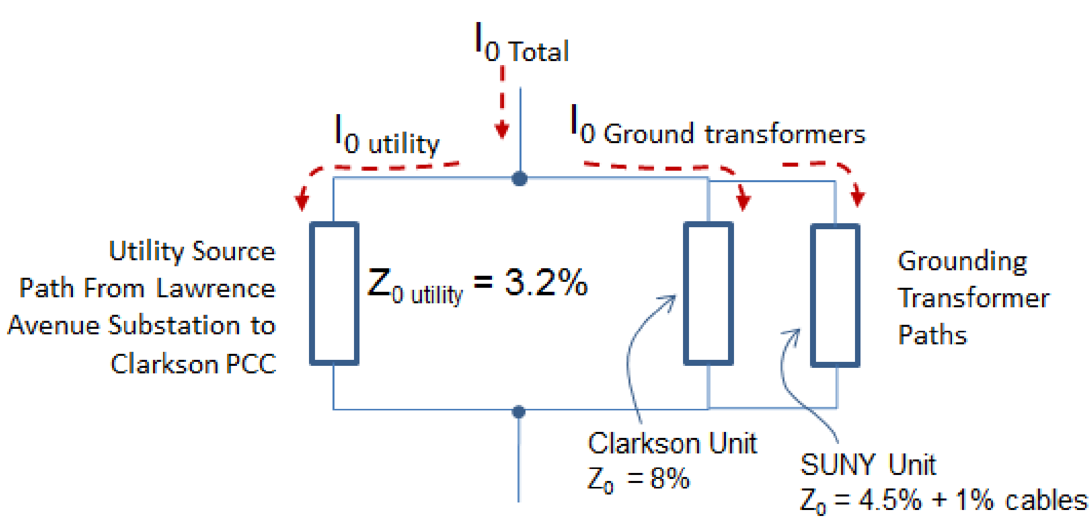


When adding grounding transformers of this size, it is important to ensure that the current diversion effect is accounted for in the protection settings on the feeder (Figure 61). Otherwise, it may desensitize the ground fault relaying of any upstream protective devices (feeder breakers, microgrid intertie breakers, etc.)

A simple check is to compare the zero-sequence impedance of the proposed grounding transformers to the zero-sequence impedance of the utility source at the point of the connection with the grounding transformer. Taking the Clarkson grounding transformer site as an example, the expected utility source zero-sequence impedance at this location is about 3.2% (on a 1 MVA base using the existing feeder impedance). On the other hand, the impedance of the proposed 1 MVA grounding transformer at Clarkson is 8% on a 1 MVA base. This transformer diverts roughly 30% of the current alone. However, the SUNY Potsdam-side grounding transformer will also divert current. In fact, it has even less impedance; therefore, its effect is more substantial. For the same L-G fault at the Clarkson grounding transformer site (and converting the SUNY Potsdam transformer 9% impedance at 2 MVA to the same base as 1 MVA) the SUNY Potsdam transformer would be 4.5% + the impedances of the connecting underground cables which would add roughly another 1% on a 1 MVA base. Figure 61 shows the overall current splitting effect. Overall, the combined total current diversion effect of both transformers is about 66% (meaning 66% of the zero-sequence current goes through the grounding transformers). Note that these calculations exclude the effect of the resistor grounded SUNY Potsdam generators, which would make the total current diversion even greater. In other words, the effect is massive and will interfere with upstream protective relaying. The effect is smaller for faults closer to the substation, but the analysis clearly shows some ground fault relaying adjustments will be needed to account for this current.

Figure 61. Zero-Sequence Current Divider Effect of the Grounding Transformers in Parallel with the Utility Source at the Clarkson Feeder 51 PCC

All impedances on a 1 MVA base. Model excludes resistor grounded 2 x 1.4 MW SUNY Potsdam generation.



While the grounding-transformer approach will require some recalibration of ground fault relays— controlling existing circuit breakers and some special provisions to deal with local potential ground rise caused by ground current flows—is the easiest approach to solving the ground fault overvoltage problem.

Note also that these grounding transformers are needed during islanded microgrid mode (as discussed in section 5.5). Using them to alleviate ground fault overvoltage in grid-parallel mode is an attractive option since some sort of effective grounding or effective grounding emulation would also be needed during islanded microgrid mode operation.

5.5.9 Load Rejection Overvoltage

Load rejection overvoltage is another form of overvoltage mentioned earlier in the report. During grid-parallel mode as long as the bulk utility system remains connected to the Potsdam Microgrid and an export path is available there is not any danger of a load rejection overvoltage event. However, if the microgrid is exporting into the bulk power system (for example via the Feeder 51 connection and perhaps this is being done for NYISO market participation purposes) and suddenly that circuit breaker opens, there will be more generation on the island at that instant than there is load. In the full-generation scenario at time of light load, it is possible there could be a 4 to 5 MW load rejection out of 10 MW of output. The voltage will suddenly rise on the system to balance conditions.

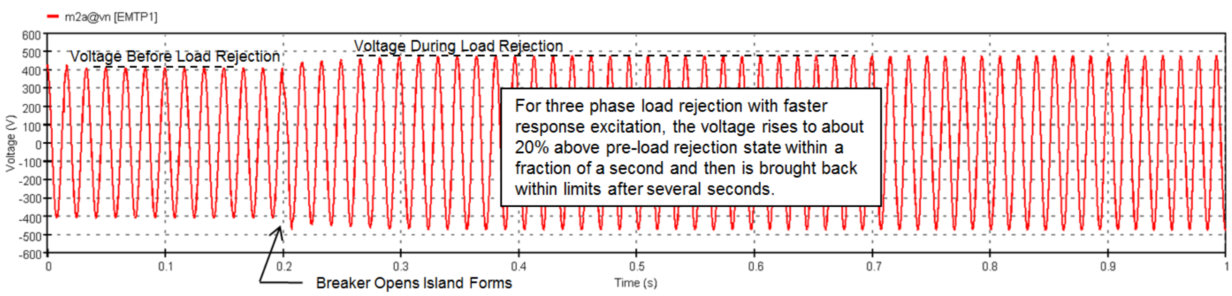
The synchronous generators can be thought of as voltage sources behind impedances and the inverter can be thought of as current controlled voltage sources (similar to current sources). Both of these sources will experience a voltage rise at their terminals when the loading is suddenly removed albeit the character and speed of response of the rise is somewhat different for each type of source.

For synchronous rotating machines the amount of voltage rise is a function of the machine impedance characteristics and time constants, the exciter response, and the amount of load rejection that occurs (e.g. ΔP is 10% or 20% or 30%, etc.). The greater the power step the more severe the voltage change. The number of surplus VARs on the system from actual capacitor banks as well as the reactive power operating state of the generator also play a role. Therefore, it is not just the real power (Watts) step change that matters. For small changes in real or reactive power (say 10% to 40%) the amount of voltage rise is not generally great enough to cause handling issues for the load. But for a full-step load, the issues might become severe, especially if surplus VARs are available.

An example of an EMTP simulation of load rejection overvoltage on a bank of generators is shown in Figure 62. In this case, there are no capacitor banks present, and the generators are running near full power, when suddenly the loading is removed. The overvoltage created is about 20% and will recover after a few seconds. In a similar situation, load rejection somewhat less severe would likely happen on the Potsdam Microgrid if power was being exported. In general, this is not an issue if the duration is less than couple seconds.

Figure 62. Mild-Load Rejection Overvoltage

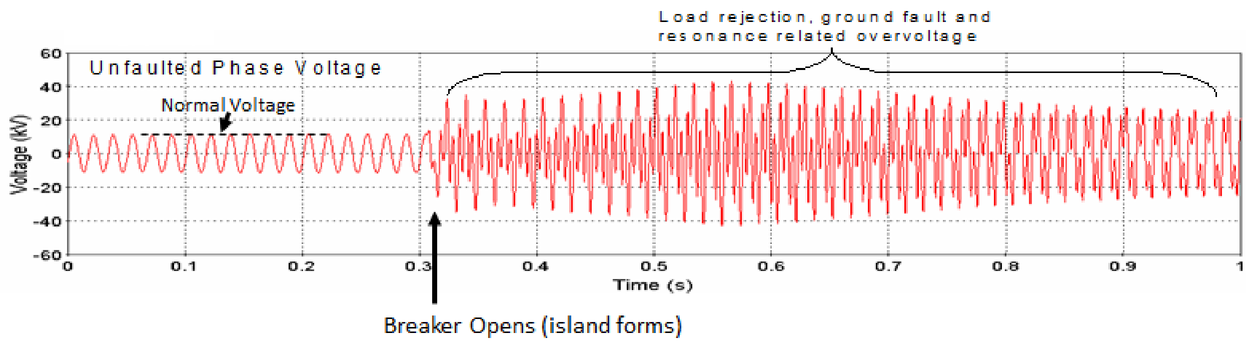
Example: EMTP simulation of a load rejection overvoltage on a bank of 480 V rotating machines where the load rejection occurs at 0.2 seconds and ΔP=100%. This example is relatively benign due to a balanced VAR loading condition (so only real watts rejection) but voltage still increases by nearly 20%.



A more serious overvoltage is shown in Figure 63. The over voltage simulation was intentionally made extra severe by applying several difficult factors at once. This includes a ground fault overvoltage condition, a full-load rejection and the presence of a large capacitor bank. The condition created is an extremely high-magnitude distorted voltage wave on the primary distribution system. Under most situations, a condition this severe would not exist on the Potsdam Microgrid. However, it provides an illustration of the dangers that must be avoided.

Figure 63. Simulated Severe "Combination" Overvoltage Event

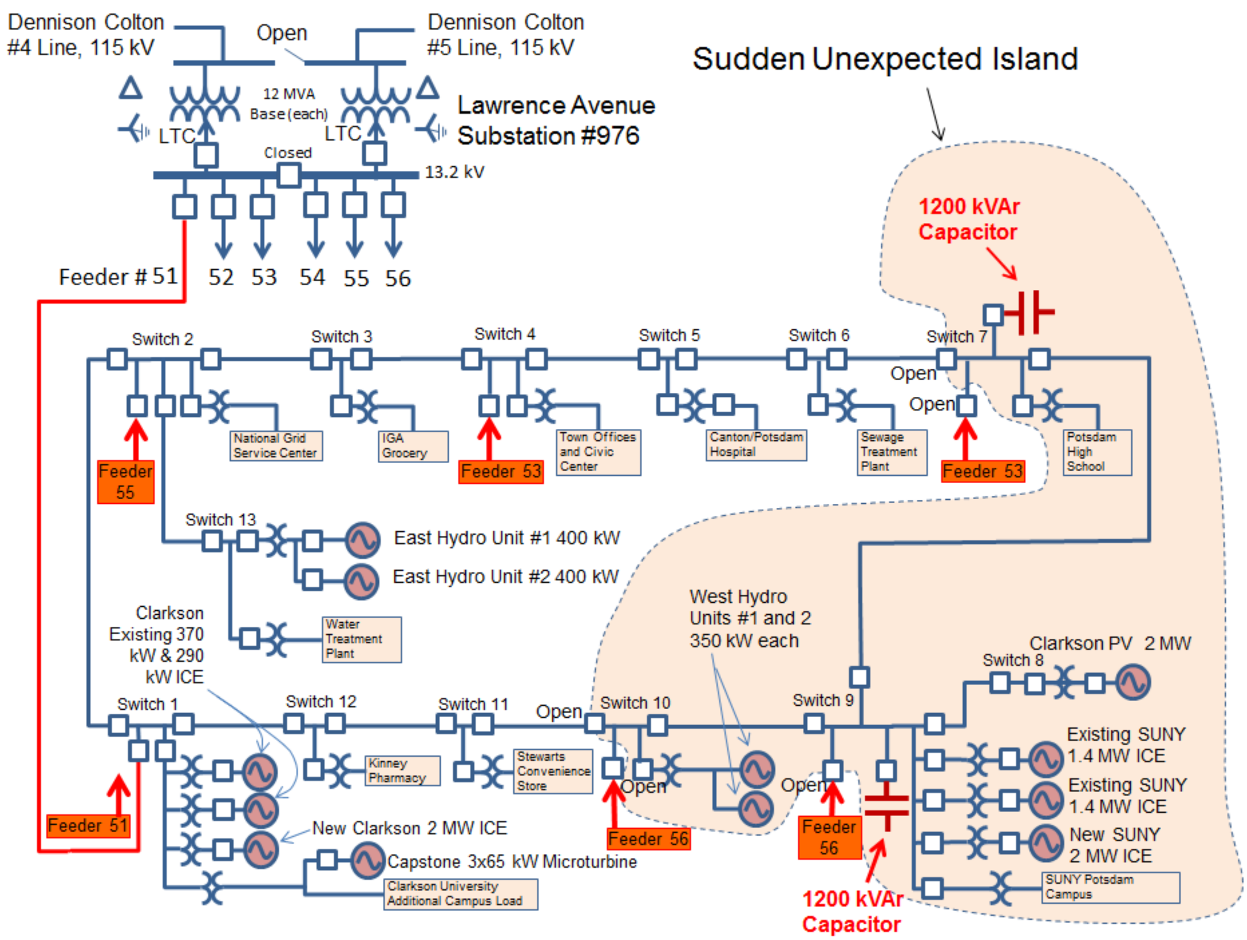
Example: EMTP simulation of a bank of rotating machines measured at primary level (ΔP=100%, ground fault overvoltage also present, plus extreme surplus VARs present, altogether resulting in severe high-resonant overvoltage.



As previously stated, the danger of broad, severe load rejection overvoltage across the entire microgrid is minor in this project given the way the grid is intended to be operated and the minimum loads expected. About a 30% to 40% ΔP load-rejection event is the highest expected and normal or day-to-day operations will be much less. But care does still need to be exercised to make sure that any sub-portions of the microgrid with a possible large surplus of real and reactive power together do not suddenly form due to the opening of circuit breakers. For example, care must be exercised in the region of SUNY Potsdam (between switches 7 and 10) at times of peak ICE generation, peak hydro generation and peak PV plant generation. If that area should suddenly become isolated during periods of lightest load at peak generation, there could be a large surplus of real power and reactive power available (Figure 64). A ground fault might simultaneously be present since faults often cause breakers to trip open. Note also the large capacitor banks on this island as well. It is one of the greater island risks from the perspective of load rejection. Operating the generation and capacitors in a manner where VARs are always being imported into a zone with surplus real-power production can help to reduce load rejection if the zone tie breaker should open.

It is understood that the number of breakers and switches may be reduced in Phase II of the project for the final system layout, consequently some of the riskier possible system breakup scenarios will disappear in the final system design.

Figure 64. Example of a Possible Load Rejection Island that Might Form Under the Right Conditions when Breakers Open



5.6 Microgrid Operation in Islanded Mode

5.6.1 Introduction

This section of the report focuses on technical analysis of the Potsdam Microgrid system when operating in the intentionally islanded mode—that is, when it's intentionally operating as an emergency power source separated from the bulk National Grid system. Operating in an intentionally islanded mode is a different environment compared to operating in grid-parallel mode. In islanded mode the DG units are the only source of energy on the island and have greater responsibility for system power quality than when operating in grid-parallel mode. The key differences between grid-parallel and islanded modes of operation are outlined in Table 64. These differences include the fact that the generators as a group must provide voltage regulation, frequency regulation, load-following of real and reactive power, and sufficient fault current to allow proper operation of protective devices within the microgrid.

Table 64. Comparison of Grid-Parallel and Intentionally Islanded Mode of Operation

Parameter	Grid-Parallel Mode (Classical DG Operation)	Intentional Island Mode (Emergency power)
Voltage Regulation	Generators “voltage follow.” The utility LTC transformers/regulators control the voltage. Generators may contribute to regulation by fixed-power factor mode or independent reactive dispatch control.	Generators are totally responsible for regulating voltage on the island.
Frequency Regulation	Generators “frequency follow” leaving frequency regulation to the utility (unless provided as ancillary service to NYISO).	Generators have total responsibility to regulate frequency of the intentional island.
Real and Reactive Power	The generators operate at a level of real and reactive power per dispatch and center needs that can be independent of the loading on the microgrid.	Generators will follow the load supplying the needed real and reactive power to exactly balance the load-to-generation.
Fault Levels	Fault-current levels on the microgrid primary will be from 100% of the normal utility source levels (with no generation running) up to roughly double those levels when all generation is running.	Fault current from the generators on the primary will be anywhere from about 25% of the normal utility fault level if only partial generation is running, up to about 100% of the utility fault level in full-generation scenario.
Islanding Protection and Protective Relaying	DTTs and anti-island protection is engaged at acceptable sensitivity levels. Overcurrent protection set to minimize interference with utility system fault protection. DG ride-through optimized for bulk grid stability.	DTTs disabled. Anti-island protection disabled or desensitized. Overcurrent protection compatible with islanded operation. DG ride-through settings optimized for microgrid stability.

5.6.2 Initial Switching Transitions and Start-Up Procedures for Islanding Mode

The transition to an intentionally islanding mode for the microgrid occurs for any of the following primary reasons:

- An unplanned outage has occurred on the upstream National Grid power system (due to lightning, wind, icing, etc.).
- A planned outage occurs on the upstream power system (for example, could be planned maintenance work by National Grid that requires a bulk source outage).
- The microgrid has separated proactively into an intentional islanding mode because a possible unplanned outage may occur in the near term (e.g., a lightning storm front is approaching, or an ice storm is approaching, etc.).
- The microgrid has separated because it has been asked by the bulk system authorities (such as National Grid or NYISO) to perform some sort of emergency demand response program and withdraw all microgrid loading from the main grid.
- It is desired to perform a live test of the microgrid to make sure it will be ready for a real outage.

The steps to perform the transition will depend on the reason for a shift into microgrid mode. For any unplanned outage (option one) the transition is not seamless—the power will go out and the island will then be established from a black start. However, for options 2 through 5, the transitions could be done either seamlessly or as outage incurring transitions.

It is possible to do option 1 as a seamless or nearly seamless approach, but to do that reliably would require energy storage and it comes at increased risk for problems with considerable investment in specialized transition equipment, controls, and energy storage capacity. For due diligence purposes, there is discussion later in this section on that approach; however, a seamless approach for option 1 is not recommended for this project.

Table 65 provides a short list of the key steps needed to transition the microgrid from a grid-parallel state into the islanded state where the DG is running as an intentionally islanded microgrid. The steps required are shown for an unexpected (unplanned) and expected (planned) intentional island.

A zone-based method of microgrid black start and assembly is based on the steps of Table 65 and illustrated in Figure 65. In this approach, the first zones energized are zones 1 and 2 (green) which are energized as separate islands picking up most or all of load at each respective campus. A caveat to the scheme is that some of the largest transformers (3 MVA) at Clarkson might need to wait until more generation is operating to be energized. In the next step, zone 3 (yellow) energizes the path across the river to prepare the connection of the two campuses. Zone 4 finalizes and ties together the two major islands, synchronizing them. Zone 5 pulls in the high school and sewage treatment facility. Zone 6 ties in the East Hydro Facility. Zone 7 completes the north side of the loop. Zones 8 through 10 connect the NG Service Center, Potable Water, and the PV system. The capacitors switch in just after their respective area is energized, but only if the VAR situation requires them to be online, so as to avoid VAR surplus in the zone.

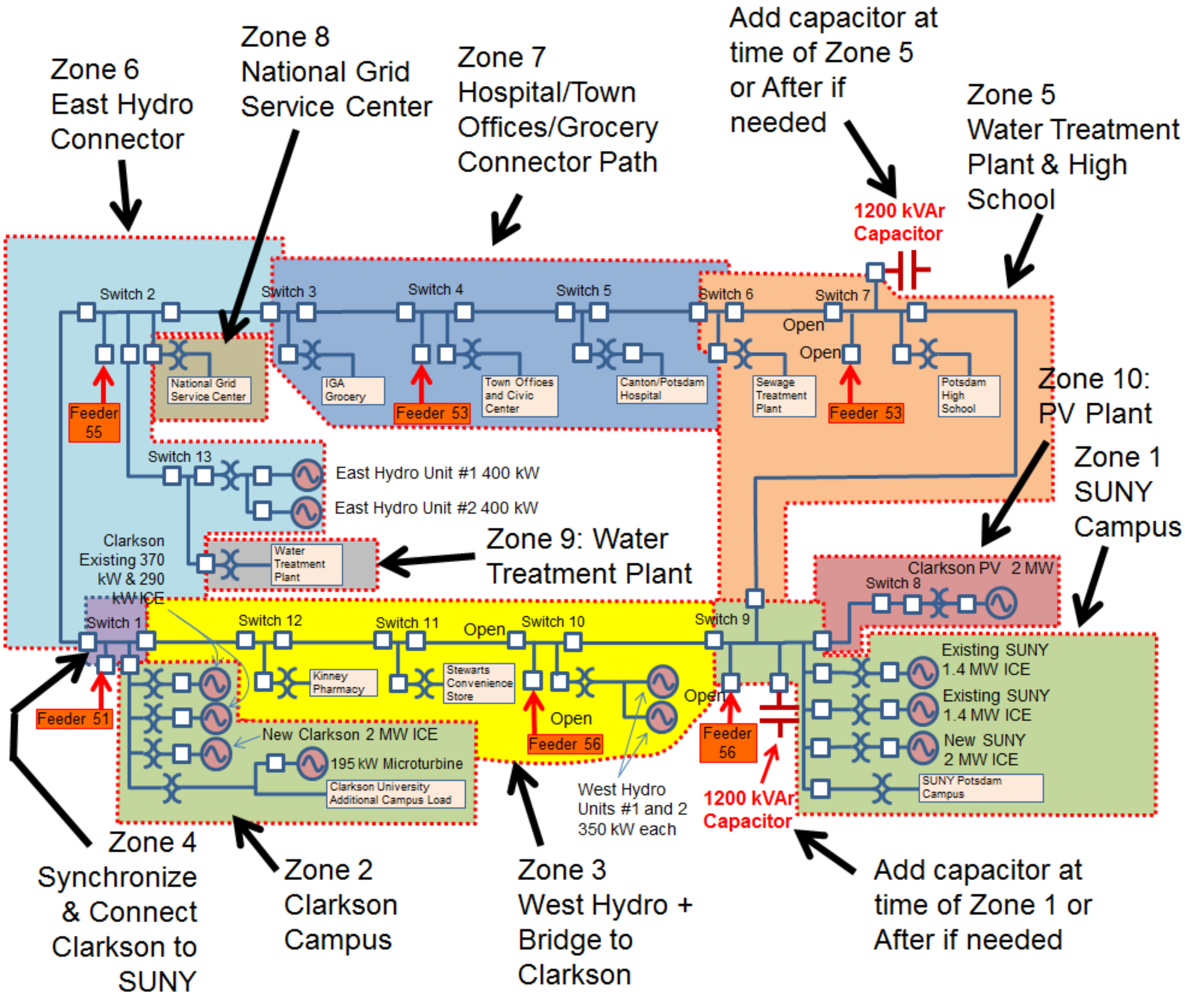
Table 65. Steps to Transition to an Intentionally Islanded Mode (Full-Microgrid Version)

Step Number	Type of Intentional Island	
	Unplanned Intentional Island	**Planned Intentional Island**
Initial Condition Just Before Event	Utility power is stable and nominal (microgrid generation may or may not be running in classical DG mode). A power "outage event" is about to occur.	Utility power is stable and nominal (microgrid generation may or may not be running in classical DG mode at this time). For whatever reason, it is desired to separate the microgrid seamlessly to an intentional island mode.
1	Utility power outage occurs due to ice storm, lightning, wind, or etc. (upstream utility source breaker opens).	Available microgrid generation that is not already running and needed is started, synchronized, and put online in Grid-Parallel Mode (still Classical DG mode at this step).
2	All running microgrid generation is tripped offline within about one second or less per normal DG methods (DTT, anti-islanding relays, etc.).	The total power output of DG units is adjusted until there is little to no power transfer (watts or VARs) at the microgrid tie breaker (such as Feeder 51 PCC). Load shed might be needed to reach this state.
3	Utility reclosing sequence completes its sequencing. If reclosing fails to successfully re-energize system, a decision is made after a suitable delay of minutes (manually or automatically) to go to intentional island mode.	Microgrid controller sends signal to all generators to be prepared to transition to the intentional island mode (DTT disabled, anti-island disabled, frequency regulation, voltage regulation, and load following, etc.).
4	A signal is sent to open microgrid tie breaker (Feeder 51 PCC) and begin microgrid start up procedure. Microgrid "subpart" splitting breakers open.	The tie breaker (Feeder 51 PCC) is opened, generators switch instantly to voltage regulation, frequency regulation, and Watt/VAR following modes, DTT disabled, anti-islanding disabled, etc., and seamlessly carries load.

Table 65 continued.

Step Number	Type of Intentional Island	
	Unplanned Intentional Island	Planned Intentional Island
5	Generation protection/control is set to intentional island mode (Anti-islanding disabled, DTT disabled, and voltage, frequency and watt and VAR modes set. Generation is started to warm up (but not paralleled with microgrid loads just yet).	
7	Load-shed signals are sent to trip non-essential loads (up to 20% to 25% of load) depending on loading conditions and generation availability.	
8	Signals sent to open switches at all major load distribution transformers (those greater than 500 kVA).	
9	SUNY Potsdam 4.8-MW generation is up and running on its bus and ready to pick-up SUNY Potsdam campus load).	
10	Clarkson 2-MW new generation is up and running (but not yet connected to Clarkson campus load).	
11	SUNY Potsdam and Clarkson each pick-up some local load at their respective campuses as allowed by generator ratings (some large transformers not online yet).	
12	Tie breakers connect microgrid subparts (synchronize and tie east to west sides).	
13	The hydro and smaller Clarkson generators brought online as those loads power up.	
14	Largest distribution transformers and final loads brought online. PV ties in.	
Final State	Intentional Island is accomplished with loss of power up to about 20-30 minutes.	Intentional Island is achieved seamlessly without loss of power.

Figure 65. Conceptual Plan for Assembly of Microgrid from a Black Start



5.6.3 Returning to Grid-Parallel Mode from Intentional Island

Once the utility power is restored in a stable fashion on the utility source side of the open Potsdam Microgrid tie breaker (e.g., Feeder 51 Clarkson PPC circuit breaker), it is not necessary to incur an outage to the microgrid to reconnect to the bulk system. The running and stable microgrid system can be connected back to the bulk utility system simply by synchronizing the power on both sides of the tie breaker to a suitable match. After the connection is made, the generation instantly transitions to grid-parallel mode, meaning that it must voltage follow, frequency follow, have islanding protection and DTT trip modes activated, and any other protection settings changed back to the appropriate grid-parallel values. If it is not desired for the generation to continue to operate once back in grid-parallel mode, the DG can be slowly ramped down and taken offline over 5- to 10-minute period. This will allow the utility voltage regulator tap changers to keep pace with the change in voltage due to the change in current flows.

5.6.4 Synchronization during Transitions and Aggregations

As previously discussed in the section on grid-parallel mode in which the recommendation (based on IEEE 1547 requirements) was synchronization of parameters to tie various parts of the microgrid together, should also be suitable for the islanding modes (Table 66).

Table 66. Synchronization Parameters for Tying Together Subparts of the Potsdam Microgrid during Transitions of Partial or Full Microgrid to Grid-Parallel Mode.

Aggregate Rating of DG Units (kVA)	Frequency Difference (Δf, Hz)	Voltage Difference (Δ V, %)	Phase Angle Difference ($\Delta\theta$, degrees)
0-500	0.3	10	20
>500-1,500	0.2	5	15
>1,500-10,000	0.1	3	10

5.6.5 Coordinating Islanded Microgrid Operation with UPS Ride-Through Capability and UPS Frequency Limits

Any UPS system serving a critical load on the microgrid that needs to operate continuously during the expected 20- to 30-minute transition time from National Grid source power to islanded generator operation must have sufficient battery ride-through time to bridge this time gap. Otherwise, if the UPS system can’t ride through the 20- to 30-minute period, the customer will need to have their own standby generation to bridge the gap until the microgrid becomes available or simply let the UPS run down and trip off.

Of course, 20 to 30 minutes is the longest time expected for the transition, and hopefully many transition events can be faster, perhaps even just 5 minutes or less, but this long gap is something that needs to be planned for and the customers notified from a customer expectation perspective, so that there are no disappointments.

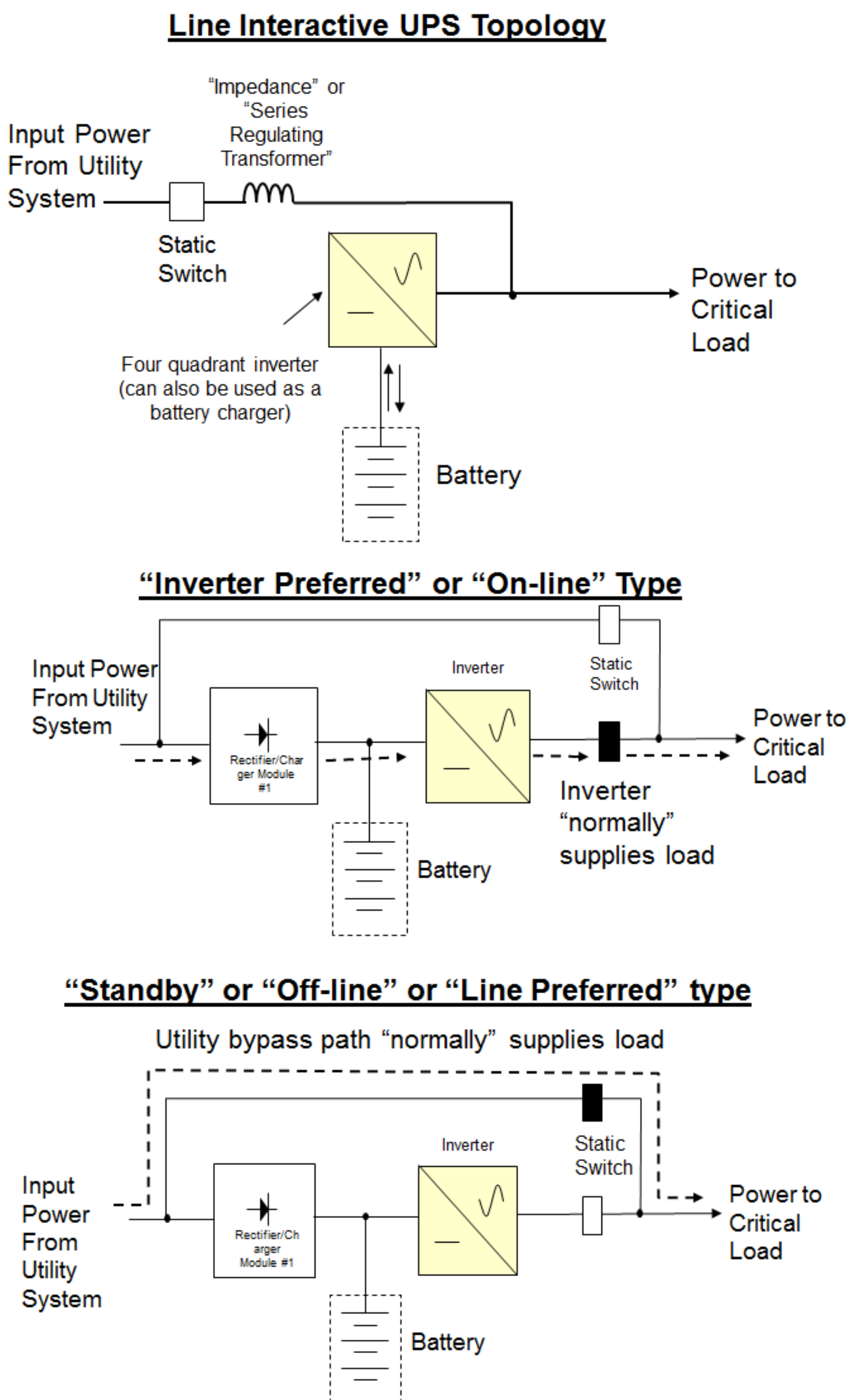
Another important factor about UPS compatibility with the microgrid when operating in the intentional islanding mode is the influence of the voltage and frequency settings of the various UPS systems on microgrid conditions. A primary question is whether such conditions will cause the settings to cycle back and forth between battery mode and grid-supplied normal mode. This could also lead to customer dissatisfaction with the microgrid operating conditions.

The utility system is almost always well within ±1 Hz frequency, but in microgrid mode we can expect the frequency variations to be on the order of ±2 Hz or even occasionally ±3 Hz. Many UPS are default programmed to hold the frequency tightly within a range of ±1 Hz, with a tight slew rate as well—and many are programed to switch to battery mode if conditions go outside bounds. UPS may also switch back and forth to/from battery mode if voltage deviations become excessive.

There are three main UPS architectures: line interactive, double conversion "inverter preferred," and double conversion line preferred (Figure 66). The line interactive type and double conversion line preferred type may tend to cycle to battery mode if the frequency or voltage variations exceed the programmed limits of the UPS. The double conversion inverter preferred type can handle wider frequency and voltage variations without cycling because it is always in the inverter mode and always running on its continuously charged battery bank.

Figure 66. Three Key UPS Architectures

Line interactive and double conversion line preferred types may be influenced more than double conversion inverter preferred types.



For the purposes of the microgrid development, it is best to work with the key customers that may have UPSs to gather information on expectations, the type of UPS architectures, and settings used. Most UPS units of a significant size have a settings menu where frequency and voltage limits can be relaxed somewhat, without adversely impacting the load.

5.6.6 Power Mismatch Allowance for Seamless Intentional Island Formation

As stated previously (Table 65), it is important to have the watts and VARs power transfer at a low or zero flow across the microgrid tie breaker at the moment of separation for the seamless transition to a planned intentional island. The question is how close to "zero" is good enough?

A large flow would be detrimental. If there is a significant "under-generation" situation such that the generators are not meeting all the demand of the loads on the microgrid and there is significant power from the utility flowing into the microgrid to make up for the mismatch, the moment the tie-breaker opens, the DG will see a step-load increase equivalent to that mismatch. The frequency will drop, and voltage will drop. On the other hand, if there is a significant over-generation condition, the DGs will see a step-load decrease and the frequency and voltage will rise. If the mismatch condition between load and generation on the island is large (say 50% of generation output at that instant), there is a good chance that the frequency and voltage change could be sufficient to destabilize or collapse the microgrid and the transition to an islanded state would not be successful. In the case of severe over generation, a load rejection and severe overvoltage might result under the right circumstances.

A small mismatch on the order of a 5% or less of the generation output is reasonable to achieve and should not lead to any serious voltage or frequency variations on the microgrid as long as the generation is set to load follow and appropriately disables anti-islanding, etc. A recommendation of this report is that the power transfer across the tie breaker should be somewhere between being perfectly matched (0% mismatch) and a 5% over generation mismatch of the connected DG capacity at the moment of separation.

As an example, the effect on generator frequency of a large sudden 100% power mismatch between prime mover and generator output is seen in Table 67. The speed (and hence frequency) of a suddenly unloaded generator with prime mover operating at rated power at the instant prior to unloading will increase rapidly. In fact, in our example within half a second the speed increase could result in roughly 70 Hz operating frequency. The governor would eventually respond, but for at least the first half second the governor would have little impact; therefore, a large shift in frequency would definitely occur and it would be necessary to shut down the generator to avoid over-speed. The table marginally over-represents the seriousness of the change, since the loading is assumed constant in the example. In fact, the overvoltage and over-frequency condition would raise the loading somewhat and the effect would reduce the speed accelerations slightly. Nonetheless, even if this situation was factored in, the frequency change would become large, quickly.

Table 67. Speed of Rotating Machine (H=1.5) After Full-Load Rejection

No governor response load assumed constant, for illustration only.

Time After Breaker Open (seconds)	Integrated Energy Input from Prime Mover (per unit of joules/sec output rating)	Energy Ratio Relative to 60 Hz Speed	Machine Frequency (Hz)
0.00	0.00	1.00	60.00
0.10	0.10	1.07	61.97
0.20	0.20	1.13	63.87
0.30	0.30	1.20	65.73
0.40	0.40	1.27	67.53
0.50	0.50	1.33	69.28

5.6.7 PV Active Anti-Islanding Protection Compatibility

The 2-MW PV system is an inverter-based power source that uses active anti-islanding algorithms to detect islands and trip them offline quickly if an island forms. The methods used vary from inverter to inverter but can include one or more of the following:

- impedance measurement
- detection of impedance at a specific frequency
- Slip-mode Frequency Shift
- frequency bias
- Sandia Frequency Shift
- Sandia Voltage Shift
- frequency jump
- various combinations of the above

The anti-islanding settings of the PV need to be disabled or greatly relaxed to allow for microgrid operation. The microgrid has a greater rate of change of frequency, greater overall frequency variations, higher impedance, greater phase shifts and larger harmonic distortion shifts than the utility sourced power system. If the settings are not relaxed it is possible the PV system may not be able to remain connected to the microgrid in a stable fashion. It might end up cycling on an off periodically in a disruptive fashion.

In addition, and obviously, the other generators on the island will need their anti-islanding settings and DTT disabled, as has already been discussed in the black start and microgrid assembly procedure. The DG relaying settings chart discussed in section 5 would need the frequency settings broadened to insure compatibility.

5.6.8 Avoiding Cable Resonances during Start-Up Procedure

Because the microgrid is underground, there are many long 13.2-kV primary cables that might be energized from one end during start-up, while the loading on the other cable end is not yet established (i.e., the loads have not yet been switched on at the destination). There will be significant cable capacitance. In addition, there are also some large 1200-kVAR capacitor banks that will be present in parts of the loop as well that can be add to these conditions. While these configurations are necessary as part of the resilient underground design arrangement, there is concern that if the cables are fed from one end by the DGs with no load or utility connection present at the other end, it could result in some significant resonances with the generators and transformers. To reduce the chance of any such harmonic resonance and/or ferro-resonance, it is recommended that the switching procedures for bringing certain loads, cables, and capacitors online are based on switching policies that are antithetical to ferro-resonance and avoid excess capacitive VARs in any zone unless resistive damping (watts loading) is present. For each zone switched in, some load should be initially connected as part of any connecting cable segment to suppress such resonances as the system is brought up and assembled from a black start. It does not take much load, only a few hundred kVA of unity PF or lagging PF load in most cases on each segment to suppress resonances.

5.6.9 Fault Levels (Islanded)

While islanded, the fault levels on the microgrid for partial generation scenarios will be considerably less than when operating in the grid-parallel mode with the utility source. Table 68 shows the three-phase fault levels that can be expected in various modes. For the full mix of 10 MW of DG in an islanded state of operation, the aggregate fault level into a tap or at the fault arc is about 3000 A on the cable primaries around the underground region of the microgrid zone. The actual levels along the cables on any given path (since current comes from multiple paths to add up to the total) can be less than half of this for certain routes. The generation cases represent the initial fault levels. The fault levels will be even lower after many cycles due to the sub-transient and transient impedance decay envelopes. Also, at times when the microgrid is split, the generation levels will be much smaller than 10 MW, perhaps as low as 2 MW of generation in the smallest possible partial microgrid. In that case, the initial fault levels are as low as about 750 A. Note also that the L-G fault levels will be roughly about 30% to 50% of the three-phase fault levels depending on the generation scenario and grounding transformer status.

Table 68. Primary Fault Levels When the Microgrid is Operating as an Island Compared to When Operating with the Utility Source

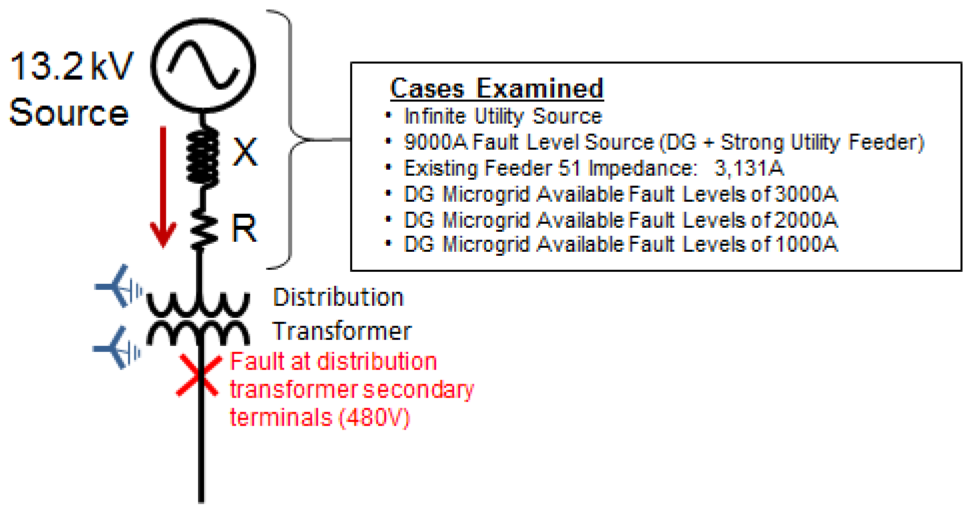
Type of Source and System Condition	Approximate Three-Phase Fault Current at 13.2 kV Cable Primary Fault Location (Currents are approximate since the fault level is affected by location and other factors.[1])
Existing Feeder 51 Impedance (Utility Source Only)	3,000 A
SUNY Potsdam Feeder 56 Impedance (Utility Source Only)	6,000 A
Existing Feeder 51 Impedance (Full 10-MW DG + Utility Source)	6,000 A
SUNY Potsdam Feeder 56 Impedance (Full 10-MW DG + Utility Source)	9,000 A
Islanded Microgrid (10-MW Full Mix DG, No Utility Source)	3,000 A
Islanded Microgrid (5-MW Mixed Type DG, No Utility Source)	1,500 A
Islanded Microgrid (2-MW ICE DG, No Utility Source)	750 A

Note 1: These are the total currents into the fault itself (meaning the fault arc or into a tapped connection that is faulted). The currents on each cable path will be less, since there are multiple paths involved.)

One of the more important factors regarding the operation of the islanded microgrid is whether it will have sufficient fault current to operate protective devices within customer premises at the secondary voltage level (i.e., at 480 V, 208 V, or 120 V). The degree to which reduced fault levels seen at the primary side of the distribution transformer influence the available fault level on the secondary side depends on the intervening impedance of the distribution transformer and the secondary cables. In cases where the transformer size is small—even though the available fault level on the primary side of the distribution transformer is reduced to a lower value—the dominating impedance of the situation is still the DT and its secondary cable, so the actual change in fault level at customer service entrances is not that great. On the other hand, if the transformer is large, the fault level may change significantly.

To examine this relationship, six cases were studied in which microgrid system source strength fed various three-phase distribution transformers. The transformers had a 480-V secondary voltage rating and the team evaluated the fault current levels at 480 V for a balanced three-phase fault at the terminals for those cases. The six cases included the transformer that was fed by an infinite source (9000 A), a source with impedance similar to Feeder 51 PCC, as currently configured and weakened microgrid source situations would be 3000 A, 2000 A and 1000 A, respectively (Figure 67).

Figure 67. Six Different System Strengths Feeding a Distribution Transformer



For the weakened source strength cases, the results of the distribution transformer secondary (480 V) fault level sensitivity analysis are shown in Table 69. We can see that there is little fault-level reduction (at the 480-V level) relative to the fault level obtained with existing Feeder 51 service for the smaller transformers of a few hundred-kVA rating or less. This is even the case when the primary-side fault level is as low as 1000 A. For example, the fault level on the secondary side drops by less than 10% for transformers of 150 kVA or less. However, for the large transformers (such as 2500 or 3000 kVA) the secondary-fault level can be cut nearly in half—so there is a huge effect for the larger transformer units. Reduced fault levels within facilities may mean that breaker tripping levels and clearing times may no longer coordinate as they did before. There are two additional things to consider in the analysis: first, the table of results does not take into account the cable impedances from the transformer secondary to service panels in the buildings. Including those extra impedances would reduce the percent changes seen somewhat—which would be helpful. Secondly, the fault levels discussed are the "initial" fault levels (sub-transient impedance initially) and after several cycles, owing to the sub-transient and transient decay periods, the percent reduction in faults levels would become even greater.

Table 69. Reduced Fault Levels on Secondary Side (480 V) of Three-Phase Transformers with Various Weaker Incoming Sources on the Primary Side of the Transformer

Transformer KVA Rating and Percent Impedance		Secondary-Fault Level in Amperes with Existing National Grid Primary Source (3,131 A)[1]	Secondary-Fault Level if Microgrid Has 3000 A Available Primary[2]		Secondary-Fault Level if Microgrid Has 2000 A Available Primary[2]		Secondary-Fault Level if Microgrid Has 1000 A Available Primary[2]	
			Amperes (480 V)	*% Change Compared to Existing National Grid*	*Amperes (480 V)*	*% Change Compared to Existing National Grid*	*Amperes (480 V)*	*% Decrease Compared to Existing National Grid*
75	3.5%	2,510	2,507	-0.1	2,474	-1.4	2,378	-5.3
112.5	3.5%	3,711	3,705	-0.2	3,628	-2.2	3,415	-8.0
150	3.75%	4,566	4,556	-0.2	4,439	-2.8	4,121	-9.8
225	4.0%	6,289	6,270	-0.3	6,048	-3.8	5,465	-13.1
300	4.0%	8,201	8,168	-0.4	7,793	-5.0	6,843	-16.6
500	4.5%	11,625	11,559	-0.6	10,820	-6.9	9,068	-22.0
750	5.75%	13,308	13,220	-0.7	12,250	-8.0	10,034	-24.6
1000	5.75%	16,880	16,739	-0.8	15,208	-9.9	11,927	-29.3
1500	5.75%	23,044	22,780	-1.1	20,030	-13.1	14,696	-36.2
2500	5.75%	32,610	32,083	-1.6	26,875	-17.6	18,064	-44.6
3000	5.45%	37,577	36,880	-1.9	30,172	-19.7	19,502	-48.1

Notes:

1 This column is the secondary-fault level at 480 V of the distribution transformer if the primary side of the transformer is fed by a source with the existing impedance of Feeder 51 at the Clarkson PCC (3,131 A available fault level).

2 These columns of ampere levels and percent changes are the secondary-fault level at 480 V of the distribution transformer if the primary side of the transformer is fed by a source with 3000 A, 2000 A and 1000 A, respectively. Percent change is relative to the transformer being fed by National Grid's existing Feeder 51 impedance.

Table 70. Fault Levels on Secondary Side (480 V) of Three-Phase Transformers with a Strengthened Primary Source

Transformer kVA Rating and Percent Impedance		Secondary-Fault Level with Infinite Primary (Amperes 480 V)[1]	Secondary-Fault Level in Amperes with Existing National Grid Primary Source (3,131 A)[2]	Secondary-Fault Level if Microgrid Has 9000 A Available on Primary[3]	
				Amperes (480 V)	*% Increase Compared to Existing National Grid*
75	3.5%	2,577	2,510	2,553	1.7
112.5	3.5%	3,868	3,711	3,812	2.7
150	3.75%	4,809	4,566	4,721	3.4
225	4.0%	6,764	6,289	6,591	4.8
300	4.0%	9,037	8,201	8,728	6.4
500	4.5%	13,380	11,625	12,714	9.4
750	5.75%	15,703	13,308	14,779	11.1
1000	5.75%	20,947	16,880	19,329	14.5
1500	5.75%	31,383	23,044	27,878	21.0
2500	5.75%	52,338	32,610	43,249	32.6
3000	5.45%	66,199	37,577	52,371	39.4

Notes:

1 This column is the secondary-fault level of the distribution transformer if the primary side of the transformer is fed by an infinite source.

2 This column is the secondary-fault level of the distribution transformer if the primary side of the transformer is fed by a source with the existing impedance of Feeder 51 at the Clarkson PCC (3,131 A available fault level)

3 These two columns of ampere level and percent change are the secondary-fault level of the distribution transformer if the primary side of the transformer is fed by a source with 9000 A available current. Percent change is relative to the transformer being fed by National Grid's existing Feeder 51 impedance. The 9000 A ampere case is equivalent to the case where SUNY Potsdam Feeder 56 is used as the utility source and all DG is running in parallel.

For the strengthened fault current cases (Table 70), when the fault level goes up on the primary side of the distribution transformer—due to either a stronger utility distribution source used and/or DG added in parallel—the fault level on the secondary side of the transformers will rise. The highest expected case is about 9000 A on the primary side if SUNY Potsdam Feeder 56 is employed and if all DG is running in parallel. As expected, the results show the small distribution transformers (those of a few hundred KVA or less) increase by less than 10%; however, for the larger transformers such as 2500- or 3000-KVA rating, the fault levels can increase 30% to 40%. Once again, the actual increases seen will be influenced by the secondary cable impedances as well as the sub-transient and transient decay-time constants. The implications of higher fault currents are that coordination may be lost and the breaker interrupting capacity may not be sufficient. It is necessary to make sure the extra current does not exceed interrupting capacity of service panel circuit breakers or interfere with coordination. The larger transformer sites would be the most important to check in this regard.

5.6.10 Voltage Flicker Levels during Motor Starts (Islanded)

When the generators are operating in an islanded mode, the transient voltage regulation during motor starts, transformer inrush events, load steps, etc., will be somewhat more sensitive than when in grid-parallel mode. Motors can be one of the more problematic types of devices in this regard. In particular, larger motors of many hundreds of horsepower rating that are starting directly across the line (no soft starter) may result in noticeable voltage fluctuations (and will also cause frequency fluctuations).

Screening of the Potsdam Microgrid loads at all the customer sites early in the project could not identify any motors that exceeded 100 hp at customer sites. This is good news since larger motors; especially something on the order of 500 hp or 1000 hp if started across the line without any special soft starting gear, could cause voltage dip related power quality issues on the microgrid.

A couple caveats to the initial screening are that Clarkson recently completed a new chiller plant that may have larger motors present than at the time of the screening. The size of these units is unknown and these need to be checked in Phase II of the project. Plus, the potable water pumping facility should be double checked again just to make sure it does not have any large motors, since it is surprising that in the first screening nothing above 100 hp was reported. It is not unusual for water pumping facilities to use higher horsepower pumping motors; therefore, it is a worthwhile check to verify there is nothing above 100 hp present.

NEMA has codes for induction motor types which relate to the locked rotor inrush impedance of the motors and determine the ratio of the across-the-line-peak-motor starting current to normal full-load running current (Table 71). Most large motors we are concerned with fall into the NEMA A through G design categories. But some motors (NEMA Code H and higher) have greater starting currents. The design category can be determined from the code letter on the motor nameplate. A code G has about 6 per unit starting current and is likely the worst case seen for any larger motors; therefore, the code G type of motor will be used as an example for the following analysis of voltage dip during motor starts. It should be noted that the terminology “across the line” means that the motor winding is connected directly (switched on directly at full voltage) with no external devices present to limit the locked rotor starting current during the initial few seconds of operation as it winds up to rated speed. As opposed to direct across-the-line starts, there can be soft starting equipment present which can include devices such as auto-transformers that reduce the input voltage or electronic soft starters that perform special switching of the waveform to limit the initial current during the starting period. In general, most soft starter methods are able to obtain a factor of two to four reduction in the starting current depending on various factors. In some cases, the starter is unable to reduce it much, due to the motor stalling during the start when the reduction method is too aggressive.

If using a code G motor for the motor starting analysis, it means that during starting (without a soft starter) there will be six times the full-load running current. There is an assumed 1 kVA of full-load power consumption per horsepower of rating; therefore, a 100 hp motor uses about 100 kVA when running at full load and will have about 600 kVA of starting power with a locked rotor start. Given the impedance of 10 MW of mixed type distributed generators feeding into the microgrid as an island, the percent voltage drop can be estimated. A 100 hp motor with code G design will cause a voltage dip of about 1.25% on the microgrid primary. As a more extreme example, a 1000 hp motor may cause a dip as great as about 12.5% during start-up (Figure 68). The nature of these voltage dips will depend on many factors regarding the exciter settings and response of the generator, but many will appear as shown in Figure 69.

Table 71. NEMA Locked Rotor Starting Currents

(Code G used as Example)

Code Letter	Approximate Ratio of Starting Current to Full-Load Running Current (No soft starting equipment present)
A	0-3.14
B	3.15-3.55
C	3.55-3.99
D	4.0-4.49
E	4.5-4.99
F	5.0-5.59
G	5.6-6.29
H	6.3-7.09
J	7.1-7.99
K	8.0-8.99
L	9.0-9.99
M	10.0-11.19
N	11.2-12.49
P	12.5-13.99
R	14.0-15.99
S	16.0-17.99
T	18.0-19.99
U	20.0-22.39
V	22.4-and up

Figure 68. Estimated Voltage Change on the Primary Microgrid with the Full 10-MW Generation Scenario Islanded and the Direct Across-the-Line Starting of 100 hp or Less Motors

(1000 hp motor also shown to illustrate severe case)

Across the line start Code A to G Motors, 100hp and less expected to yield 1.25% or less voltage change for full (10 MW) microgrid scenario

Motors Present on Microgrid Not Expected to Exceed 100hp (prior to chiller plant addition)

Motor HP	Starting KVA (SKVA) for a Code G Motor (has about 6X Starting kVA/HP)
20	120
50	300
100	600
200	1200
500	3000
1000	6000

Example of a large 1000hp motor

Starting KVA	%Voltage Dip
Less than 600	<1.25%
1,052	2.5
2,160	5.0
3,328	7.5
4,560	10.0
5,860	12.5
7,240	15.0
8,700	17.5
10,256	20.0
11,912	22.5
13,676	25.0
15,560	27.5
17,580	30.0
19,752	32.5
22,088	35.0
24,616	37.5
27,348	40.0

The motor starting voltage dips are shown plotted on the flicker curve with 10 MW and 5 MW of mixed generation (Figure 70). The cases shown are for across-the-line starting without a soft starter. For the full generation case (10 MW) the voltage change on the primary would be small (1.25%) and not expected to cause issues given the typical number of motor starts expected per day. At partial generation scenarios of 5 MW or less, the flicker becomes more noticeable and might exceed irritation levels depending on how often the motors are starting. Use of soft starters could cut by half or even more the amount of flicker present and help keep the dips within reasonable limits for partial microgrid situations where less generation is available. It is worth mentioning that some partial microgrid scenarios might have as little as 2 MW of generation present and in those cases 100 hp motors started directly across the line could cause a serious degree of flicker if the number of starts per day is high.

Figure 69. Nature of a Typical Motor Starting Voltage Dip on a Generator

(Illustration per Caterpillar Generator Manual)

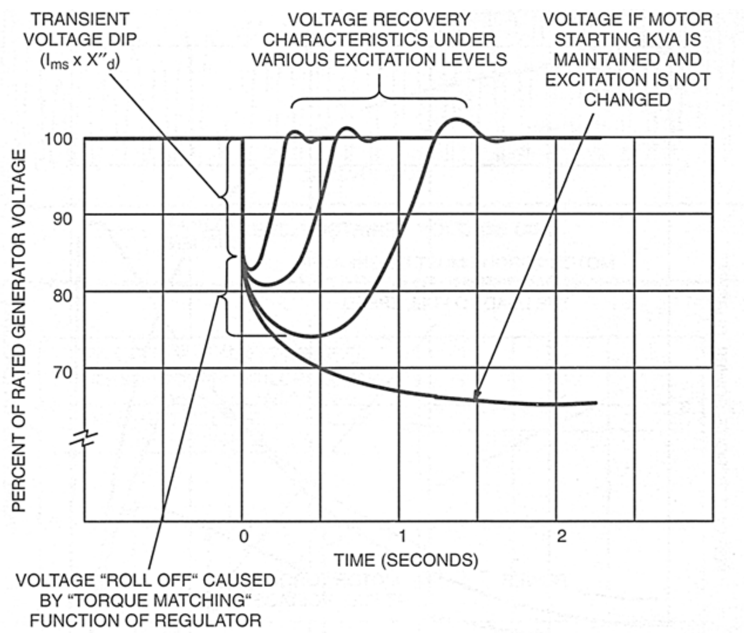
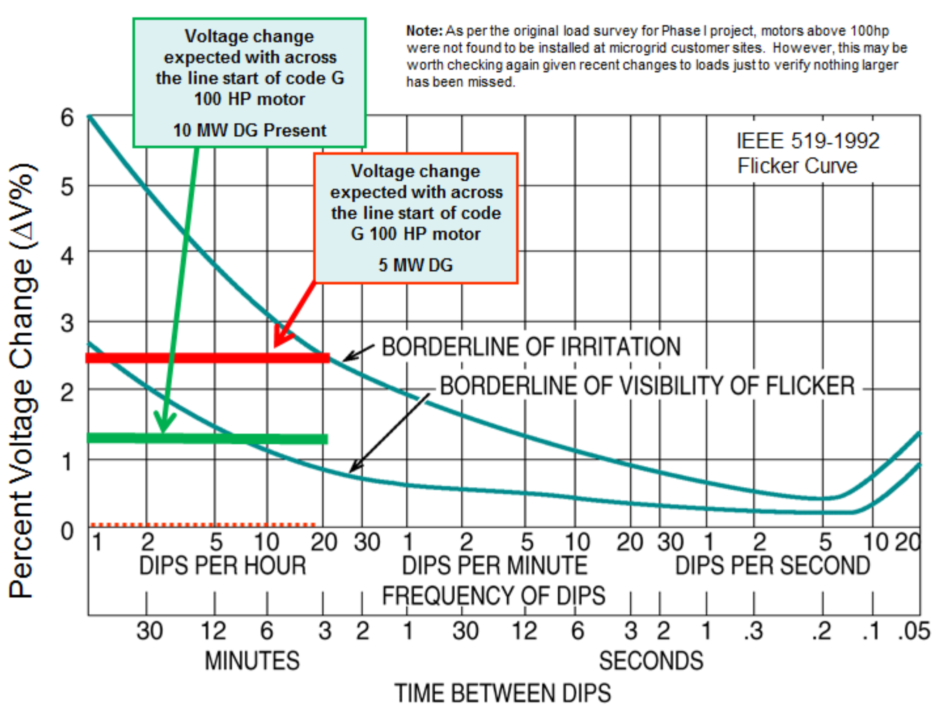


Figure 70. Example of 100 hp Motor Starting Voltage Dip Plotted on Flicker Curve

(for 5-MW and 10-MW generation scenario)



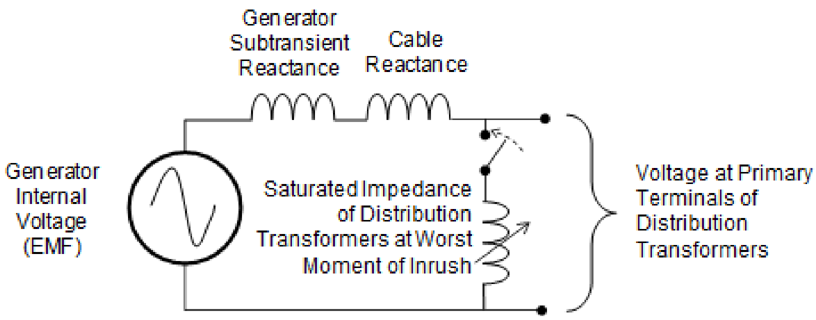
5.6.11 Voltage Sags during Transformer Inrush (Islanded)

Voltage stability during start-up of the microgrid in intentional island mode is an important factor in the system's performance. When bringing the system up from a black start condition, it is required to "assemble" the island by energizing many pad mount distribution transformer units and picking up large load blocks served by the transformers. The voltage dips which occur during this process must be limited so as not to cause the microgrid to collapse. Pad mount transformer "energization" is probably one of the most demanding aspects of islanded black start procedures. Some of the transformers are as large as 3000-kVA rating and represent a huge magnetizing inrush (with respect to the generation size).

It is difficult to gauge how much voltage dip will occur each time a large transformer and load block is energized since many parameters are impacted. The transformer magnetizing inrush varies each time due to the trapped flux level of the core (beaker closing) and the angle of energization not always being the same. Furthermore, the angles and trapped flux state can be different, resulting in different levels of inrush on each phase. It also depends on the quantity and mix of motors and other load types which add to the magnetizing inrush.

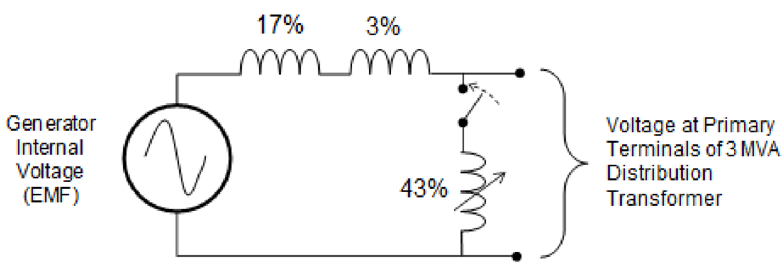
To better understand the nature of how transformer inrush impacts the microgrid generation, a model for the worst-case effect of energizing a transformer on the generator voltage is shown in Figure 71. As a rule of thumb, the moment a transformer is energized, the inrush current associated with the first cycle is about half as large as what the current would be if the transformer secondary was fully shortened. In other words, the effective value of the "saturated impedance" during the first cycle of inrush is about twice the rated impedance of the transformer on the transformer's base rating. Fortunately, this does not last long since the transformer quickly becomes unsaturated and the inrush current decays to a much lower value in subsequent cycles. The inrush process is non-linear, producing a burst mainly of 2nd, 3rd, 4th, 5th, and a few other harmonics. During the inrush, a voltage divider effect is created as shown in the model whereby the voltage on the primary terminals of the transformer (the microgrid primary) can be estimated by the voltage divider equation using the ratio of the upstream source impedance and the saturated transformer impedance (Figure 71).

Figure 71. Simple Model for Worst-Case Inrush Related Voltage Dip at Moment of Peak Transformer Inrush



To calculate the relative impedances of the voltage divider components, it is necessary to convert all impedances in the above model to the same common base. Using the 12-MVA used throughout the report, the DG source impedance consists of the generator sub-transient reactance plus the reactance of the 13.2-kV primary cable impedance to the location of the distribution transformer being energized. As an approximation, the full 10-MW block of mixed type DG sources along with the microgrid cable impedance will have roughly 17% + 3% = 20% reactance on a base of 12 MVA. These values are approximate because the exact values used depend on where on the microgrid the transformer is energized. A 3-MVA distribution transformer is the worst case that we know of at customer sites and will have roughly 43% "saturated impedance" during the initial inrush moment (on a 12 MVA base). These impedances in the model are as shown (Figure 72).

Figure 72. Inrush Model for 3-MVA Transformer Energization with Impedances (on a 12 MVA base)



The model shows that the RMS voltage on the microgrid at the transformer will dip down to about 68% of nominal voltage during the first cycle of worst-case inrush. While a dip to 68% seems severe, in practice the average voltage disturbance over many cycles and on all phases won't be nearly as bad because the inrush current decays rapidly with time and inrush conditions are not equally severe on all phases. Smaller transformers will cause proportionally less voltage dip. The load behind each transformer will cause an additional voltage dip, albeit the inrush is by far the largest component.

A big concern that we must be careful about is that the procedure for connecting some transformers will involve conditions where only part of the microgrid generation is online (not the full 10 MW). If there is only 5 MW or even 2 MW running in a zone and a 2- or 3-MVA transformer is energized, the voltage dip effect will be much larger. In those cases of limited generation, the source impedance is effectively much higher relative to the inrush resulting in more voltage dip. The dips could easily become severe enough to disrupt sensitive loads during the microgrid assembly process.

There is no getting around the fact that "assembly" of the microgrid in an island starting from a black start is going to be a rough process from a voltage perspective as the various loads and transformers are energized. There will be various voltage dips (sags) and flicker occurring, and the generator protective relays need to be coordinated to ride through the inrush but still provide suitable overcurrent protection during regular faults. This should not be an issue given that the available fault levels during islanded operation of the generator are high enough that the relays can be set above the expected inrush magnitudes and durations for the transformers. However, a procedure whereby larger transformers are not allowed to be energized until sufficient generation is available, could be helpful in limiting the voltage changes. Methods to "pre-energize" transformers behind impedance could help—there are a number of possible ways to do this. From a stability perspective, the generators can ride through many cycles of deep sag (as discussed later in the report); therefore, the inrush is not expected to be a stability problem as long as the relays are coordinated to ride through the voltage dip.

5.6.12 Inrush Levels for Various Size Transformers

S&C Electric publishes a guide for transformer fusing selection based on expected inrush levels. The guide includes curves that provide estimates for typical worst-case inrush for various size transformers ranging from small units up to multi-MVA sized units. Two of the charts in that guide (one for inrush at 0.01 seconds and the other at 0.1 seconds) are reproduced in this report for convenience and are useful in understanding the levels of inrush that could be expected from various size transformers

(Figure 73). The worst-case initial current inrush is also shown (Figure 74). Notice that the levels of inrush current shown are greatly influenced by the impedance of the energy source feeding the transformer (as determined by the ratio I_{load}/I_{Flt}).

Figure 73. Maximum Expected Inrush Currents per S&C Fusing Selection Guide

Right: During first half cycle

Left: After six cycles

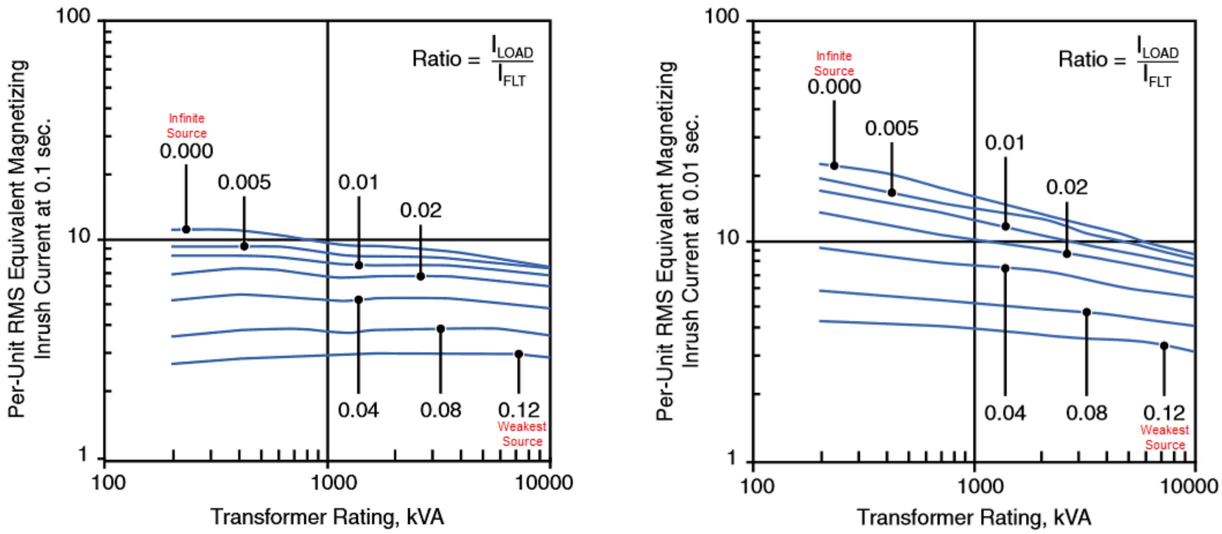
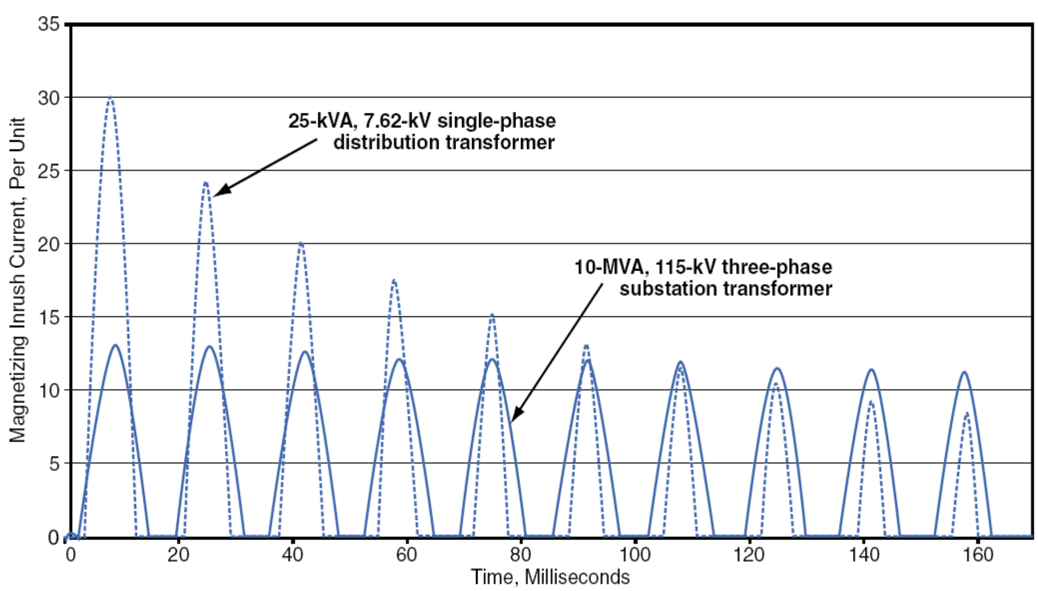


Figure 74. Worst-Case Inrush Current Profiles for Transformer Connected to Infinite Source

(Illustration from S&C Fusing Selection Guide)



5.6.13 Cold-Load Pickup

On distribution feeders there is phenomena called "cold-load pickup." Unlike magnetizing inrush or motor starts that last seconds at most, this is a longer duration current (lasting up to about 15 minutes) that can be up to twice (on residential feeders) the normal full-load current when the feeder is energized after being dead for a long time (over 20 minutes). This temporary increase in steady-state current is due to loss of diversity of thermostats within HVAC equipment and other devices that all want to be "on" when the feeder is first energized after a long outage. The load on the microgrid likely behaves more like a commercial/industrial feeder load where loss of diversity during a long power outage has less impact than on residential feeder circuits. With this type of circuit, a 2X factor would not be expected. The loss of diversity may result in perhaps up to 1.5 per unit of normal peak load, although it is difficult to say for sure. The project team will need to consider cold load in the load pickup procedure. In such situations, it might not be possible to pick up all load quite a fast as desired if it has been "cold" for some time. The solution would be simply to do more load shedding, add time delays to switch on equipment, and/or delay the energization of some sections of the microgrid by a few minutes as the cold-load subsides in areas that are already up and running.

5.6.14 Microgrid Primary Cable-Loop Voltage Target Level

During intentionally islanded operation of the microgrid, the voltage target of the 13.2-kV microgrid primary cables on a 120 V basis should be somewhere in the 120-122 V range. This is near the middle of the ANSI voltage regulation window but biased slightly above the middle. This target zone will allow some headroom for voltage rise across distribution transformers and secondary-service cables at the customer sites that have DG present. Thus, DG injecting power at such sites under most/all expected operating states of real and reactive power will not create a voltage rise so large that exceeds ANSI Range-A limit (126 V) at those sites. The 120-122 V target range leaves 4-6 V of headroom which should be adequate for the expected power flows across the distribution transformer impedance and secondary-cable impedance at generator sites. Keep in mind that some generation sites are "generation only" such as the Clarkson 2-MW PV system or the hydroelectric sites. On the other hand, many generation sites also share load and a generator on (or nearly on) a common secondary-system bus. Thus, this voltage guideline is meant to protect not just the generators but also loads from high voltage.

For load sites on the microgrid that have no generation at the site, the voltage is always going to be lower on the secondary side of the transformer. The targeted 120-122 V primary cable operating range will allow for up to 6-8 V of drop across the distribution transformer impedance and secondary service conductors, such that the voltage at those customers service entrances would be expected to always be higher than 114V (the lower ANSI range A limit) under all typical loading scenarios.

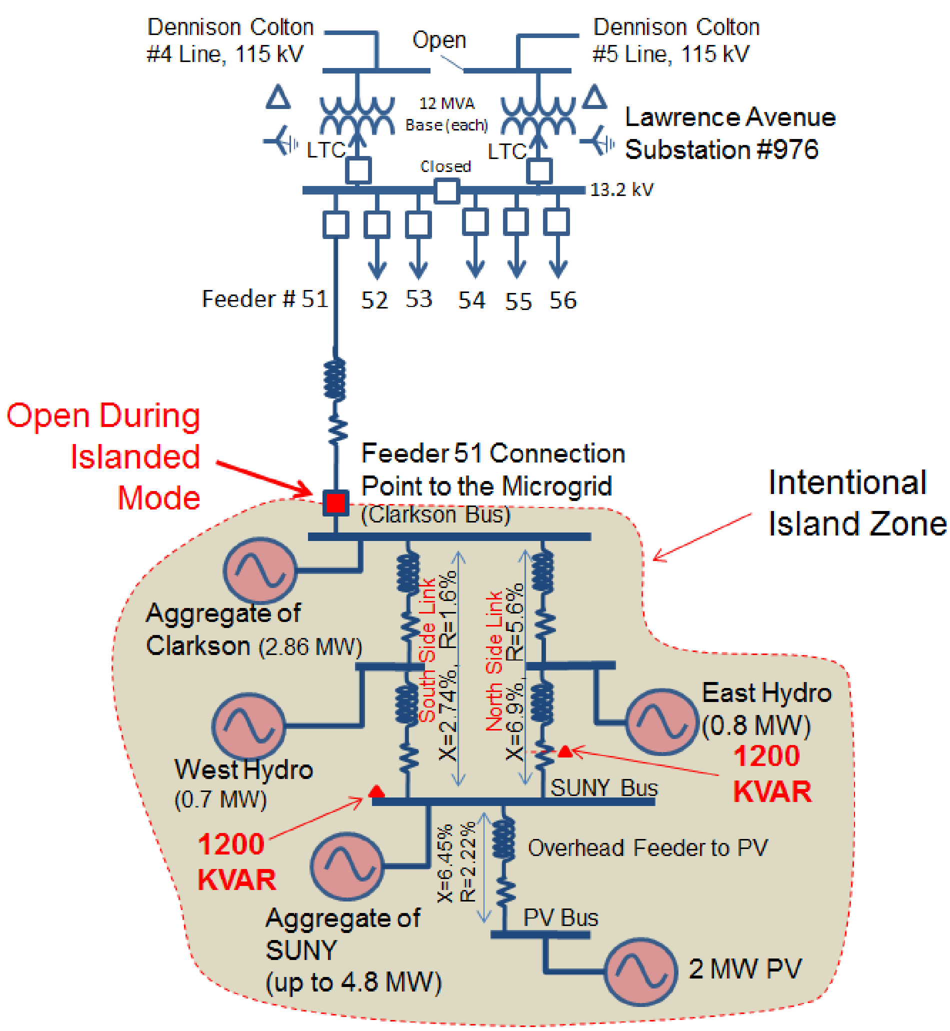
The target voltage range on the primary feeder can be maintained by having the microgrid control system continuously adjust the synchronous generator excitation level and governors of the largest machines as needed to balance power production sharing and voltage levels. While the generators at SUNY Potsdam and Clarkson are a couple of miles apart, one way to think of the situation, from a steady-state regulation perspective, is that they are connected on a fairly stiff (low-impedance bus) relative to the machine ratings as discussed in the next section.

5.6.15 Microgrid Cable Loop Thought of as a Bus

From the point of view of steady-state voltage regulation, the primary cables can be sort of thought of as a "low-impedance transfer bus" that connects two large generation sources and loads; that is, the SUNY Potsdam cluster of loads/generation and the Clarkson cluster of loads/generation (Figure 75). The other loads and sources in between are much smaller in comparison. The primary cables of the microgrid, especially the south side link between the Clarkson campus and SUNY Potsdam campus, while it does have some impedance, it must be recognize that it is quite low compared to the impedance of the generation sources and their secondary cables and distribution step-up transformers. During islanded microgrid mode, with full generation operating and all planned loads connected, no more than about 4 MW of power would ever be passed from the SUNY Potsdam side to the Clarkson side or vice versa. And even 4 MW is an unlikely occurrence—most of the time it would be less. The nature of the way the islanded microgrid is to be operated and the sizes/locations of the generators and loads do not really allow for any more than about 4 MVA under virtually all "islanding" scenarios even though the cable capacity is much higher. This is important because the impedance of the south side link is X = 2.74% and R = 1.6% on a 12 MVA basis and would be about X = 0.91% and R = 0.53% on only a 4 MVA basis. At the maximum power transfer expected during islanding, with the expected real and reactive power levels, the voltage drop across the south primary cable path is less than 1% (less than 1.2 V on a 120 V basis). The point is that it should be possible to easily maintain the 120-122 V range discussed as long as the southside cable path is available. The northside cable path has more impedance (a bit over double the south side) and would be more difficult with only that path by itself. The north path by itself would see about 2% voltage drop during a 4-MVA transfer across it. With both paths combined, if run in the closed loop mode, the drop is even less than with either path alone.

Figure 75. Islanded Operation

There is only a relatively small impedance between the SUNY Potsdam side cluster of loads/generation and Clarkson side cluster of loads/generation. Impedance shown on 12-MVA base, but the maximum power transfer across underground cables to be less than 4 MVA.



5.6.16 Voltage Changes due to PV Power Variations

During intentionally islanded operation, if the PV system is connected to the microgrid and experiencing variations in power due to partly cloudy conditions, there will be voltage changes imposed on the system. As mentioned previously, the worst-case PV variations for a 2-MW rated PV system would be 0 to 2 MW over about 30 seconds. Keep in mind the actual variations will be somewhat better (more like 60% to 80% of this nameplate rating); however, 2 MW will be utilized as a conservative measure.

Unlike motor starting currents that are sudden instantaneous demand steps, derived from a reactive current nature, the PV power variations change slowly and smoothly over several tens of seconds, minutes or even longer depending on the type of cloud shading conditions. Power may go up or down depending on whether the cloud shading arrives or recedes from the solar array field.

Another factor to consider is the tendency to run the PV inverters at or near unity power factor rather than in a state of high VAR production or absorption. Although VAR production or absorption cases are possible, it will be assumed, until further data is available, that the PV system is operating at a power factor near 1.0 ±0.02.

The above factors imply the following in the analysis:

1. The slower "smoother" power changes of PV mean that the sub-transient and transient behavior of the machine is not critical to the analysis—the way it was for motor starting. Rather, the voltage is very much a factor of the synchronous reactance of the machines, the exciter responses, the PF of the current change, and the governor response.
2. Unity PF power variations can be helpful to minimize the voltage change effects on islanded rotating synchronous machines. Unity PF is best for islanding when it comes to the voltage change that occurs.
3. The PV power fluctuations also have an effect on the microgrid frequency which indirectly influences voltage by changing the machine internal EMF as well as changing loads out on the system that are frequency dependent.

It is not possible to model precisely the voltage variation effects until the equipment settings and more details of the project characteristics are finalized in Phase II of the design project. For now, a preliminary estimate of the voltage changes that could occur for 2 MW variations and which are based on the assumptions of Table 72 is shown in that table. The estimated worst-case variations of voltage on the microgrid primary cables would be about 2% or less with those assumptions. EMTP simulations give a wide range of answers depending on which assumptions are employed. Notice that this "2%" value is with 10 MW of DG operating. If only a partial microgrid is operating, such as 5 MW or 2 MW, the changes would be larger. It is not recommended to operate the PV in parallel with the islanded microgrid unless the full generation mix is operating or unless some special provisions with energy storage are made for smaller microgrid generation quantities. The voltage change would also be somewhat higher at the PV site PCC itself.

Table 72. Voltage Change due to 2-MW PV Power Swings during Islanded Microgrid Conditions

Type of Condition	Assumptions	Voltage Change Expected on the 13.2 kV Microgrid Loop
PV with 2-MW Output Variations due to Cloud Shading	• Islanded microgrid • Full-generation scenario: 10 MW of DG operating • Unity PF operation of PV (±0.02) • 0-2 MW ramps up or down require at least 30 seconds to occur • Loads on microgrid are not frequency sensitive by more than 2% per Hz • Frequency is regulated to ±3% by governors and controls • Exciter response time is 1 second or faster • Exciters set to regulate voltage to 121 V at a measured point on the primary cable system. Measurements and adjustments made at least once every 5 seconds or faster • Uses isochronous governing	No more than 2% Voltage variations expected at 13.2 kV underground primaries. But variations would be slightly higher at the terminals of generators located behind the impedances of transformers and secondary cables

5.6.17 Frequency Regulation (Islanded)

When the microgrid is connected to the bulk power system, the impact of load steps is negligible on the frequency. However, once the system is islanded, the inertia and total rating of the generation on the island is much smaller. The frequency will be more significantly impacted by load steps. It is important to make sure that varying loads and load blocks connected to the grid do not seriously degrade the frequency regulation of the island. For satisfactory operation of the island, transient frequency dips during load steps should be no greater than ±5% (albeit a design goal is to keep these to ±3% or less).

To ensure that the frequency does not deviate too much from nominal and that the occurrences of such frequency variations are limited in their repetition rates, it is reasonable to establish guidelines for the largest load steps and repetition rates for those load steps. Table 73 is a first cut attempt to create a set of guidelines for the types of load steps that should be allowed on the islanded microgrid.

Table 73. Recommended Load-Step Rates versus Size of Load Step

Size of Load Step (L_{step}) as a Fraction of Operating ICE and Hydroelectric Generation Capacity	Maximum Recommended Daily Rate of Recurrence
Lstep ≤ 1%	No Limit
1% < Lstep ≤ 2%	500
2% < Lstep ≤ 3%	200
3% < Lstep ≤ 5%	40
5% < Lstep ≤ 7%	25
7% < Lstep ≤ 10%	8
Lstep Exceeding 10%	Should be Extremely Rare or Only During Black Start Assembly of the Microgrid

A 10% load step is considered the largest step that should be allowed frequently during steady operation of the microgrid. Base on the machine characteristics, this should limit the frequency change to within about a ±3% band around 60 Hz as loads cycle on/off (with isochronous governing). The 10% guideline is intended for cyclic loads that repeat up to 8 times per day (not hundreds of times per day). Small load steps can occur more frequently. Please also note the caveat that these are “real power steps” as related to frequency regulation, and any loads having significant magnetizing inrush, higher initial real currents, and/or high reactive current steps made need to be restricted per voltage flicker requirements discussed earlier. It is recognized that on rare occasions larger load steps than 10% will occur during islanding start-up (to assemble the microgrid) and for other reasons.

An electronic isochronous governor controller is recommended for the generators. This type of controller is the ideal because it allows the load sharing between generators to be managed while maintaining constant frequency (in the steady state) without any droop. Another type of governing that is sometimes employed, is droop governing. However, droop governing is based on the concept that the generator frequency slightly decreases as its load increases. This method allows a bank of generators (all with similar droop characteristics) to equally share load. The problem with droop governing is that as the load increases, the frequency of the entire generator bank decreases. With droop governing, it may be more difficult to keep the frequency within a suitable band for sensitive devices or devices that have tight operating windows (such as some types of UPS equipment).

As mentioned previously in the report, UPS systems come with fixed or programmable operating windows for frequency (Hz tolerance in ±%) and rate of frequency change (Δ Hz/second). If frequency conditions go outside the window the UPS may transition to its local battery source thinking that the "grid" is outside acceptable limits. Having UPS equipment unnecessarily and excessively cycle back and forth between operating modes should be avoided. A small amount of occasional cycling is okay from time to time—but constant use will wear out the equipment, the batteries, and may cause possible disruptions of the critical loads the UPS units are serving. The Table 73 step-load guidelines were in part developed to help avoid this issue.

The frequency window of operation for a UPS could be set as tight as ±1% in some critical application cases or as wide as ± 6 or even ±8% in others where equipment tolerances are not so critical. Another type of frequency tripping found on UPS systems is the "slew rate." This is the rate of change of frequency. This function may trip at as low as 0.25 Hz/sec in some applications where high slew rates cause issues or as high as 2 Hz/sec or higher in others where slew rate is not so critical. There are hundreds of UPS units of all size scattered throughout the microgrid and they likely have a wide range of frequency trip windows and slew rate tripping conditions.

5.6.18 Harmonics (Islanded)

As discussed earlier in the report, DG devices must meet IEEE 1547 guidelines for harmonics (Table 74). It is not expected that any of the generation equipment to be acquired or in use for the project will necessarily exceed the limits. However, care always needs to be exercised anytime DG is applied as a system with non-linear loads present and circuit elements such as capacitors, cables, and inductive impedances where the conditions may be present to create resonances that amplify the otherwise benign harmonic levels (amplification occurs due to the Q factor of the resonance) to magnitudes that exceed the IEEE requirements.

Table 74. IEEE 1547 Harmonic Requirements

Harmonic Order	Allowed Harmonic Current Level Relative to Fundamental Current (Odd Harmonics Only[1,2])
h < 11th	4.0%
11th ≤ h < 17th	2.0%
17th ≤ h < 23rd	1.5%
23rd ≤ h < 35th	0.6%
35th or greater	0.3%
Total Harmonic Current Distortion	5%

Notes:

1 The greater of the maximum load current integrated demand (15 or 30 minutes) at PCC without DG unit or the DG unit current capacity at PCC.

2 Even harmonics are limited to 25% of odd harmonic values.

Screening the microgrid circuit with the formulas below using the values of the cable capacitance, the capacitances of the two 1200 kVAR capacitor banks, and the possible combination of generator, cable and source transformer inductive reactance we can show that there are several possible resonances associated with low order harmonics such as the 5th, 7th, 9th, etc., that might arise.

Harmonic Order:

$$N = \sqrt{\frac{X_{c-nominal}}{X_{effective}}}$$

Harmonic Frequency:

$$f = 60\sqrt{\frac{X_{\mathrm{c-nominal}}}{X_{effective}}}$$

Harmonic Resonance Amplification Factor (Q):

$$Q = {X_{c-resonant}}/{R_{effective}}$$

Equation Parameters:

$R_{effective}$ is the equivalent combination of the line resistance and load resistance
$X_{effective}$ is the equivalent combination of the load and source inductive reactances
$X_{c\text{-}nominal}$ is the capacitor bank reactance at 60 Hz
$X_{c\text{-}resonant}$ is the capacitor bank reactance at resonant frequency

The modes in which these occur depend on the mix of generation that is running and how many capacitors are switched on, etc. The good news is that despite the direct possibility of a resonance, the circuit loading will in general be enough to dampen the Q value to well under two such that a problematic amplification of the harmonics is unlikely. The one caveat is that during situations where the grid is being assembled from black start or during extremely light loading periods, such resonances might become more pronounced due to the lack of loading for damping.

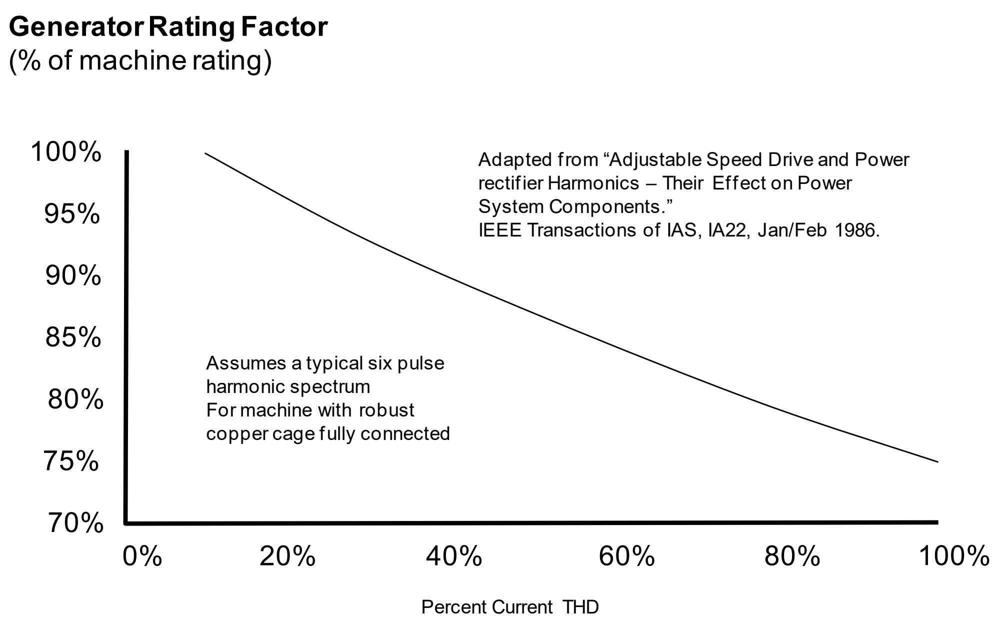
The background harmonics already present are not known by this author but may eventually need to be measured for this project to get a sense of the environment. Perhaps there is already much data available that can be used for the next phase of work. It's likely the background harmonic levels and spectrums are typical of most commercial buildings—this means moderately high but not excessively high. As a guess, the load currents may have up to 10% to 15% current distortion. Only measurements can confirm the actual level.

The ratio of available fault level (I_{sc}) to load level (I_L) is approximately 7:1 to 20:1 depending on the state of generation and state of loading at a given time. A low ratio such as this (a higher ratio such as 50 or higher would be preferable) means that the circuit voltage waveform could be vulnerable to harmonic currents imposing distortion on it if the loads have a high degree of current THD.

A factor that is helpful for harmonics on the microgrid is that the project will use separate grounding transformers (as opposed to grounded neutral generators). While the purpose of using separate grounding transformers was not related at all to harmonics, it was done for ground fault overvoltage mitigation purposes. This choice does have the ancillary benefit in that the transformers help with harmonics by alleviating the line-to-neutral load serving duty from the DG equipment and shields those devices from seeing the "triple" harmonics that appear in the line-to-neutral mode. Grounding transformers also provide a more linear source of ground current compared to many models of generators with grounded neutrals. Of course, harmonics in the line-to-line mode of the generators and the impacts of harmonic loads are still a factor to be watched, but at least from the line-to-neutral mode perspective the situation is improved by the use of grounding transformers.

Overall, at this point, there is not a particularly severe concern about harmonics other than in the lightly loaded situations where cable and power factor correction capacitances may lead to resonances. But it is clear that measurement data should be obtained to determine the background levels. If the current THD exceeds 10% with a broad spectrum, some derating of the generators may be needed. The amount of derating is small, just 10% percent for up to about 40% current THD (Figure 76). It is unlikely that current THD will be that high based on the typical THD level seen at these types of commercial and campus loads. However, a high-measured current THD would mean the voltage THD would be very likely outside IEEE limits of 5% owing to the relatively small I_{sc}/I_L ratio of the system and that a mitigation program might be needed.

Figure 76. Derating of a Generator due to Harmonics



5.6.19 Load Unbalance (Islanded)

Two types of unbalance are negative sequence and zero-sequence unbalance. Negative sequence unbalance in particular causes excessive heating of the rotor and other components due to the 120 Hz effective induction frequency caused by the counter rotating negative sequence field. Zero-sequence unbalance is due to residual current in the generator neutral and also causes added stress and heating due to its own direct contribution to the negative sequence.

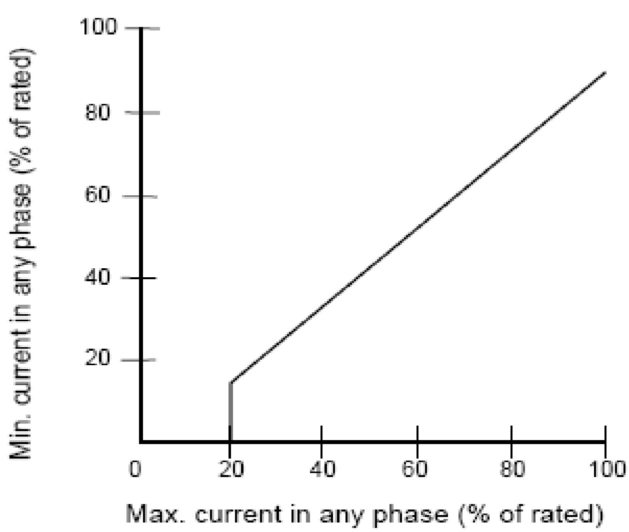
Unbalance of the load is a much larger issue for an islanded generator than one operating in grid-parallel mode. In grid-parallel mode of operation, the amount of unbalance (negative and zero-sequence current and voltage) that the generator sees is a function of the utility source negative and zero sequence voltage components imposed on the generator terminals. Even when the load current at a particular site is significantly unbalanced (say 20% to 25%), the voltage in a grid-parallel situation remains fairly well balanced due to the relatively low-negative and zero-sequence impedances of the utility source. In general, both of these sequence components of voltage unbalance are rarely if ever beyond 2% at most substations. In fact, it is not unusual for these components to be under 1%. Overall, in grid-parallel mode the utility source assumes the major role of supplying most of the unbalanced current to the load and the generators supply only a small residual amount based upon the ratio of the impedances of the machine and utility source.

Once the generators become islanded, the situation changes. Now the sources on the island must supply all unbalanced current to the load so these sources are exposed more significantly to both the negative-sequence component and the zero-sequence component of unbalance. Fortunately, in the specific case of the Potsdam Microgrid because separate grounding transformers are used (which will carry the neutral current) we the zero-sequence component of unbalance will not be a concern (although the transformers will need to be rated). However, while the use of grounding transformers does shield the generator from neutral unbalance currents (the zero-sequence component), it does not shield the generators from phase unbalance (that is the negative sequence only type unbalance). We still need to consider that type of unbalance and negative sequence is the most important factor that causes heating on the face of the generator rotors that can lead to thermal damage.

Industry standards require that machines are rated to handle up to about 10% continuous negative sequence current. If the negative sequence impedance of the machine is 0.20 per unit this translates into a negative sequence voltage of about 2%. For the islanded application the continuous negative sequence voltage at machine terminals should not be allowed to exceed 2% for any considerable length of time and the current should not be allowed to exceed 10% of the rated phase current at full load. Since the negative sequence voltage heats the rotor quickly, if the unbalance limit is exceeded, the machine can quickly overheat and be damaged if it is at or near rated load. If we reduce the load, it can handle slightly more unbalance.

A curve from one particular manufacturer for generator steady-state unbalance capability is shown below for illustration purposes (Figure 77). At 100% load the curve shows that the allowable negative sequence unbalance is up to 10% (i.e., 100% × [1-90/100]). At a loading of only 20% of rated load the curve shows that the difference between minimum and maximum phase current is up to 25% (i.e., 100% × [1-15/20]). While this curve is specific to one particular manufacturer's machine, it is fairly representative of many machines. The load-unbalance condition at the microgrid load sites are not known at this stage. In the Phase II effort, data can be assessed to determine if the unbalance levels are a threat and require any sort of mitigation.

Figure 77. Negative Sequence Unbalance Capability of a Typical Generator



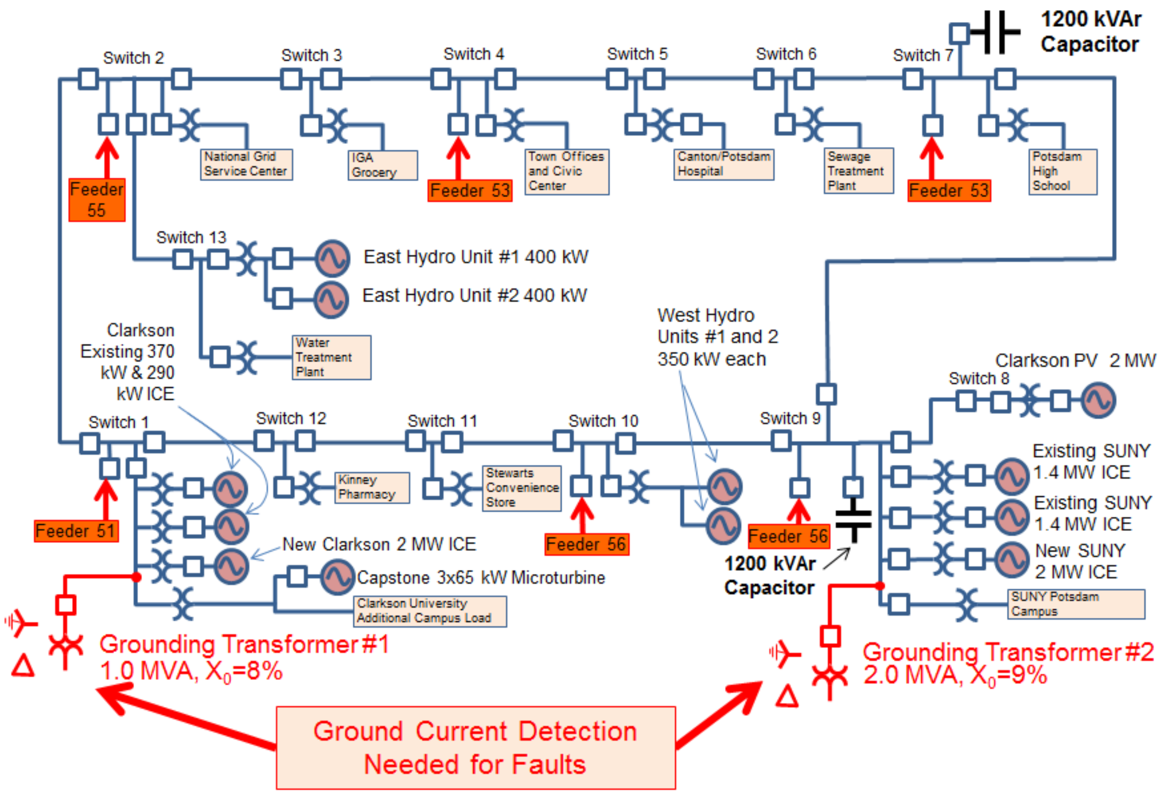
5.6.20 Microgrid Effective Grounding (Islanded)

The effective grounding scheme for the microgrid was discussed earlier in the grid-parallel section of the report. However, its operation in the intentionally islanded mode must be considered as well. As mentioned in section 5 of the report, the two selected grounding transformers (Units #1, 1 MVA, X_0=8 and Unit #2, 2 MVA, X_0=9%) will be sufficient to provide effective grounding on the system with all generation running with COG=72% or less. During islanding mode (intentional or not) when ground faults occur, the maximum voltage on the island due to neutral shift on the unfaulted phases won't exceed 131% given this type of grounding. The 131% figure excludes the effects of any load rejection overvoltage which can add to the effect of the grounding.

As shown in Figure 78, the use of two grounding transformers sized for the generation on the SUNY Potsdam and Clarkson sides of the system allows the microgrid to operate each side independently if desired. It also serves the needs of the initial black start and assembly of the grid from its subparts, such that it can start with two separate effectively grounding islands, which then can be assembled together into a full microgrid. In the full-grid mode, the two grounding transformers and any other ground sources will share the zero-sequence current in proportion to their relative impedances. The zero-sequence impedance of the actual cables on the microgrid is roughly one-tenth to one-twentieth the impedance of the two grounding transformers, such that the cable impedances play a minimal role in the division of current.

Figure 78. Microgrid Effective Grounding Scheme

Provides two zones of neutral grounding from which to assemble the grid to full capacity or operate as two separate islands.



Also shown in Figure 78 is the fact that the ground current flow due to loads and ground faults will mostly flow back through the grounding transformers and not through the generators (since most or all other generators are not effectively grounded.) The SUNY Potsdam generators are an exception The generators, while not effectively grounded, have a resistive grounding that is low enough to allow a significant amount of ground current to flow back through those two generator units—consequently not all the current is going to go through the two grounding transformers.

As part of the control scheme of the microgrid, it is desirable to measure the current and voltage conditions at the grounding transformers and to install some protection on them that will be useful for certain functions. For one thing, the micorgrid can indicate if they are online or not (such that microgrid operation can be disabled if they aren’t online). In addition, current transformers (CTs) in the grounding transformer neutral wires can sense the ground current flow and use that information to determine the total neutral current flow from a steady-state loading and a transient-fault current protection perspective. The flow levels will tell the controller how much zero-sequence unbalance load current is present on the system, and ground faults can be detected, and the major DG sites can be tripped due to such faults if needed. Voltage sensing can also be used combined with current sensing to detect certain types of malfunctions within the grounding transformer. The ground current waveforms measured from these points would also tell the controller something about the nature “triple” harmonics as well; triple harmonics are the 3rd, 6th, 9th, etc., which are zero-sequence harmonics carried in the neutral path.

An important factor to be considered in the design and installation of grounding transformers is that anytime there is a large grounding current source present, there will be zero-sequence currents coming through the earth/neutral wires to the sources concentrated in that location. During ground faults this can cause some potential rise locally and the transformer site will need to be treated somewhat like a small substation in that regard. There are several IEEE standards that apply to grounding of substations and energy sources. These include IEEE 80-2000 which is the document IEEE Guide for Safety in AC Substation Grounding. There is also IEEE 487-2007 which is the document IEEE Recommended Practice for the Protection of Wire-Line Communication Facilities Serving Electric Supply Locations, as well as IEEE 1590-2009 the IEEE Recommended Practice for the Electrical Protection of Communication Facilities Serving Electric Supply Locations Using Optical Fiber Systems.

The important factors the IEEE standards address are to make sure the design of the installation avoids any step and/or touch potentials that could be dangerous and make sure any telecommunication and data lines coming into the “zone of influence” are adequately protected if the potential rise exceeds a certain voltage threshold of concern. Usually that threshold of concern is a 300 V rise or higher for zone modeled around the unit where some sort of isolation on telecommunication cables is needed if a metallic communication line should pass within the zone.

5.6.21 DG Plant Stability (Grid-Parallel and Islanded)

An important parameter is how stable the DG plants of the microgrid will be when subjected to power system disturbances such as deep voltage sags. These disturbances could be the result of faults on distribution cables within the microgrid or faults originating on the distribution circuits external to the microgrid or out on the 115 kV transmission systems.

In grid-parallel mode, it is beneficial if the microgrid generation can ride through short duration disturbances, especially those associated with voltage sags due to faults on the 115-kV transmission system. This ride-through capability helps the plant continue to provide power system support during and immediately after a bulk power system fault has occurred and has been cleared by circuit breakers.

On the other hand, in islanded mode, stability is also important because if a cable section internally within the microgrid becomes faulted it is desirable for the nearest circuit breaker devices to sectionalize out the faulted section without the microgrid fully collapsing. For pickup of large loads (particular those with inrush or a large-load block during grid assembly), it is beneficial to handle the largest possible inrush/load steps without losing stability and collapsing.

Generator stability is predicated on the dynamics of the balance of the prime mover's mechanical rotating shaft input energy, the generator's electrical output energy, and the stored inertial energy of the machine's rotating mass. Just prior to an electrical disturbance (a deep-voltage sag) the prime mover power input is essentially in balance with the electrical power output, so the machine is spinning at constant speed. If the electrical output of the machine should drop (due to a voltage sag) the machine rotor will start to accelerate because the prime mover cannot ramp down its power to match reduced electrical output (at least not instantly, it takes a few seconds until the engine governor can force a response). Until the governor can match input/output power, electrical output will be less than mechanical input, and the machine speed accelerates, increasing the rotor power angle. If the angle advances too much, the DG could lose synchronism with the other generators on the system and become unstable. The DG would need to be tripped offline just prior to becoming unstable so it does not slip a pole and get damaged by the extreme forces on the shaft.

The basic concept of generator acceleration/deceleration during the voltage sag is illustrated in Figure 79 as a power angle curve that looks like a half-wave sinusoid. This curve represents the output power of the machine versus what is known as the rotor power angle (δ). When the machine is operating at a steady-state power level at nominal voltage, the upper curve applies. It will be running at a fixed power angle (δ at t=0) which is typically 20 to 30 degrees at rated machine power but varies based on machine design. At sudden reduced power due to sagged voltage, such as a power of roughly 50% in the example of Figure 79, the lower power curve applies. During the fault period of reduced voltage, the power transfer from the machine is reduced but the prime move is still putting in power at the prior power level, so the machine will accelerate storing the excess energy from the prime mover as rotational inertia (orange shaded area). The power angle increases during this period. After the fault is cleared, the voltage returns to essentially what it was before, and the unit gives back the excess energy it collected from the prime mover (this is the decelerating period). As long as the decelerating area (shaded green) is large enough to counter the accelerating area, the machine will be stable. If that is not the case, it will continue to swing until slips out of synchronism. You can see from the sinusoidal shape of the power curve that if the rotor accelerates too much during the accelerating period, it is impossible for the remaining decelerating area to counter the advance of the rotor. For the DG, the interest lies in understanding what sort of voltage sags depths and for how long they need to last before the generator stability is lost—before it reaches a critical angle of instability.

A screening criterion recommended to CEA to help assess the stability of a particular DG connection point on the system is the ratio of the available utility-source short-circuit MVA at the DG connection point to the rated MVA of the DG[12](Table 75). For the Potsdam Microgrid project this ratio is calculated based on the available fault level multiplied by nominal voltage at various points on the system. At the microgrid Feeder 51 tie point (near Clarkson), the utility short-circuit MVA is about 70 MVA and the total aggregate rotational machine DG plant connected to that node is rated at about 10 MVA (excludes inverters and induction generators). The ratio between these two parameters is a factor of seven. But the "effective ratio" is closer to 10 when we consider that the various DG plants are operating at less than the sum of the full nameplate power rating during grid-parallel operation. CEA guidelines suggest that for a ratio of between 5 and 20 rotor power angle swings up to $\Delta\delta$=35 degrees can be tolerated (as measured starting from fault initiation to fault clearing) without losing stability.

Figure 79. Generator Stability Concept

Upon fault initiation, the DG accelerates until the fault is cleared, then it decelerates until the energy lost in the deceleration period is equal to the energy gained in the acceleration period.

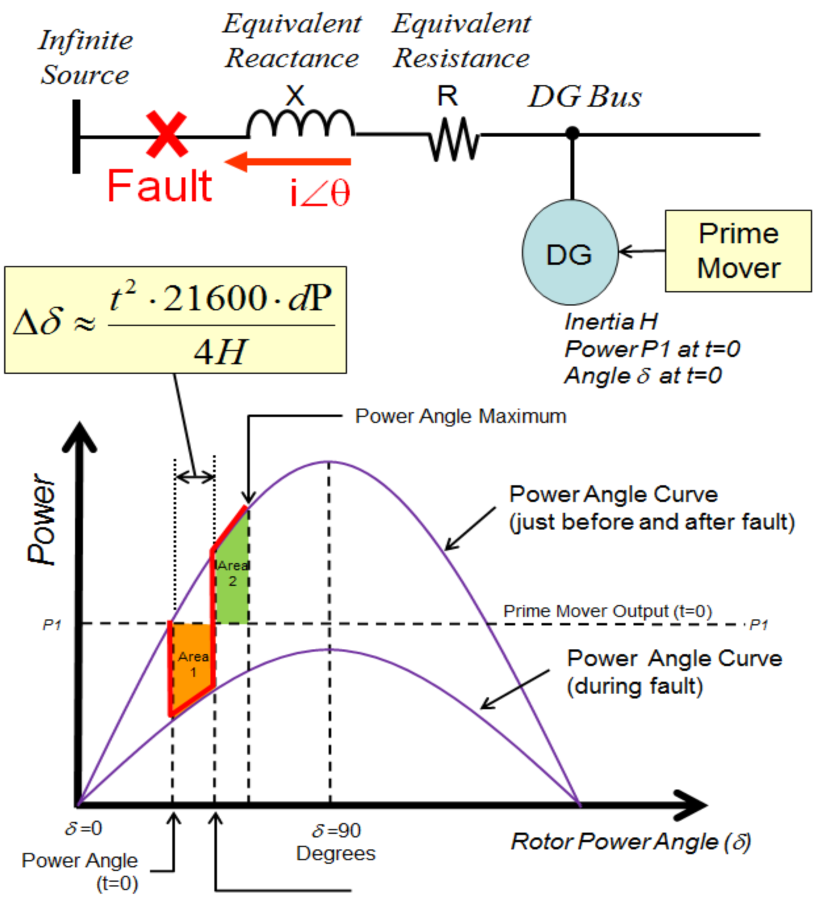


Table 75. CEA Stability Screening Criteria

Maximum recommended power angle swing for various ratios of utility system short-circuit MVA to DG machine MVA.

Ratio of $MVA_{SCutility}/MVA_{rated\text{-}DG}$	Maximum Recommended Change in Power Angle ($\Delta\delta$ in degrees)	Stability Condition
Ratio ≥ 20	50°	Less Sensitive
5 ≤ Ratio < 20	35°	Moderately Sensitive
3 ≤ Ratio < 5	25°	Most Sensitive

A screening formula CEA recommends for calculating the increase in rotor power angle ($\Delta\delta$) for a sagged voltage condition is given by the following:

$$\Delta\delta \approx \frac{t^2 \cdot 21600 \cdot d\mathrm{P}}{4H}$$

In the equation, $\Delta\delta$ is the rotor power angle change (from fault initiation to fault clearing), t is the duration of the fault in seconds, dP is the change in generator power with respect to full-rated, apparent power of the machine, and H is the inertia constant of the machine. The factor 21,600 is a constant that takes into account various unit conversions and machine physics in order to provide an output ($\Delta\delta$) in "degrees."

With the machine parameters expected for the Potsdam Microgrid DG units, the screening formula can be used to determine how long the machines will remain stable for a given fault condition on the system (Table 76). As stated earlier, the maximum recommended change in power angle is $\Delta\delta$=35 degrees according to the ratio of $MVA_{SCutility}/MVA_{rated\text{-}DG}$ at the microgrid point of connection. To be conservative for the Potsdam project a $\Delta\delta$=25 degrees or less limit is shaded in green in the table and 35 degrees or less includes the orange and green areas. If we stick to the green areas only, the generators can successfully ride through very deep voltage sags, causing a change in power (ΔP) of 90% and maintain stability if the voltage returns to near normal within about sisx cycles. It is also evident that the shallower voltage sags (such as those that cause ΔP of 50%, 20%, or only 10%) allow greater ride-through time before stability is lost. For example, with a shallow voltage sag that results in ΔP=20% there is about 13 cycles of ride-through time before leaving the green zone.

Table 76. Stability Analysis

Change in rotor angle for various fault durations and power change levels is shown (number of cycles needed for 25 degrees and 35 degrees).

Cycles of Fault Duration	Δδ Rotor Angle in Degrees at Moment of Fault Clearing for the Indicated ΔP Condition			
	Very Deep Voltage (ΔP=90%)	Deep Voltage Sag (ΔP=50%)	Moderate Voltage Sag (ΔP=20%)	Mild Voltage Sags (ΔP=10%)
5	16.2	9.0	3.6	1.8
6	23.3	13.0	5.2	2.6
7	31.8	17.6	7.1	3.5
8	41.5	23.0	9.2	4.6
9	52.5	29.2	11.7	5.8
10	64.8	36.0	14.4	7.2
11	78.4	43.6	17.4	8.7
12	93.3	51.8	20.7	10.4
13	109.5	60.8	24.3	12.2
14	127.0	70.6	28.2	14.1
15	145.8	81.0	32.4	16.2
16	165.9	92.2	36.9	18.4
17	187.3	104.0	41.6	20.8
18	210.0	116.6	46.7	23.3
19	233.9	130.0	52.0	26.0
20	259.2	144.0	57.6	28.8
21	285.8	158.8	63.5	31.8
22	313.6	174.2	69.7	34.8
23	342.8	190.4	76.2	38.1
24	373.2	207.4	82.9	41.5
25	405.0	225.0	90.0	45.0
26	438.0	243.4	97.3	48.7
27	472.4	262.4	105.0	52.5

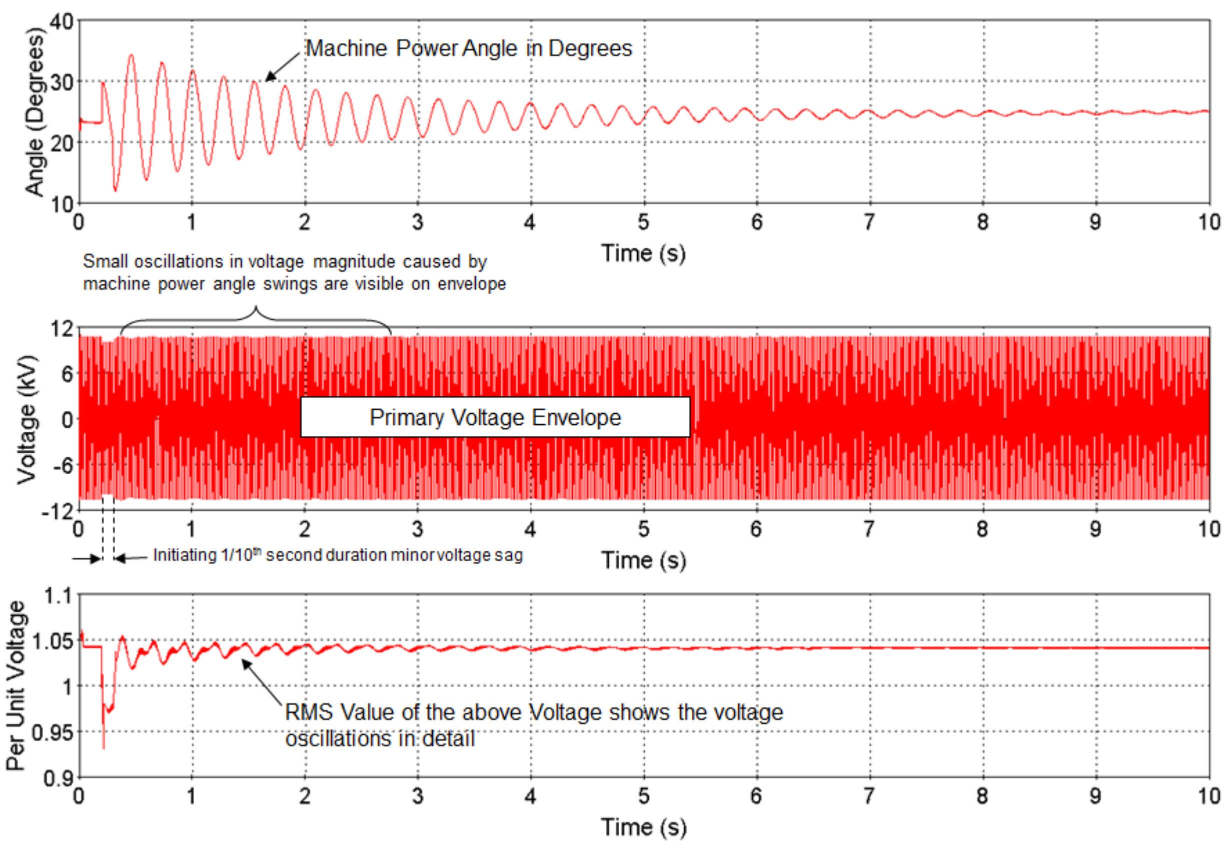
Extra Conservative Stability Limit (Δδ < 25 degrees)

Screening Guideline Stability Limit (Δδ < 35 degrees)

Since this is a preliminary analysis and there are several unknowns that had to be assumed at this stage, the time durations in Table 76 should not be considered the final set of clearing times to use for the project. But they do give a guideline for the sort of clearing times to work with in the final, more detailed design. Given the expected incoming transmission voltage sag durations and expected depth of sags, the allowable sag durations of the table show that we can set the protection to ride through many of the shorter external disturbances that are most critical for the bulk system ride-through. For an internal fault within the microgrid on the cables, the sag would be very deep and more difficult to ride through. But even in such a case, the numbers show that high-speed switchgear might be able to clear a faulted cable zone before the grid collapses. Whether this internal robustness is needed is a separate issue since internal faults would be rare.

As an example of a stability simulation, Figure 80 shows an EMTP simulation of a mild stability disturbance showing the power angle (Δδ), the 60 Hz voltage waveform, and RMS voltage of that waveform. A six-cycle duration mild voltage sag imposed on several megawatts of ICE DG plant connected on a bus with impedance similar to the Clarkson Feeder 51 PCC. The initial machine power angle (δ) is about 23 degrees for the loaded machine and the change (Δδ) in power angle remains well within the stability limit criteria.

Figure 80. EMTP Simulation of the Stability Response of an ICE Generator to a Mild Voltage Sag



5.6.22 Energy Storage for Stability and Seamless Transition

There is interest in applying energy storage on this project for a number of different purposes. These include the following:

- Enhancing frequency regulation
- Improving stability
- Mitigating voltage changes
- Seamless transition to islanded status from the grid-parallel mode

Regarding frequency regulation, a relatively small amount of energy storage of 30 seconds up to, at most, a few minutes at 50% to 90% of the load step amount could be effective for the microgrid to mitigate changes in frequency due to loads steps and PV variations. This amount of energy storage would be particularly helpful during microgrid black start and assembly into a larger microgrid where significant load steps are occurring. For example, to smooth the 2-MW load steps, the power rating of the device would need to between about 1 MW to 2 MW and it would need to have 30 seconds up to several minutes of energy storage deliverable at that power level.

Energy Storage also could be used during load-rejection events. A very fast acting storage device (with one to two cycle response time) could absorb excess energy and stabilize the system frequency so as to improve voltage and dynamic stability. Figure 81 shows an example of an ICE generator with H inertia value of 1.5 and the effect of a full loss of load at the terminals.

Figure 81. EMTP Simulation of Load Rejection on an Example 2-MVA (1.6 MW) Generator Showing the Sudden Rise of Frequency

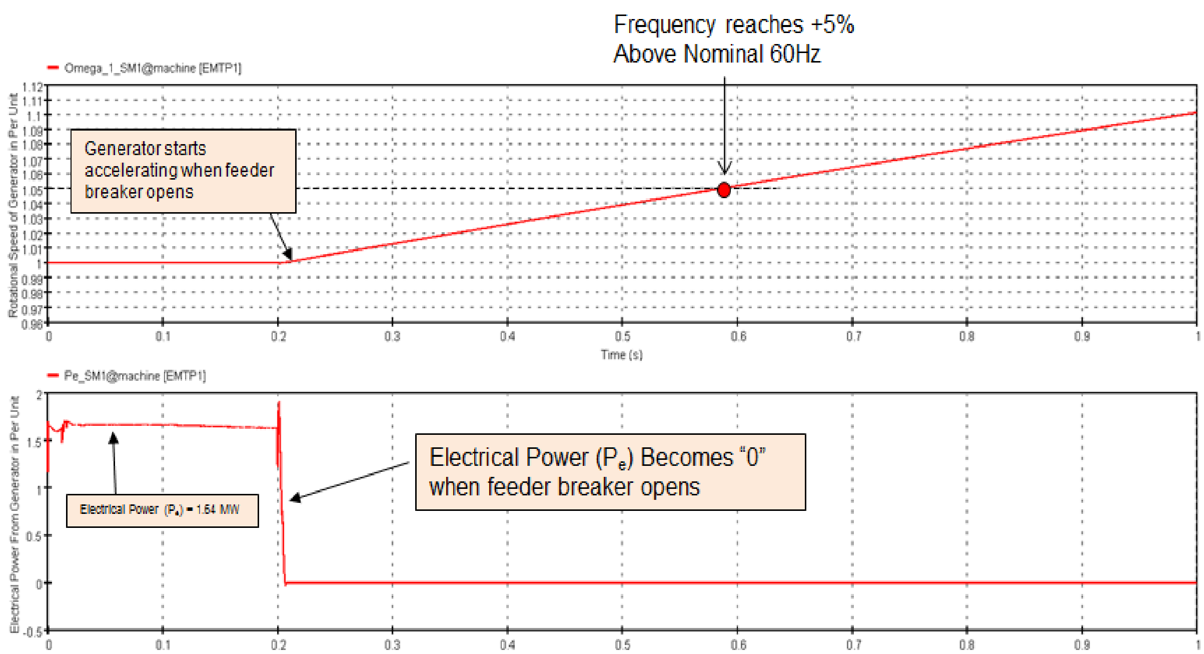


Figure 81 demonstrates how rapidly the speed runs away following the loss of load. The frequency has already reached +5% above nominal within 0.4 seconds of the event and the unit would need to be tripped off. A fast-acting load absorption device rated at about 1.4 MW in the 1.6 MW machine case example could absorb most of the excess energy and slow down the frequency acceleration to such a degree that the governor would have time to reduce throttle and prevent the over-frequency condition.

Regarding voltage changes and flicker due to typical loading steps, it is true that storage can help, especially in situations where the impedance causing the voltage variations has a very low X/R ratio. However, it is also true that in the vast majority of situations it is usually more cost effective to use dynamic reactive power control rather than energy storage to mitigate voltage issues such as flicker. Most locations on the power system have sufficient X/R ratio of the sources such that real power storage is not necessarily needed. A high-speed dynamic VAR compensation can be done with a static compensator (an inverter that produces or absorbs VARs) or with inverters that have the capability and are part of PV systems or other devices. The Potsdam 2-MW PV inverters almost certainly have that capability already to a certain extent depending on the brand and type (although it is likely not being used right now). It is also noteworthy that rotating synchronous machines themselves can dynamically vary the VARs at fairly high speed (but not as fast as inverters). The rotating machines will be suitable for filtering out voltage fluctuations of about one second or longer duration using the exciter response. For faster filtering, such as is needed with load steps due to motor starts, a higher speed VAR correcting inverter is more appropriate and can filter voltage changes as rapidly—within a cycle or two. Inverter products associated with energy storage can usually perform real power control (±watts) and reactive power control (±VARs) and thus operate in what is referred to as “all four quadrants” of power.

Perhaps the most demanding of the energy storage applications under consideration at the Potsdam Microgrid is to do a seamless transition from grid-parallel to islanded state. This requires a very large amount of energy storage (kWh) and storage power capacity (kW) such that it would not likely be practical on this project. Such a device would likely cost millions of dollars at current market prices for the equipment (see discussion of details later in this section). The microgrid project has up to about 10 MW of loading that needs to be picked up instantly, and it may require 5 to 30 minutes of support at that level to make all the operating decisions and get all the generation available and functioning.

Whether the storage needed is 5 minutes or 30 minutes would depend on the extent of automation in the microgrid generation start-up and switching process as well as the various human response time and decision-making factors. If it was highly automated and reliable, perhaps only 5 minutes of storage at about 10 MW would be needed for the process. A more manually oriented switching process that involves manual decision making could require up to 30 minutes of storage. Table 77 summarizes some of the storage applications discussed.

Table 77. Some Energy Storage Applications for the Potsdam Microgrid

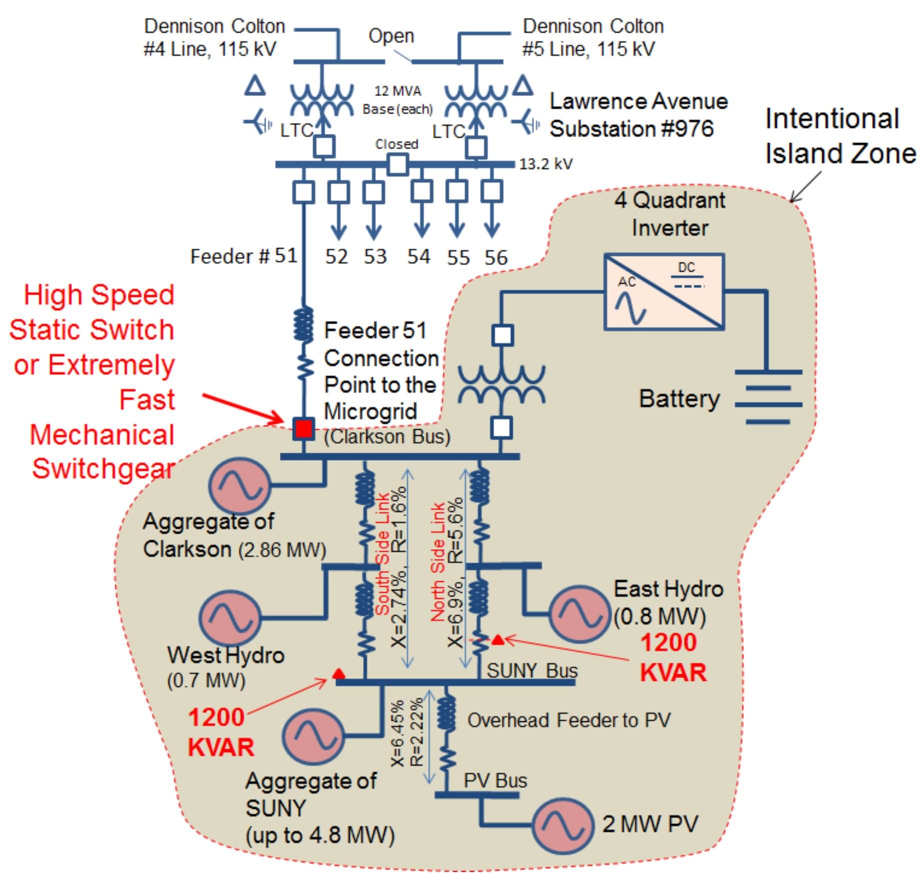
Type of Energy Storage Application on the Potsdam Microgrid	Amount of Power Capacity Recommended	Duration of Storage Needed at the Recommended Power Level[1]
Enhance Frequency Regulation Under Mild Disturbance Conditions	50-90% of the load step of concern	30 seconds to a few minutes
Improve Load Rejection Voltage and Generator Sag Stability	25 to75% of real kilowatts load on the island	5 seconds to 30 seconds
Mitigate Voltage Changes	Use reactive power instead (although real power can help in low X/R ratio feed point applications)	
Seamless Transition	110% of the peak demand of load to be carried at the time seamless transfer is desired	5 to 30 minutes

Note 1: The actual energy required is equal to the product of the time shown in this column multiplied by the power capacity needed in the adjacent column. However, that is for *ideal* storage devices with no limitations on discharge rate or charging rate, and no internal losses. For non-ideal devices, like batteries, losses can be high at high rates and the amount of energy (kWh) may be considerably higher to reach a stated power level due to battery heating limits and other factors.

Regarding the location of energy storage, the underground primary cables of the resilient microgrid will act somewhat as a low impedance transfer bus compared to the impedance of the generation and the loads on the grid. This means the energy storage could be placed anywhere on the microgrid primary cables and could even be distributed at multiple sites rather than one location if desired—and still accomplish its objectives as long as a proper control system is in place.

The seamless transition concept would involve a configuration as shown in Figure 82. To do seamless transfer with the storage requires a large capacity storage device with fast switchgear (or static switch) that can deliver the expected generation to load mismatch at the time of the separation to microgrid mode. If no generation running at the time is assumed and the system is at peak load, somewhere on the order of 10 MW or a bit more might be needed depending on the speed of load shedding. As stated earlier, up to 30 minutes storage at that power level might be required if generation is expected to be slow to dispatch. On the other hand, as little as 5 minutes is possible with a highly automated dispatch and control system. ICE generators can be brought online quickly (within 10 seconds or so) if they are preheated and pre-lubricated, but 5 minutes is still a good margin of storage to provide flexibility in dealing with reclosing and operating dispatch decisions, etc.

Figure 82. Equipment for "Seamless" Transition to Intentionally Islanded Microgrid Mode



Regarding the term "seamless transition" there are several degrees of seamless transition that could be considered depending on how much money is to be spent and how much complexity and power quality desired. Options are illustrated in Table 78.

Table 78. Different Grades and Reliabilities of Seamless Transfer

Type of Seamless Transfer	Waveform Condition that Gets Through to the Microgrid	Equipment Required
Pure Seamless Transition	A minor switching perturbation 1/16th to 1/4th of a cycle duration	• 13.2 kV rated high power static witch (SCRs or IGBT • Energy Storage with 4-Quadrant inverter • Step-up transformer • Controls and ancillaries
Quasi-Seamless Transition	Up to 3 cycles of very deep voltage sag conditions or outage conditions (but DG if running can ride though) per stability analysis	• 13.2 kV, 3 cycle total clearing time high speed mechanical switchgear • Energy Storage with 4-Quadrant inverter • Step-up transformer • Controls and ancillaries
Quasi-Seamless Transition Relying on High-Speed Load Shedding without Storage	3 cycles of deep voltage sag condition but risk of system collapse if generation to load mismatch not quickly corrected	• 13.2 kV, 3 Cycle total clearing time high speed mechanical switchgear • High speed load shed controls and ancillaries

The first approach in the table, the pure seamless transition, would give the best waveform and employs a solid state high speed switch (often referred to as a static switch). It uses solid state switching elements such as SCR or IGBT devices, it would need to be rated at 13.2 kV and handle at least the full 10-MW power loading at the tie point. It also would need high-speed controls. There would be a 10 MW four quadrant inverter with energy storage and related balance of system elements. Such a scheme could transition from grid-parallel mode to islanded mode almost instantly with only a very tiny perturbation of the waveform (perhaps a sixteenth to a quarter of a cycle at most). The big drawbacks here are cost, complexity, and equipment availability. The whole package would likely cost many millions of dollars—perhaps even $10 million considering development efforts. A big drawback is availability of components such as the 13.2 kV static switches. And there is a risk of nuisance transfer events that fail to successfully transition owing to the complexity of the technology.

Figure 81 demonstrates how rapidly the speed runs away following the loss of load. The frequency has already reached +5% above nominal within 0.4 seconds of the event and the unit would need to be tripped off. A fast-acting load absorption device rated at about 1.4 MW in the 1.6 MW machine case example could absorb most of the excess energy and slow down the frequency acceleration to such a degree that the governor would have time to reduce throttle and prevent the over-frequency condition.

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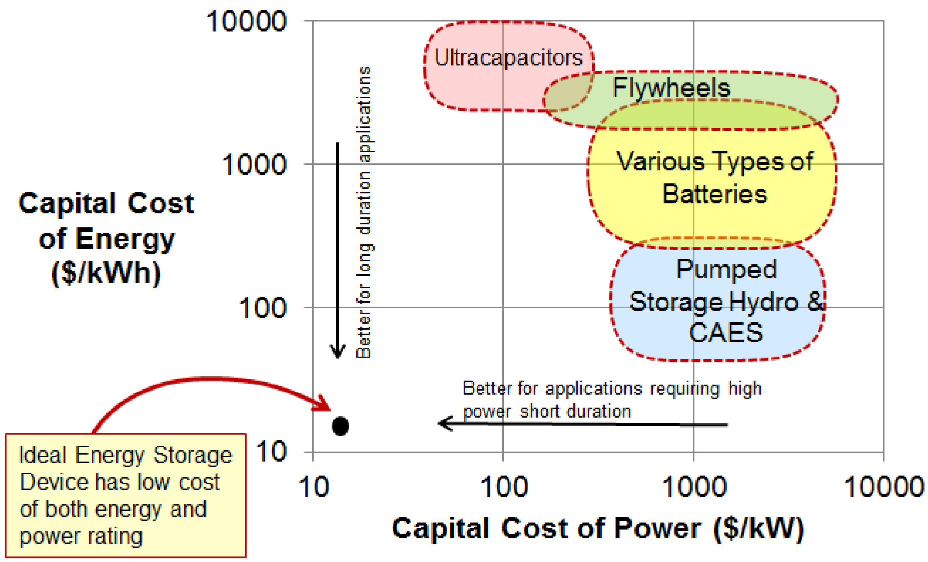
5.6.23 Type of Energy Storage Technology

There are three main energy storage technologies that are applicable in the Potsdam Microgrid application for the options we have discussed here. These would be batteries (of various types), advanced high-speed composite flywheels, and ultracapacitors. The technology that is most suitable depends on the ratio of the power storage (kWh) required to power capacity (kW) that is required. For applications that require high power for short periods, such as one minute or less, the use of ultracapacitors can be competitive. For applications involving longer durations of many minutes, flywheels and batteries probably make more sense than ultracapacitors. For applications going much beyond 15 minutes, batteries make the most economical sense considering the three technological option. Figure 83 shows the costs of the three energy storage technologies plus pumped storage hydro and compressed air energy storage. It is noteworthy that many are improving rapidly, and this chart may become obsolete soon.

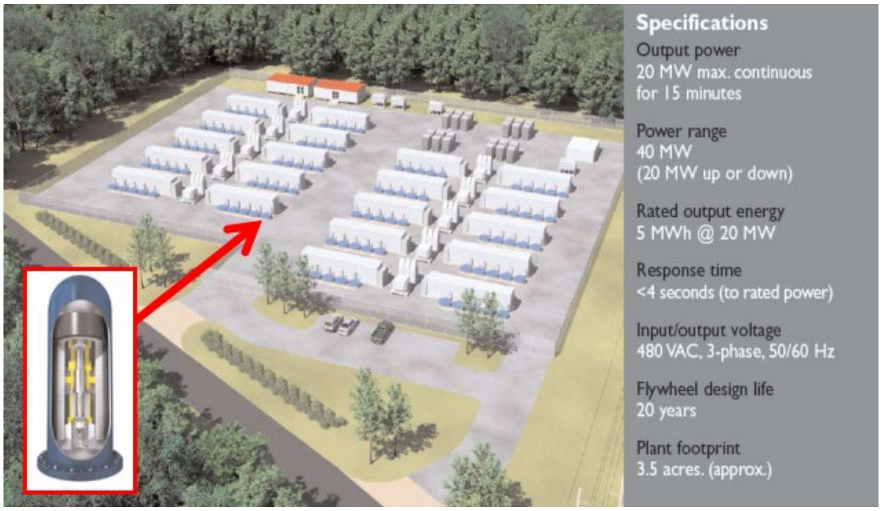
Figure 83. Energy Storage Costs

(Based on an average of data adapted from the Energy Storage Association)



An example of an energy storage product is the Beacon Power Smart Energy Matrix Flywheel System shown in Figure 84. This technology could be suitable for frequency regulation, voltage regulation, transient PV cloud shading mitigation, etc. The plant shown is larger than needed for the Potsdam Microgrid. Each of the "shipping containers" with 5 associated flywheels has 1 MW capacity. One or two of those shipping containers would be ideal for frequency regulation, voltage regulation, transient PV, and cloud shading mitigation on the Potsdam Microgrid.

Figure 84. Beacon Power Smart Energy Matrix Flywheel System



The battery market is also seeing a huge amount of progress with various types of batteries, including sodium chemistries, flow batteries, advanced lead acid, and lithium-ion approaches. Perhaps lithium-ion batteries are getting more attention than any other battery technology due to their high-energy density from a weight perspective (kWh per kg), making them the preferred battery for electric cars. But many vendors are making lithium battery products now for electric power storage ranging from residential scale (a few kWh) up to hundreds of megawatt-hours. For example, Tesla has a number of lithium-ion products as shown below (Figure 85 a and b) that could be applicable to the Potsdam grid. The Tesla products could be scaled anywhere from their smallest home sized unit (13.5 kWh, 5 kW Powerwall II) all the way up to the size needed (10 MW) to do the pure seamless transfer approach.

Figure 85. Tesla Scalable Battery Products that Could Be Suitable for the Potsdam Microgrid Project

a. Small Scale: Tesla Powerwall 2: 13.5 kWh, 5 kW Continuous (multiple units can be paralleled)

b. Large Scale: 210 kWh, 50 kW Continuous (multiple units can be paralleled to scale up)

5.6.24 Should Energy Storage Be Used at All?

The conclusion of this analyst is that options like "pure seamless transition" are simply gold-plated options that are too expensive and not appropriate given the project and its objective to provide only standby power to microgrid customers and not seamless UPS grade power.

Some of the other lesser applications mentioned—such as energy storage assisting with frequency regulation during load steps as well as energy storage mitigating PV variations and helping with microgrid start-up procedures—can make some sense in this project. While we do not necessarily need the storage support for these functions, since analysis shows the project can get by without it, its presence would still certainly improve the operational flexibility and the power quality to some extent. These are tangible factors but quantifying their value and determining whether or not there is a positive cost/benefit relationship is more difficult. The kilowatt-hours of energy storage needed for the applications are discussed in Table 77 from an ideal sense, where the storage device has no limits on charge or discharge rates or internal losses. Ultracapacitors in this regard would be favorable since they have very low internal losses at high-charge/discharge rates. Other technologies, such as lithium-ion batteries would require somewhat higher energy capacity than the ideal values of the table because the internal heating would be too damaging with the ideal ratings. Factoring in the typical discharge rates that are suitable for lithium batteries, the storage functions discussed in this paragraph for the three applications other than the seamless transitions could be accomplished with about 1 MW of power capacity and 250 to 500 kWh of energy capacity of lithium-ion battery storage.

5.7 Dynamic Studies and Power Quality Analysis Conclusions

This study has reviewed a range of power quality and dynamics factors associated with the Preliminary Design of an Underground Resilient Microgrid in Potsdam, NY. The microgrid operates in two main modes (grid-parallel and islanded operation) and the key conclusions of the study have been broken down into those categories. The findings are summarized in this section.

5.7.1 Microgrid General Characteristics

The conceptual details of the microgrid were provided in the main body of the report. However, to facilitate the discussion in this summary section, a condensed version of the key characteristics is provided in the Table 79 below.

Table 79. Summary of Potsdam Microgrid Characteristics

Microgrid Characteristic	Range of Expected Values
Expected Number of Customers	Initially 14 Customer Sites ± 3 sites: Two college campuses, a hospital, key governmental offices, some critical town commercial services, and a few commercial power generation sites
Full Microgrid Loading (MW and MVA)	9 or 10 MW Maximum, 3-4 MW Minimum 11-12 MVA Maximum 4-4.5 MVA Minimum (At least 80% of the load is at SUNY Potsdam and Clarkson Campus Sites—all other loads are much smaller than the campuses)
Splitting of Microgrid	At times it can split into two microgrids (SUNY Potsdam east side of river and Clarkson west of river)
Substation Bulk Power Source (National Grid Company)	Lawrence Avenue Substation (Station #976) 115 kV: 13.2 kV substation with 2 x 12 MVA-base rated transformers, 2 buses (bus tie switch closed), 3 feeders on each bus (feeders 51 through 56)
13.2 KV Microgrid Tie Point	Feeder 51 is the design's main focus (Alternative tie points include feeders 53, 55, and 56)
Main Microgrid Cables and Geography	All main 13.2 kV microgrid primary cables are underground in loop configuration with sectionalizing options. Areas served spans roughly two miles long, east-west by about one mile wide north-south.
Maximum Full-Rated Generation on Microgrid	11.155 MW (but actual peak generation will be roughly 10 MW) Includes 7.46 MW ICE, 2 MW PV, 1.5 MW Hydro, 195 kW microturbine
Modes of Operation Expected	Grid-parallel mode (More than 99% of time) Islanding on an unplanned basis (much less than 1% of time) Islanding on a planned basis (much less than 1% of time)
Seamless Transition from Grid-Parallel to Islanded Mode?	No. This is not recommended for the project, but options are discussed in the reported. Expect outage time during transition of 5-30 minutes.
Energy Storage	Not necessary, but can be helpful to regulate frequency and stabilize grid
Power Quality Expectations	Microgrid will mitigate longer duration interruptions due to ice storms, wind storms lightning, etc. There is no expectation of mitigating short disturbances such as momentary interruptions, voltage sags, etc.

5.7.2 Grid-Parallel Microgrid Key Conclusions

In utility grid-parallel operation, the analysis shows that the microgrid should work well and that there are no major problems. However, there are a few items of concern that can be addressed with straightforward design solutions as the project moves forward. Below is a summary of the concern in each category of analysis along with solutions.

5.7.2.1 Steady-State and Dynamic Voltage Regulation in Grid-Parallel Mode

The most important issue identified is that the Feeder 51 feed point impedance where it ties to the microgrid is high for the expected total power loading at that point. This feed point is heavily loaded in the proposed microgrid arrangement since it now carries both SUNY Potsdam and Clarkson load as well as other loads (currently it only has Clarkson load). With the extra loading comes much more voltage variation than is desired. The loading seen at Feeder 51 tie point could vary from a peak load with no generation running of over 10 MW import to over 5 MW export if all generation is running at light load—this is a 15 MW spread. In addition, VARs could vary widely as well at Feeder 51 depending on the desired VAR export/import modes of operation, making the ensuing voltage change even larger. The various voltage issues identified, and possible solutions are listed below (Table 80).

Table 80. Voltage Regulation Conclusions & Recommendations

Issue Category or Location	Grid-Parallel Voltage Issue Solutions/Comments
115 kV Level Transmission	• No Issues identified (voltage impact of 10 MW of microgrid generation is too small to be significant at this level)
Substation LTC	• Substation LTC might experience reverse power at light load during full generation – Make sure controls are set at LTC controller to handle export if it should ever occur (this is a simple check of settings)
Microgrid Tie Point Impedance of Feeder 51	• Upgrade Feeder 51 to reduce its impedance • Use an alternative feeder with lower impedance (Feeder 53 or 56) • Consider adding a step voltage regulator bank at Feeder 51 tie point to deal with voltage swings • Curtail generation export (Volt/Watt function) and/or use dynamic reactive power capabilities of largest machines to help control the voltage (such as fixed power factor mode absorbing VARS, or Volt/VAR function)
1200 kVAR Capacitor Banks	• Use switched capacitors rather than fixed to avoid overcompensation at times of light load (this is also especially needed for islanded operation and black start procedures)
Voltage at Generators and Regulation Mode of Generators	• Coordinate carefully any “close-loop” voltage regulation modes of generators with upstream LTC. Or use open-loop methods instead. • Ramp large generators slowly (over 2 minutes or more) • Be on lookout for high-terminal voltage at generators (use generator curtailment, fixed power factor mode to absorb VARS, etc., as solution)
Voltage Regulation Across Underground Cables (between SUNY Potsdam and Clarkson side)	• If the tie point impedance and other factors above are solved, the voltage regulation along the actual underground cables themselves will be excellent because that impedance is relatively low

5.7.2.2 Impact on Fault Levels and Protection in Grid-Parallel Mode

The fault levels on the utility primary system are going to change as a result of the microgrid. For some situations they will double or triple and for others they will go down depending on the numerous operating scenarios. For grid-parallel scenarios, there are a wide range of possibilities that include which tie feeders are used (51, 53, 55 or 56) and how much generation is in parallel with utility source at a given time. Table 81 captures a summary of the various factors and issues discussed in the body of report that need to be considered.

Table 81. Chart of Fault Current and Protection Conclusions

Voltage Level or Zone of System	Possible Fault Current Issues with Existing Utility Equipment and Recommended Further Study for Phase II
115 kV Transmission	During grid-parallel mode there is potentially up to about 315 A additional fault current contributed by the DG at the 115-kV level. For phase II we will need to evaluate the impact of this on the zone tripping accuracy of the 115-kV line.
13.2 kV Lawrence Avenue Substation Transformer and Feeder Circuit Breakers	During grid-parallel mode a 2,800 A contribution to faults on the 13.2 kV substation bus comes from the DG and can add to the utility current. Roughly a 20% increase compared to utility source alone. Factors to consider: • Evaluate effect on interrupting capacity of bus tie, feeder breakers, and other devices • Evaluate coordination effects on tripping times of bus tie and feeder breakers • Substation transformer low-side and protection and high-side switches (if reverse relaying) • Sympathetic trip evaluation (feeder breakers and bus tie breaker) • Desensitization of feeder ground fault relaying
Distribution Transformers	Primary side fault levels will change considerably at customer distribution transformers (anywhere from half the present values to triple the present values). Transformer fusing should be checked to make sure transformers that see increased current and need current liming fuses will get them.
Secondary Side at Customer Sites	Fault levels will change at the secondary side of DT units and at customer service panels. Sites with large distribution transformers are influenced the most. Check interrupting capacity of secondary breakers as well as coordination as appropriate.

Overall, there are a number of issues that will need to be studied in Phase II of project (Table 81) as the final details of the DG configuration become available.

5.7.2.3 Unintentional Islanding Protection (Grid-Parallel Mode)

The study determined that sufficient generation is present relative to load in the several possible unintentional islanding zones that could form if the utility source circuit breaker should open. These include the following:

- The entire Feeder 51 zone
- Any of several alternative feeder zones (if an alternative feeder is used such as 53, 55 or 56)
- Zones created by opening the microgrid tie breaker, with any of the feeder possibilities
- Multi-feeder islanding involving one or both transformer busses at the Lawrence Avenue Substation

These possible islands will need DTTs to the largest ICE generator units to disable them in a timely fashion. DTTs are recommended for SUNY Potsdam's large existing 1.4 MW units (they already have them) as well as the two new proposed 2-MW ICE units to be installed. The report also identified that there may be sufficient generation to pose an islanding threat to the 115-kV high side of the station and the transmission lines which might require DTT there as well. However, data is needed on the protection settings and loading on that side of the system to determine the risk level and mitigation needs. The speed of the DTTs need not be time-coordinated to shut down the DG before the utility breaker opens but it should still be relatively fast to reduce fault energy contribution to arcs and reduce heating of faulted cables, etc.

5.7.2.4 Ground-Fault Overvoltage (GFO)

Ground fault overvoltage was identified as a problem for the microgrid since existing distributed generation is not effectively grounded and the load to generation level is not high enough to suppress GFO. The following choices were examined as possible solutions:

- Implement time-coordinated DTT (on largest ICE units)
- Effective grounding of each large ICE generator on the system
- Emulation of effective grounding by means of adjacent grounding transformers on the microgrid in the appropriate locations

To solve the issue at the 13.2 kV level of the system, the third option, use of adjacent grounding transformers was determined to be the best approach. A 2 MVA, X_0=9% Impedance unit is recommended at the SUNY Potsdam side and 1 MVA X_0=8% unit is recommended at the Clarkson side. This combination of transformers provides operational flexibility, avoids retrofitting existing DG sites (which would be difficult) and provides effective grounding for the intentional islanding mode as well. An outstanding issue that still needs to be resolved in Phase II of the study is the possibility of GFO at the 115-kV level. At this stage, we do not have sufficient loading/generation and protection scheme data to determine the need at that level. However, it is possible some form of protection and/or some other mitigation may be required as well.

5.7.2.5 Ground Fault Relaying Desensitization and Ground Potential Rise

Ground fault relaying desensitization caused by the recommended grounding transformers will be severe. Those two sources and the existing SUNY Potsdam generators as well will divert the majority ground fault current, thereby impacting the protective relaying functions for feeder ground faults protection. Adjustments to utility feeder ground fault relaying settings will likely be required. Also, some ground potential rise will be present at these sources during ground faults. Appropriate design of the units and nearby telecommunication wireline devices will be needed per IEEE standards discussed in the body of the report.

5.7.2.6 Load Rejection Overvoltage (LRO)

The analysis in the body of the report shows that there will be some load-rejection voltage rise present when the microgrid tie circuit breaker (or feeder circuit breaker) suddenly opens and isolates the microgrid when export of power (watts and VARs) is in progress. However, based on examining the amount of expected generation surplus under most scenarios and the planned DTT protection scheme, the load rejection will be relatively mild and not likely more than 20% voltage rise for far less than half a second. Situations to watch out for would be when there is a large surplus or real and especially reactive power present in the microgrid zone. While a 20% voltage rise for less than half a second is benign, it can be more serious if combined with a ground fault overvoltage (which is a possibility). If power must be exported, the load-rejection voltage rise can be eliminated entirely by allowing only the export of real power and having a moderate compensating import of VARs in the microgrid zone. A time-coordinated transfer trip can also be an approach to mitigate the LRO, but it is not likely needed in this case as long as real and reactive power levels are carefully managed.

5.7.2.7 Low Voltage Ride-Through and Under-Frequency Load Shedding

For grid-parallel mode operation, if the aggregated Potsdam Microgrid generation is to act as a bulk system resource at times, its protection response will need to be coordinated with the under-frequency load shedding scheme of the bulk power system. It also needs to ride-through the short duration bulk transmission fault related voltage sags. The stability analysis indicates the microgrid can likely ride through very deep six-cycle sags and eight-cycle sags of 50%.

5.7.3 Islanded Microgrid Key Conclusions

In the intentional islanding mode of operation, the analysis also shows that the microgrid can work well, as long as careful consideration of several factors in the operation of the system are heeded. Some items of concern that should be addressed as the project moves forward are discussed below.

5.7.3.1 Island Start-Up Procedure

A microgrid start-up procedure is provided in the first part of section 5.5 for both a black start situation (utility power out) and a transition to islanded state from an operating utility system. The procedure points out that during black start, care needs to be exercised to bring the microgrid up in blocks and not subject generation to too large of a load step or transformer inrush all at once. Recommendations are provided for synchronizing parameters for generation blocks and the size of load steps and transformer blocks to be brought online. There is also some concern about the capacitors and resonances as the microgrid is assembled. Care needs to be exercised in the way load is brought online to minimize these types of effects.

5.7.3.2 Fault Levels (Islanded Mode)

The primary fault levels on the islanded microgrid system will vary greatly depending on how much generation is operating. The scenarios range from about 2 MW all the way up to 10 MW of generation. When all generation is operating, the fault levels are similar to the utility Feeder 51 source alone with its present impedance. However, fault levels become much less with only partial generation and may be a bit low for the protection settings employed at some existing customer service panels (especially customers with the largest distribution transformers).

5.7.3.3 Voltage Regulation and Flicker during Islanded Mode

During islanded mode, the generators (especially in partial microgrid modes where only 2 to 4 MW are running) will not provide voltage regulation as suitable as the utility system for a given size load step due to the higher impedance of the generator source. The transient voltage regulation of the generator is expected to be roughly two to three times more sensitive to current fluctuations than the utility grid running alone. To help minimize voltage fluctuations, it is recommended for the full-microgrid generation scenario that across-the-line motor starts be limited to no more than 100 hp and soft start motor applications are limited to no more than 200 to 400 hp depending on the soft-start settings. A listing of load-step, block-size, and repetition rates is provided in Table 73.

5.7.3.4 Frequency Regulation

The frequency regulation on the microgrid island will be poorer than when the National Grid bulk system is connected. To limit frequency excursions once the island is established and stably operating, the largest real-power, load variation steps should be limited to no more than 10% of the connected and running DG capacity (in the maximum DG scenario about 1000 kW real-power step). This should keep frequency variation to within ±3%. A listing of load-step, block-size, and repetition rates is provided in Table 73. During the island start-up, limit the power steps on the island to no more than 20%, which should keep the variations within about a ±5% band during that period as the island is constructed. Use of isochronous prime mover governing is recommended to help maintain a narrow frequency operating window. Review the operating frequency limits and slew-rate trigger settings for its UPS equipment and, for units that have adjustable settings, make sure they are set as broadly as the connected critical loads allow. This will reduce unnecessary UPS cycling during frequency excursions. Customers may need to be educated on UPS procedures and response.

5.7.3.5 Harmonic Distortion in Islanded Mode

The microgrid likely has the usual non-linear load environment expected at commercial buildings and facilities of this nature. The aggregated THD of the current at such environments might be roughly 15% THD or less. However, there is no way to know this for sure without evaluating measurements. The best locations to measure the existing loads (prior to construction of the microgrid) would be at the points of common coupling of the Clarkson and SUNY Potsdam campuses. Also, using the existing CTs at the feeder heads at Lawrence Avenue Substation (Feeder 51, 56, etc.) could give an overall representation of what sort of currents to expect. Table 82 summarizes the key points.

Table 82. Summary of Harmonic Findings for Islanded Operation

Harmonic Topic of Interest	Findings and Recommendations
Existing Distortion Levels	The existing THD of the harmonic currents are likely to be 15% or less. But a measurement program is recommended to determine this for sure (perhaps a database of measurements already exists?)
Generator Derating to Serve Harmonics	A derating curve that serves as an illustration of a typical machine's capability was provided in the body of the report. As long as the distortion is 10% or less no derating would be needed.
Harmonic Resonance	Several low-order resonances have been identified but will not likely be an issue unless Q is high. Procedures to avoid high Q resonance can be utilized – or filter mitigation applied.
Low I_{sc}/I_L ratio	The low ratio of between 7:1 and 20:1 means that harmonic current distortion more easily impresses itself on the voltage waveform. Care should be exercised to watch this condition and make sure than the *voltage* THD does not exceed IEEE 5% specification.

5.7.3.6 Generator Unbalance Capability (Islanded Mode)

The generator unbalanced current load capability is at least 10% at maximum rated loading on the machines. However, at lighter loads it will be a more. One curve from a generator manufacturer discussed in section 6 suggests that there is 10% capability at full load with the capability gradually increasing as loading becomes lighter, such that it is 25% at a very light load. If the loading on the microgrid is within these limits it is unlikely there will be unbalanced load issues. Negative sequence voltage unbalance should be watched to make sure it is not much beyond about 2%.

5.7.3.7 Effective Grounding and Ground Fault Overvoltage (Islanded Mode)

As discussed in the grid-parallel conclusions/summary section, the use of separate grounding transformers (one at Clarkson and one at SUNY Potsdam) has been determined to be a good approach. This provides neutral voltage stabilization during unbalanced loading. The grounding transformers handle the zero-sequence current (alleviating the requirement that the generators handle it), and during ground faults the transformers prevent GFO. The use of two units as positioned at the respective campuses allows the microgrid to split in subparts. The transformers will need protection and ground fault current detection coordinated with the system controller.

5.7.3.8 Microgrid Stability (Islanded Mode)

DG units should be able to ride through deep voltage sags up to six cycles and even longer for less severe voltage sags (see the stability section in body of the report). If a fault occurs on the underground cables of the microgrid, the ability to ride through sags up to six cycles should provide ample time to use high-speed fault clearing (with instantaneous relay tripped circuit breakers) that could isolate the faulted section without having to drop the entire microgrid. While the high-speed fault clearing is an interesting feature, it is not clear what the need is in the practical implementation of the grid, since the chance of a cable failure during islanded operation is low and even if it did occur, the grid could simply be shutdown, the cable section *manually sectionalized out* and then the grid restored through the black start assembly procedure.

5.7.3.9 Energy Storage Application (Islanded Mode)

Energy storage is not necessary for this particular microgrid because it should be capable of handling the expected loads steps. Nevertheless, a small amount of storage (about 1,000 kW capacity rating, able to provide that output/input for about 2 minutes) would still be helpful to improve the frequency regulation due to load steps, PV variations, and various load transients during the assembly procedure of the microgrid. The high-speed dynamic reactive power support capability of the inverter used for the storage device could also help with voltage as well. For batteries, the actual amount of energy storage needed will be higher than the product of 1000 kW × 2 minutes due to the allowable discharge rates of batteries.

5.7.3.10 Seamless Transition from Grid-Parallel to Intentional Island

Several seamless transfer approaches for unexpected utility system outages were discussed in section 6 of the report. However, none of them are considered worthwhile in this analyst view, given the complexity and cost of the equipment and the fact that the objective of the microgrid is not UPS grade power but rather it is a simpler standby-generation grade of power where interruptions in the transition are considered acceptable. In addition, seamless transfer adds a degree of risk where rapid decisions to separate from the bulk grid are required, resulting in potential nuisance activation, which could cause more issues than it solves.

6 Microgrid Mode Scheduling, Reliability, and Benefits

The results reported in this section support the detailed design and performance analyses discussed in prior sections. Clarkson University conducted this portion of the study.

There are three components of research reported in this section:

- Microgrid optimal scheduling, considering both main grid-on and islanding modes
- Reliability analysis of the microgrid when in islanding mode
- Benefits to the community from an improved restoration rate

Optimal scheduling of the microgrid will provide the ability for the microgrid to maximize the economic benefits of the microgrid during normal grid-connected operation. During islanding mode, performance optimization will provide the performance metrics that will allow the microgrid to allocate its limited resources for the greatest benefit to the community. We present a general framework for the analysis to support specific implementation of this method to the Potsdam Microgrid during the course of the grid development.

The ability to operate reliably in islanding mode is a key parameter of the microgrid. The methodology for determining the maximum load that can be served with 98% availability is presented, followed by analysis of competing generation scenarios to identify the most effective configurations for new generation added to the microgrid.

Finally, we present an analytical method for predicting the microgrid's benefit to the greater community as a result of serving the critical community loads—such as emergency services and support for service restoration crews—and improving restoration response.

6.1 Introduction

Microgrids are introduced to address the integration challenges due to the emergence of a larger number of distributed energy resources (DER) and further address ongoing energy, economics, and environmental challenges by making smarter power grids. A microgrid, which is technically a small-scale power system with the ability to self-supply and island, provides a distributed local intelligence for the power system to supply loads in a reliable and economic manner as discussed in D. E. Olivares (et al) [1-5].

Microgrids introduce unique opportunities in power system operation and planning, such as improved reliability by introducing self-healing at the local distribution network and lowering the possibility of load shedding, higher power quality by managing local loads' demand response, reduction in carbon emission by the diversification of renewable energy sources, economic operation by reducing power transmission costs and utilization of less costly energy sources, offering energy efficiency by responding to real-time market prices, reducing the total system expansion cost by deferring investments on new generation and transmission facilities, and providing a quick and efficient response for supplying load in remote areas. The salient feature of a microgrid is its ability to be islanded from the main power distribution network. Islanding is typically performed to rapidly disconnect the microgrid from a faulty distribution network to safeguard the microgrid components from upstream disturbances and allow an uninterrupted supply of local loads. It is also performed to protect voltage sensitive loads from significant voltage drops when a quick solution to main grid voltage problems is not imminent. The microgrid is economically operated in grid-connected mode; however, sufficient capacity should always be available in case that microgrid is required to switch to the island mode. The microgrid is islanded from the main grid using upstream switches at the PCC when needed, and the microgrid load will be fully supplied using local resources.

6.1.1 Microgrid Resource Scheduling

The microgrid scheduling in grid-connected and islanded modes is performed by the microgrid master controller based on security and economic considerations. The master controller determines the microgrid interaction with the main grid, the decision to switch between grid-connected and islanded modes, and optimal operation of local resources. The microgrid optimal scheduling performed by the microgrid master controller is considerably different from the unit commitment (UC) problem solved by the ISO for the bulk power grid. Variable distributed generation resources and energy storage systems play major roles in microgrid operation due to their considerable size compared with local loads. In addition, generation resources are close to loads and power is transmitted over medium or low voltage distribution networks; hence, the network congestion would not be an issue in power transfer. A considerable percentage of local loads could also be responsive to price variations, which makes the microgrid load/generation balance more uncertain. Finally, when grid-connected, the main grid could be regarded as an infinite bus with unlimited power supply/demand, which enables mitigating power mismatches of microgrid through power transfer with the main grid. The main grid could further provide reserves for the microgrid operation when predicted variable generations are not materialized or load forecast errors are high. However, the optimal microgrid scheduling and the UC problem in the main grid share a common objective, that is, to determine the lease cost operation of available resources to supply forecasted loads while taking prevailing operational constraints into consideration. Although sharing a common objective, the aforementioned differences would not allow a direct use of existing UC methods to the microgrid optimal scheduling problem. The rapid development and deployment of microgrids call for new methodologies to comprehensively model all the active components in microgrids and particularly focus on microgrid islanding requirements when the main grid power is not available.

The microgrid optimal scheduling is extensively investigated in the literature. The state-of-the-art energy management system (EMS) architectures for microgrids are reviewed in a study by D. E. Olivares, C.A. Canizares, and M. Kazerani [15], where centralized and distributed models are identified as common microgrid EMS schemes. The centralized EMS collects all the required information for the microgrid scheduling and performs a centralized operation and control [16-20]. While for the distributed EMS, however, each microgrid component is modeled as an agent with the ability of discrete decision-making. The optimal schedule is obtained using iterative data transfers among agents [21-23]. Both centralized and distributed EMS schemes offer benefits and drawbacks, but the centralized model is more desirable as it ensures a secure microgrid operation and is more suitable for application of optimization techniques when applied on a single-owner microgrid with enough system observability and constant operational goal. The main drawbacks of the centralized scheme are reduced flexibility in adding new components and extensive computational requirements [24]. As one of the most important capabilities of microgrid, the islanding studies are also extensively conducted. A. Seon-Ju and M. Seung-II [25] propose an economic dispatch model for a microgrid which applies additional reserve constraints to enable islanding. C. Gouveia, J. Moreira, C. L. Moreira, and J. A. P. Lopes [26] present a load management model to improve microgrid resilience following islanding, considering the microgrid limited energy storage capability and frequency response. A method to determine the amount of storage required to meet reliability targets and guarantee on island-capable operation with variable generation is proposed in a study by J. Mitra and M. R. Vallem [27]. In a study by C. Gouveia (et al), storage systems are applied in the microgrid to balance power, smooth out load, reduce power exchange with the main grid in the grid-connected mode, and ensure successful transition to the islanded mode. However, how to seamlessly transfer from the grid-connected model to islanded model is still an open question in microgrid operation, which highly depends on the ride through requirement of the specific microgrid design.

This report studies a centralized microgrid optimal scheduling model which considers both grid-connected mode requirements and islanding mode requirements. The object is to minimize the day-ahead, grid-connected operation cost of the microgrid using available local generation resources, energy storage systems (ESS), flexible loads, and the main grid power, subject to prevailing operational constraints. The solution is examined for its islanding capability to ensure the sufficient online capacity of microgrid for quickly switching to the islanded mode if required. An islanding criterion is studied to demonstrate the resiliency of the microgrid to operate in variable time of islanded mode. An iterative model based on the Bender decomposition is employed to decouple the grid-connected operation (as a master problem) and islanded operation (as a subproblem). The iterative model significantly reduces the problem computation burdens and enables a quick solution. The microgrid operation is modeled as a mixed integer programming (MIP) problem and solved using commercial MIP solver.

The studied model in this report is developed specifically for microgrids, which efficiently considers the uncertain microgrid islanding (from islanding time and duration standpoints) requirement in the microgrid optimal scheduling problem. This model enables the microgrid to operate in the islanded mode and adequately supply the local loads with unknown time and extent of the main grid disturbances. The islanding duration is considered via a specific criterion: a 24-hour islanding event, which refers to the possible islanding event that takes 24 hours long. The proposed decomposition framework could reduce the computation burdens and makes the studied model suitably applicable to centralized microgrid EMS schemes.

Section 6.2 outlines and introduces the microgrid components, section 6.3 presents detailed modeling of microgrid components associated with optimal scheduling, and section 6.4 presents the numerical simulations for microgrid operation during both grid-connected and islanded modes. Illustrative examples are presented in section 6.6 to show the effectiveness and efficiency of the studied model on a real microgrid.

6.1.2 Microgrid Availability

Microgrid reliability analysis has attracted increased attention in recent years. One of the important reliability indices is the unavailability of the components and the system. Unavailability of a system varies by the system peak load. Traditionally, these studies focus on determining the ability of the microgrid to increase the overall peak load carrying capability (PLCC) of a distribution system. This is generally acquired from Loss of Load Expectation (LOLE) risk level of 0.1 days/year [2].

However, these studies do not provide a solution for the calculation of the reliability of a microgrid operating in isolated mode for an extended period during a long-term resiliency event.

This study utilizes a new technique to estimate the reliability of a resilient microgrid in islanded condition. Consistent with previous sections, the proposed framework is implemented on the underground community type microgrid to be built in Potsdam, NY. The proposed Potsdam Microgrid has a design criteria unavailability of 2%, which was required by NYSERDA. In the next section, this criterion is utilized to determine the peak load that can be served in the proposed Potsdam Microgrid while maintaining an unavailability of 2%. It is concluded that the new generation consists of either four 1 MW units or two 1.25 MW units and one 1.5 MW unit. The Potsdam Microgrid availability analysis is presented in section 6.6.

6.1.3 Benefit to the Community from Improved Restoration Rate

In assessing the benefits and costs of a resilient microgrid, it is important to include the benefits to the community from reduced outage time. Section 6.7 includes the development of the theory to perform this analysis and benefits estimate for the Potsdam Microgrid.

6.2 Microgrid Components

The critical microgrid components, which need to be studied and modeled in its optimal operation problem, include loads, generation resources, and ESS, as well as main grid power. Microgrid loads could be roughly divided into two categories: fixed and flexible loads. Fixed loads are those that cannot be shifted or curtailed and must be satisfied during normal operation conditions. Flexible loads are those with consumption flexibilities, such as curtailable (curtailable loads) or deferrable (shiftable loads) in order to obtain optimal microgrid operation requirements.

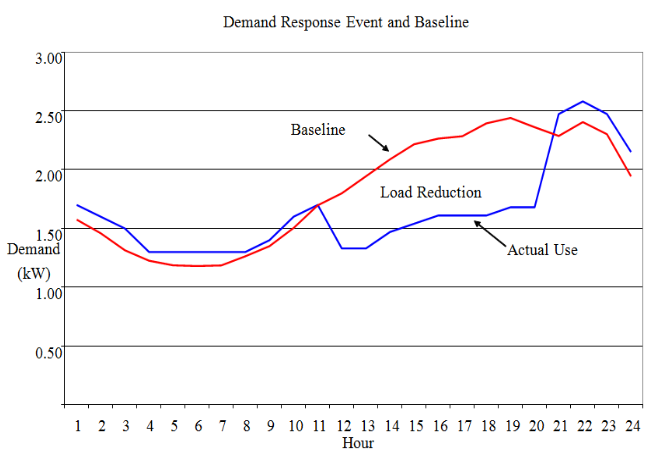
Distributed generation resources in a microgrid include both dispatchable and non-dispatchable units. Dispatchable units are those with controllable outputs and their operations are subject to technical constraints, depending on the unit type, such as capacity limits, ramping limits, minimum on/off time limits, and fuel and emission limits. Non-dispatchable units, on the contrary, mainly are those renewable resources (i.e., PV system or Wind Turbine) without controllable outputs since their input sources are uncontrollable. The intermittency feature of the non-dispatchable unit indicates that the generation is not always available, and the volatility feature indicates that the generation is fluctuating in different time scales. These characteristics negatively impact the non-dispatchable unit generation and increase the forecast errors associated with their outputs. Thus, these units are commonly reinforced with an on-site ESS. The primary application of ESS is to coordinate with the non-dispatchable generation resources to guarantee the microgrid generation adequacy. ESS can also be used for load shifting, where the stored energy at times of low prices is generated back to microgrid when the electricity price is high. This action is analogous to shifting the load from high-price hours to low-price hours. The ESS also plays a major role in microgrid islanding applications due to its quick response capability.

6.2.1 Baseline Load and Demand Response Events

According to the Federal Energy Regulatory Commission (FERC), demand response (DR) is defined as: "Changes in electric usage by end-use customers from their normal consumption patterns in response to changes in the price of electricity over time, or to incentive payments designed to induce lower electricity use at times of high wholesale market prices or when system reliability is jeopardized [29]." In short, demand response programs ask customers to reduce their electricity demand in response to a price signal or financial incentive. Typically, the request to reduce demand is made for a specific time period on a specific day which is referred to as a demand response event or simply, an event. As shown in Figure 86, each demand response event has three key measurement components.

Baseline is the amount of energy the customer would have consumed without a request to reduce, Actual Use is the amount of energy the customer consumed during the event period, and Load Reduction is the difference between the baseline and the actual use. Hence, Baseline Demand – Actual Demand = Load Reduction [30].

Figure 86. Demand Response Event and Baseline



6.2.2 The Distributed Generation (DG)

DG comprises small generators that produce several kilowatts to tens of megawatts of power and is usually connected to the power grid at the distribution or substation levels. Generally, DG units use a range of generation technologies, including gas turbines, diesel engines, solar PV systems, wind turbines, fuel cells, biomass, and some small hydroelectric generators. Some DG units, which are capable of providing heat for buildings or industrial processes using the “waste” energy from electricity generation, are designed to operate as the CHP system.

Utilities and their customers are allowed to own and operate their DGs, which is able to supply a variety of theoretical benefits to the broader power system [31]. Basically, most of the larger-scale DG units are dispatchable and able to communicate with system operators, as done in the common central station generation facilities. However, according to some state-of-the-art studies, the small-scale DG units, especially those in residential applications, are not commonly monitored and controlled by utilities or system operator. Moreover, renewable DG units, for example, wind turbines and PV systems, are also not dispatchable.

In 2009, about 13,000 commercial and industrial DG units with a combined capacity of about 16 gigawatts (GW) were connected to utility systems in the U.S. [32]. Of these units, 10,800 (83%) were smaller than 1 MW, averaging 100 kW each [33]. Internal combustion engines, combustion turbines, and steam turbines comprised more than 4 GW each of installed capacity, while hydroelectric, wind, and other generator technologies totaled 3 GW. In the same year, 93,000 residential PV installations totaled about 450 MW of capacity. While 90% of solar PV installations between 1998 and 2007 were smaller than 10 kW, the largest installations generated more than 14 MW [34]. Federal and state policies are expected to drive growth in DG in the coming decades. Sixteen states and the District of Columbia currently have renewable portfolio standards with specific DG provisions [35]. Some states have provisions in their renewable portfolio standards that require some fraction of retail electricity sales to come from renewable DG by 2020.

6.2.2.1 Solar Panel System (PV)

A PV system is a power generation system designed to convert solar power to electricity. PV system components include solar panels to absorb and convert sunlight into electricity, an inverter to change the electric current from DC to AC, as well as mounting, cabling and other electrical accessories to set up a working system. It may also use solar tracking to improve the system's overall performance and include an integrated battery solution to coordinate with the PV outputs, as prices for storage devices are expected to decline.

PV systems range from small rooftop mounted or building integrated systems, with capacities from a few to several tens of kilowatts, to large utility-scale power stations of hundreds of megawatts. Nowadays, most PV systems are grid-connected, while off-grid or stand-alone systems only account for a small portion of the market. Operating silently and without any moving parts or environmental emissions, PV systems have developed from being niche market applications into a mature technology used for mainstream electricity generation. A rooftop system recoups the invested energy for its manufacturing and installation within 0.7 to 2 years and produces about 95 percent of net clean renewable energy over a 30-year service lifetime.

Because of the exponential growth of photovoltaics, price for installing PV systems have rapidly declined in recent years. However, they vary by market and the size of the system. In 2014, prices for residential 5-kilowatt systems in the United States were around $3.29 per watt [36], while in the highly penetrated German market, prices for rooftop systems of up to 100 kW declined to $1.24 per watt [37]. Today, solar PV modules account for less than half of the system's overall cost [38], leaving the rest to the other balance of system (BOS) components and to soft costs, which include customer acquisition, permitting, inspection and interconnection, installation labor, and financing costs [39].

Photovoltaic systems are generally categorized into three distinct market segments: residential rooftop, commercial rooftop, and ground-mount, utility-scale systems. Their capacities range from a few kilowatts to hundreds of megawatts. A typical residential system is around 10 kW and mounted on a sloped roof, while commercial systems may reach a megawatt-scale and are generally installed on low-slope or even flat roofs. Although rooftop mounted systems are small and display a higher cost per watt than large utility-scale installations, they account for the largest share in the market. There is, however, a growing trend towards bigger utility-scale power plants, especially in the "sunbelt" region of the planet. Large utility-scale solar parks or farms are power stations capable of providing an energy supply to large numbers of consumers. Generated electricity is fed into the transmission grid, or combined with one, or many, domestic electricity generators to feed into a small electrical grid (hybrid plant). PV systems are generally designed to ensure the highest energy yield for a given investment. Some large photovoltaic power stations such as Solar Star, Waldpolenz Solar Park and Topaz Solar Farm cover tens or hundreds of hectares and have power outputs up to hundreds of megawatts. A small PV system is capable of providing enough AC electricity to power a single home, or even an isolated device in the form of AC or DC power. For example, military and civilian Earth observation satellites, street lights, construction and traffic signs, electric cars, solar-powered tents, and electric aircraft may contain integrated photovoltaic systems to provide a primary or auxiliary power source in the form of AC or DC power, depending on the design and power demands. In 2013, rooftop systems accounted for 60 percent of worldwide installations. However, there is a trend away from rooftop and towards utility-scale PV systems, as the focus of new PV installations is also shifting from Europe to countries in the Sunbelt region of the planet where opposition to ground-mounted solar farms is less accentuated. In urban and suburban areas, photovoltaic arrays are commonly used on rooftops to supplement power use; often the building will have a connection to the power grid, in which case the energy produced by the PV array can be sold back to the utility in some sort of net metering agreement. Some utilities, such as Solvay Electric in Solvay, NY, use the rooftops of commercial customers and telephone poles to support their use of PV panels. Solar trees are arrays that, as the name implies, mimic the look of trees, provide shade, and at night can function as street lights.

6.2.2.2 Energy Storage System

There are multiple definitions for the energy storage system. In the PJM Interconnection LLC grid, an energy storage system is a flywheel or battery storage facility solely used for short-term storage and injection of energy at a later time to participate in the PJM energy and/or Ancillary Services markets as a Market Seller [40]. In the California Independent System Operator LLC power grid, an energy storage system is commercially available technology that is capable of absorbing energy, storing it for a period of time, and thereafter dispatching the energy [41]. For the New York Independent System Operator LLC grid, these technologies act as a load when withdrawing energy or charging and as a generator when injecting energy or discharging. Additionally, NYISO states that these devices can continuously switch between charging and discharging and can respond to a NYISO signal to charge or discharge very rapidly [42].

Energy comes in multiple forms including radiation, chemical, gravitational potential, electrical potential, electricity, elevated temperature, latent heat and kinetic. Energy storage involves converting energy from forms that are difficult to store to more conveniently or economically storable forms. Also, there are so many different methods to build an energy storage for the whole ESS, like the mechanical storage (hydroelectricity, pumped-storage, compressed air, flywheel energy system), thermal storage (latent heat thermal energy storage), electrochemical (rechargeable battery, flow battery, super capacitor, ultra-battery), other chemical (hydrogen, underground hydrogen, power to gas, biofuels, methane, aluminum, boron, silicon, and zinc), electrical method (capacitor, superconducting magnetics). Usually, the ESS plays two important roles in the power systems, one is frequency regulation, some types of the ESS cannot store too many electricity energy, however, they can provide enough output power in a very short time to keep the power balance of the power system, and the other is to store electricity energy, unlike the first kind of the ESS, these parts of the ESSs are designed for storing as much electrical energy as possible, they cannot output the same amount of the power in a very short time, while they can store much more energy than the first one.

6.2.2.3 The Benefits of DG Units

DG installations theoretically can improve reliability, reduce costs, reduce emissions, and improve power quality (see Table 83) [43].

Table 83. Theoretical Benefits of Distributed Generation [44]

Reliability and Security Benefits	Economic Benefits	Emission Benefits	Power Quality Benefits
• Increased security for critical loads • Relieved transmission and distribution congestion • Reduced impacts from physical or cyberattacks • Increased generation diversity	• Reduced costs associated with power losses • Deferred investment for generation, transmission, or distribution upgrades • Lower operating costs due to peak shaving • Reduced fuel costs due to increased overall efficiency • Reduced land use for generation	• Reduced line losses • Reduced pollutant emissions	• Voltage profile improvement • Reduced flicker • Reduced harmonic distortion

More benefits accrue to specific stakeholders and may not benefit the distribution system operator or the other customers of the system. Therefore, existing DG interconnection standards prevent owners from realizing some of these hypothetical benefits. The ability of DG units to help maintain supply to local loads during a broader system outage event, improves system reliability by creating “islanded” mode, in which a section of a distribution feeder is disconnected from a faulted area. Such an action is called “islanding.” It is worth noting that a successful islanding operation requires the rest of sufficient generation to meet local loads’ requirements and has the necessary distributed system control capabilities [45]. Even if islanding operation is successfully activated, it is still highly possible that the potential reliability ability of generators is limited because of variable energy resources, such as the generators with limited fuel reserves, or generators with low-individual reliabilities.

The economic benefits of DG units can be realized after utilities finish the DG installation to defer investments in both transmission and distribution infrastructures [46]. It is highly possible that DG units are able to relieve transmission congestion and reduce system loss in some instance, since DG units are typically located closer to load relative to central plants [47]. While, on the other hand, the DG units owned by individual customers, are often capable of reducing utility revenue but also providing customers long-term electricity cost stability and saving. Such kind of saving includes multiple forms. Firstly, current policies and standards allow DG units owners to avoid paying the fixed network costs. Secondly, DG unit owners are able to avoid potential financial risks associated with increased block electricity tariffs, which means the customers who consume more than a specified amount of electricity power pay a higher rate, while those who are offered sufficient subsidies, are able to receive energy cost saving from their DG units. It is possible that the electricity generated by self-owned DG units is more expensive than the electricity purchased from traditional power stations.

The emission benefits of DG units can be realized by some types of the renewable generators, such as solar PV systems and wind turbines, or CHP systems, whose energy efficiency of employing waste heat is much higher than traditional central generation units [48]. However, the magnitudes of emission benefits associated with DG depend on the characteristics of individual DG Units and the characteristics of the local power system to which they are connected.

DG capable of providing constant, uninterrupted power can improve power quality by mitigating flicker and other voltage regulation problems. On the one hand, DG units can supply constant and uninterrupted electricity energy, which can help to improve power quality of connected-in power system by mitigating flicker and other types of voltage regulation problems. On the other hand, those DG units, which connected to the local power grid via power electronic inverters (e.g., solar PV system, fuel cells, and most types of wind turbines) are generally regarded as the sources of voltage waveform distortion.

Because of the high-installation costs, it is very likely that installation of a large number of renewable DG units relies on environment-friendly policies, mandates, or financial subsidies. It is highly possible that in the next few years, implementation of these government policies will increase the rapid growth of DG unit installations. During a long-term period, the cost reductions will also influence such growth. The average installation cost of residential and commercial solar PV system decreased from about $10.50 per watt DC (Wdc) in 1998 to about $7.60 per Wdc in 2007 (both figures are in 2007).

USD before incentives and tax credits) [51]. In September 2011, residential, commercial, and industrial PV installed system costs had fallen to $7.10, $5.10, and $3.70 per Wdc, respectively [52]. Compared with traditional and conventional generation resources, these costs are still not competitive in most areas of U.S. In conclusion, the distributed generation technologies are becoming more and more competitive, even though it is currently still more expensive than traditional generation technologies and highly dependent on policies, mandates and subsidies.

6.2.2.4 Meeting the Interconnection Challenges

The increased penetration of DG units presents a significant challenge for distribution systems planning and operation, since most of the existing distribution systems are designed, operated, and protected following the “unidirectional power flow” rule. In fact, the generation of DG units was such a small amount that electrical engineers usually thought of it as a reduction in local load. However, the situation is changing now with increased capacity of DG units in distribution systems. Therefore, it becomes possible that DG units are capable of having some influence on power system reliability, power quality and power system safety, positively or negatively [53].

6.2.2.5 IEEE Standard 1547

In recognition of the potential negative influence of DG units on distribution systems and the need for uniform criteria and requirements for the integration of DG units, the industry collaborated with the

IEEE to create IEEE Standard 1547 [54], which firstly released in 2003 and later incorporated into the Energy Policy Act of 2005 [55]. The primary purpose of this IEEE standard is to ensure that the DG units do not have adverse influence on other consumers and electrical equipment, which are connected to the local power system. It is designed for all the inter-connection DG units, whose capacity is 10 megavolt amperes (10 MVA, approximately 10 MW) or less. There are several provisions about how to limit the adverse impacts on power quality in this standard. For example, the standard requires that DG units are not able to "create objectionable flicker for other customers" [56]. Here, "flicker" refers to rapid variations of voltage that is able to cause noticeable variations in lighting and interrupt the normal operations of electronics. For example, if clouds pass by photovoltaic cells, flicker will occur, since shades on PV panels are capable of causing rapid change of their power outputs [57]. Solar plane operators are allowed to employ ESS, static volt-ampere reactive compensators, or other forms of reactive compensation to limit potential flicker problems [58]. All the DG units use inverters when they are connected to the local power system, such as the solar PV systems. They are allowed to "employ advanced inverter functionality to provide this reactive compensation" [59].

IEEE Standard 1547 was a first attempt at establishing uniform interconnection criteria for small generators and included a range of provisions to mitigate many of the challenges associated with DG integration. However, as DG penetrations continue to grow, modifications to this standard will become increasingly important. In particular, adding provisions for islanded operation of DG units would permit them to enhance the reliability of supply, and enabling DG units to actively regulate the voltage at their interconnection points would ease the burden of providing uniform and constant voltage along distribution feeders.

According to IEEE Standard 1547, DG units, whose capacities are less than 10 MVA, are required to disconnect from the local main power grid as soon as possible if an outage event has occurred. In addition, this IEEE standard requires the DG units' disconnection during the unintentional islanding events. However, it does not have specialized requirements for intentional islanding. Although, during the development of IEEE standard 1547, some scholars argued that the DG units should have the ability to disconnect from the main power grid, since it would help to prevent damage to the distribution system equipment. It is worth noting that the recently released IEEE Standard 1547.4 discusses the intentional use of DG to supply power to a disconnected part of the distribution system when a fault is present in another part of the distribution system. Distributed generation units, which are connected to the grid in a way that complies with this standard, should be capable of sustaining islanded operation and providing reliability benefits. However, intentional islanding will require generators that are large enough to supply adequate real and reactive power to the island operation. It also necessitates distributed monitoring and control systems capable of maintaining local supply and demand balance as well as regulating the voltage and frequency within appropriate ranges. These monitoring and control capabilities add cost, and owners of very small DG units are unlikely to invest in this capability. Additionally, voltage and frequency regulation capabilities only are allowed in islanding operations and not when the island is reconnected to the distribution system. Therefore, even though IEEE Standard 1547.4 has been released, intentionally designed islanding schemes probably will be limited to larger DG units for the immediate future.

6.3 Model Description

6.3.1 Microgrid Optimal Scheduling Model

The microgrid optimal operation includes two operation modes: grid-connected and islanded. The whole microgrid operation problem formulates the two operation modes and decomposes the integrated problem into a two-level model. The upper-level master problem determines the optimal commitment and dispatch of available dispatchable units, charging and discharging schedules of energy storage systems (ESS), schedule of flexible loads, and the power transfer with the main grid, which represents the grid-connected operation mode. The optimal schedule from the upper-level problem will be checked in the lower level subproblem to examine the microgrid generation adequacy and confirm an uninterrupted supply of loads for a variety of islanding scenarios which represents the islanded operation mode. If any islanding is not feasible, that is, microgrid does not have sufficient online capacity to supply the local load, a Benders cut, based on the unit commitments and ESS schedules is generated and sent back to the master problem for revising the current schedule. The Benders cut indicates that power mismatches in the subproblem can be mitigated by readjusting the unit commitments and ESS schedules in the master problem. The revised solution will be examined in the next iteration of the subproblem for islanding. The iterative process continues until all islanding scenarios are feasible. It is possible, however, in some scenarios that change in unit commitments and ESS schedules do not provide required online capacity to guarantee a feasible islanding. In this situation, another Benders cut is generated based on flexible loads schedules. This cut would revise the flexible loads specified operating time interval to shift the load and accordingly enable the islanding. The inconvenience realized by consumers as a result of this change will be penalized in the objective. These Benders cuts indicate that power mismatch in the subproblem can be mitigated by readjusting load schedules in addition to unit commitments and ESS schedules in the master problem.

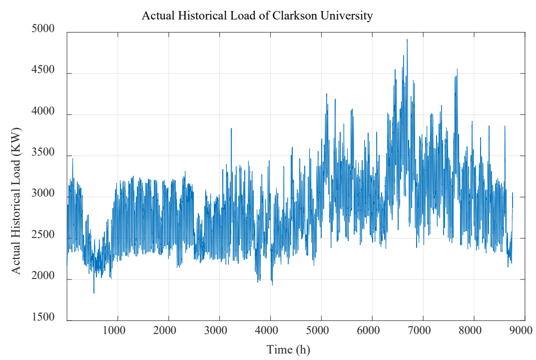
The final solution is obtained when all islanding scenarios are guaranteed feasible. Note that the cuts discussed above are represented in the form of inequality constraints which provide a lower estimate of the total mismatch in the subproblem as a function of scheduling variable in the master problem [60].

In this report, the day-ahead operation for microgrid is considered, which calculates the optimal schedules for microgrid resources during a 24-hour scheduling horizon. However, the model studied could be applied to any other scheduling horizon based on the master controller's decision without any change in the model and formulation. Selection of a 24-hour scheduling horizon would enable microgrid master controller to benefit from day-ahead market price forecasts provided by the utility company and also keep track of ESS daily charging/discharging cycles. The dispatchable units' commitments and ESS charging/discharging schedules will be determined in the master problem and remain unchanged in the subproblem. The microgrid fixed load and generation of non-dispatchable units are forecasted with an acceptable accuracy. The market price at the point of common coupling, that is, the price that microgrid purchases the main grid power and sells excess power to the main grid, is also forecasted. It is assumed that microgrid components are highly reliable and are not subject to outage during the scheduling horizon.

6.3.2 Load Modeling—Estimation of Baseline Load and Demand Response Value

In this section, historical load data for approximating baseline load and potential DR capability of individual microgrid consumers are discussed. For this paper, the baseline-load value can be regarded as the hourly total load data and the potential demand response capability can be regarded as the input hourly flexible loads data in the latter case study. Hence, the difference between the baseline load value and the potential demand response value can be regarded as the input hourly fixed load data in the latter case study. Figure 87 shows the one-year historical load data of the Clarkson University from December 1, 2013 to November 30, 2014.

Figure 87. Actual Historical Load of Clarkson University



6.3.2.1 ARMAX Time Series Model

The autoregressive-moving-average with exogenous inputs model (ARMAX) is used on historical load data to derive the load profile coefficients that would match the historical load data to the best extent.

In the statistical analysis of time series, autoregressive-moving-average models provides a parsimonious description of a weakly stationary stochastic process in term of two polynomials, one for the autoregressive polynomial (AR) part and the second for the moving average polynomials (MA) part. The notation ARMA (p,q) model, in which p is the order of the AR polynomials part and q is the order of the MA polynomials part. The AR model (p) is described as the following:

$$X_t = C + \sum_{i=1}^{p} \varphi_i X_{t-i} + \varepsilon_t$$

Equation 6.1

$\varphi_1 \cdots\cdots \varphi_p$ are parameters, c is a constant, and ε_t is white noise error term. It is a random variable. The MA model (q) is described as:

$$X_t = \mu + \varepsilon_t + i = 1\sum_{i=1}^{q} \theta_i \varepsilon_{t-1}$$

Equation 6.2

$\theta_1 \cdots\cdots \theta_q$ are the parameters of the model, μ is the expectation of X_t (usually assumed to equal 0), and the $\varepsilon_t, \varepsilon_{t-1} \cdots$ are white noise error terms. Therefore, the notation ARMAX (p,q,b) where p is the order of the AR polynomials part, q is the order of the MA polynomials part, and the b is the number of exogenous inputs terms. Moreover, this model contains the AR (p) and MA (q) models and a liner combination of the last b terms of a known and external time series d_t. It is given by:

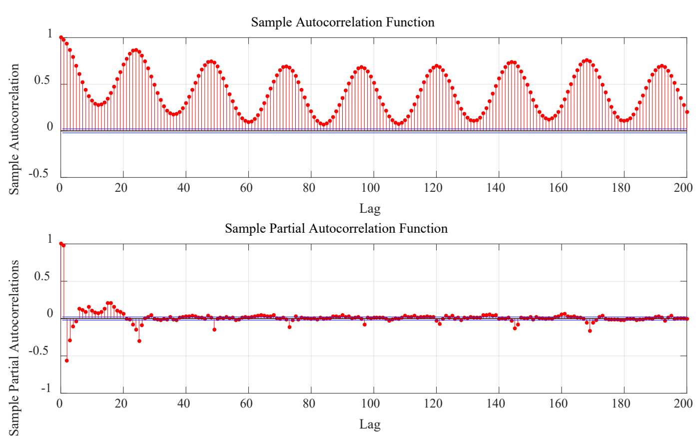
Equation 6.3

$$X_t = \varepsilon_t + \sum_{i=1}^{p} \varphi_i X_{t-i} + \sum_{i=1}^{q} \theta_i \varepsilon_{t-1} + \sum_{i=1}^{b} \eta_i d_{t-i}$$

$\eta_1 \cdots\cdots \eta_b$ are the parameters of the exogenous input d_t [61].

The general ARMAX scheme is able to be described as follows: First step is to use the autocorrelation function (ACF) and partial autocorrelation function (PACF) to determine the order of notation ARMAX (p, q, b). Figure 88 shows the ACF and PACF of load series of the microgrid from December 1, 2013 to November 30, 2014, respectively. The blue lines indicate the approximate upper- and lower-confidence bounds. If the ACF value at a certain lag is smaller than the 95% confidence bound, we will assume there is no significant autocorrelation at that lag. Furthermore, orders are determined by lags where ACF and PACF die out.

Figure 88. ACF and PACF of the Entire Load Series



There are two alternatives to the ARMAX model to predict the one-year baseline load series. One method is to build a single ARMAX model based on the entire series, and then consider a 24-step forecast for the next day, and then to a year. The other method is to consider 24 different hourly models. That is, dividing the entire series into 24 sets corresponding to different hours of a day, building ARMAX models based on different hourly series, and forecasting one step ahead for each ARMAX model. The forecast results of the 24 ARMAX models constitute the one-year baseline load forecast. Figures 89–91 show the ACF of load value series for the first hour and two-peak hours, that is, hours 10 and 20, of each day in the microgrid from December 1, 2013 to November 30, 2014. Comparing Figures 89–91 with Figure 88, it is obvious that, although hourly ACFs are not exactly the same, the load value series ACF of the same-hour dies out more quickly than the load value series of the entire day. Hence by considering the hourly-based series, the ARMAX model can better fit a series with proper AR and MA orders. Here we consider different hourly ARMAX models instead of a single ARMAX model for the entire series [62].

Figure 89. ACF and PACF of Load Series for the Daily Hour 01:00

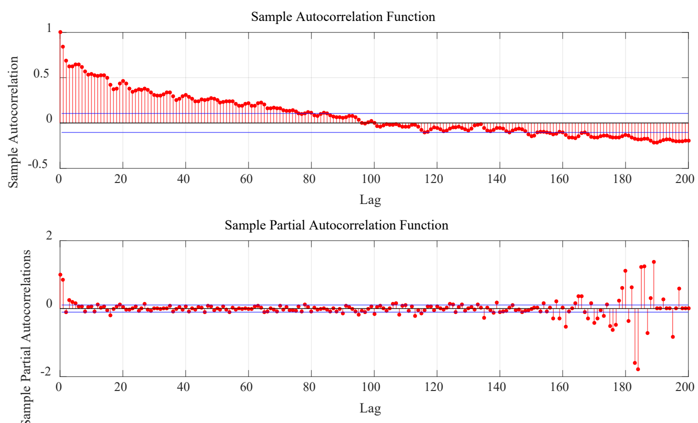


Figure 90. ACF and PACF of Load Series for the Daily Hour 10:00

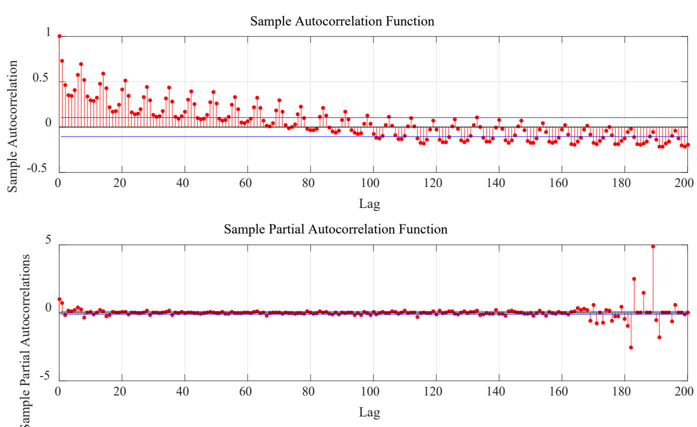
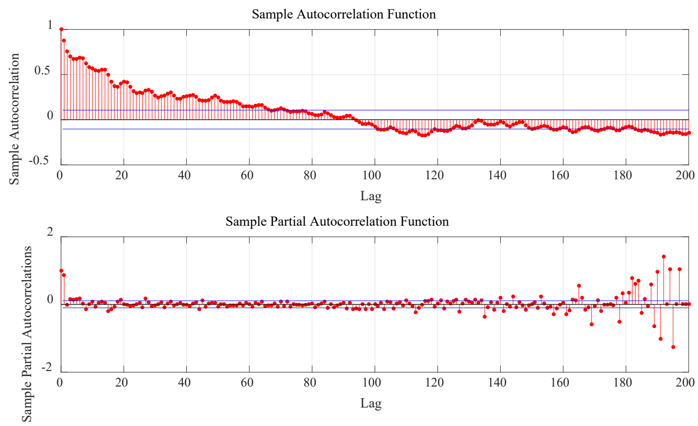


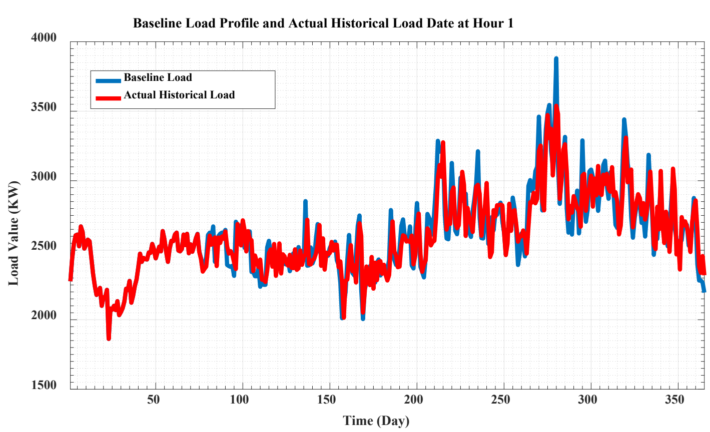
Figure 91. ACF and PACF of Load Series for the Daily Hour 20:00



6.3.2.2 Approximate the Baseline Load Profile

Twenty-four hourly ARMAX models are derived to approximate the base load profiles of the same hour (hours 1 ~ 24) using different days' data throughout the year. That is, 8760 historical load data points are divided into 24 sets with 365 data points for each hour. Then, the 24 ARMAX models can be used to get the base load profiles of each hour and, in turn, the load profile of the entire year. Figure 92 shows the base load profile in hour 1 obtained from the ARMAX model and the actual historical load data. The blue line represents the actual historical load data in hour 1 and the red line represents the baseline load value in hour 1.

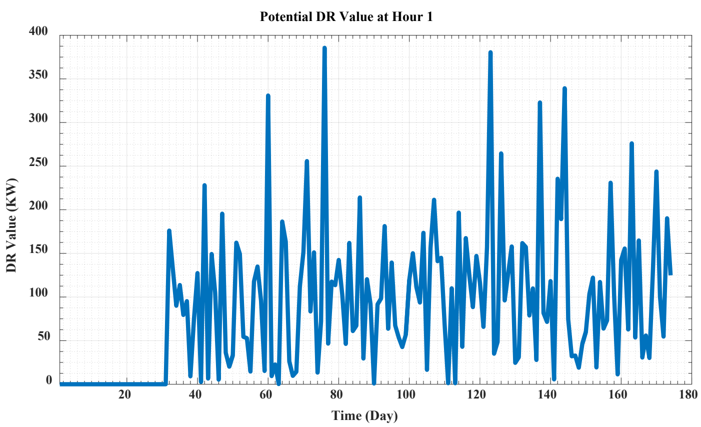
Figure 92. Base Load Profile and the Actual Historical Load Data in Hour 1



6.3.2.3 Statistical Characteristics of the Demand Response Values

Based on the approximated base load profile from ARMAX model and the actual historical data, we can get the difference between the two (i.e., approximated base load profile—actual historical data). The positive difference values could be regarded as the potential DR capability that could be provided by the entity. Figure 93 shows the potential DR capability of the microgrid for the daily hour 01:00 from December 1, 2013 to November 30, 2014.

Figure 93. Potential DR Capability at Hour 1



Finally, this section derives some statistical characteristics of the positive difference values, obtained in step 2, for approximating the potential DR capability of individual entity at each hour. Table 84 shows the potential DR capability approximation of Clarkson University at hour 1 using different statistical characteristics.

The 5% means that, when a real demand response event happened in Clarkson University at hour 1, the probability of this DR event's value larger than this special value, 235.32 kW, is no larger than 5%. Similarly, the 50% and the 95% mean that when a real DR event happened in Clarkson University at hour 1, the probability of this DR event's value larger than this special value, 64.55 kW or 1.033 kW, is no larger than 50% or no larger than 95 %. The Including 95% means that, when a real demand response event happened in Clarkson University at hour 1, the probability of this DR event's value between this special interval, larger than 5.01 kW and less than 383.76 kW are no less than 95%.

Table 84. Potential DR Approximation at Hour 1

At Base Load of 2626.66 kW	Demand Response (kW)
5%	235.32
50%	64.55
95%	1.033
Including 95%	5.01
	383.76

6.3.3 Photo-Voltaic (PV) System Model

6.3.3.1 PV System Model Estimation

Based on previous studies such as Solar Radiation and Ambient Temperature Effects on the Performances of a PV Pumping System [63], both the sun insolation and environmental temperature are able to strongly influence the final output power generated from photo-voltaic equipment (PV cell). Because of the typical I-V characteristics of solar cells and PV modules, electrical power output decreases in an almost linear manner when the load curve meets the I-V curve of the PV system on the "left" side of the Maximum Power Point (MPP), towards lower operating voltage [64].

Hence, on one hand, the relationship between sun insolation and power output is capable of being described as an equation (6.4), where P_{output} means the output power generated from a PV system, the $S_{rightnow}$ means the sun insolation (kW/m^2)to this PV system in the present moment, the S_{1-sun} is defined as the solar radiation of 1 kW/m^2 under the standard test conditions (STC, corresponding to cell temperature of 25 ^oC, wind speed of 1 m/s, air mass ratio of 1.5) [65], and the $P_{\max}$ means the maximum value of the PV system, while, in this study, it is equal to the rated output power of the PV system connected with the microgrid, 2 MW.

Equation 6.4

$$P_{output} = \frac{S_{rightnow}}{S_{1-sun}} \times P_{\max}$$

$$T_{PVcell} = T_{amb} + \left(\frac{NOCT - 20^{o}C}{0.8}\right) \times S_{rightnow}$$

Equation 6.5

$$P_{output} = \left(1 - X\right) \times \left(T_{PVcell} - T_{bestwork}\right) \times P_{\max}$$

Equation 6.6

$$P_{output} = a \times \frac{S_{rightnow}}{S_{1-sun}} \times P_{\max} + b \times (1 - X) \times (T_{PVcell} - T_{bestwork}) \times P_{\max}$$

Equation 6.7

On the other hand, as the cell temperature increases, the V_{oc}, open-circuit voltage, decreases substantially while the I_{sc}, short-circuit current, increases only slightly, which means PV cells perform better on cold than hot days. Therefore, for crystalline silicon cells, V_{oc} drops by about $0.37\% / {}^{o}C$ increase in temperature, and I_{sc} increases by approximately $0.05\% / {}^{o}C$, which results in a decrease in maximum power output available by about $0.5\% / {}^{o}C$ [66].

Hence, the relationship between temperature of the PV cell and the output power, which is generated from the PV system, is able to be described by equations (6.5) and (6.6), where the temperature of the PV cell (℃), and the temperature of the ambient air (℃), NOCT (normal operating temperature (NOCT) is defined as the PV cell temperature in a module when ambient temperature is 20℃, solar irradiation is 0.8, and wind speed is 10 mph, results in a decrease in maximum power output [67].

Therefore, the function for PV cell output power can be tentatively estimated via equation (6.7), where a and b are two coefficients.

6.3.3.2 PV Cell Output Power Model Approximation

The following figures show the output power generated from the local PV system (Figure 94), Global Horizontal Irradiance data (i.e., total amount of shortwave radiation received from above by a surface horizontal to the ground; Figure 95) [68] and ambient temperature (data from the National Solar Radiation Database; Figure 96) [69], which is employed to build the solar PV cell output power function equation (6.7).

Figure 94. Output Power of PV System

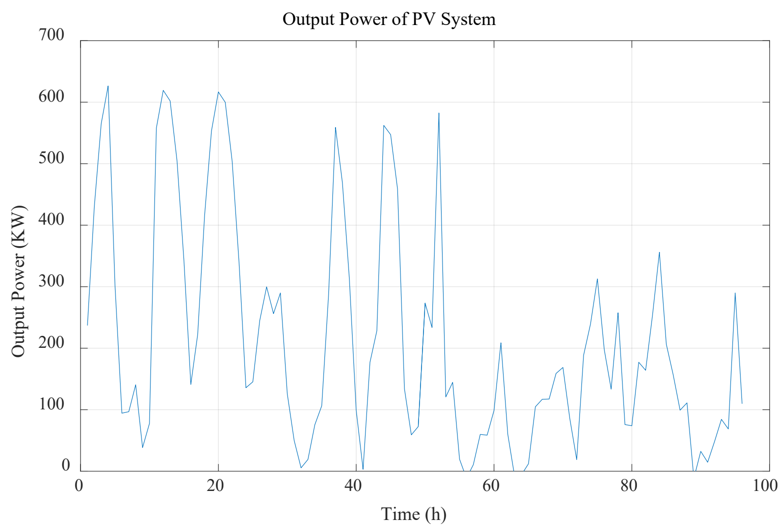


Figure 95. Global Horizontal Irradiance (GHI) Value

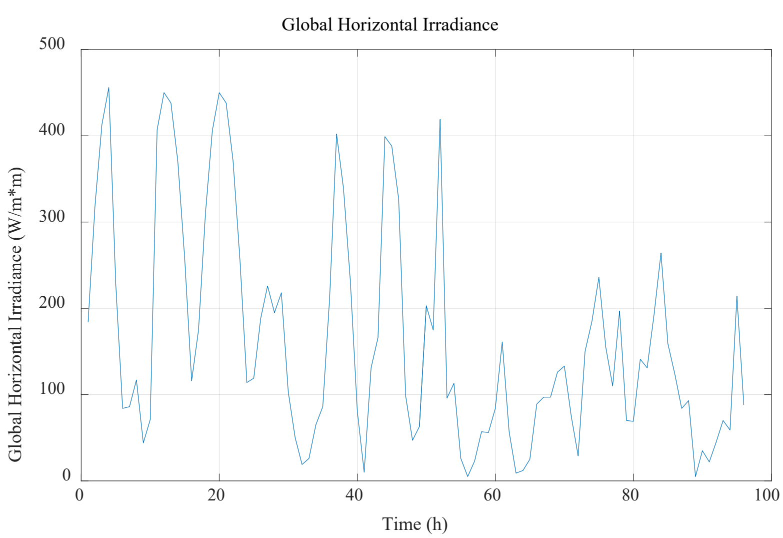
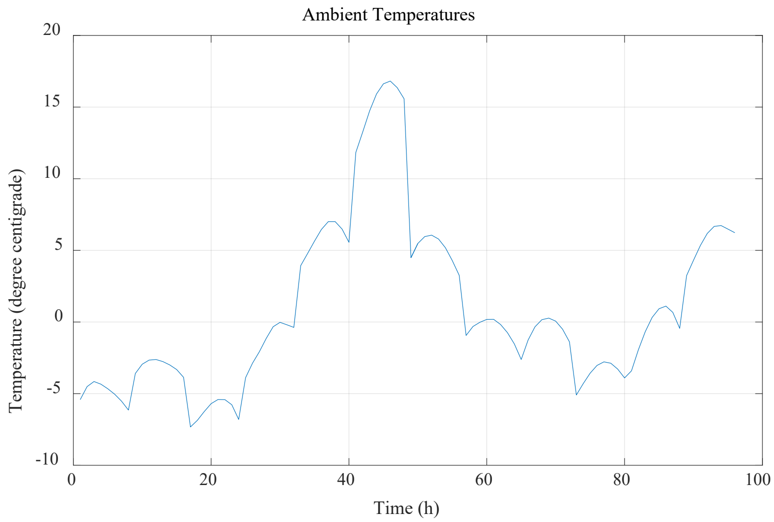


Figure 96. Ambient Temperatures



According to the analysis described in section 6.3.3.1, the non-linear curve fitting algorithm has been applied to build the following equation:

Equation 6.8

$$P_{output} = 0.7004 \times \frac{S_{rightnow}}{S_{1-sun}} \times P_{max} + 4.2876 \times 10^{-4} \times (1 - X) \times (T_{cell} - T_{bestwork}) \times P_{max}$$

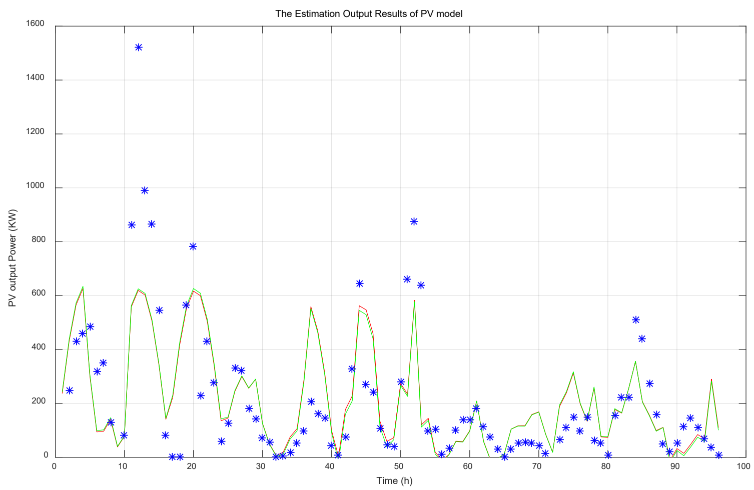
Additionally, a polynomial fitting algorithm has been employed to verify equation (6.7) as follows:

Equation 6.8

$$P_{output} = 1.441 \times S_{rightnow} + (-0.3517) \times T_{amb} + (-23.98)$$

Figure 97 shows the results of PV cell output power model, the verification model, and the actual historical PV cell generation data, where the blue points are the 96 real PV output values; the red line is the results of PV cell output power model, and the green line is the verification curve.

Figure 97. The Estimation Output Results of the PV Model



6.3.4 Energy Storage System Model

The ESS is subject to charging and discharging minimum and maximum limits depending on its mode. Additionally, the characteristics of the ESS determine that only one mode, either charging or discharging, is allowable each hour. The amount of charged/discharged power and the ESS capacity limits determine the state of charge (SOC). The ESS is also restricted to minimum charging and discharging time limits.

As is shown in equation (6.10) and (6.16), ESS power is related to its charging and discharging minimum and maximum limits, which depends on the characteristics of its mode. Therefore, during the charging period, the charging state v_{it} is one and discharging state u_{it} is zero; while, minimum and maximum charging limits are required. Similarly, during the discharging period, the discharging state u_{it} is one and charging state v_{it} is 0; while, minimum and maximum discharging limits are required, as well. During the charging state, the charging power of ESS is assumed as a negative value; hence, the associate limits are denoted with a negative sign and superscripts ch , dch are respectively used for ESS charging and discharging period. As is shown in equation 6.12, it is worth noting that concurrent charging and discharging of the ESS is not possible. Based on equations 6.13 and 6.14, the amount of charged/discharged power and capacity limits determine ESS SOC. Moreover, the SOC value at $t=1$ moment is determined based on the SOC value at the last hour of previous scheduling horizon.

Furthermore, the ESS is assumed to maintain similar SOC value during both begin and end period of the scheduling horizon. ESS are also restricted to minimum charging and discharging time limits, as show in equation 6.15 and 6.16, which are the minimum number of consecutive hours that ESS should maintain charging/discharging once the operational mode is charged.

Equation 6.10
$$P_{it} \le P_{it}^{dch,\max} u_{it} - P_{it}^{ch,\min} v_{it} \quad \forall i \in S, \forall t$$

Equation 6.11
$$P_{it} \ge P_{it}^{dch,\min} u_{it} - P_{it}^{ch,\max} v_{it} \quad \forall i \in S, \forall t$$

Equation 6.12
$$u_{it} + v_{it} \le 1 \quad \forall i \in S, \forall t$$

Equation 6.13
$$C_{it} = C_{i(t-1)} - P_{it} \quad \forall i \in S, \forall t$$

Equation 6.14
$$0 \le C_{it} \le C_i^{\max} \quad \forall i \in S, \forall t$$

Equation 6.15
$$T_{it}^{ch} \ge MC_i (\mathrm{u}_{it} - u_{i(t-1)}) \quad \forall i \in S, \forall t$$

Equation 6.16
$$T_{it}^{dch} \ge MD_i (\mathrm{v}_{it} - v_{i(t-1)}) \quad \forall i \in S, \forall t$$

6.3.5 Grid-Connected Operation Model

The target of the microgrid grid-connected operation is to minimize the total operation cost as follows:

Equation 6.17
$$Min \sum_t \sum_{i \in G} [\mathrm{F}_i \cdot (\mathrm{P}_{i,t}) \cdot I_{i,t} + SU_{i,t} + SD_{i,t}] + \sum_t \rho_t \cdot P_{M,t} + c \cdot \sum_t \left(Y_{dt} + Y_{ct} \right)$$

The first term in the objective is the operation cost of microgrid dispatchable units, which include the generation cost, the start-up and shut down cost during the whole scheduling horizon. The generation cost could be simply approximated by a piecewise liner model. The second term is the cost of power transfer from the main grid based on the market price. The last term models the ESS repeated recharging/discharging cost. For each charging/discharging status switch, a fixed cost c is incurred, which could be estimated as the capital cost of the ESS over the whole discharging/charging cycles. When the microgrid excess power is sold back to the main grid, $P_{M,t}$ would be negative; thus, this term would represent a benefit for the microgrid. The objective is subject to generating units, ESS, and load constraints, as follows:

$$\sum_i P_{it} + P_{M,\mathrm{t}} = \sum_d D_{dt} \quad \forall t$$ **Equation 6.18**

$$-P_M^{max} \le P_{M,t} \le P_M^{max} \quad \forall t$$ **Equation 6.19**

$$P_i^{\min} I_{it} \le P_{it} \le P_i^{max} I_{it} \quad \forall i \in G, \forall t$$ **Equation 6.20**

$$P_{it} - P_{i(t-1)} \le UR_i \quad \forall i \in G, \forall t$$ **Equation 6.21**

$$P_{i(t-1)} - P_{it} \le DR_i \quad \forall i \in G, \forall t$$ **Equation 6.22**

$$T_{it}^{on} \ge UT_i (I_{it} - I_{i(t-1)}) \quad \forall i \in G, \forall t$$ **Equation 6.23**

$$T_{it}^{off} \ge DT_i (I_{i(t-1)} - I_{it}) \quad \forall i \in G, \forall t$$ **Equation 6.24**

$$P_{it} \le P_{it}^{dch,\max} u_{it} - P_{it}^{ch,\min} v_{it} \quad \forall i \in S, \forall t$$ **Equation 6.25**

$$P_{it} \ge P_{it}^{dch,\min} u_{it} - P_{it}^{ch,\max} v_{it} \quad \forall i \in S, \forall t$$ **Equation 6.26**

$$u_{it} + v_{it} \le 1 \quad \forall i \in S, \forall t$$ **Equation 6.27**

$$C_{it} = C_{i(t-1)} - P_{it} \quad \forall i \in S, \forall t$$ **Equation 6.28**

$$0 \le C_{it} \le C_i^{\max} \quad \forall i \in S, \forall t$$ **Equation 6.29**

$$T_{it}^{ch} \ge MC_i (\mathrm{u}_{it} - u_{i(t-1)}) \quad \forall i \in S, \forall t$$ **Equation 6.30**

$$T_{it}^{dch} \ge MD_i (\mathrm{v}_{it} - v_{i(t-1)}) \quad \forall i \in S, \forall t$$ **Equation 6.31**

The power balance equation 6.18 ensures that the sum of power generated by distributed energy resources (i.e., dispatchable and non-dispatchable units and ESS) and the power transfer from the main grid matches the hourly load of the Microgrid. The forecasted generation of non-dispatchable units is used in 6.18. The power of ESS can be positive (discharge), negative (charge) and zero (export). The main grid power can be positive (import), negative (export), and zero. The power transfer with the main grid is limited by the flow limits of the line connecting the microgrid to the main grid (6.19). The dispatchable unit generation is subject to minimum and maximum generation capacity limits (6.20), ramp up/down rate limits (6.21 to

6.22), and minimum up/down time limits (6.23 to 6.24). The unit commitment state I_{it} is 1 when the unit is committed and is 0 otherwise. The equations describing ESS operation, from 6.25 to 6.31, have been discussed in section 6.3.4 (ESS System Model).

6.3.6 Islanded Operation Model

The objective of the island operation of the microgrid is to minimize the microgrid total operation costs (6.32), as follows:

$$Min\sum_{t}\sum_{i\in G}[\mathrm{F}_{i,s}\cdot(\mathrm{P}_{its})\cdot I_{its}+SU_{its}+SD_{its}]+\sum_{t}\rho_t\cdot P_{M,ts}+c\cdot\left(Y_{dt}+Y_{ct}\right)$$

Equation 6.32

Similarly, the first term in the objective function of the islanded operation model is the operation cost of the microgrid dispatchable units, which include the generation cost, the start-up and shut down cost during the whole scheduling horizon. The generation cost could be simply approximated by a piecewise liner model. The second term is the cost of power transfer from the main grid based on the market price. However, during the 24-hour islanded event, the hourly power transfer from the utility grid is zero, which means the cost of power transfer from the main grid power is zero, $\sum_{t}\rho_t\cdot P_{M,ts}=0$. The last term models the ESS repeated recharging/discharging cost. For each charging/discharging status switch, a fixed cost c is incurred, which could be estimated as the capital cost of the ESS over the whole discharging/charging cycles. When the microgrid excess power is sold back to the main grid, $P_{M,t}$ would be negative; thus, this term would represent a benefit for the microgrid.

The objective function is subject to generating units, ESS, and load constraints, as follows:

Equation 6.33 $$\sum_i P_{its} + P_{M,ts} = \sum_d D_{dts}$$

Equation 6.34 $$I_{its} = \hat{I}_{it} \quad \lambda_{its} \quad \forall i \in G,\ \forall \mathrm{t}$$

Equation 6.35 $$u_{its} = \hat{u}_{it} \quad \mu_{its}^{dch} \quad \forall i \in S,\ \forall \mathrm{t}$$

Equation 6.36 $$v_{its} = \hat{v}_{it} \quad \mu_{its}^{ch} \quad \forall i \in S,\ \forall \mathrm{t}$$

Equation 6.37 $$z_{dts} = \hat{z}_{dt} \quad \pi_{dts} \quad \forall d \in D,\ \forall \mathrm{t}$$

Equation 6.38 $$-P_M^{\max} U_{ts} \le P_{M,ts} \le P_M^{\max} U_{ts} \quad \forall \mathrm{t}$$

Equation 6.39 $$P_i^{\min} I_{its} \le P_{its} \le P_i^{\max} I_{its} \quad \forall i \in G,\ \forall \mathrm{t}$$

Equation 6.40 $$P_{its} - P_{i(t-1)s} \le UR_i \quad \forall i \in G,\ \forall \mathrm{t}$$

Equation 6.41 $$P_{i(t-1)s} - P_{its} \le DR_i \quad \forall i \in G,\ \forall \mathrm{t}$$

Equation 6.42 $$P_{its} \le P_{it}^{dch,\max} u_{its} - P_{it}^{ch,\min} v_{its} \quad \forall i \in S,\ \forall \mathrm{t}$$

Equation 6.43 $$P_{its} \ge P_{it}^{dch,\min} u_{its} - P_{it}^{ch,\max} v_{its} \quad \forall i \in S,\ \forall \mathrm{t}$$

Equation 6.44 $$C_{its} = C_{i(t-1)s} - P_{its} \quad \forall i \in S,\ \forall \mathrm{t}$$

Equation 6.45 $$0 \le C_{its} \le C_i^{\max} \quad \forall i \in S,\ \forall \mathrm{t}$$

During the 24-hour islanded operation mode, the hourly power from the utility grid is 0. Hence, as is shown in the power balance equation (6.33), the second term, the main grid power $P_{M,ts}$, is zero. Moreover, unit commitments, energy storage charging/discharging schedules, and load schedules are obtained from the grid-connected master problem. These given variables are replaced with local variables for each scenario to obtain associated dual variables (6.34 to 6.37). Dual variables are later used in this section to generate islanding cuts. The islanded operation subproblem is further subject to dispatchable unit generation and ramp-rate limits (6.38 to 6.41), ESS power and capacity limits (6.42 to 6.45).

6.4 Numerical Simulations

A microgrid with four dispatchable units, one non-dispatchable unit, one ESS, and five flexible loads is used to analyze the proposed microgrid optimal scheduling model. The characteristics of units and ESS are given in Tables 85–86. The forecasted values for microgrid hourly fixed load, microgrid hourly flexible loads values, non-dispatchable unit generation, and market price over the 24-hour horizon are given in Tables 87–90 and Figures 98–101. Additionally, the flow limits of the line connecting the microgrid to the main grid are 15 MW.

Table 85. Characteristics of Generating Units

Unit	Type	Cost Coefficient ($/MWh)	Min-Max Capacity (MW)	Min Up/Down Time (h)	Ramp Up/ Down Rate (MW/h)
G1	dispatchable	27.7	1-5	3	3
G2	dispatchable	39.1	1-5	3	3
G3	dispatchable	61.3	0.8-3	1	3
G4	non-dispatchable	0	0-2	-	-

Table 86. Characteristics of the Energy Storage System

Storage	Capacity (MWh)	Min-Max Charging/Discharging Power (MW)	Min Charging/Discharging Time (h)
ESS	10	0.4-2	5

Table 87. Microgrid Hourly Fixed Load

Time (h)	1	2	3	4	5	6
Load (MW)	8.354	9.252	8.856	7.888	7.572	7.902
Time (h)	7	8	9	10	11	12
Load (MW)	7.742	8.49	9.07	11.78	12.726	12.442
Time (h)	13	14	15	16	17	18
Load (MW)	12.266	12.488	8.884	8.382	7.242	8.838
Time (h)	19	20	21	22	23	24
Load (MW)	9.786	9.322	9.746	10.012	8.662	8.886

Figure 98. Microgrid Hourly Fixed Load

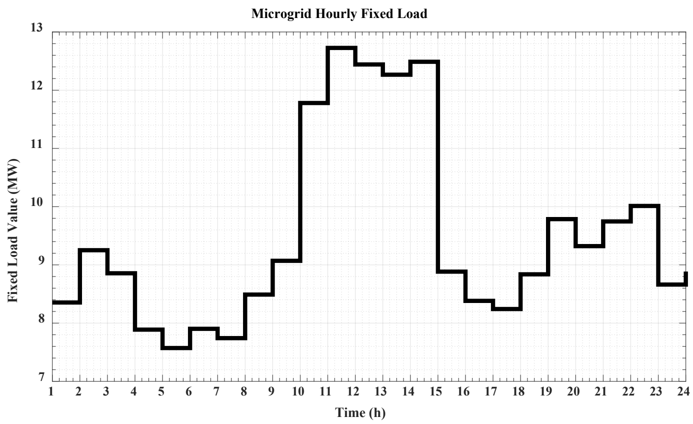


Figure 99. Maximum Capacities of Microgrid Hourly Demand Response Events

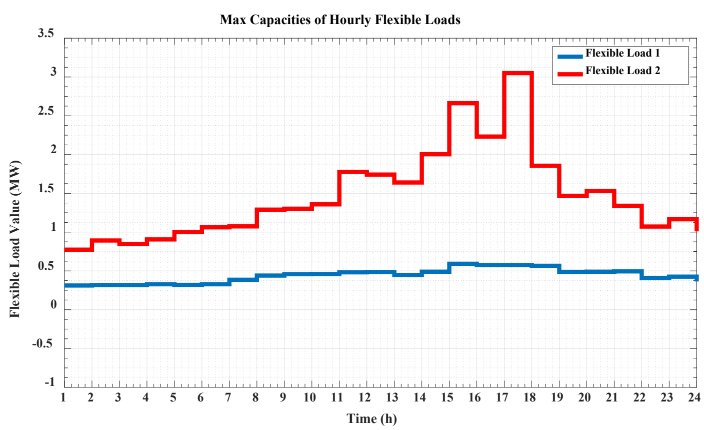


Table 88. Maximum Capacities of Microgrid Hourly Flexible Loads Values

Time (h)	1	2	3	4	5	6
DR 1 Value (MW)	0.312	0.318	0.318	0.328	0.32	0.328
DR 2 Value (MW)	0.774	0.892	0.848	0.906	1.00	1.062
Time (h)	7	8	9	10	11	12
DR 1 Value (MW)	0.386	0.440	0.458	0.460	0.482	0.486
DR 2 Value (MW)	1.074	1.290	1.302	1.358	1.776	1.742
Time (h)	13	14	15	16	17	18
DR 1 Value (MW)	0.448	0.49	0.592	0.576	0.576	0.566
DR 2 Value (MW)	1.640	2.004	2.662	2.232	3.05	1.856
Time (h)	19	20	21	22	23	24
DR 1 Value (MW)	0.488	0.490	0.494	0.410	0.426	0.364
DR 2 Value (MW)	1.468	1.53	1.34	1.072	1.166	1.010

Table 89. Generation of Non-Dispatchable Unit

Time (h)	1	2	3	4	5	6
G5 (MW)	0	0	0	0	0	0
Time (h)	7	8	9	10	11	12
G5 (MW)	0	0	0.039	0.281	0.661	0.875
Time (h)	13	14	15	16	17	18
G5 (MW)	0.64	0.098	0.103	0.01	0	0
Time (h)	19	20	21	22	23	24
G5 (MW)	0	0	0	0	0	0

Figure 100. Generation of Non-Dispatchable Unit

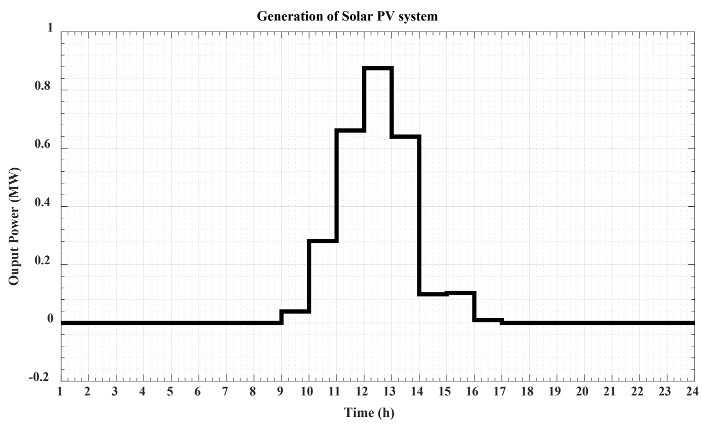
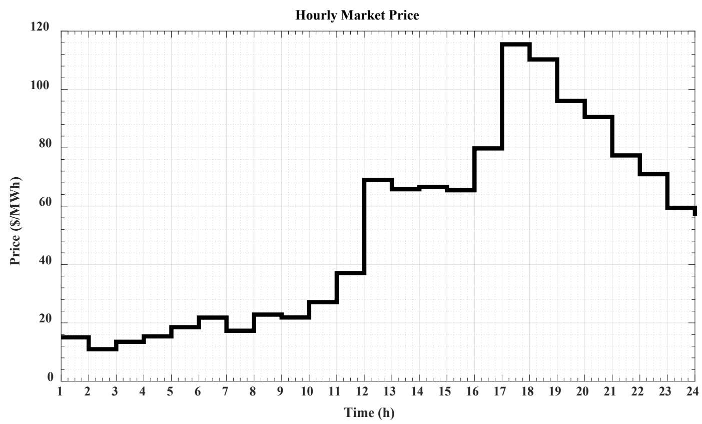


Table 90. Hourly Market Price

Time (h)	1	2	3	4	5	6
Price ($/MWh)	15.03	10.97	13.51	15.36	18.51	21.8
Time (h)	7	8	9	10	11	12
Price ($/MWh)	17.3	22.83	21.84	27.09	37.06	68.95
Time (h)	13	14	15	16	17	18
Price ($/MWh)	65.79	66.57	65.44	79.79	115.45	110.28
Time (h)	19	20	21	22	23	24
Price ($/MWh)	96.05	90.53	77.38	70.95	59.42	56.68

Figure 101. Hourly Market Price



6.4.1 Grid-Connected Mode

The grid-connected mode of microgrid optimal scheduling is studied for a 24-hour horizon. The DER schedule, including dispatchable unit commitment states and ESS schedule, is shown in Table 91. The commitment state of one means that the units are on, while off is 0. The ESS charging, discharging, and idle states are represented by -1, 1, and 0 respectively. In Figure 102, the blue line represents hourly generation of unit 1, the red line represents hourly generation of unit 2, the green line represents hourly generation of unit 3 and the black line represents the hourly market price. It is clear that units 1 to 3 are committed and dispatched at the maximum capacity when the market price is larger than their cost coefficient. As is shown in Figure 103, the ESS is charged at low-price hours one to five and discharged at high-price hours 16 to 20, shifting a total load of 10 MWh from peak hours to off-peak hours.

Figures 102 to 103 indicate that the microgrid would decide on the supply source only based on economic considerations. A unit is committed only when its cost coefficient is lower than the market price. Additionally, it would generate its maximum power to sell the excess power to the main grid and increase microgrid income. The microgrid also discharges the ESS at peak hours, when the market price is at its highest, for the same reasons. In low-price hours, the power is purchased from the outside main grid as much as possible (i.e., 15 MW) which is equal to the maximum capacity of the power transfer. The power purchased is reduced as the market price is increased and generation of power from local resources becomes more economic. Figure 104 also indicates that if the hourly market price is more expensive than the load shedding cost, the microgrid would cut off some flexible loads because of the same economic considerations.

Table 91. Distributed Energy Resources Schedule in Grid-Connected Mode

	Hours (1-24)																							
G1	0	0	0	0	0	0	0	0	0	0	1	1	1	1	1	1	1	1	1	1	1	1	1	1
G2	0	0	0	0	0	0	0	0	0	0	0	1	1	1	1	1	1	1	1	1	1	1	1	1
G3	0	0	0	0	0	0	0	0	0	0	0	1	1	1	1	1	1	1	1	1	1	1	0	0
ESS	-1	-1	-1	-1	-1	0	0	0	0	0	0	0	0	0	0	1	1	1	1	1	0	0	0	0

Figure 102. Generation of Dispatchable Units in Grid-Connected Mode

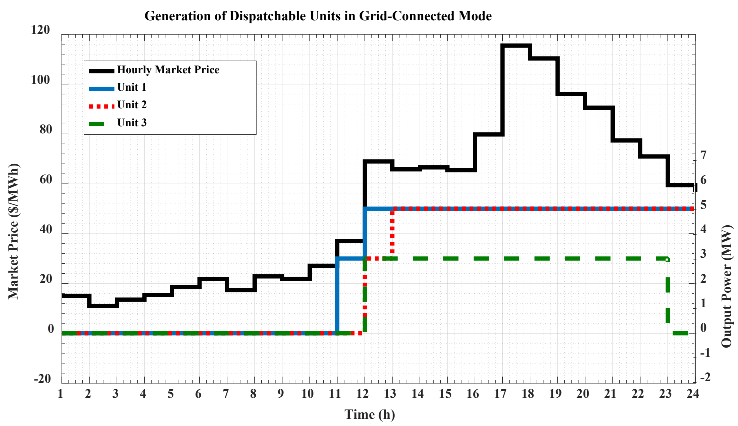


Figure 103. Generation of Energy Storage System in Grid-Connected Mode

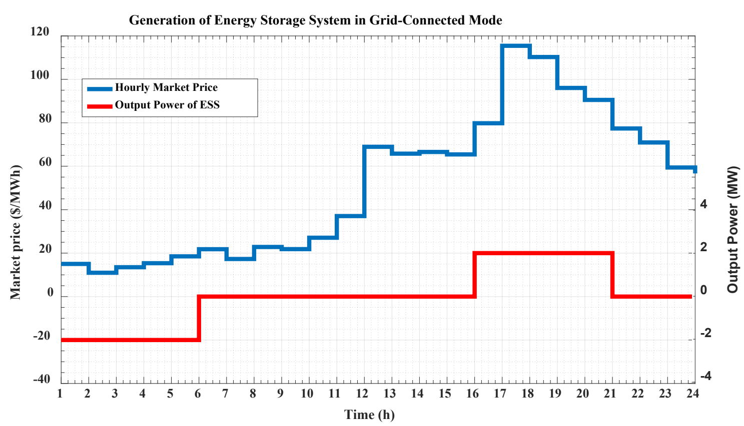
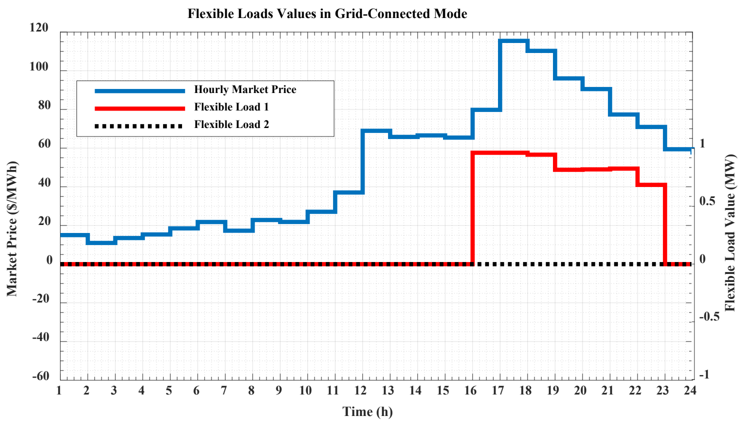


Figure 104. Flexible Load Values in Grid-Connected Mode



6.4.2 Islanding Mode

The islanding mode microgrid optimal scheduling is studied considering a 24-hour islanding event. The distributed energy resources schedule, including dispatchable unit commitment states and ESS schedule, is shown in Table 92. The commitment state as 1 means that the units are on, otherwise, it is 0. The ESS charging, discharging, and idle states are represented by -1, 1, and 0 respectively.

Table 92. Distributed Energy Resources Schedule in Islanding Mode

	Hours (1-24)																							
G1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
G2	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
G3	1	0	0	0	0	0	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	1	0	0
G4	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
ESS	0	0	0	-1	-1	-1	-1	-1	0	1	1	1	1	1	0	0	0	0	0	0	0	0	0	0

Since it is a 24-hour islanding event, the main grid power is zero from hours one to 24. As shown in Figures 105 to 106, the less expensive units 1 and 2 are committed during the entire scheduling horizon, as these offer lower cost power. Unit 3 will be committed and dispatched immediately if the less expensive units 1 and 2 and the ESS are not able to generate enough energy with the help of hourly flexible loads. The ESS is charged at low-load demand hour (hours four to eight) and discharged at peak load demand hours (hours 10 to 14), shifting a total load of 10 MWh from peak hours to off-peak hours. Additionally, flexible loads are scheduled to minimize the consumption cost and adapt to start and end times provided by the consumers, as shown in Table 92 and Figure 107. As is shown in Figure 107, the blue line represents Flexible Load FL 1 and the red line represents Flexible Load FL 2. Compared with the main grid-on operation, the results of islanding operation indicate that not only do the economic consideration, but also, the microgrid system reliability consideration determines the supply source. During the whole islanding operation, a unit will be committed to keep the power balance. In the meantime, the unit is dispatched by following the economical consideration. The microgrid also discharges the ESS at peak hours, when the load demand is at its highest period for the same reasons.

Figure 105. Generation of Dispatchable Units in Islanding Mode

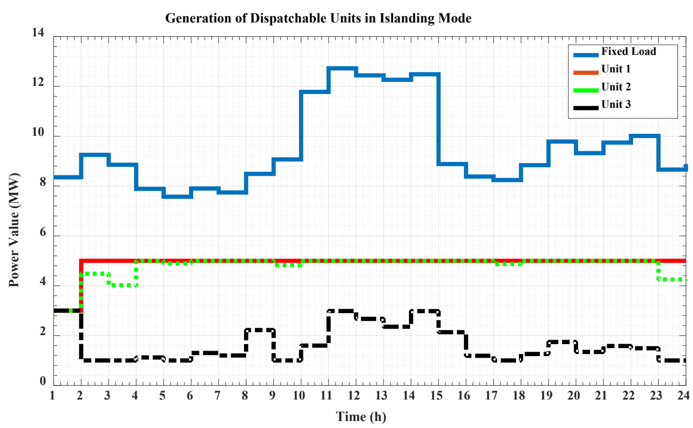


Figure 106. Generation of Energy Storage System in Islanding Mode

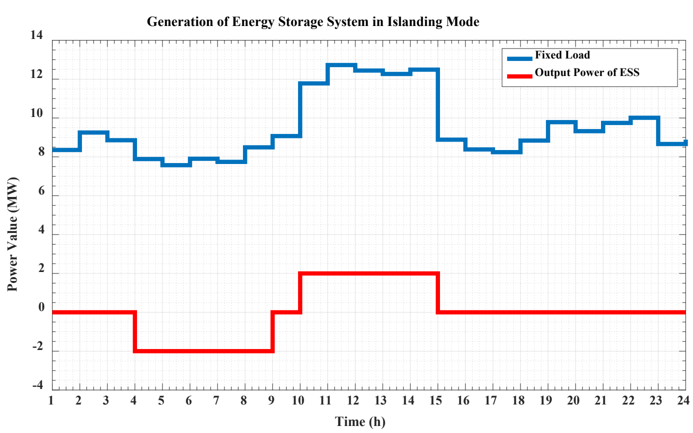
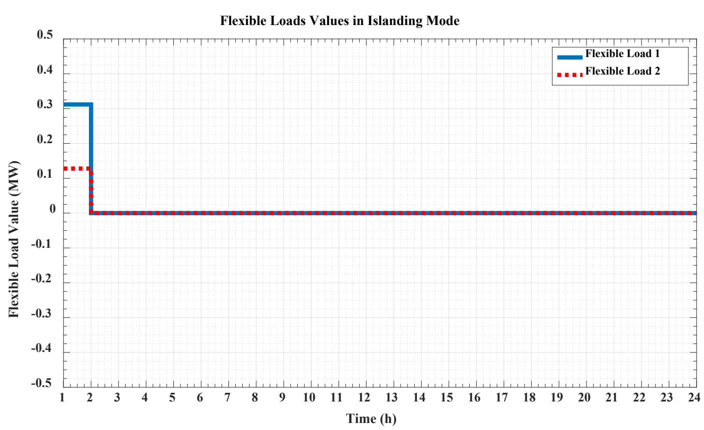


Table 93. Flexible Loads Schedule in Islanding Mode

Time (h)	1	2	3	4	5	6
DR 1 Value (MW)	0.312	0	0	0	0	0
DR 2 Value (MW)	0.128	0	0	0	0	0
Time (h)	**7**	**8**	**9**	**10**	**11**	**12**
DR 1 Value (MW)	0	0	0	0	0	0
DR 2 Value (MW)	0	0	0	0	0	0
Time (h)	**13**	**14**	**15**	**16**	**17**	**18**
DR 1 Value (MW)	0	0	0	0	0	0
DR 2 Value (MW)	0	0	0	0	0	0
Time (h)	**19**	**20**	**21**	**22**	**23**	**24**
DR 1 Value (MW)	0	0	0	0	0	0
DR 2 Value (MW)	0	0	0	0	0	0

Figure 107. Flexible Loads Values in Islanding Mode



6.5 Discussion of Optimal Scheduling Algorithm

Microgrids improve the power system economics by utilizing a variety of local generation resources, ESS, and flexible loads along with energy purchase from the main grid. They also increase the reliability of local systems by ensuring an uninterrupted supply of loads when the main grid power is not available. The following list specifies features of the microgrid optimal scheduling with consideration of both grid-connected mode and islanding mode constraint models studied in this report:

- Least-cost operation: The proposed model determines the optimal schedule of dispatchable generating units, ESS, and flexible loads, along with the main grid power transfer to minimize the cost of supplying local loads.

- Consumer convenience: The consumer decisions in scheduling flexible loads are not changed unless it is required to obtain a feasible islanding solution. The changes, however, are penalized to reduce the inconvenience for consumers and reflect the load schedule outside specified operating time intervals.
- Models reliability, scalability, and flexibility: The proposed models are comprehensive in modeling the practical constraints of microgrid components. Moreover, the proposed mixed integer programming model puts no limits on the number of components to be considered in the microgrid. Additionally, the functions of building models and the results of models are feasible and reasonable.
- Computational efficiency: In order to reduce the computation burdens and obtain the solution in a short amount of time, the islanding scenarios are examined as a subproblem and coupled with the grid-connected operation via islanding cuts. The decomposition reduces the size of the original problem and increases the solution speed.

6.6 Peak Load Carrying Capability of a Resilient Microgrid in Islanded Mode

The reliability of a component is the probability that the component performs the assigned task for a given period of time under the operating conditions [70]. Reliability in power systems involves analyzing adequacy and security of the power system. Adequacy is defined as the presence of sufficient facilities to satisfy the consumer demand. The concept of security is the capability of the system to respond to disturbances [71].

Reliability analysis includes a variety of indices and can be evaluated for different purposes. Some reliability studies focus on analyzing the resource adequacy [72-74]. Other studies, such as Jose Fernando Prada’s [75], use reliability indices for pricing operating reserves. Reliability is used for planning process in NYISO [76]. Different types of software are developed to perform reliability analysis in transmission systems [77-78]. Dan Zhu [80] in his assessment provides an interconnection analysis from a reliability standpoint. In addition, studies by Dan Zhu, Salma Kahrobaee, Tempa Dorji, Frances Xavier Bellart Llavall, and Hamid Falaghi (et al) [80-84] focus on distribution system reliability. Others focus on the effect of renewable sources, such as wind power on the reliability indices [85].

Microgrid reliability analysis has attracted increased attention in recent years [86-88]. One of the important reliability indices is the unavailability of the components and the system. Unavailability of a system varies by the system peak load. Traditionally, these studies focus determining the ability of the microgrid to increase the overall PLCC of a distribution system. This is generally acquired from

LOLE risk level of 0.1 days/year [71]. However, these studies do not provide a solution for the calculation of the reliability of a microgrid operating in isolated mode for an extended period during a long-term resiliency event.

This paper utilizes a new technique to estimate the reliability of a resilient microgrid in islanded condition. The proposed framework is implemented on an underground community type microgrid, which is planned to be built in Potsdam, NY. The proposed Potsdam Microgrid has a design criteria unavailability of 2%, which was required by NYSERDA. In the next section, this criterion is utilized to determine the peak load that can be served in the proposed Potsdam Microgrid while maintaining an unavailability of 2%.

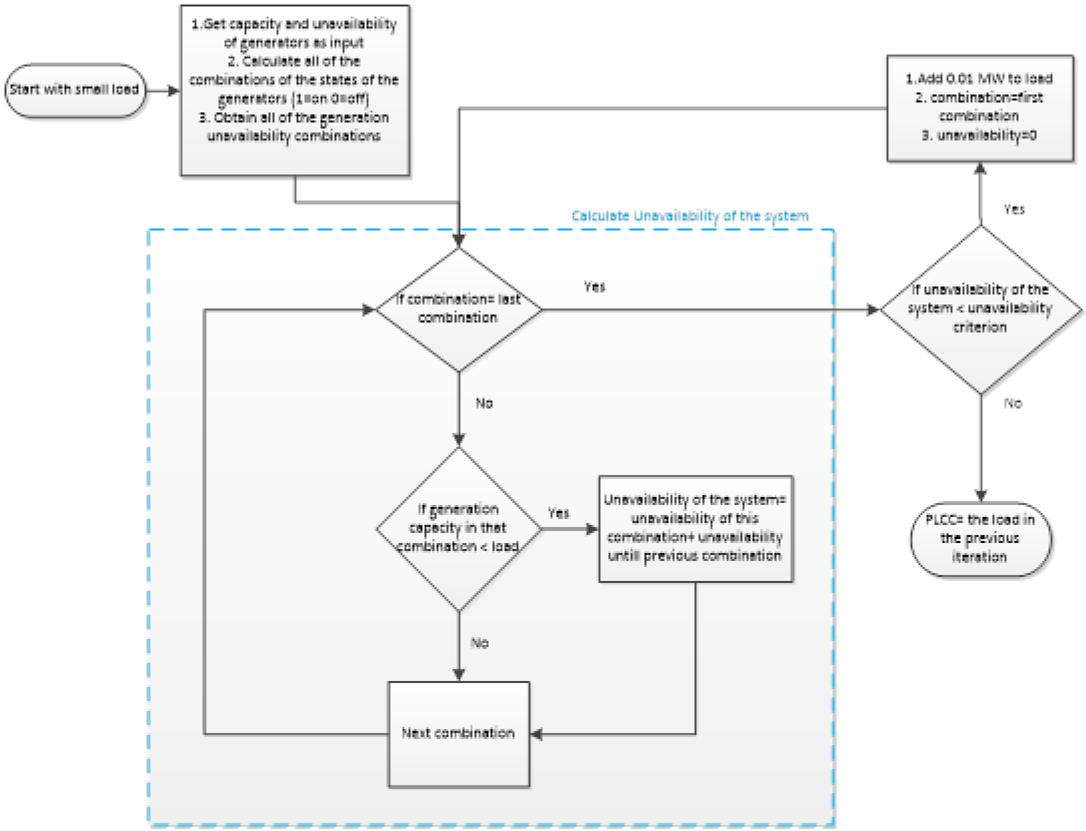
6.6.1 Peak Load Carrying Capability of a Resilient Microgrid in Islanded Condition

A new class of resilient microgrids is under development that has the primary purpose of providing electric power during and following major storms or other long-term (multi-day to multi-week) disruptions. These events, while unlikely, have major impacts on communities. The capability to provide reliable electric power during a resiliency event will improve a community's ability to provide emergency shelter, food, and services. It will also provide service for recovery teams, enabling faster restoration of local services.

By nature, resilient microgrids will generally be generation limited. It is therefore important to determine the reliability of the microgrid during operation when the main grid is not available. In this particular study, generation and loads are connected by underground primary distribution lines. The availability of these lines is high and is assumed to be sufficiently high to be considered always available during the event [89]. Similarly, the availability of the natural gas fuel supply is considered to be similarly high and is assigned an availability of 1.0.

The proposed diagram to find the PLCC of a resilient microgrid in islanded condition is depicted in Figure 21. The scheme starts with a small load and finds the unavailability of the system for this load. Then the scheme increases the load with a 0.01 MW step and repeats the same procedure until the unavailability criterion is not achieved.

Figure 108. Proposed Diagram to Find PLCC in a Resilient Microgrid



To find the unavailability for a specific load, a combination matrix of the generators is calculated. Equation 6.46 depicts the combination matrix of three generators (0 = off, 1 = on). The combination matrix is extended for a case with N generators and shown as a 2^N×N matrix in Equation 6.47. Each row of the matrix is one combination of the N generators. To find the unavailability in each of the combinations, all zeros in that combination should be replaced with unavailability and all ones should be replaced with availability. The multiplication of the replaced numbers in each combination (row) will be equal to the unavailability in the associated combination. If the generation capacity in that combination is less than load, the unavailability of this combination is added to unavailability until the previous combination is reached. The last combination will result in the unavailability of the islanded resilient microgrid. The proposed scheme is utilized in a practical microgrid, and the effect of generation on PLCC is studied thoroughly in the next section.

$$\begin{bmatrix} 0 & 0 & 0 \\ 0 & 0 & 1 \\ 0 & 1 & 0 \\ 0 & 1 & 1 \\ 1 & 0 & 0 \\ 1 & 0 & 1 \\ 1 & 1 & 0 \\ 1 & 1 & 1 \end{bmatrix}$$

Equation 6.46

$$\begin{bmatrix} 0 & 0 & 0 & 0 & \cdots & 0 & 0 & 0 \\ 0 & 0 & 0 & 0 & \cdots & 0 & 0 & 1 \\ 0 & 0 & 0 & 0 & \cdots & 0 & 1 & 0 \\ \vdots & \vdots & \vdots & \vdots & \vdots & \vdots & \vdots & \vdots \\ 1 & 1 & 1 & 1 & \cdots & 1 & 1 & 1 \end{bmatrix}$$

Equation 6.47

6.6.2 Proposed Implementation on the Potsdam Microgrid

The proposed scheme is implemented on a practical case study. Table 94 shows the generator capacities of the Potsdam Microgrid case studies (both generation in place and proposed added generation). The existing generation is natural gas fueled, and the new is either natural gas or dual fuel. The generation currently in place is not sufficient to support the microgrid load, so the new generation must be added.

Table 94. Generator Capacities of the Potsdam Microgrid Case Studies (Installed and Proposed)

Generators in the System: 1.4 MW, 1.4 MW, 0.3 MW, 0.2 MW, 0.06 MW, 0.06 MW, 0.06 MW (total = 3.48 MW)							
Proposed Added Generation	1×2.5 MW 1×1.5 MW	2×1.25 MW 1×1.5 MW	1×2.5 MW 2×0.75 MW	4×1.25 MW	4×0.75 MW	4×1 MW	2×2.5 MW

Usually the generator availability is provided by the manufacturer. However, for this case, the availabilities of the generators were not obtainable. Therefore, three cases are studied with different generator unavailability indices. In the first case, unavailability of the generators are considered to be 0.01 which are estimated by Department of Army [89]. The second case is evaluated for generator unavailability indices of 0.03, which is provided by industry as the best estimate for Potsdam Microgrid. The third case utilizes a maximum estimated unavailability of 0.05 for all the generators. Tables 95 to 97 depict the PLCC values for generator unavailability indices of 0.01, 0.03, and 0.05, respectively.

The expected unavailability of the units in the Potsdam Microgrid will be 0.03; therefore, the results presented in Table 96 are of primary importance. The preferred generation alternative is Option VI, where 4 to 1 MW units will serve 6.08 MW of load with unavailability less than 2%. Option II is the second most likely option, where two new 1.25 MW units plus one new 1.5 MW unit will provide 5.98 MW of load with less than 2% unavailability. Either of these two options seems to be an equally good choice for the microgrid.

Table 95. PLCC of the System for Different Proposed Generation Units with all Generator Unavailability Indices Equal to 0.01

Generators in the system: 1.4 MW, 1.4 MW, 0.3 MW, 0.2 MW, 0.06 MW, 0.06 MW, 0.06 MW (total = 3.48 MW)			
Case	Added Generators	Maximum Load for Availability of at least 0.98	Unavailability at Maximum Load (see prior column)
I	1×2.5 MW 1×1.5 MW	5.98	0.0112
II	2×1.25 MW 1×1.5 MW	6.08	0.0119
III	1×2.5 MW 2×0.75 MW	6.08	0.0115
IV	4×1.25 MW	7.08	0.0031
V	4×0.75 MW	5.08	0.0024
VI	4×1 MW	6.08	0.0024
VII	2×2.5 MW	6.78	0.02

Table 96. PLCC of the System for Different Proposed Generation Units with all Generator Unavailability Indices Equal to 0.03

Generators in the System: 1.4 MW, 1.4 MW, 0.3 MW, 0.2 MW, 0.06 MW, 0.06 MW, 0.06 MW (total = 3.48 MW)			
Case	Added Generators	Maximum Load for Availability of at least 0.98	Unavailability at Maximum Load (see prior column)
I	1×2.5 MW 1×1.5 MW	4.98	0.0091
II	2×1.25 MW 1×1.5 MW	5.98	0.0172
III	1×2.5 MW 2×0.75 MW	4.98	0.0081
IV	4×1.25 MW	7.02	0.0190
V	4×0.75 MW	5.08	0.0197
VI	4×1 MW	6.08	0.0198
VII	2×2.5 MW	5.98	0.0129

Table 97. PLCC of the System for Different Proposed Generation Units with all Generator Unavailability Indices Equal to 0.05

Generators in the System: 1.4 MW, 1.4 MW, 0.3 MW, 0.2 MW, 0.06 MW, 0.06 MW, 0.06 MW (total = 3.48 MW)			
Case	Added Generators	Maximum Load for Availability of at least 0.98	Unavailability at Maximum Load (see prior column)
I	1×2.5 MW 1×1.5 MW	4.92	0.0185
II	2×1.25 MW 1×1.5 MW	4.83	0.0140
III	1×2.5 MW 2×0.75 MW	4.92	0.0161
IV	4×1.25 MW	5.83	0.0091
V	4×0.75 MW	4.33	0.0080
VI	4×1 MW	5.08	0.0080
VII	2×2.5 MW	5.77	0.0189

6.6.3 Peak Load Conclusions

This section analyzes generation availability metrics for the Potsdam Microgrid operating in the isolated mode. The results show that the choice of generation options has a significant impact on the ability of the microgrid to serve load with 98% availability. Table 96 shows that Options II and VI will serve 6 MW reliably with 4 MW of new generation. Option 1, however, will only serve 5 MW of load at this same reliability.

6.7 Benefit to the Community from Improved Restoration Rate

A new time-varying interruption cost model has been developed to analyze the cumulative and incremental costs of electric power outages during severe weather events. The time-varying model is analyzed from the time when the storm ends to the time when the last customer's power is restored. The proposed model estimates minimum, maximum, and average interruption costs for a wide range of customers. Consumers connected to the power grid fall in three general classes, [90] and can be defined as follows:

- Medium and large commercial and industrial (non-resident customers with sales > 50,000 kWh per year).
- Small commercial and industrial (non-resident customers with sales < 50,000 kWh per year).
- Residential customers

Significant research has been conducted into interruption costs for commercial and industrial customers. In general, there has been relatively less attention given to the impacts of power interruptions on residential consumers. The evaluation of impact on residential customers has been focused on short-term interruptions lasting up to several hours [90-92]. This research has focused on the residential consumers' willingness to pay to avoid the interruption. Power interruptions due to major storm events have attracted great attention in recent years. Therefore, a complete event analysis (10 to 14 days) considering all factors is needed. This analysis is not valid for longer term interruptions when residential consumers incur significant costs and significant impacts due to the power interruption.

Restoration analysis is an important step in assessing the cost of a power outage. Most of the power outage restoration curves (percentage restored versus outage duration) after severe weather storms follow similar trends during the outage period [98, 99]. In addition, it is also shown in Lansing Board of Water & Light (BWL) December 2013 ice storm [99] that the ice storm restoration also fits the national experience.

Several factors influence the power restoration rate: topography, population density, damage levels, tree removals, severity and scope of the storm, storm preparation time, and post-storm issues. Fully-equipped trucks and the availability of replacement equipment will have a large effect on the restoration time. Lack of restoration staff and the inability to move resources due to the unavailability of the roads are also important factors in the restoration process [98, 100]. Some factors, such as population density are almost constant for a specific region and are not required to be included in the proposed model. Other factors, except the number of crews involved in the restoration are modelled as an uncertainty factor. In this analysis, it is considered that available crews have sufficient resources that allow them to be productive.

In section 2 a new cost model is developed for residential customers. Section 3 presents the number of crews deployed during severe weather events. In section 4, a restoration model for Lansing Board of Water & Light (BWL) December 2013 ice storm is developed, and the effect of increased restoration staff is analyzed. The newly developed model is first fit to the best equation; then numerical-based analysis is studied to analyze increased restoration crew effect. It is shown that increased number of crews has a significant effect in the restoration rate and hastens the restoration process.

There are many factors that determine the impact of power outages caused by severe weather events. The main factors include:

- The time when the power outage occurs. The moment when the power outage occurs, including season, day, and time of day, determines what activities are interrupted, and thus have a large impact on the cost estimates.
- The duration of the outages also affects the cost of the power interruption. Some costs such as loss of computer files occurs instantaneously. Others, such as food spoilage, occur with the passage of time. The impact of individuals or families being displaced from their residence is significant and needs to be a factor even in cases where the displaced people do not incur out-of-pocket expense as a result.

When displaced persons move to shelters or other emergency temporary housing, there are costs to society, impacts on the individuals, and costs to individuals. It is necessary to capture the full range of impacts on residential electric power consumers to correctly plan for power grid recovery from major storms. It is important to note that the results provided by this model will be used to determine the appropriate level of readiness for extreme weather events. The results from this model do not represent actual costs to individuals. Furthermore, the results of this model cannot be used to justify cost recovery of storm damage from service providers.

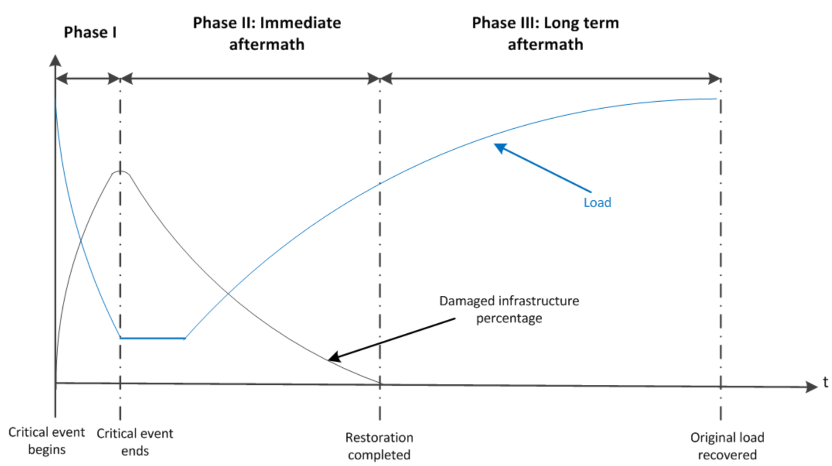
6.7.1 General Considerations for the Power Outage Cost Model

A critical event affects power systems in three phases as shown in Figure 109 [112]:

- Phase I occurs during the critical event and lasts for a short time; at most for a few days.
- Phase II is the immediate aftermath or recovery and restoration phase. Phase II starts from the moment the critical event ends and lasts up to the time when infrastructure is repaired. The phase usually lasts from a few days up to several weeks. At the end of this phase, power is restored to the customers served before the event. However, some of the loads could be lost during the critical event.
- Phase III is referred to as the long-term aftermath and follows Phase II. The phase lasts until the load is restored to the levels before the critical event and might last from a few weeks to several months or even years.

Cost evaluation differs in each of the three phases of any critical event. The cost model presented in this section is evaluated for Phase II. It is possible to estimate the costs in dollars per customer ($/#c) or dollars per kilowatt hour not served ($/kWh). In this report all costs are in $/#c unless otherwise mentioned. Different distribution circuit design configurations (such as radial, loop, networked, with or without Smart Grid technology) also influence the duration of Phase II. The proposed model is independent of Phase II recovery period and can be applied for any estimated severe weather outage duration.

Figure 109. Timeline of a Critical Event



This research is based on the Berkeley study [90] which itself is assembled from 24 studies conducted by eight major U.S. utilities over 13 years. These studies contain data sets from the entire southeast, most of the western U.S. and the Midwest south of Chicago.

Residential Data Sets

Commercial and industrial (C&I) customer power interruption costs can be estimated based on the profit lost, but residential power interruption cost is more difficult to evaluate. Power interruption of residential customers can be measured in terms of "inconvenience" rather than in terms of labor or monetary costs [90, 103]. Therefore, the inconveniences associated with disrupted activities, uncomfortable room temperature, and loss of lighting are estimated in these studies [90-92]. This research requires a complete monetary and non-monetary cost analysis; thereby, the Berkeley study, which analyzes cost impacts during an eight-hour period, is not suitable for the extended power interruptions. In the next section, a new power outage cost model is presented and analyzed during a period of ten days.

6.7.2 Power Outage Cost Model

A cost model is proposed to evaluate power outage cost impacts on residential customers. The proposed time-dependent residential cost model incorporates the both inconvenience and monetary costs. Monetary costs analyzed in the model are divided into three main categories including food spoilage, increased food cost, and shelter costs.

Residential Cost Model

Developing a residential customer cost model is different than commercial and industry customer cost models. Previous residential power outage analyses are based on willingness to pay (WTP) or willingness to accept (WTA) models. In WTP models, customers are asked how much they are willing to pay for a decrease in power interruption. There are other methods for evaluating the residential power outage costs [102], but a complete long-term evaluation of the cost impacts has not been widely accepted.

In the following sections, monetary costs defined as food spoilage, increased food cost, and shelter costs are analyzed in detail.

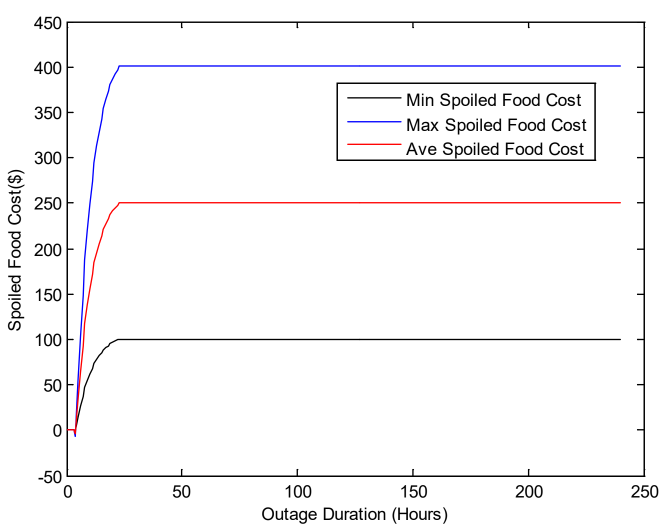
6.7.2.1 Food spoilage

A refrigerator will keep food cold up to four hours if it is unopened. Full freezers will hold food safely for approximately 48 hours if the door remains closed (half-full freezers will hold food safely for up to 24 hours). These times may vary due to the age of the unit, condition of the seals, temperature setting, and amount of food [95,104]. Medicine and food spoilage losses due to lack of refrigeration during a power outage varies according to these factors. However, some companies such as ConEdison, reimburse food spoilage costs up to $500 [96]; hence, a $100-$400 range is reasonable for the maximum spoiled food cost. Claims for losses as a result of power outages caused by conditions beyond the control of the utility companies, such as severe weather disasters, or floods are not reimbursed by these companies. Considering these factors, cumulative cost functions are estimated and plotted in Figure 110, which starts four hours after the event and ends after one day. Functions related to minimum and maximum spoiled food costs are presented in Equations 6.48 and 6.49, respectively. Figure 110 shows the estimated cumulative cost of spoiled food and medication loss during a power outage.

Equation 6.48 $$\boldsymbol{f(t) = 106.86 - 196.3 + e^{-\frac{t}{6.76}}} \quad 4<t<24$$

Equation 6.49 $$\boldsymbol{f(t) = 427.43 - 785.19 + e^{-\frac{t}{6.76}}} \quad 4<t<24 \qquad (6.49)$$

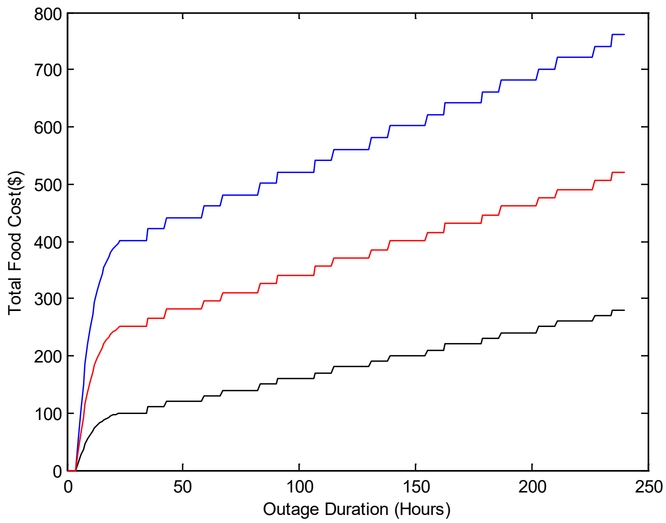
Figure 110. Estimated Cumulative Cost of Spoiled Food and Medication Loss during a Power Outage



6.7.2.2 Increased Food Cost due to Power Outage

Usually customers will not be able to cook during power outages. Therefore, they will encounter increased food costs until the power is restored. An incremental cost of $10 to $20 is added per meal (except breakfast) at hours 12:00 and 20:00 of each of the outage days. Figure 111 represents the estimated cumulative food cost. Assuming the food in the refrigerator is usable the first day, the increased food cost for meals is modeled after day one.

Figure 111. Estimated Cumulative Food Cost during a Power Outage



6.7.2.3 Shelter Cost

Because of extreme event impacts, including power outage, some houses may not be habitable, and a proportion of the population will need to seek alternative housing or shelter. There is a difference between sheltering and housing during a post-disaster period [97]. Sheltering represents the activity of staying in a place during or immediately after the disaster where regular daily activities are suspended. Housing is defined as the activity of staying in a place where normal daily activities are returning to normal conditions. As a result of this difference, providing a place for people to stay during and after the disaster is based on four stages, which are presented as follows [97, 98]:

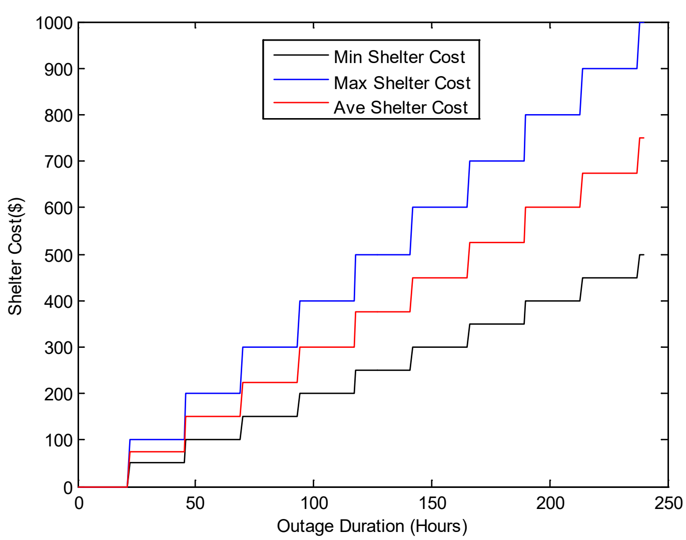
- Emergency shelter, which can be a public shelter, taking shelter at a friend’s house, or shelter under a plastic sheet. The duration for emergency shelter is usually from one night to a couple of days. Extensive preparation of food, water, and medication is not necessary for this period.

- Temporary shelter, which can be a public shelter or a tent, lasts up to a couple of weeks. Extensive preparation of food, water, and medication is essential during this stage.
- Temporary housing activities are returned to normal conditions for the residents.
- Permanent housing is when people return to their reconstructed homes, or they settle in a new home. In this period everything has returned to pre-disaster conditions.

The affected customers may or may not pass through all these stages. In addition, some stages may be applied simultaneously for some customers. Most of the studies include an analysis of temporary housing during the post-disaster stage [106-109]. The proposed cost model is analyzed during Phase II of Figure 109; therefore, temporary shelter costs are used for the 10-day duration analysis.

Many factors such as quality, durability, security, size, weather resistance, design, privacy, noise, cleanness, and providing necessary services affect the cost of temporary shelter. Also, some customers will stay in a hotel rather than shelters, with an average estimated cost of $150.25 per night [110]. However, a range of $50-100 per night per family is reasonable for the temporary shelter cost and is added to the cost model at hour 23:00 of each day and shown in Figure 112.

Figure 112. Estimated Cumulative Shelter Cost during a Power Outage



6.7.2.4 Inconvenience Cost

Most of the studies that analyze the value of lost load (VoLL) are based on the WTA or WTP models [90-92]. These studies usually analyze the leisure or inconvenience costs that customers experience over a period of several hours. The residential database used in the Estimated Value of Service

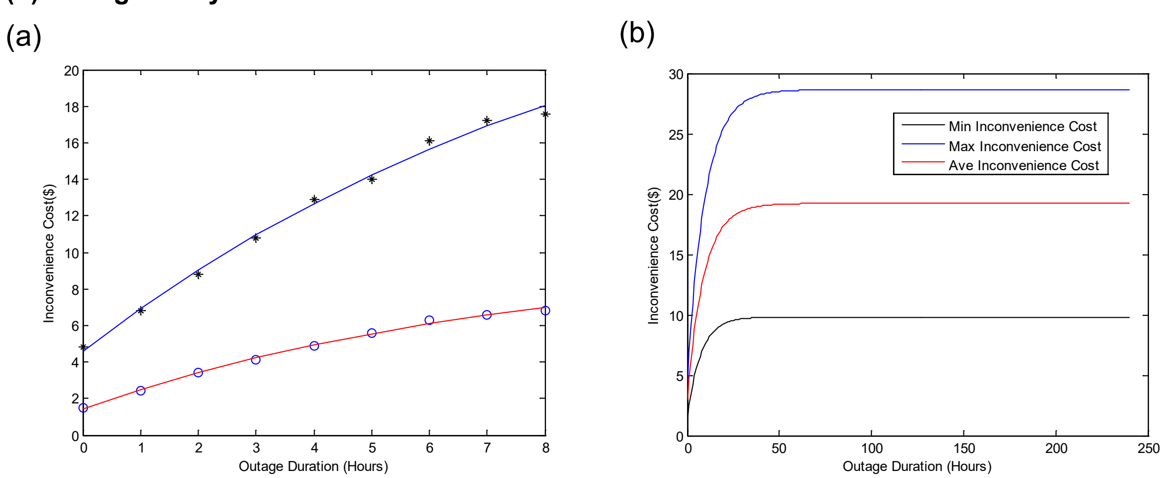
Reliability for Electric Utility Customers in the United States [90] is utilized for modeling the inconvenience costs. Figure 113(a) represents the minimum and maximum inconvenience costs obtained from Ernes Orlando Lawrence Berkeley National Laboratory [90]. By using these estimated costs, the best functions representing minimum and maximum inconvenience costs are estimated and presented in Equations 6.50 and 6.51, respectively.

Equation 6.50 $$\boldsymbol{f(t) = 9.82 - 8.4 + e^{-\frac{t}{7.4}}}$$

Equation 6.51 $$\boldsymbol{f(t) = 28.65 - 24.06 + e^{-\frac{t}{9.76}}}$$

Figure 113(b) depicts the abovementioned functions for a 10-day period. As depicted in the figure, costs will saturate after two days. However, this raises a question: Is it appropriate to estimate the 10-day cost by using these functions based on data in the first 8 hours? By considering the exponential trend in Figure 113(a) and comparing the costs with the shelter and spoiled food costs range, the 10-day cost function presented in Figure 113(b) is the best model based on the data. In addition, as customers are paying for other life necessities, there will be a negative impact on the inconvenience costs for long-term analyses. So, it can be expected that the customers will not pay for the inconveniences after a couple days, and the costs in the WTP model will follow the trend shown in Figure 113(b).

Figure 113. Estimated Inconvenience Cost during a Power Outage (a) during Eight Hours and (b) during 10 Days

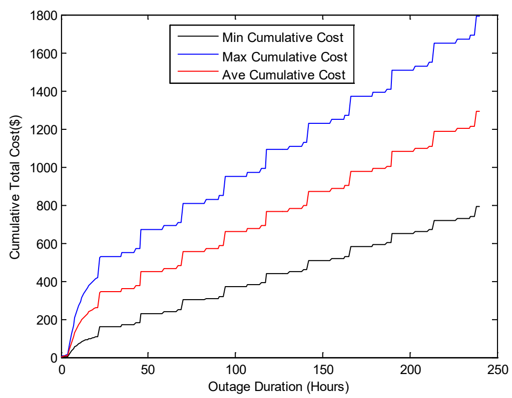


6.7.3 Cumulative Residential Cost Model without Considering Timing of Outage

To obtain a complete time-varying cost model, the three costs mentioned in previous sections are added together. Figure 114 depicts the cumulative cost model for residential customers, assuming the power interruption starts at midnight.

Figure 114. Estimated Cumulative Cost for Residential Customers

Power outage occurs at midnight.



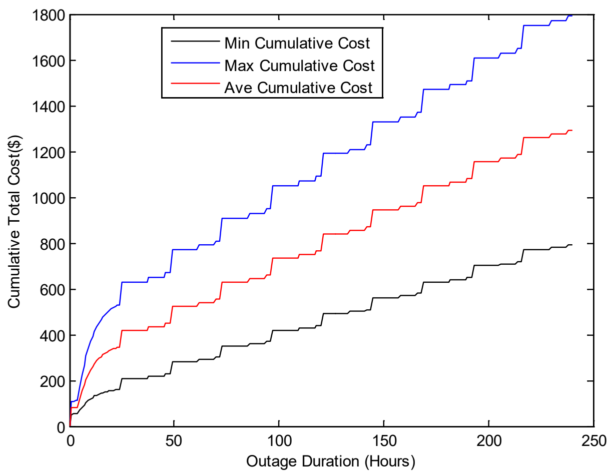
In this model the effect of time of interruption is not considered. In the next section, the effect of time of power outage is studied.

6.7.4 Cumulative and Incremental Residential Cost Models Considering Timing of Outage

It is considered in this case that the outage occurs at hour 21:00. Considering the time of the power outage, the procedure developed in previous sections is applied. Figure 115 shows the results of this analysis.

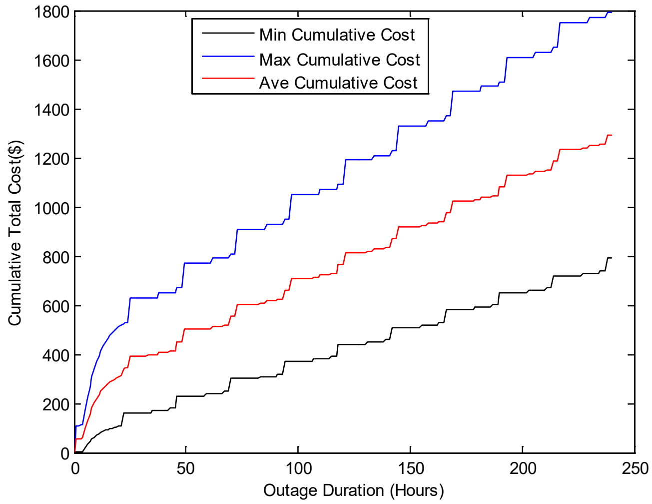
Figure 115. Estimated Cumulative Cost per Residential Customer

Power outage occurs at hour 21:00.



Power outages starting at each hour of the day are analyzed and the cumulative costs for all 24 situations are obtained. The analysis of these 24 cases shows that the maximum cumulative cost at hour 21:00, presented in Figure 115, is the worst case maximum cost and the minimum cumulative cost at hour 0:00, presented in Figure 114, is the minimum cost over all cases. Therefore, by utilizing these two curves, the minimum, average, and maximum of the cumulative cost is obtained and shown in Figure 116. Average cumulative total cost is the average of the maximum cumulative cost of the power interruption at hour 21:00 and the minimum cumulative cost of the power outage at hour 0:00.

Figure 116. Estimated Cumulative Cost Model for Residential Customers



This analysis provides an estimate of total costs considering all factors. The potential consequences of power outages on residential customers are estimated. The residential cost analysis shows that monetary costs have a significant affect in the cost estimates. Therefore, residential cost models without considering the monetary costs are not suitable for evaluating the residential cost impacts.

The next section proposes a procedure that is capable of comparing the cost of power outages with different crew deployment and restoration rate models.

6.7.5 Proposed Procedure to Analyze the Electric Power Outage Cost Effect of Severe Weather Events during Immediate Aftermath Phase

Community response to severe weather events has attracted increased attention in recent years. Restoration of the electric power grid is a key component of disaster recovery. The availability of a resilient microgrid that provides electric power would speed the restoration by allowing for additional restoration crews and improving crew efficiency. It would also provide basic services to displaced population. The investment in the microgrid would reduce the impact on the community by reducing the recovery time. It is important to balance the benefit this microgrid provides to the community with the cost of the microgrid. This section proposes an analytical framework in which communities can assess the customer costs with different crew deployment models.

Figure 117. Proposed Diagram for Analyzing Increased Crew Deployment Cost

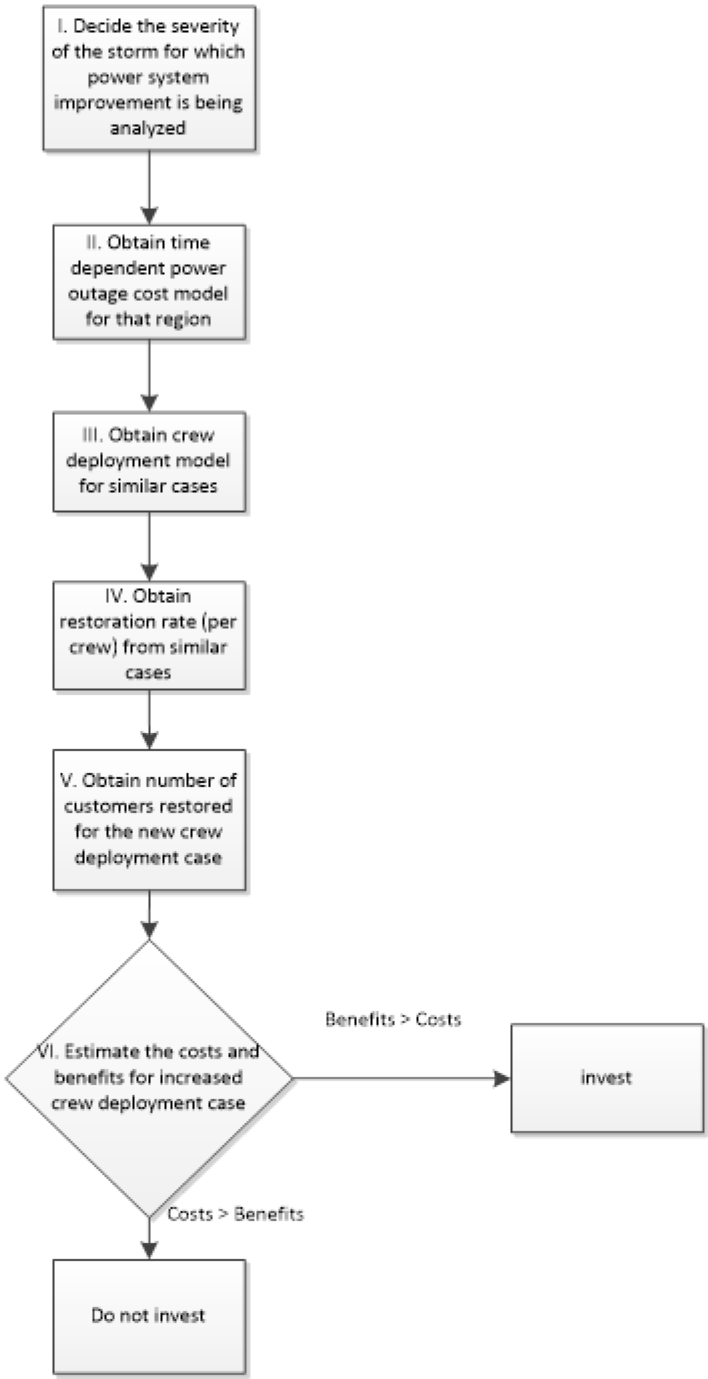


Figure 117 shows the proposed method for analyzing various scenarios predicting residential consumer impacts during severe weather storms. Figure 117 shows that two key models are necessary to this analysis: a cost model (Block II) and a restoration rate per crew model (Block IV). With these two models available, a given storm (Block I) can be analyzed for a variety of crew deployment options (Block III).

This analysis starts with deciding the severity of the storm and number of customer power outages. For a given case k, let the N_k be the number of residential customers out of service and let $PR_k(t)$ be the proportion of customers whose service is restored at any given time (t)—then the customers still to be restored are the following:

Equation 6.52 $$\boldsymbol{NO_k(t) = N_k(1 - PR_k(t))}$$

For a given case, there will be a restoration rate per crew, that is, a stochastic function of the proportion of customers restored.

Equation 6.53 $$\boldsymbol{PCRR_k(PR_k)}$$

At any given point in the restoration, $PCRR_k$ will have an expected value with a defined uncertainty.

The number of crews working on the restoration will be determined by the emergency response team, within certain parameters. Let the number of crews in a given restoration scenario j be NC_{kj}(t). Constraints of NC_{kj}(t) include the availability of crews, knowledge of the severity of the event, the time it takes to get crews on site, the availability of infrastructure and supplies to support the restoration effort, the cost of the restoration, and other factors. The restoration coordinators will determine NC_{kj}(t).

As a planning tool, multiple crew deployment scenarios j will be analysed to study the event recovery. Because of the stochastic function $PCRR_k(PR_k)$, each scenario will be solved using Monte Carlo analysis. Two restoration rate models are developed. In the first model, the expected restoration rate variation at hour i is independent from hour i-1. In the second model, the variation percentage is considered to be constant during time. In the first model, localized variables dominate the uncertainty in restoration rate. These would include localized pockets of particularly heavy damage or short-term logistics issues, for example. The second model provides the heavier weight to storm specific impacts—geographic issues that impact the restoration or issues related to the nature or particular impacts of the storm, for example.

The stochastic time-dependent power outage cost model for residential consumers is given in Figure 116. Costing models and methodologies for commercial and industrial electric power consumers have been previously reported in the literature [90].

The cost per customer for event k is defined as CPC_k(t). This cost is the mean cost per customer determined for the event in question. At any given time t_i, a cost per customer is determined from the stochastic range of costs at that time. That cost is applied to the customers who are out of service in that hour. The cumulative impact to the customers at the beginning of hour t_{i+1} is then:

Equation 6.54

$$\boldsymbol{TC_k(t_{i+1}) = TC_k(t_i) + CPC_k(t_i) \cdot NO_k(t_i)}$$

This cost function is evaluated in each step following the calculation of the number of customers predicted to be restored in that hour. This full algorithm is solved repeatedly to get a stochastic distribution of the results of the restoration time and cost impact on consumers.

6.7.6 Restoration Rate per Crew Model

The effectiveness of the restoration effort following a major weather event depends on many factors. These include the geographic area of the damage, the extent of the damage, the availability of crews, materials and resources for the recovery effort, etc. [99,111]. Recovery resources would include appropriately outfitted trucks, physical access to damage areas, capability to house and feed crews, etc. Materials such as poles and cross arms needed to replace damaged and destroyed components are also critical to the recovery effort. The recovery effort also depends on the type of crews available, the availability of personnel to plan, dispatch, and coordinate the crews, and the stage of the recovery.

The predictive model developed in this study is a function of the number of crews deployed and the percent of customers restored. It is assumed that the infrastructure is available to support the deployed crews (i.e., if a crew is on site but not deployed due to lack of materials, supplies, or other support, it will not be counted). There is no distinction made in the model as to type of crew—it is assumed that the mix of crews is appropriate for the effort.

The second input variable in the model is percentage of customers restored. The repair rate per crew per hour will vary throughout the restoration effort. A typical recovery would be expected to start out at a relatively low value during the damage assessment phase. It would then typically raise to a peak value as prioritized repairs are made that restore multiple customers at a time. It will then decline gradually as the repairs are made to sections with fewer and even single customers. There will be variation in the restoration rate model due to the nature of the damage. For example, in a situation where the entire transmission grid serving an area is down, there will be an extended period with few if any restorations taking place, while transmission repairs are done. However, suitable restoration models for predictive analysis can be developed from prior experience.

6.7.7 Restoration Model Case Study

A December 2013 ice storm that impacted the Lansing Board of Water & Light (BWL) has been thoroughly documented in the literature [99]. This event is used for a case study in this project. While there is significant data available for larger recent events, the team found that certain critical information was not available in the open literature. This event resulted in 40,000 customers losing power in the BWL service area.

Figure 118 shows the crew deployment timeline for this event. Figure 119 shows the pace of restoration following this storm, plotted as a decreasing number of customers remaining out of service as a function of time.

Figure 118. Reported Crew Deployment Timeline

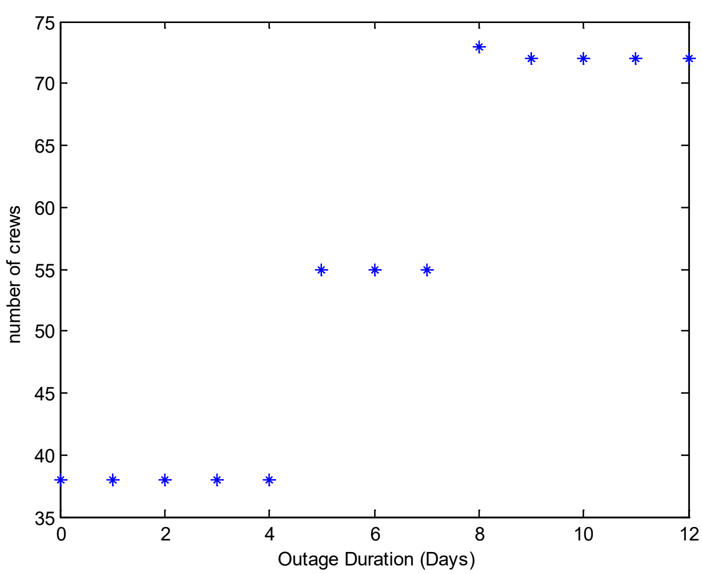
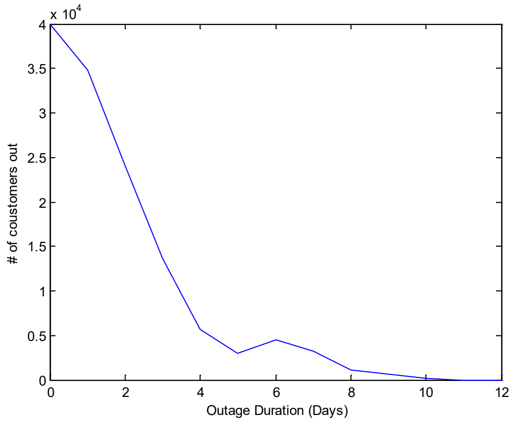


Figure 119. Reported Customer Restoration Record after Weather Disaster



6.7.7.1 Equation-Based Restoration Model of the Case Study

To obtain the number of customers restored per day at any hour, the model needs to be estimated with an equation. Equation 6.55 depicts the restoration model obtained from this analysis. The best estimated function is presented in Figure 121.

Equation 6.55

$$f(x) = 1.117 \times 10^4 e^{-\frac{1}{2}\left(\frac{x-2.5}{1.5}\right)^2}$$

In the next section, the acquired model is utilized in order to analyze the effect of increased number of crews in the restoration model.

6.7.7.2 Effect of Increased Number of Crews in the Restoration Model

The number of deployed crews plays an important role in the restoration rate (Figure 120). To investigate this effect, the restoration model should be assessed independently of the number of crews and the outage duration. Therefore, acquiring a model for the number of customers restored per hour per crew versus percentage of customers restored is a necessity. Figure 121 (open circles) shows this data for the Lansing event. In the event, as shown in Figure 119, the number of customers out of service increased on day 6 of the restoration—which is not considered a typical pattern of restoration. Figure 121 (red line) shows the same data with the anomaly removed. The resulting data set was used to find an estimated function. The plot of this function is also shown in Figure 122.

Figure 120. Estimated Number of Customers Restored per Day

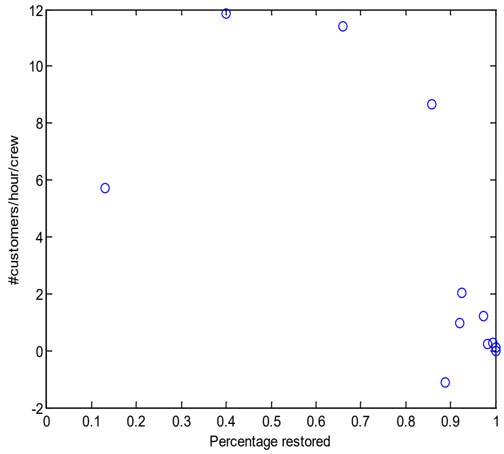
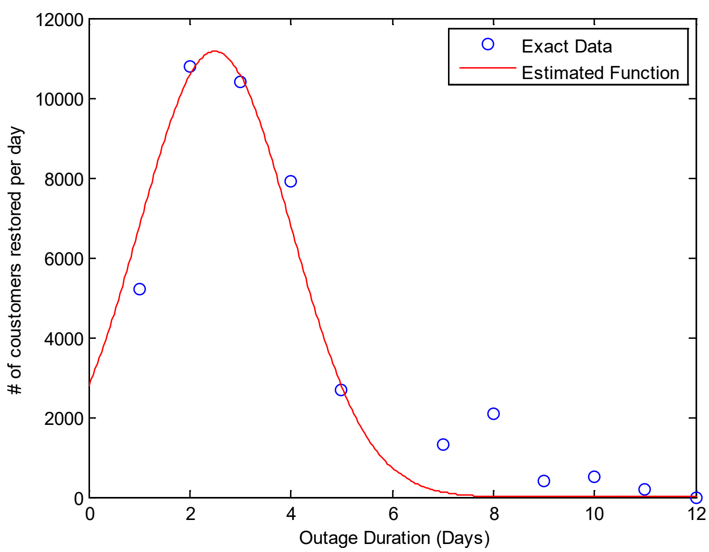


Figure 121. Number of Customers Restored per Hour per Crew versus Percentage of the Customers Restored

Exact data (open circles) and processed data with negative restoration rate period removed (red line).



To analyze the restoration rate with different numbers of crews, two cases are studied. Case I is the base case, with restoration as it occurred. Case II is the accelerated restoration case, where additional crews were available to restore service. In Case II, it is assumed that the additional crews have materials and dispatch instructions to be as effective in their efforts as the crews in Case I. Table 98 shows the number of crews deployed by day in the two case studies.

Table 98. Number of Crews in Two Case Studies

Day	1	2	3	4	5	6	7	8	9	10	11	12
Number of Crews in Case I	38	38	38	38	38	55	55	55	73	72	72	72
Number of Crews in Case II	72	72	72	72	72	72	72	72	72	72	72	72

The number of customers restored in the first hour for the second case is obtained from Equation 6.56.

Equation 6.56 $$\boldsymbol{N_{Cur2} = N_{Cur1} * \frac{N_{c2}}{N_{c1}}}$$

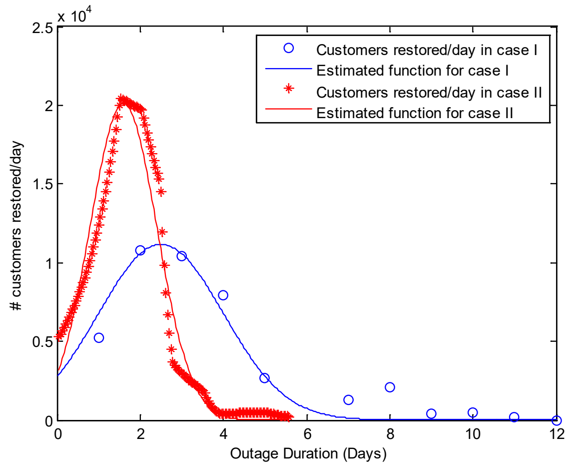
Where N_{Cur1}, N_{Cur2} , N_{c1}, and N_{c2} are the number of customers restored in case I, the number of customers restored in case II, the number of crews in case I, and the number of crews in case II, respectively.

For the rest of the analysis time interval, Equation 6.57 is utilized to obtain the number of customers in case II.

Equation 6.57 $$\boldsymbol{N_{Curi} = R_{i-1} * N_{c2}}$$

Where N_{Curi} is the number of customers restored at hour i, and R_{i-1} is the restoration rate at hour i-1 obtained from the estimated function presented in Figure 121. In order to obtain R_{i-1}, the percentage of the customers restored at hour i-1 is obtained; then, restoration rate is obtained from the figure. Figure 122 shows the obtained model for case II, in which the restoration process is finished after about 5.5 days.

Figure 122. Number of Customers Restored in the Two Case Studies



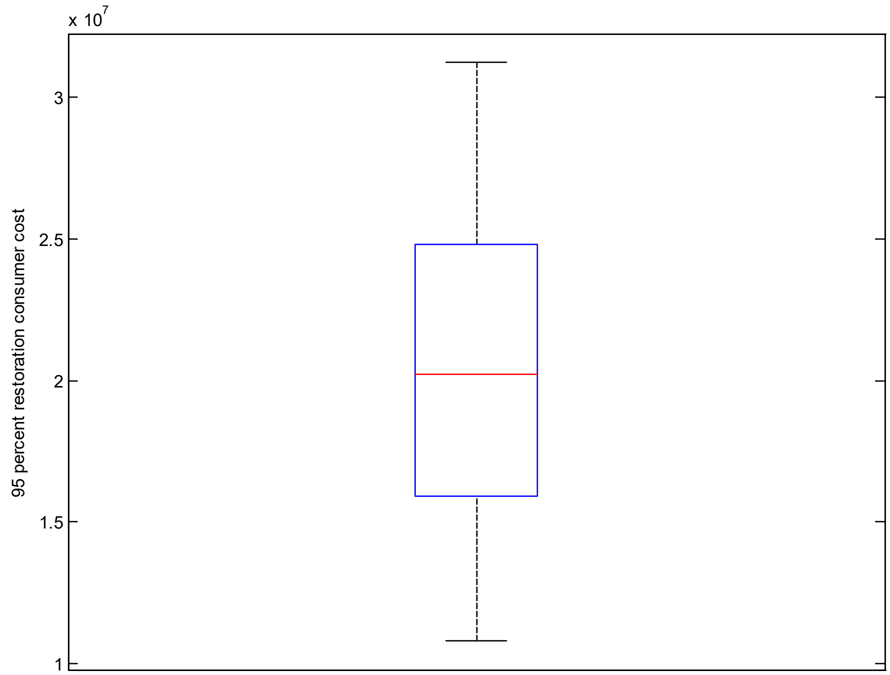
6.7.7.3 Cost Analysis of the Case Study

The cost models developed in previous sections are used to analyze the cost for two cases presented in Table 98. In this cost study, it is assumed that the restoration rate per hour per crew is not exactly known. At each point in the restoration function of Figures 121 and 122, a uniformly distributed uncertainty of (-30%, +30%) in the restoration efficiency is modeled. In this study, two stochastic restoration rate models were studied:

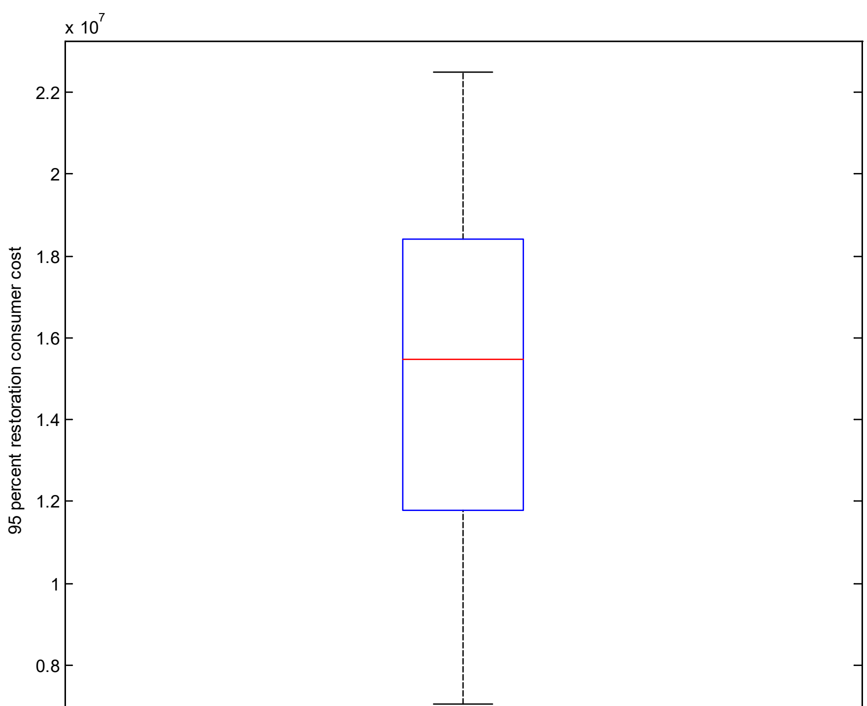
- Model I: The restoration rate uncertainty varies for each hour of the restoration.
- Model II: The restoration rate uncertainty is constant throughout the event.

Model I would represent that hourly variation in restoration efficiency that the crews would experience throughout the process, due to the normal fluctuations in productivity across the impacted area. Model II represents the variation between events, due to severity of the event, geographic diversity and other factors that make restoration in some areas more difficult than others. In practice, it is expected that the actual uncertainty in a given event would be a combination of these two factors. For a given case and model, a Monte Carlo analysis is conducted in hourly increments of the restoration. The analysis is conducted up to the point where 95% of the customers are restored to service. From this analysis, a consumer cost-estimate range is acquired for the two crew deployment cases presented in Table 98.

Figure 123. Monte Carlo Results for Restoration Model I—Rate Uncertainty Varies by Hour

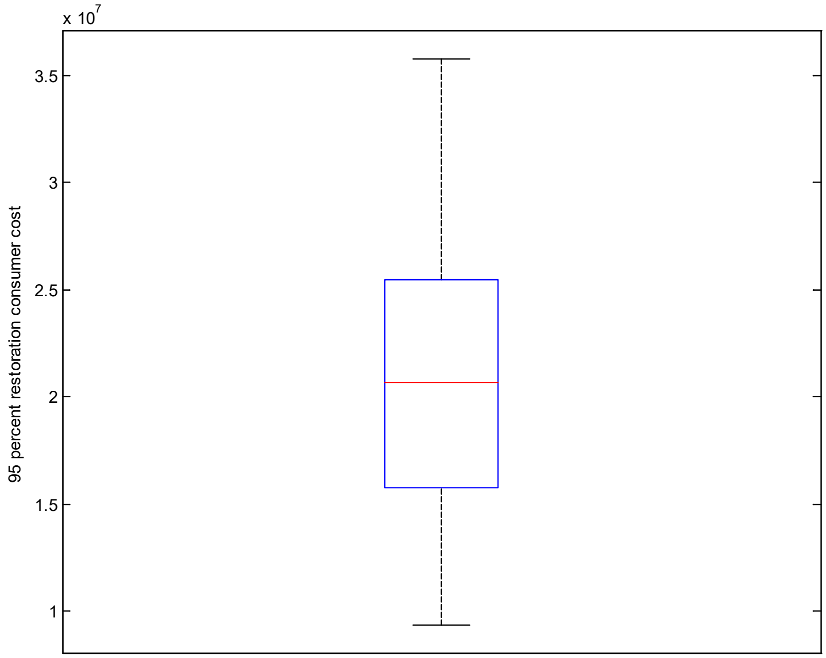


(a) Case I: Actual Restoration

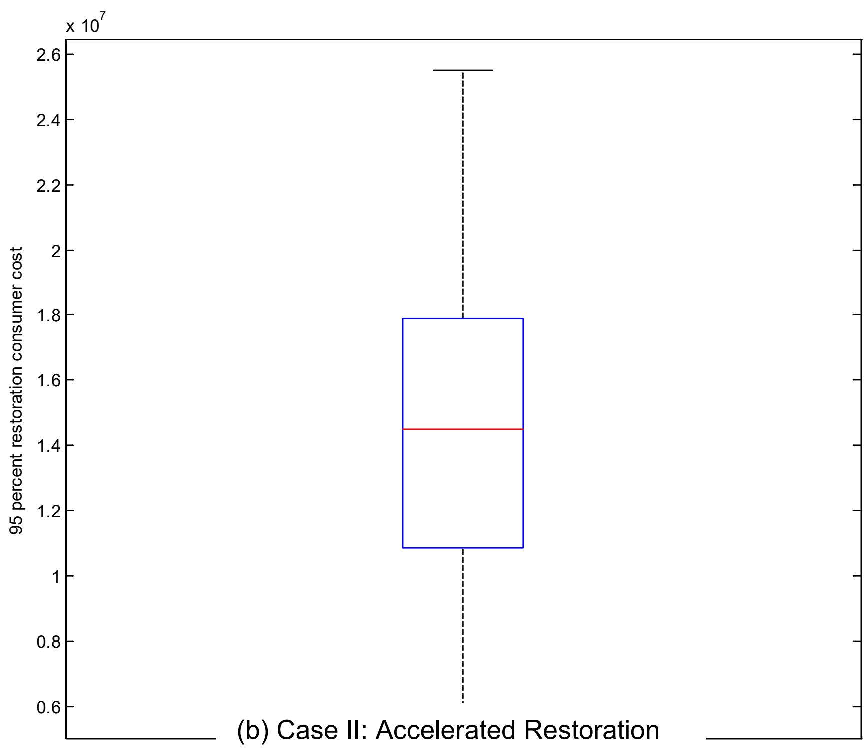


(b) Case II: Accelerated Restoration

Figure 124. Monte Carlo results for Restoration Model II—Rate Uncertainty is Constant



(a) Case I: Actual Restoration



(b) Case II: Accelerated Restoration

Figure 123 shows a box plot of the Monte Carlo analysis for Model I restoration, showing mean result, upper and lower quartile results, and the upper and lower extremes. The model predicts that the mean customer cost impact is reduced from just over $20 million to $15.5 million, a reduction of $4.5 million. The reductions in the 25% and 75% quartiles are similar, with the reduction in the highest extreme case being somewhat larger.

Figure 124 shows the results for Restoration Model II. In this case, the median costs are reduced from just over $20 million to approximately $14 million, a reduction of $6 million. Again, similar reductions in the 25% and 75% quartiles are predicted, with the reduction in the high extreme indicating somewhat larger.

6.8 Microgrid Scheduling, Reliability, and Benefits Conclusions

Power interruptions due to major storm events have attracted great attention in recent years. In order to estimate the outage cost, a new time-varying cost model is proposed. This proposed model analyzes the estimated cost for residential customers. It is shown for residential customers that monetary costs (shelter, spoiled food, and increased food costs) are important factors in assessing the residential cost model. The proposed model considers all these factors during a 10-day period.

These cost estimates can be used to make accurate decisions for investments such as building microgrids or improving power system infrastructure. To obtain an accurate decision, factors affecting the restoration rate should be analyzed thoroughly. This report shows that increased number of crews decreases the restoration time significantly. A consumer cost model is also presented to show the impact of the crew deployment.

7 Conclusions

This report presents the results of the feasibility study for the proposed Potsdam Underground Resilient Microgrid. The project has developed an initial stage design for a resilient microgrid that will provide reliable power for essential services and allow Potsdam to act as a hub for emergency operations during North Country disaster conditions, such as the ice storms, major snow events, and microburst weather conditions experienced over recent years.

The design includes a new underground system for power and communications, interconnecting approximately twelve operational entities, including emergency service providers, utilities, generation sources, staging areas, and other essential service providers (housing, fuel, financial, food, etc.).
The underground 13.2 kV-primary distribution network will be owned and operated by National Grid, the electric service provider for the Potsdam area. The design target duration for self-sustained islanded operation is two weeks, which may be extended depending on the performance of renewable generation.

When not in islanded operation, it is intended that the microgrid will operate in concert with the existing distribution system to optimize the value of the interconnected renewable and conventional generation, energy storage (if present), and load-control systems to the benefit of their owners and the electric system.

The planned entities connected to the underground microgrid will include Clarkson University, SUNY Potsdam, Canton-Potsdam Hospital, Village of Potsdam buildings, Potsdam Central School, plus commercial providers of fuel, food, and other essential commodities and services.

The deliverable for the project is a design, with cost estimates, for a self-sustaining resilient underground microgrid in Potsdam, NY, with the intent to propose its demonstration to a future New York State or federal program.

This project has included seven major components:

- Generation and load study
- Primary distribution system steady-state design
- Primary distribution short-circuit study
- Dynamic performance analysis and design
- Availability study
- Benefit-cost analyses
- Control and communications

Based on the findings of this report, the initial plan and design of the Potsdam Microgrid is adequate and sufficient to meet the project objectives as detailed in the project's statement of work. This project is technically feasible. However, further work will be required to finalize the design, equipment ratings, and layout of the microgrid.

7.1 Generation and Load Study

The generation/load study assessed the load data for those entities who potentially will be connected to the microgrid. The baseline scenario in this study assumed no outages, no load curtailments, and no internal generation (whether existing or new) to meet the annual load of the microgrid. The baseline scenario assumes that all electricity is purchased, and all Potsdam Central School thermal needs are met by boiler thermal generation with purchased natural gas (which is at a different rate compared to the natural gas used by distributed generation and CHP).

The initial step of the study also determined the amount and nature of existing generation available among these entities. The study then used the DER-CAM model to analyze a number of new generation scenarios and sensitivities and compare them to a Baseline Scenario covering a whole year. This report includes the scenarios considered in this analysis.

The peak load of the proposed microgrid will be approximately 9 MW. There is existing conventional generation of approximately 3 MW. A main conclusion is that approximately 4 MW of new natural gas or dual-fuel generation is the preferred amount of new generation needed for this microgrid. This level of new generation will also require up to 2 MW of demand response during isolated operation.

7.1.1 Primary Distribution System Steady-State Design

The project proposes a 13.2-kv underground loop system for the microgrid. The underground system would have a primary connection point to the overhead system, which would be taken from a dedicated feeder coming out of National Grid's Lawrence Avenue Substation. This proposed point of connection is at the present Clarkson University point of service. Clarkson is currently served by a dedicated overhead feeder. This feeder would need to be upgraded to be able to carry the full-microgrid load. There would also be several manual points of connection to the microgrid from the existing overhead feeders available to serve the microgrid for maintenance purposes. These would not have the capability to carry the full-microgrid load, however, so that the microgrid must be operated accordingly when fed in this manner.

Details of the design are contained in this report. The report presents three design options for the primary underground network. The options provide differing levels of fault sensing and clearing as well as operating automation.

7.1.2 Primary Distribution Short-Circuit Study

The report includes a comprehensive short-circuit study for the range of operating scenarios of the microgrid. This short-circuit study shows the range of fault currents available across the scenarios. These are used to determine the interrupting duty required of the circuit breakers, reclosers and/or fuses used in the three scenarios of the study.

The protection schemes in these scenarios are the following:

- High-speed line differential and bus differential protection with circuit breakers at each node
- A combination of circuit breakers and fused disconnects
- A two-zone underground system with reclosers, fuses and fused disconnects separating the zones, and a recloser at the point of connection to the overhead system

Cost estimates are provided for each of these scenarios.

7.1.3 Dynamic Performance Analysis and Design

This portion of the study reviewed the range of power quality and dynamic factors associated with the proposed microgrid. The microgrid will operate in two main modes, which were considered separately. The issues covered in this report include:

- Voltage regulation
- Fault current and protection
- Unintentional islanding
- Ground fault overvoltage
- Ground fault relaying desensitization
- Load rejection overvoltage
- Low-voltage ride through and under-frequency load shedding
- Islanded microgrid key issues
    - Island start-up procedure
    - Fault levels (islanded)
    - Frequency regulation
    - Harmonic distortion
    - Voltage regulation (islanded) and flicker
    - Generator unbalance
    - Effective grounding and ground fault overvoltage
    - Stability
    - Energy storage
    - Seamless transition

Each of these issues is discussed in the report, along with recommendations specific to the Potsdam Microgrid.

7.1.4 Availability Study

An analysis of the microgrid availability during an extended period of isolated operation is presented in the report. As a design goal the microgrid is available 98% of the time during this mode of operation. By nature, the analysis shows that a given microgrid will have 98% availability up to a certain loading level.

The analysis shows that for a given level of new generation, the microgrid availability will vary significantly based on the configuration of the units. The maximum achievable load level for this availability varies by over 1 MW on this 9 MW system, based on the size and number of units selected to supply the desired MW level of generation.

7.1.5 Benefit-Cost Analyses (BCA)

An overall microgrid BCA was completed as a part of this project. The benefit-cost assessment model of IEc was the primary tool used for this analysis. This tool has been selected for the NY Prize program, and a description of the tool is available as a part of the NYSERDA NY Prize program information. The report provides analysis of the various generation and distribution scenarios developed during the project. Results show the BCA for each option considering no major power outages and the average number of days of major power outage per year where benefits equal costs.

In general, the benefit-cost ratio is less than one in the cases considering no major power outages. The average number of long-term outage days per year where benefits equal costs was found to range from 0.33 days/year to 1.56 days/year for the range of generation and distribution options considered in this study. All of these studies consider full-build out of the microgrid.

7.1.6 Control and Communications

The report started as an initial discussion of the Control/Monitoring System design and the Control System functional design that will be required to implement this microgrid design. It is clear that, to be effective, the microgrid communications/control system will need to have extensive monitoring capability as well as direct control of generation. It will also need direct control of key load points. In some cases, loads will be switched on and off, while in other cases loads will be modulated. There will need to be a set of loads that will respond nearly instantaneously to demand response signals for the microgrid scheduler. It will be a challenge to implement demand response across the range of load entities on the microgrid. This challenge will include both the technical aspects of interfacing the scheduler with the various building control systems present among the load entities. It will also include developing the capability to assess load priorities across the several entities, all of which provide a critical service for the event response.

7.1.7 Summary

The report provides initial planning and design studies for the Potsdam Resilient Underground Microgrid. The project shows the feasibility of the Potsdam microgrid, and also demonstrates that the benefits can exceed the costs, based on the design options chosen and the assumed levels of extended interruptions that the microgrid will experience.

Further work will be required to finalize the design, equipment ratings, and layout of the microgrid. Specific future works have been recommended and are described in the preceding sections. However, based on the findings of this report, the initial plan and design of the Potsdam Microgrid is adequate and sufficient to meet the project objectives as detailed in the project's statement of work.

As a result of the work, National Grid proposed the Community Resilience Reforming the Energy Vision (REV) Demonstration Project, which focuses on this resilient microgrid. This REV Demonstration Project began in Quarter 3 of 2016 and will finalize the design and implementation plan for the proposed microgrid.

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Appendix A. Example Calculations

A.1 Installed Cost versus Annualized Cost of Investment

Annualized Cost of Investment is calculated based on the following formula:

$$A: \frac{C}{\frac{\left(1-\frac{1}{1+r^{t}}\right)}{r}}$$

A, C, r, and t are defined in the following table. The table shows the variation in Annualized Costs under different payback periods and interest rate/cost of capital assumptions.

Red cells represent variations in primary drivers of the Annualized Cost/Capital Recover Cost.

The column in blue represents the principal assumptions used in this study and the DER-CAM.

Table A1. Example of Investment Cost versus Annualized Costs

Annualized Investment Cost		Rate A	Rate B	Rate C		Lifetime A	Lifetime B	Lifetime C		Cost A	Cost B	Cost C		CF A	CF B	CF C
t: Payback Periods (Years)		15	15	15		10	15	20		15	15	15		15	15	15
r: Interest Rate/Cost of Capital		5.0%	8.3%	12.0%		8.3%	8.3%	8.3%		8.3%	8.3%	8.3%		8.3%	8.3%	8.3%
C: Installed Cost ($/kW)		1,100	1,100	1,100		1,100	1,100	1,100		800	1,100	1,400		1,100	1,100	1,100
A: Annualized Cost ($/kW-Year)		106	131	162		166	131	115		95	131	167		131	131	131
Ratio of A/C		10%	12%	15%		15%	12%	10%		12%	12%	12%		12%	12%	12%
Ratio of C/A		10.380	8.405	6.811		6.620	8.405	9.603		8.405	8.405	8.405		8.405	8.405	8.405
Assumed Capacity Factor		90%	90%	90%		90%	90%	90%		90%	90%	90%		30%	60%	90%
Generation (kWh)		7,884	7,884	7,884		7,884	7,884	7,884		7,884	7,884	7,884		2,628	5,256	7,884
Capital Recovery Cost ($/kWh)		0.0134	0.0166	0.0205		0.0211	0.0166	0.0145		0.0121	0.0166	0.0211		0.0498	0.0249	0.0166

A.2 Check of Annualized Cost Order of Magnitude

The following table presents the components of the Annual Costs for scenario 26U. In scenario 26U, most of the cost is due to internal microgrid generation, since based on the utility rate and fuel price assumptions, in normal nonemergency days, it is more economical to generate electricity on site than purchase from the utility.

Table A2. Annual Cost Components of Scenario 26U

Annual Cost Components									
				Rate			Months		Costs
Utility Electricity Purchase	629,008	kWh	x	0.0731	$/kWh			=	$45,996
Average Monthly Peak Demand	359.2	kW	x	9.18	$/kW	x	12	=	$39,569
Electric Utility Monthly Fixed Charges	1,000.0	$/Month				x	12	=	$12,000
Gas Utility Monthly Fixed Charges	100.0	$/Month				x	12	=	$1,200
Microgrid Direct Heating Fuel Costs	53,440	($)						=	$53,440
Annualized Microgrid DG Investment Costs	256,776	($)						=	$256,776
Microgrid DG Generation Fuel Costs	1,641,807	($)						=	$1,641,807
Microgrid DG Generation FOM Costs	285,450	($)						=	$285,450
Microgrid DG Generation VOM Costs	974,049	($)						=	$974,049
Total Annual Cost									$3,310,287

A.3 Effective Utility Rate Compared to the Cost of DG Electricity Generation

The following table compares the effective rate in $/kWh of electricity purchased from the utility with cost of 1 kWh of electricity generated by the microgrid, under different natural gas (NG) and diesel prices and also under different microgrid distributed generation electrical efficiencies.

Table A3. Comparison of Cost of Electricity Purchased versus Electricity Produced

(September Example)

Cost of Electricity Purchased from the Utility				
Demand Rate ($/kW)	9.18	9.18	9.18	9.18
Energy Rate ($/kWh)	0.0731	0.0731	0.0731	0.0731
September Peak (kW)	9,113.3	9,113.3	9,113.3	9,113.3
September Load (kWh)	5,555,527	5,555,527	5,555,527	5,555,527
Demand Charge ($)	83,660	83,660	83,660	83,660
Demand Charge ($/kWh)	0.0151	0.0151	0.0151	0.0151
Effective Electricity Rate ($/kWh)	0.0882	0.0882	0.0882	0.0882
Cost of Electricity Generated by the Microgrid				
	NG	NG	Diesel	Diesel
Fuel Price ($/kWh)	0.0116	0.0116	0.0763	0.0763
DG Efficiency	41.0%	27.0%	41.0%	27.0%
Cost of Electricity Produced ($/kWh)	0.0283	0.0429	0.1862	0.2828
DG VOM ($/kWh)	0.0170	0.0170	0.0170	0.0170
DG Cost of Electricity ($/kWh)	0.0453	0.0599	0.2032	0.2998

A.4 Effective Cost of Purchased Power—Based on July Data

The following table presents an estimate of the cost of purchased power under the SC-3A rate, based on the July model data. Effective rate depends on the relative values of monthly peak (kW) and energy (kWh) of purchased power.

Table A4. Annual Cost Components of Scenario 26U

Peak and Load		
July Peak (kW)		7,652.2
July Load (kWh)		2,593,324
Customer and Demand Charges		
Customer Charges - Distribution Delivery ($)		1,000.0
Customer Charges ($/kWh)		0.00039
Demand Charges - Distribution Delivery ($/kW)		9.18
Demand Charge ($)		70,247.20
Demand Charge ($/kWh)		0.02709
Energy Charges		
Energy Charges - Electricity Supply Service Charge - Average of Annual Daily Charges ($/kWh)		0.03712
Miscellaneous Charges		
RkVA Charges ($/RkVA)		1.02
RkVA Charges ($)		7,805.24
RkVA Charges ($/kWh)		0.00301
System Benefit Charge - Total SBC Rate of Adjustment-Effective January 1, 2015 ($/kWh)		0.00458
Renewable Portfolio Surcharge ($/kWh)		0.00332
Rule 46.3 Electricity Supply Reconciliation Mechanism (ESRM) ($/kWh)		0.00327
Rule 46.1.3.7 Capacity Tag Charge Billing Rate ($/kW)		4.42337
Capacity Tag Charge ($)		33,848.51
Capacity Tag Charge ($/kWh)		0.01305
Rule 46.2 Legacy Transition Charge ($/kWh)		0.00212
Transmission Revenue Adjustment - SC3A-Subtransmission ($/kWh)		(0.00225)
Effective Elec. Rate ($/kWh)		**0.0887**
Miscellaneous Charges ($/kWh)		0.0241
Effective Rate - without Miscellaneous Charges ($/kWh)		**0.0646**
Effective Rate - without Customer and Demand Charge ($/kWh)		0.0612

A.5 Variable Cost of Microgrid Generation versus Effective Rate of Utility Power Purchase

The following table compares the variable cost of microgrid generation with the effective rate of power purchased from the utility under (a) different gas prices, and (b) different DG efficiency rates. The red column is based on the study assumptions.

Table A-5. Comparison of Cost of Electricity Purchased versus Electricity Produced

(September Example)

Effective Cost of Microgrid Generation	**NG**	**NG**	**NG**	**NG**	**NG**	**NG**	**NG**	**NG**	**NG**	**NG**	**NG**	**NG**
Fuel Price ($/kWh)	0.0103	0.0103	0.0103	0.0154	0.0154	0.0154	0.0171	0.0171	0.0171	0.0205	0.0205	0.0205
Fuel Price ($/Therm)	0.3003	0.3003	0.3003	0.4506	0.4506	0.4506	0.4999	0.4999	0.4999	0.5998	0.5998	0.5998
Fuel Price ($/MMBtu)	3.00	3.00	3.00	4.51	4.51	4.51	5.00	5.00	5.00	6.00	6.00	6.00
DG Efficiency	50.0%	41.0%	30.0%	50.0%	41.0%	30.0%	50.0%	41.0%	30.0%	50.0%	41.0%	30.0%
Cost of Elec. Produced ($/kWh)	0.0205	0.0250	0.0342	0.0308	0.0375	0.0513	0.0341	0.0416	0.0569	0.0409	0.0499	0.0682
DG VOM ($/kWh)	0.0170	0.0170	0.0170	0.0170	0.0170	0.0170	0.0170	0.0170	0.0170	0.0170	0.0170	0.0170
Variable Cost of Microgrid Electricity ($/kWh)	**0.0375**	**0.0420**	**0.0512**	**0.0478**	**0.0545**	**0.0683**	**0.0511**	**0.0586**	**0.0739**	**0.0579**	**0.0669**	**0.0852**
Stand-By Charge ($/kW) from SC-7	3.71	3.71	3.71	3.71	3.71	3.71	3.71	3.71	3.71	3.71	3.71	3.71
Stand-By Charge ($)	28,389.66	28,389.66	28,389.66	28,389.66	28,389.66	28,389.66	28,389.66	28,389.66	28,389.66	28,389.66	28,389.66	28,389.66
Stand -By Charge ($/kWh)	0.01095	0.01095	0.01095	0.01095	0.01095	0.01095	0.01095	0.01095	0.01095	0.01095	0.01095	0.01095
Customer Charge ($)	1,000.00	1,000.00	1,000.00	1,000.00	1,000.00	1,000.00	1,000.00	1,000.00	1,000.00	1,000.00	1,000.00	1,000.00

Table A-5 continued

Variable Cost of Microgrid Electricity ($/kWh)	**0.0375**	**0.0420**	**0.0512**	**0.0478**	**0.0545**	**0.0683**	**0.0511**	**0.0586**	**0.0739**	**0.0579**	**0.0669**	**0.0852**
Customer Charge ($/kWh)	0.0004	0.0004	0.0004	0.0004	0.0004	0.0004	0.0004	0.0004	0.0004	0.0004	0.0004	0.0004
Capital Recovery and Fixed Costs* ($/kWh)	0.0166	0.0166	0.0166	0.0166	0.0166	0.0166	0.0166	0.0166	0.0166	0.0166	0.0166	0.0166
Cost to Produce – with Fixed Costs ($/kWh)	**0.0654**	**0.0699**	**0.0791**	**0.0757**	**0.0824**	**0.0962**	**0.0791**	**0.0865**	**0.1018**	**0.0859**	**0.0949**	**0.1132**
Effective Elec. Rate ($/kWh)	0.0887	0.0887	0.0887	0.0887	0.0887	0.0887	0.0887	0.0887	0.0887	0.0887	0.0887	0.0887
Difference ($/kWh)	**0.0232**	**0.0187**	**0.0096**	**0.0130**	**0.0062**	**(0.0075)**	**0.0096**	**0.0021**	**(0.0131)**	**0.0028**	**(0.0062)**	**(0.0245)**
Effective Rate - No Miscellaneous Charges ($/kWh)	0.0646	0.0646	0.0646	0.0646	0.0646	0.0646	0.0646	0.0646	0.0646	0.0646	0.0646	0.0646
Difference ($/kWh)	**(0.0008)**	**(0.0053)**	**(0.0145)**	**(0.0111)**	**(0.0179)**	**(0.0316)**	**(0.0145)**	**(0.0219)**	**(0.0372)**	**(0.0213)**	**(0.0303)**	**(0.0486)**

* Includes only the installed cost of generation, does not include other infrastructure costs.

Appendix B. DG Characteristics

The following three tables provide an overview of distributed generation characteristics and cost. Our modeling assumptions were informed by the information provided in the following tables.

Table B1. DG Technology Characteristics

Note: The fixed O&M (FOM) costs do not appear to be correct. The FOM costs should be in the range of $25 to $75/kW/year.

Source: "A Review of Distributed Energy Resources," New York Independent System Operator, Prepared by DNV GL, September 2014; http://www.nyiso.com/public/webdocs/media_room/publications_presentations/Other_Reports/Other_Reports/A_Review_of_Distributed_Energy_Resources_September_2014.pdf

Characteristic	Internal Combustion Technologies			Fuel Cell Technologies				Storage Technologies		Solar
	Reciprocating Engine	Microturbine	Combustion Gas Turbine	Proton Exchange Membrane (PEMFC)	Phosphoric Acid (PAFC)	Molten Carbonate (MCFC)	Solid Oxide (SOFC)	High Power e.g., li-ion	High Energy e.g., NaS	PV
Size	30kW-6+MW	30-400kW	0.5-30+MW	<1kW-500kW	50kW-1MW (250kW module typical)	<1kW-5MW (250kW module typical)	<1kW - 5MW	kWs to MWs	kWs to MWs	0.2 kW per module, could be 000s of MW
Power Density (mW/cm^2)	2,900 - 3,850	3,075 - 7,175	1,750 - 53,800	350-800	140 - 320	100 - 120	150 - 700	N/A	N/A	up to 175
Operating Temperature	450°C (850°F)	980°C (1,800°F)	1,930°C (3,500°F)	50-100°C (122-212°F)	150-200°C (302-392°F)	600-700°C (1,112-1,292°F)	600-1,000°C (1,202-1,832°F)	ambient	290-360°C	Ambient + ~20 C
Start-up Time	10s to 15 mins	Up to 120s	2 - 10 min	15 - 30 min	3-4 hrs	8 - 24 hrs	8 - 24 hrs	ms	ms	ms
Elec. Efficiency (LHV) %	30-42%	14-30%	21-40%	36-50%	37-42%	45 - 50%	40-60%	93-97%	85-90%	15%
Electric+Thermal (CHP) Efficiency %	80-85%	80-85%	80-90%	50-75%	<85%	<80%	<90%	90-94% AC	78-80% AC	n/a
Installed Cost ($/kW)	$700-1,200/kW	$1,200-1,700/kW	$400-900/kW	$3,500/kW	$4,500 - 9,000/kW	$4,200 - 7,200/kW	$3,500 - 8,000/kW	$1,200-1,800/kW	$3,500-4,000/kW	$2,000-5,000/kWp
Fixed O&M Cost	$600-1,000/kW	$700-1100/kW	$600/kW	$1000/kW	$400/kW	$360/kW	$175/kW	$8-30/kW	$15-40/kW	$10-30/kWp
Variable O&M Cost	$0.007 - 0.02/kWh	$0.005 - 0.016/kWh	$0.004 - 0.01/kWh	$0.003/kWh	$0.002/kWh	$0.004/kWh	$0.0045-0.0056/kWh	$0.002-0.004/kWh	$0.03 0.09/kWh	$10-30/kWp
Maintenance Interval/Fuel Cell Module Durability	750 - 1,000 hrs: change oil and oil fiter 8,000 hrs: rebuild engine head 16,000 hrs: rebuild engine block	5000 - 8000 hrs	4000 - 8000 hrs	20,000 + hrs	40,000 - 80,000 hrs	40,000+ hrs	25,000 - 70,000 hrs	2 yr interval, 10 yr life	2 hr interval, 10 year life	8,000 hrs (annual maintenance for central inverters)

Table B2. CHP Technology Characteristics

Source: "Catalog of CHP Technologies." U.S. EPA & CHP Partnership, March 2015; http://epa.gov/chp/documents/catalog_chptech_full.pdf

Technology	Recip. Engine	Steam Turbine	Gas Turbine	Microturbine	Fuel Cell
Electric efficiency (HHV)	27-41%	5-40+%[2]	24-36%	22-28%	30-63%
Overall CHP efficiency (HHV)	77-80%	near 80%	66-71%	63-70%	55-80%
Effective electrical efficiency	75-80%	75-77%	50-62%	49-57%	55-80%
Typical capacity (MW_e)	.005-10	0.5-several hundred MW	0.5-300	0.03-1.0	200-2.8 commercial CHP
Typical power to heat ratio	0.5-1.2	0.07-0.1	0.6-1.1	0.5-0.7	1-2
Part-load	ok	ok	poor	ok	good
CHP Installed costs ($/kW$_e$)	1,500-2,900	$670-1,100	1,200-3,300 (5-40 MW)	2,500-4,300	5,000-6,500
Non-fuel O&M costs ($/kWh$_e$)	0.009-0.025	0.006 to 0.01	0.009-0.013	0.009-.013	0.032-0.038
Availability	96-98%	72-99%	93-96%	98-99%	>95%
Hours to overhauls	30,000-60,000	>50,000	25,000-50,000	40,000-80,000	32,000-64,000
Start-up time	10 sec	1 hr - 1 day	10 min - 1 hr	60 sec	3 hrs - 2 days
Fuel pressure (psig)	1-75	n/a	100-500 (compressor)	50-140 (compressor)	0.5-45
Fuels	natural gas, biogas, LPG, sour gas, industrial waste gas, manufactured gas	all	natural gas, synthetic gas, landfill gas, and fuel oils	natural gas, sour gas, liquid fuels	hydrogen, natural gas, propane, methanol
Uses for thermal output	space heating, hot water, cooling, LP steam	process steam, district heating, hot water, chilled water	heat, hot water, LP-HP steam	hot water, chiller, heating	hot water, LP-HP steam
Power Density (kW/m^2)	35-50	>100	20-500	5-70	5-20
NO_x (lb/MMBtu) (not including SCR)	0.013 rich burn 3-way cat. 0.17 lean burn	Gas 0.1-.2 Wood 0.2-.5 Coal 0.3-1.2	0.036-0.05	0.015-0.036	0.0025-.0040
NO_x (lb/MWh$_{TotalOutput}$) (not including SCR)	0.06 rich burn 3-way cat. 0.8 lean burn	Gas 0.4-0.8 Wood 0.9-1.4 Coal 1.2-5.0.	0.52-1.31	0.14-0.49	0.011-0.016

Table B3. DG (no CHP) Capital Costs

Source: Internal – unofficial - GE discussion/communication

Fuel Based Generation	Installed Cost ($/kW)	Unit Cost ($/kW)
Reciprocating Engine (Natural Gas) (334 kW - 2 MW)	$1,800 - $1,400 (2010$/kW)	$930 - $885 (2010$/kW)
Reciprocating Engine (Diesel-2) (300 kW)	$850 - $1,804 (2010$/kW)	$517 - $1,224 (2010$/kW)
Reciprocating Engine (Bio-Diesel) (37kVA - 6MW)	$850 - $1,804 (2010$/kW)	$517 - $1,224 (2010$/kW)
Reciprocating Engine (Propane) (50kW - 10 MW)	$1,800 - $1,400 (2010$/kW)	$930 - $885 (2010$/kW)
Reciprocating Engine (Gasoline, Portable) (10 - 17.5 kW)	(site specific interconnection)	$210 - $191 (2014 $/kW)
Micro-Turbine (65 kW -200 kW)	$2,490 - $2,440 (2010$/kW)	$1,257 - $1,359 (2010$/kW)
Gas Turbine (3,510 kW - 5,670 kW)	$1,910 - $1,280 (2010$/kW)	$1,130 - $826 (2010$/kW)
Fuel Cell (300 kW - 2.8 MW MCFC)	$7,485 - $5,600 (2010$/kW)	$5,685 - $3,800 (2010$/kW)
Sterling Engine (1 kW - 9 kW)	$9,000 (2007$/kW)	

Appendix C. Existing Generation Characteristics

The following is information provided by Clarkson University.

Clarkson University

- The microturbines are the standard Capstone 65 kW units, we have three of them. They are currently managed by Carrier over a remote connection.
- The CAMP 370 kW cogeneration unit is a Waukesha Enginator model VHP3600G, 1200 rpm. 480 V/277V rated at 469 kVa for primary duty. The engine controller is an Altronic EPC-100 air/fuel ratio controller. The generator protective relay is a Basler solid state relay.
    - The generator throwover switch is a GE Type QMR THFP panel-board unit.
    - The CAMP building transformer is a GE Class AA dry type transformer, 3000 kVa, 13200-480Y/277, three-phase, 60 hertz. Its impedance is 5.9%. As an estimate, it has an X/R ratio of 5. It is located adjacent to the generator, so there is negligible line impedance between the two.
    - The primary switch feeding for this transformer is an S and C unit.
- The Cheel 290 kW generator is a Waukesha unit identical to the CAMP unit, apart from the kW rating. The transformer there is 1000 kVa.

Village Hydro Units

East Dam

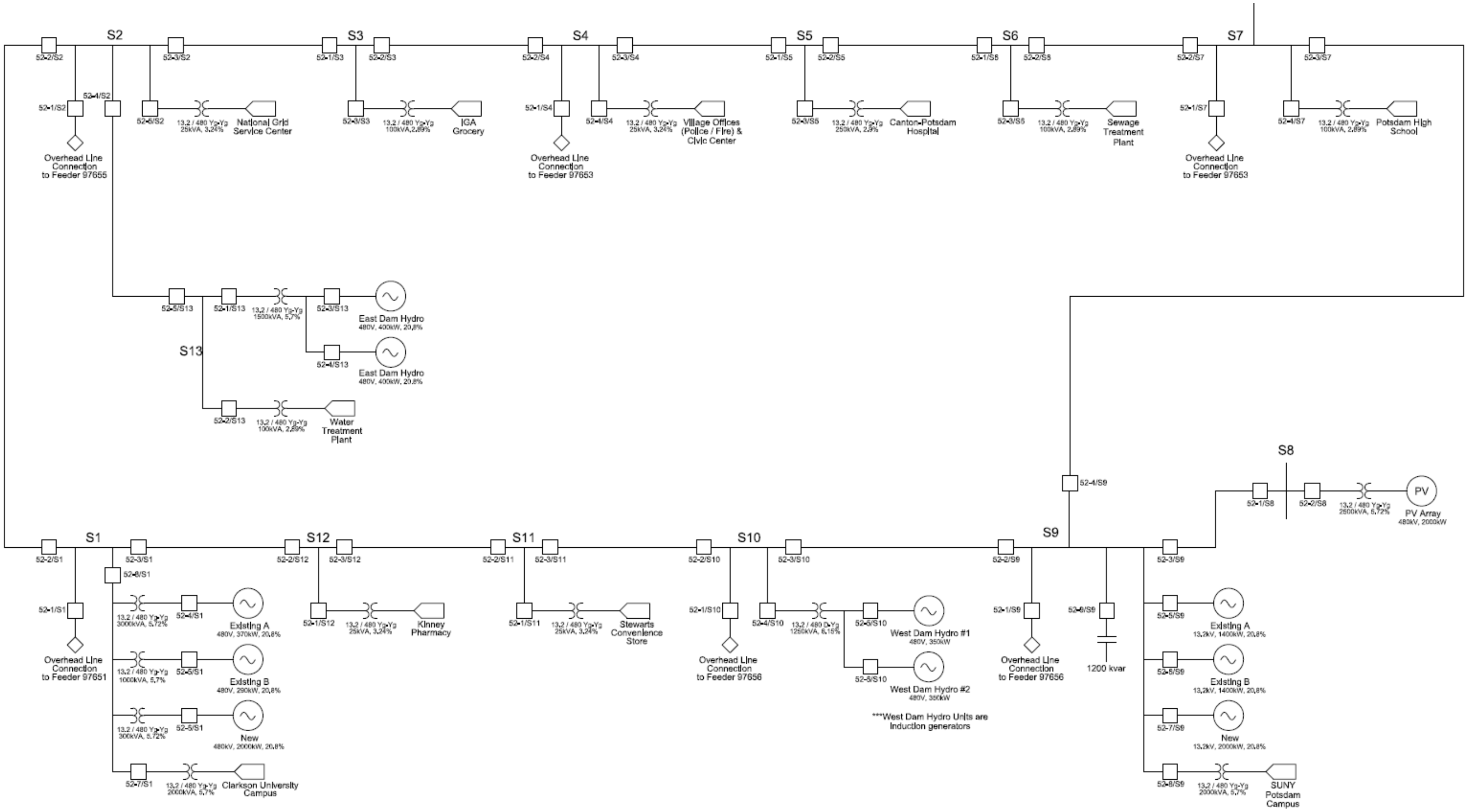
- Two units, both are Shinko Brushless AC TSCQ2-G-800, 500 kVA, 10 poles, 720 rpm. 480v, 602A. Exciter is Type ASN-C-450, 70v, 6.8 A.
- Shinko AVR, Type GEC3211X, output 20A. 1982. Eopo340602. Shink MVR type GEC 1299.
- Phoenix automatic synchronizer, series 6000. These units are controlled manually.
- Transformer is Pullman Transformer Engineering Company, 1500 kVA, 13.2 kV delta, 480wye/277v 5.7% impedance.
- Units are likely ungrounded.

West Dam

- Two units are both WEG induction motors—600 HP rating. 600v, 906 rpm wye connected.
- Ungrounded.
- Beckwith M3410A intertie/generator protection.
- HMI shown in photo. There is a wireless connection to east hydro at the location of the control room. This is not fully functional but does provide some metering data.
- The transformer is sunbelt 1250/1400 kVA, 6.2% impedance, 13200/7620v grd wye: 600/347v grd wye.
- 120kVAR Gentec power factor control center on each unit.
- Obermeyer flow controller.

Appendix D. Microgrid One-Line Diagram and Short-Circuit Results

Figure D-1. Microgrid One-Line Diagram



Microgrid One-line

Appendix 1

Figure D-2. Case MG Only

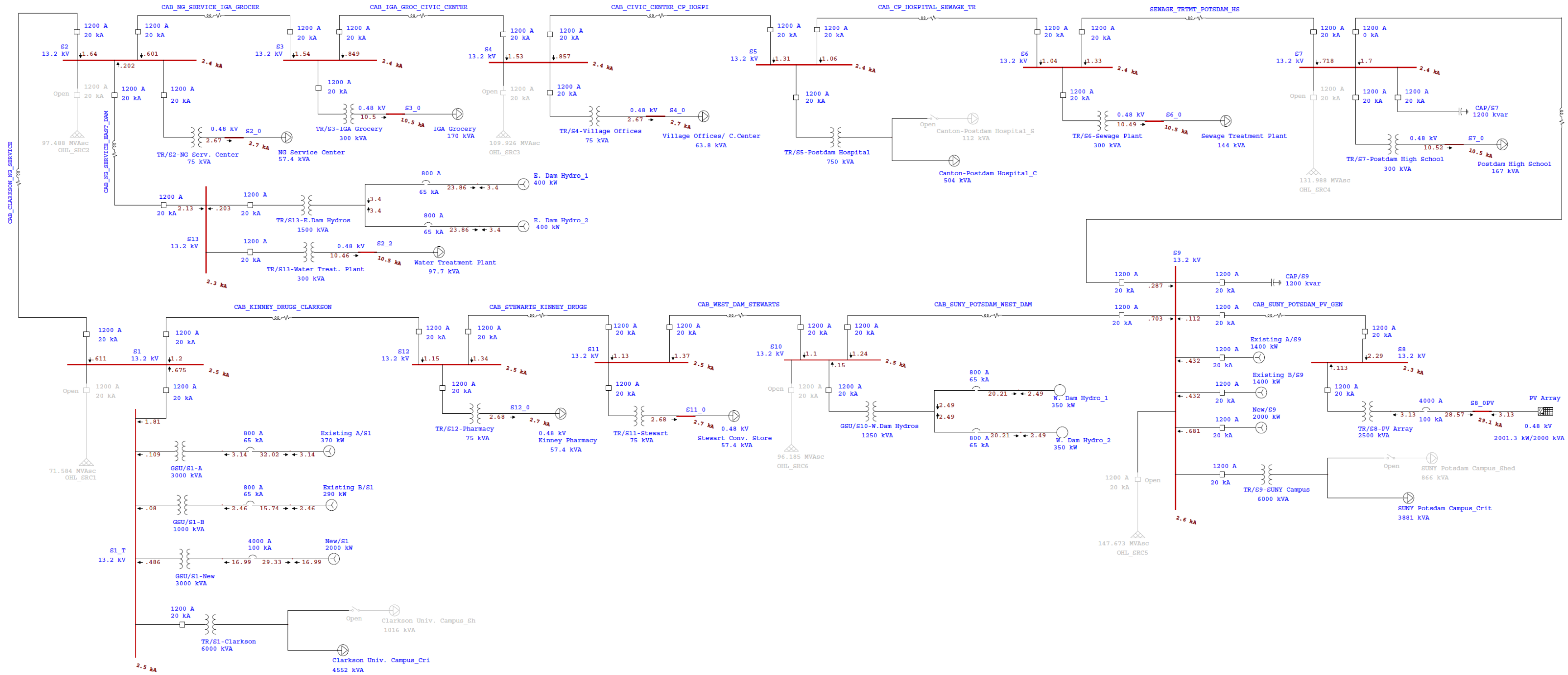


Figure D-3. Case 1

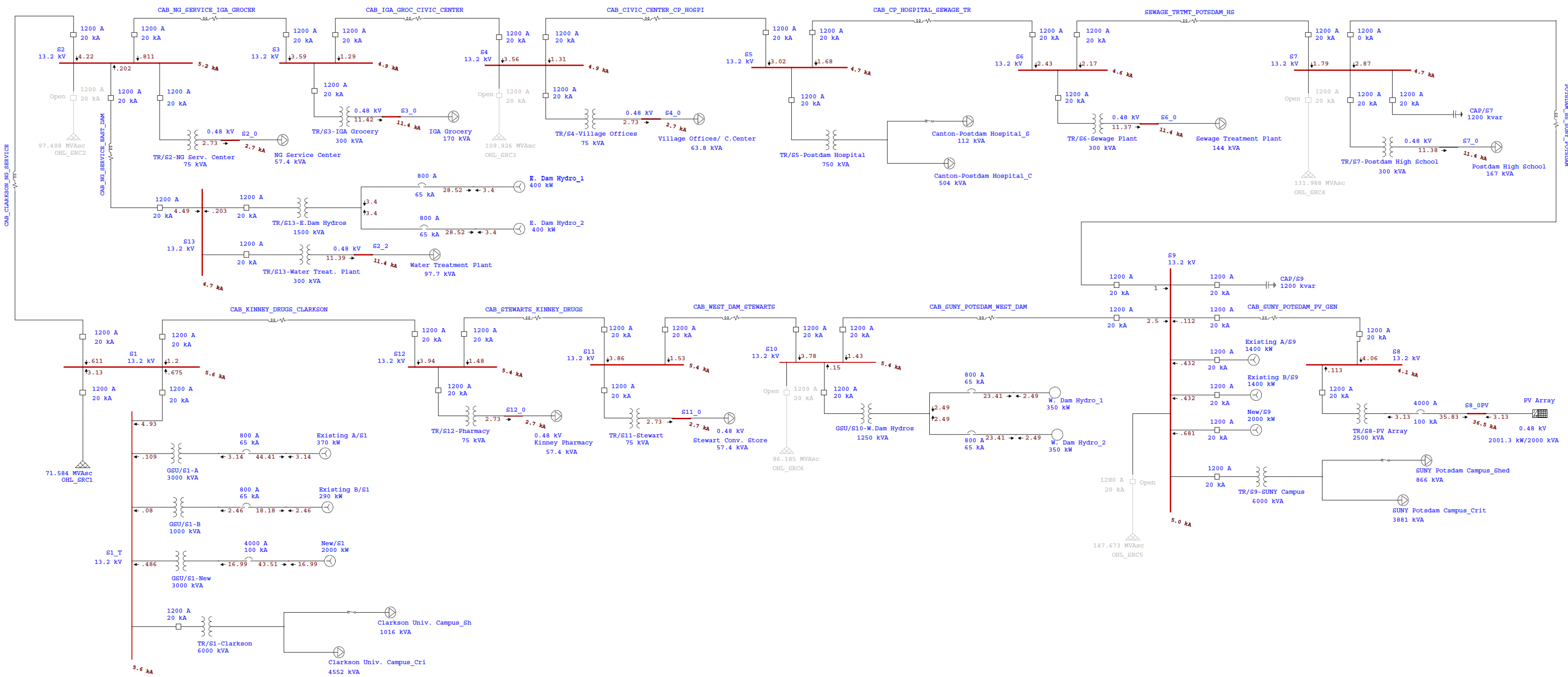


Figure D-4. Case 2

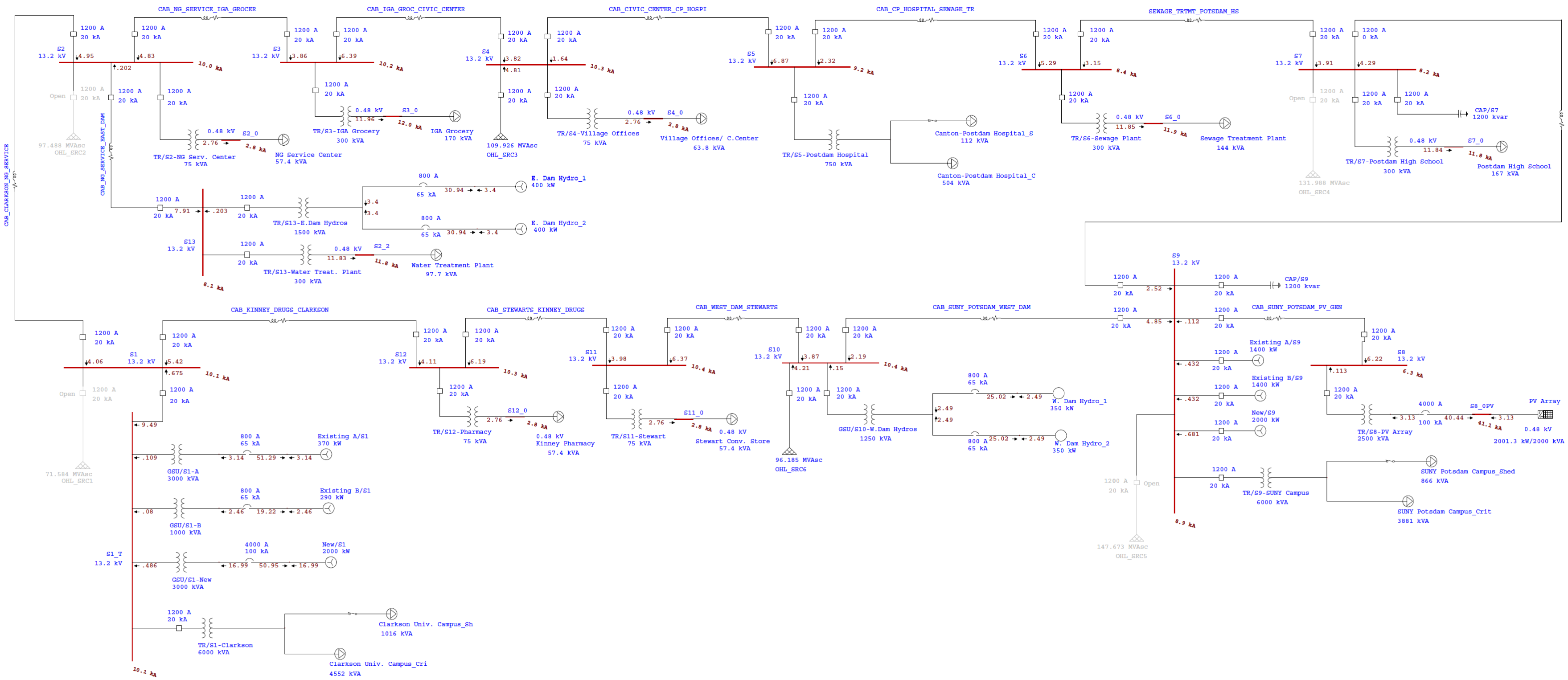


Figure D-5. Case 2a

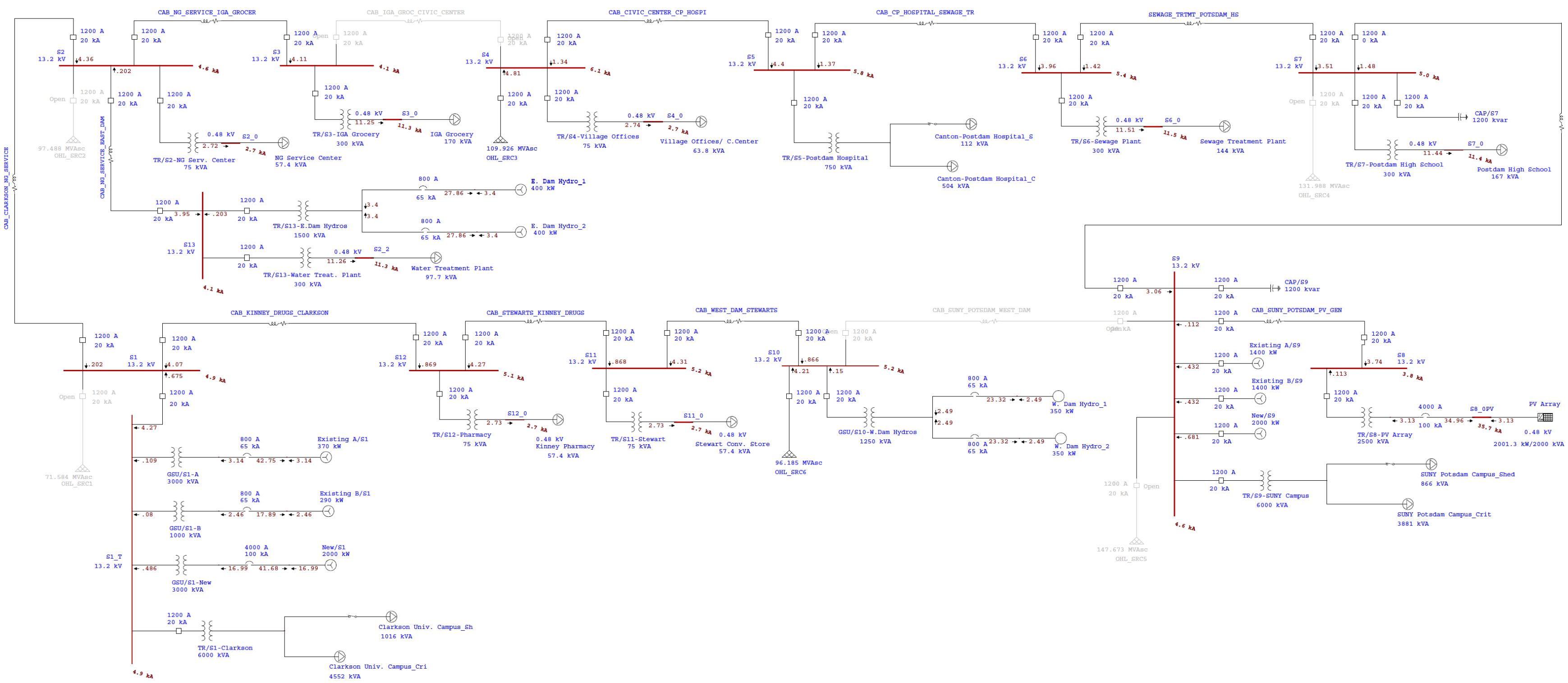


Figure D-6. Case 3

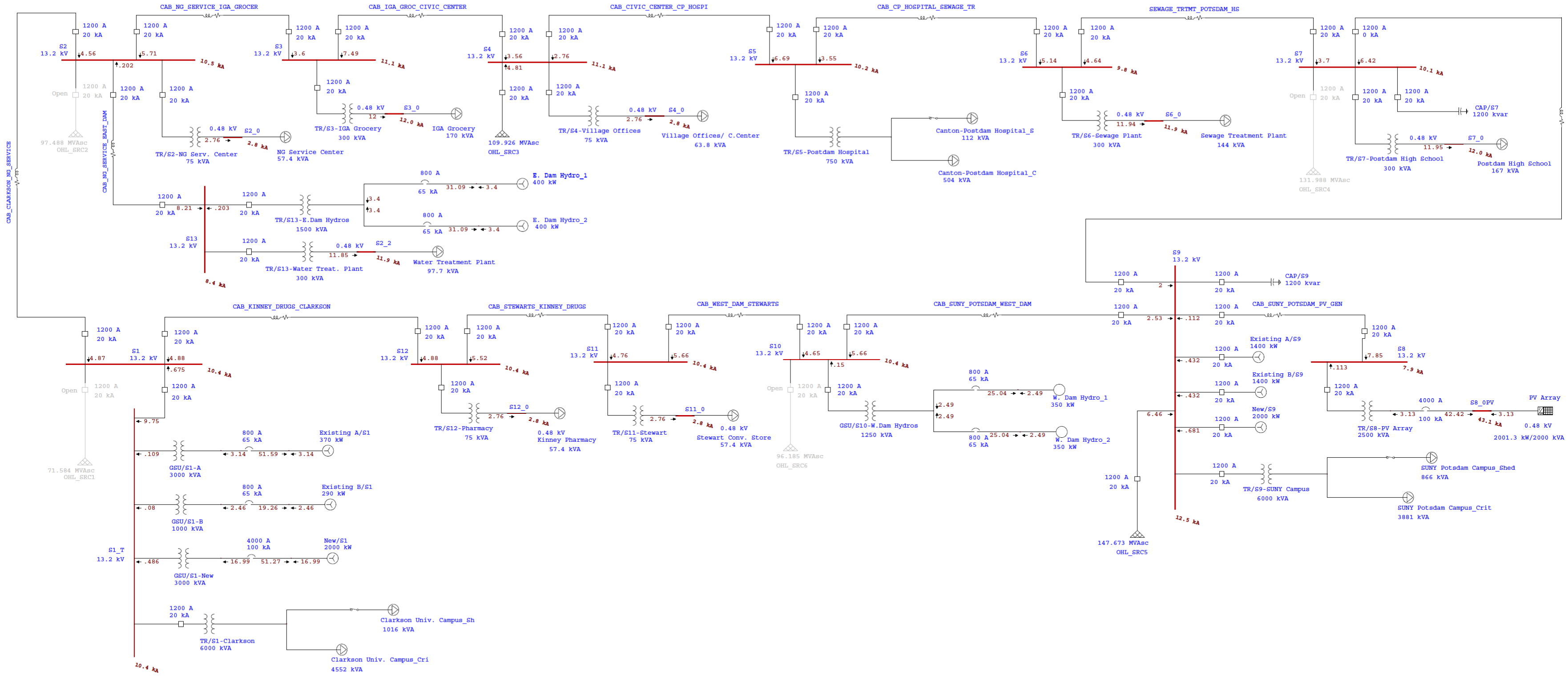


Figure D-7. Case 3a

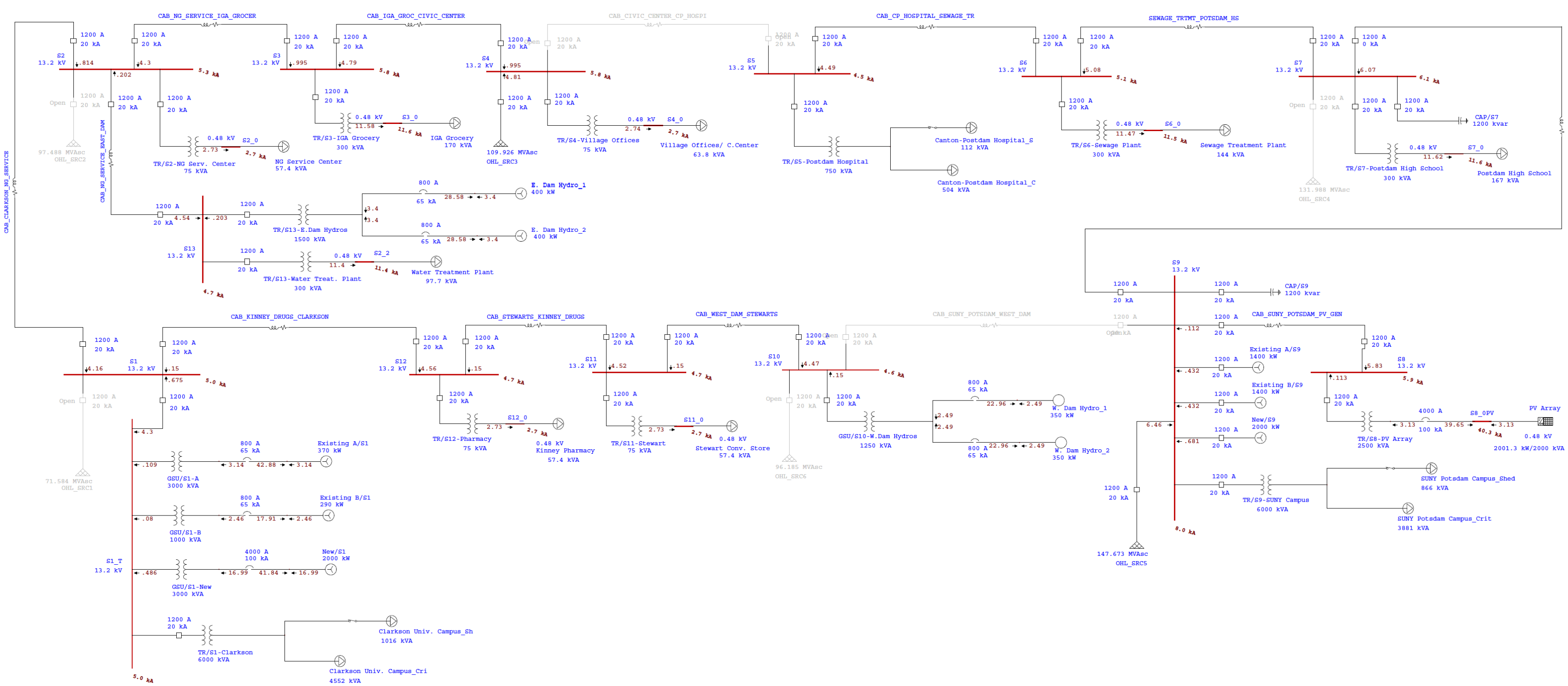


Figure D-8. Case 4

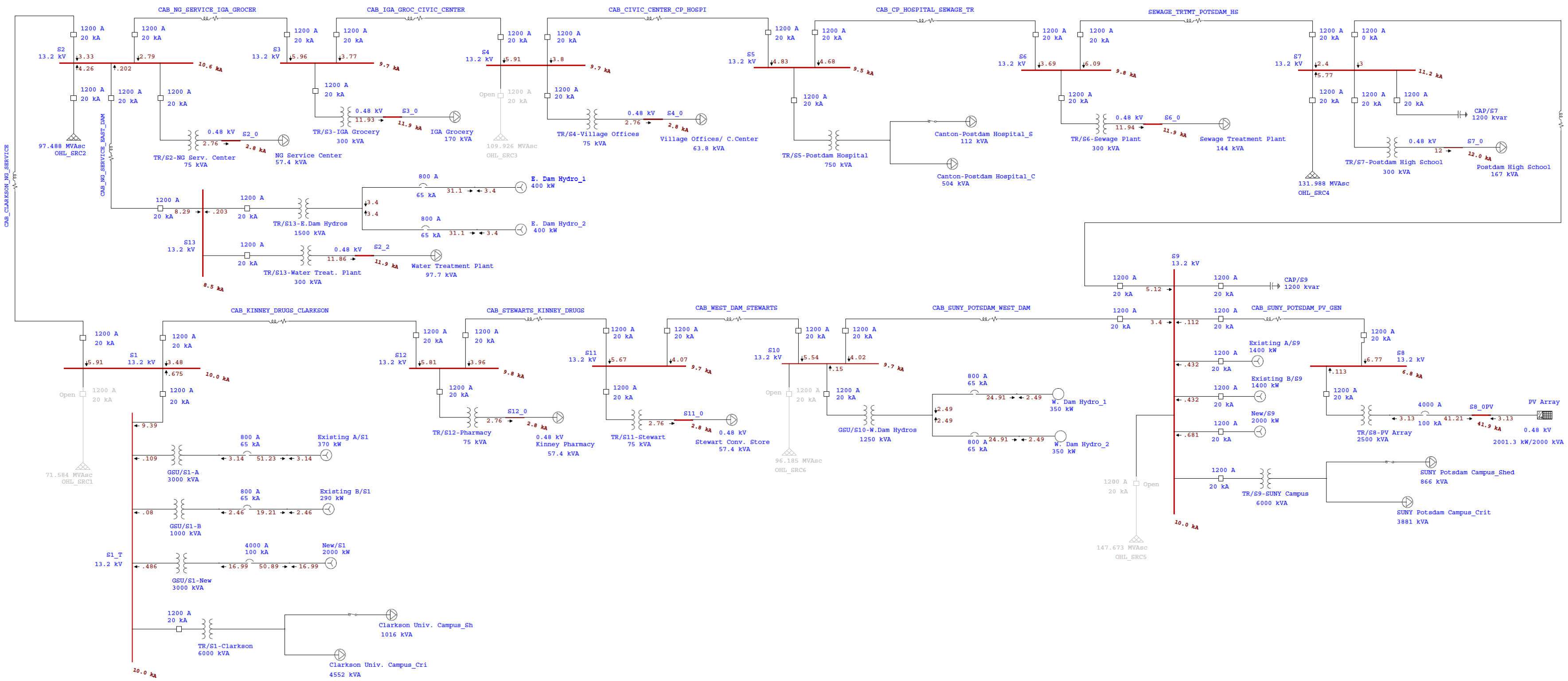


Figure D-9. Case 4a

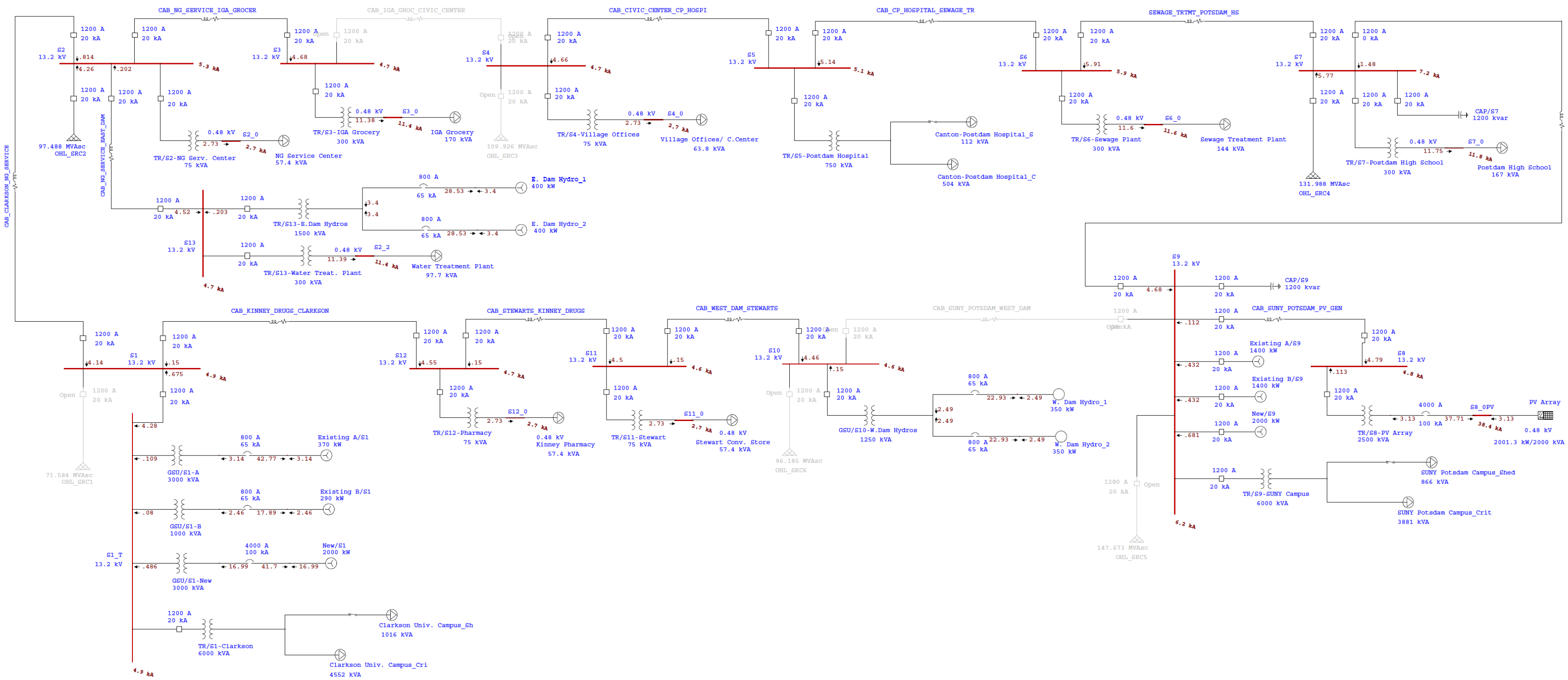


Figure D-10. Case 5

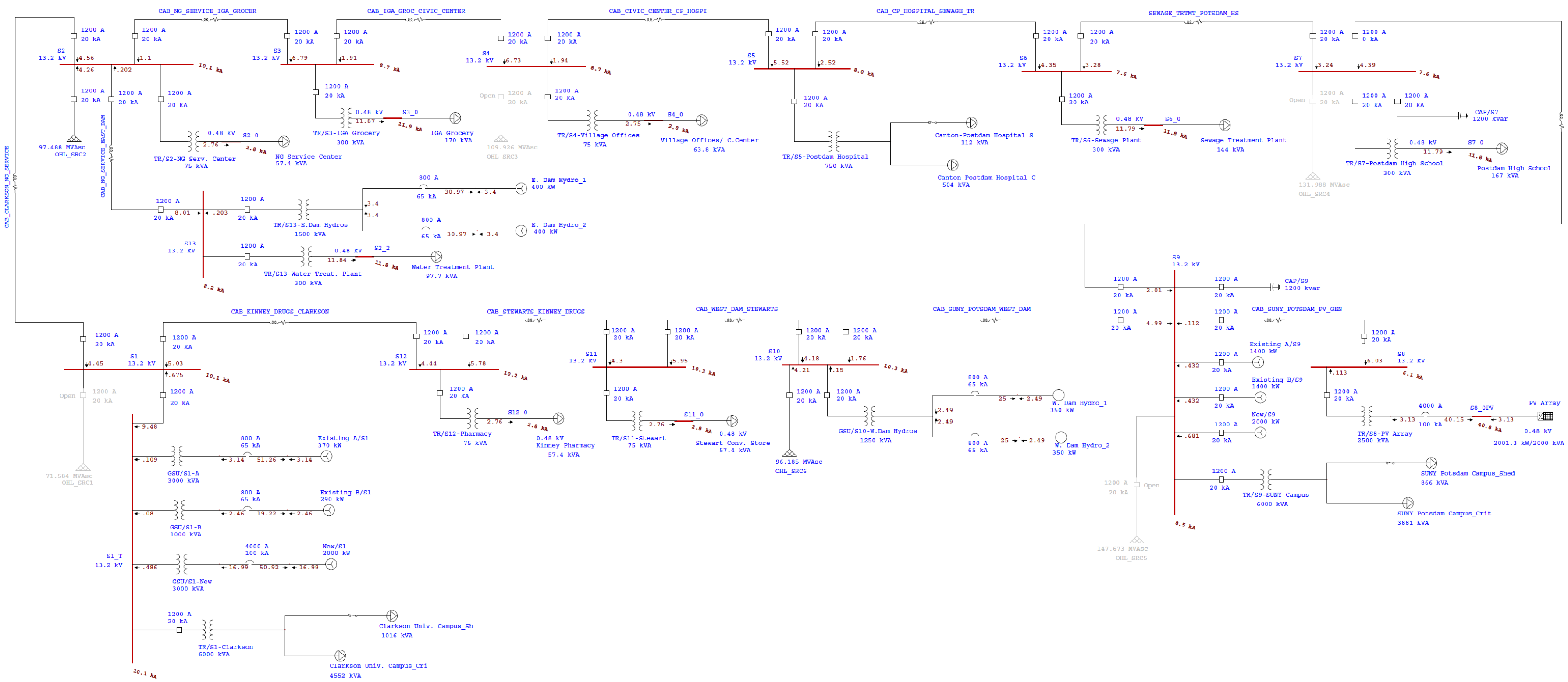
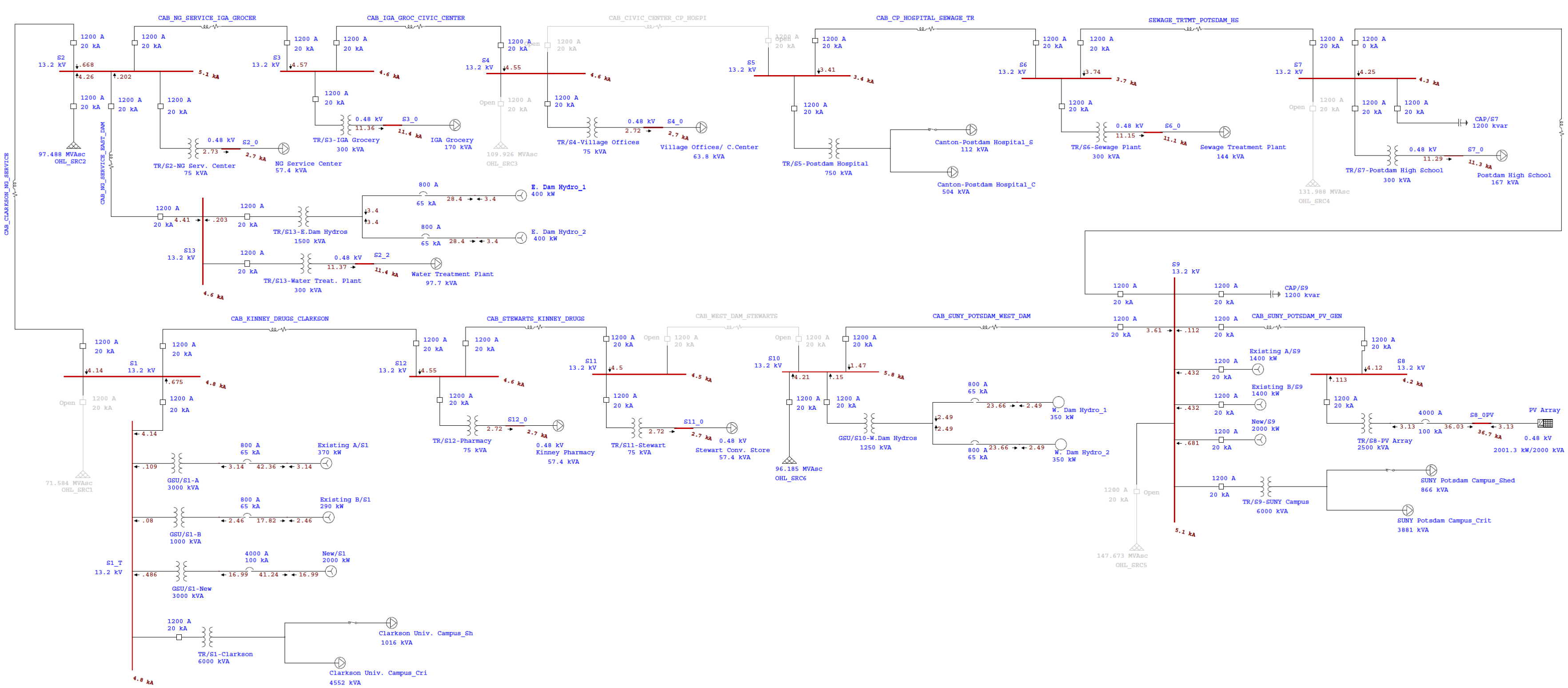


Figure D-11. Case 5a



Appendix E. NY Prize Benefit-Cost Analysis—Facilities Questionnaire

This section is based verbatim (except for the underlying data and section numbering) on the NY Prize Stage 1 IEc's BCA Facilities Questionnaire template, using its original format.

This questionnaire requests information needed to estimate the impact that a microgrid might have in protecting the facilities it serves from the effects of a major power outage (i.e., an outage lasting at least 24 hours). The information in this questionnaire will be used to develop a preliminary benefit-cost analysis of the community microgrid you are proposing for the NY Prize competition. Please provide as much detail as possible.

For each facility that will be served by the microgrid, we are interested in information on:

I. Current backup generation capabilities.

II. The costs that would be incurred to maintain service during a power outage, both when operating on its backup power system (if any) and when backup power is down or not available.

III. The types of services the facility provides.

E.1 Backup Generation Capabilities

1. Do any of the facilities that would be served by the microgrid currently have backup generation capabilities?
   a. ☐ No - proceed to Question 4
   b. ☒ Yes - proceed to Question 2

2. For each facility that is equipped with a backup generator, please complete the table below, following the example provided. Please include the following information:
   a. **Facility name:** For example, "Main Street Apartments."
   b. **Identity of backup generator:** For example, "Unit 1."
   c. **Energy source:** Select the fuel/energy source used by each backup generator from the dropdown list. If you select "other," please type in the energy source used.
   d. **Nameplate capacity:** Specify the nameplate capacity (in MW) of each backup generator.

e. **Standard operating capacity:** Specify the percentage of nameplate capacity at which the backup generator is likely to operate during an extended power outage.

f. **Average electricity production per day in the event of a major power outage**: Estimate the average daily electricity production (MWh per day) for the generator in the event of a major power outage. In developing the estimate, please consider the unit's capacity, the daily demand at the facility it serves, and the hours of service the facility requires.

g. **Fuel consumption per day:** Estimate the amount of fuel required per day (e.g., MMBtu per day) to generate the amount of electricity specified above. This question does not apply to renewable energy resources, such as wind and solar.

h. **One-time operating costs:** Please identify any one-time costs (e.g., labor or contract service costs) associated with connecting and starting the backup generator.

i. **Ongoing operating costs:** Estimate the costs ($/day) (e.g., maintenance costs) associated with operating the backup generator, excluding fuel costs.

Note that backup generators may also serve as distributed energy resources in the microgrid. Therefore, there may be some overlap between the information provided in the table below and the information provided for the distributed energy resource table (Question 2) in the general Microgrid Data Collection Questionnaire.

Table E1. Backup Generation Capabilities

Facility Name	Generator ID	Energy Source	Nameplate Capacity (MW)	Standard Operating Capacity (%)	Avg. Daily Production During Power Outage (MWh/Day)	Fuel Consumption per Day		One-Time Operating Costs ($)	Ongoing Operating Costs ($/Day)
						Quantity	Unit		
Clarkson Campus	GEN Clarkson A	NG	0.29	100.00	6.96	91.34	MMBtu/day	200.00	8.74
Clarkson Campus	GEN Clarkson B	NG	0.20	100.00	4.68	66.54	MMBtu/day	200.00	5.34
Clarkson Campus	GEN Clarkson C	NG	0.37	100.00	8.88	112.22	MMBtu/day	200.00	13.18
Clarkson Campus	GEN Clarkson D Small NG	NG	0.21	100.00	5.06	69.12	MMBtu/day	200.00	5.78
Canton Hospital	GEN Hospital B	Diesel	0.60	100.00	14.40	148.89	MMBtu/day	200.00	26.30
Canton Hospital	GEN Hospital C	Diesel	0.06	100.00	1.44	23.40	MMBtu/day	200.00	1.64
SUNY Potsdam Campus	GEN SUNY CHP A	NG	1.40	100.00	33.60	301.71	MMBtu/day	200.00	107.40

Facility Name	Generator ID	Energy Source	Nameplate Capacity (MW)	Standard Operating Capacity (%)	Avg. Daily Production During Power Outage (MWh/Day)	Fuel Consumption per Day		One-Time Operating Costs ($)	Ongoing Operating Costs ($/Day)
						Quantity	Unit		
SUNY Potsdam Campus	GEN SUNY CHP B	NG	1.40	100.00	33.60	301.71	MMBtu/day	200.00	107.40
SUNY Potsdam Campus	GEN SUNY Bowman Hall	Diesel	0.50	100.00	12.00	127.96	MMBtu/day	200.00	20.55
SUNY Potsdam Campus	GEN SUNY Portable Gen A	Diesel	0.35	100.00	8.40	106.16	MMBtu/day	200.00	11.51
SUNY Potsdam Campus	GEN SUNY Performing Art Center	Diesel	0.25	100.00	6.00	78.74	MMBtu/day	200.00	6.85
SUNY Potsdam Campus	GEN SUNY Portable Gen B	Diesel	0.23	100.00	5.52	75.34	MMBtu/day	200.00	6.30
SUNY Potsdam Campus	GEN SUNY Maxy Hall	Diesel	0.13	100.00	3.00	44.51	MMBtu/day	200.00	3.42
SUNY Potsdam Campus	GEN SUNY Kellas Hall	Diesel	0.10	100.00	2.40	37.22	MMBtu/day	200.00	2.74
SUNY Potsdam Campus	GEN SUNY Small NG	Diesel	0.28	100.00	6.72	88.19	MMBtu/day	200.00	7.67
SUNY Potsdam Campus	GEN SUNY Small DS	NG	0.04	100.00	0.96	16.38	MMBtu/day	200.00	1.10
Civic Center	GEN VIL A	Diesel	0.06	100.00	1.44	23.40	MMBtu/day	200.00	1.64
Civic Center	GEN VIL B	Diesel	0.50	100.00	12.00	127.96	MMBtu/day	200.00	20.55
Civic Center	GEN VIL C	NG	0.13	100.00	3.00	44.51	MMBtu/day	200.00	3.42
Civic Center	GEN VIL D	NG	0.04	100.00	0.96	16.38	MMBtu/day	200.00	1.10

E.2 Costs of Emergency Measures Necessary to Maintain Service

We understand that facilities may have to take emergency measures during a power outage to maintain operations, preserve property, and/or protect the health and safety of workers, residents, or the general public. These measures may impose extraordinary costs, including both one-time expenditures (e.g., the cost of evacuating and relocating residents) and ongoing costs (e.g., the daily expense of renting a portable generator). The questions below address these costs. We begin by requesting information on the costs facilities would be likely to incur when operating on backup power. We then request information on the costs facilities would be likely to incur when backup power is not available.

__A. Cost of Maintaining Service while Operating on Backup Power__

1. Please provide information in the table below for each facility the microgrid would serve which is currently equipped with some form of backup power (e.g., an emergency generator). For each facility, describe the costs of any emergency measures that would be necessary in the event of a widespread power outage (i.e., a total loss of power in the area surrounding the facility lasting at least 24 hours). In completing the table, please assume that the facility's backup power system is fully operational. In your response, please describe and estimate the costs for:
   a. One-time emergency measures (total costs)
   b. Ongoing emergency measures (costs per day)

   Note that these measures do not include the costs associated with running the facility's existing backup power system, as estimated in the previous question.

   In addition, for each emergency measure, please provide additional information related to when the measure would be required. For example, measures undertaken for heating purposes may only be required during winter months. As another example, some commercial facilities may undertake emergency measures during the workweek only.

   As a guide, see the examples the table provides.

Table E2. Costs of Emergency Measures Necessary to Maintain Service

Facility Name	Type of Measure (One-Time or Ongoing)	Description	Costs	Units	When would these measures be required?
Clarkson Campus	One-Time Measures	Emergency Measures	5,000	$	In event of natural disaster
Clarkson Campus	Ongoing Measures	Daily cost of portable generator	10,000	$/Day	In event of natural disaster
Canton Hospital	One-Time Measures	Emergency Measures	5,000	$	In event of natural disaster
Canton Hospital	Ongoing Measures	Daily cost of portable generator	10,000	$/Day	In event of natural disaster
SUNY Potsdam Campus	One-Time Measures	Emergency Measures	5,000	$	In event of natural disaster
SUNY Potsdam Campus	Ongoing Measures	Daily cost of portable generator	10,000	$/Day	In event of natural disaster
Civic Center	One-Time Measures	Emergency Measures	1,000	$	In event of natural disaster
Civic Center	Ongoing Measures	Daily cost of portable generator	2,000	$/Day	In event of natural disaster

B. Cost of Maintaining Service while Backup Power is Not Available

1. Please provide information in the table below for each facility the microgrid would serve. For each facility, please describe the costs of any emergency measures that would be necessary in the event of a widespread power outage (i.e., a total loss of power in the area surrounding the facility lasting at least 24 hours). In completing the table, please assume that service from any backup generators currently on-site is not available. In your response, please describe and estimate the costs for:

   a. One-time emergency measures (total costs)
   b. Ongoing emergency measures (costs per day)

   In addition, for each emergency measure, please provide additional information related to when the measure would be required. For example, measures undertaken for heating purposes may only be required during winter months. As another example, some commercial facilities may undertake emergency measures during the workweek only.

   As a guide, see the examples the table provides.

Table E3. Cost of Maintaining Service while Backup Power is Not Available

Facility Name	Type of Measure (One-Time or Ongoing)	Description	Costs	Units	When would these measures be required?
Clarkson Campus	One-Time Measure	OEM Measures	20,000	$	In event of natural disaster
Clarkson Campus	Ongoing Measures	OEM Measures	40,000	$/Day	In event of natural disaster
SUNY Potsdam Campus	One-Time Measure	OEM Measures	20,000	$	In event of natural disaster
SUNY Potsdam Campus	Ongoing Measures	OEM Measures	40,000	$/Day	In event of natural disaster
Canton Hospital	One-Time Measure	OEM Measures	20,000	$	In event of natural disaster
Canton Hospital	Ongoing Measures	OEM Measures	40,000	$/Day	In event of natural disaster
Water Utility	One-Time Measure	OEM Measures	5,000	$	In event of natural disaster
Water Utility	Ongoing Measures	OEM Measures	10,000	$/Day	In event of natural disaster
Sewage Plant	One-Time Measure	OEM Measures	5,000	$	In event of natural disaster
Sewage Plant	Ongoing Measures	OEM Measures	10,000	$/Day	In event of natural disaster
Central School	One-Time Measure	OEM Measures	4,000	$	In event of natural disaster
Central School	Ongoing Measures	OEM Measures	8,000	$/Day	In event of natural disaster
IGA Grocery	One-Time Measure	OEM Measures	2,000	$	In event of natural disaster
IGA Grocery	Ongoing Measures	OEM Measures	4,000	$/Day	In event of natural disaster
Stewart Shop	One-Time Measure	OEM Measures	2,000	$	In event of natural disaster
Stewart Shop	Ongoing Measures	OEM Measures	4,000	$/Day	In event of natural disaster
Kinney Drugs	One-Time Measure	OEM Measures	2,000	$	In event of natural disaster

Facility Name	Type of Measure (One-Time or Ongoing)	Description	Costs	Units	When would these measures be required?
Kinney Drugs	Ongoing Measures	OEM Measures	4,000	$/Day	In event of natural disaster
Civic Center	One-Time Measure	OEM Measures	2,000	$	In event of natural disaster
Civic Center	Ongoing Measures	OEM Measures	4,000	$/Day	In event of natural disaster
National Grid Service Center	One-Time Measure	OEM Measures	2,000	$	In event of natural disaster
National Grid Service Center	Ongoing Measures	OEM Measures	4,000	$/Day	In event of natural disaster

E.4 Services Provided

We are interested in the types of services provided by the facilities the microgrid would serve, as well as the potential impact of a major power outage on these services. As specified below, the information of interest includes some general information on all facilities, as well as more detailed information on residential facilities and critical service providers (i.e., facilities that provide fire, police, hospital, water, wastewater treatment, or emergency medical services (EMS)).

*A. Questions for: **All Facilities***

1. During a power outage, is each facility able to provide the same level of service when using backup generation as under normal operations? If not, please estimate the percent loss in the services for each facility (e.g., 20% loss in services provided during outage while on backup power). As a guide, see the example the table provides.

Table E4. Loss of Services on Backup Generation

Facility Name	Percent Loss in Services When Using Backup Gen.
Clarkson Campus	50%
SUNY Potsdam Campus	50%
Canton Hospital	50%
Water Utility	0%
Sewage Plant	0%
Central School	100%
IGA Grocery	100%
Stewart Shop	100%
Kinney Drugs	100%
Civic Center	100%
National Grid Service Center	0%

2. During a power outage, <u>if backup generation is not available</u>, is each facility able to provide the same level of service as under normal operations? If not, please estimate the percent loss in the services for each facility (e.g., 40% loss in services provided during outage when backup power is not available). As a guide, see the example the table provides.

Table E5. Loss of Services when Backup Generation is Not Available

Facility Name	Percent Loss in Services When Backup Gen. is Not Available
Clarkson Campus	100%
SUNY Potsdam Campus	100%
Canton Hospital	100%
Water Utility	100%
Sewage Plant	100%
Central School	100%
IGA Grocery	100%
Stewart Shop	100%
Kinney Drugs	100%
Civic Center	100%
National Grid Service Center	100%

*B. Questions for facilities that provide: **Fire Services***

1. What is the total population served by the facility?

17,428

2. Please estimate the <u>percent increase</u> in average response time for this facility during a power outage:

75%

3. What is the distance (in miles) to the nearest backup fire station or alternative fire service provider?

7.2

C. Questions for facilities that provide: ***Emergency Medical Services (EMS)***

1. What is the total population served by the facility?

32,154

2. Is the area primarily served by the facility? (check one):
   ☒ Urban
   ☐ Suburban
   ☐ Rural
   ☐ Wilderness
3. Please estimate the percent increase in average response time for this facility during a power outage:

75%

4. What is the distance (in miles) to the next nearest alternative EMS provider?

10

D. Questions for facilities that provide: ***Hospital Services***

1. What is the total population served by the facility?

55,000
21

3. What is the population served by the nearest alternative hospital?

44,000

E. Questions for facilities that provide: ***Police Services***

1. What is the total population served by the facility?

17,428

2. Is the facility located in a (check one):

☒ Metropolitan Statistical Area?

☐ Non-Metropolitan City?

☐ Non-Metropolitan County?

3. Please estimate:

a. The number of police officers working at the station under normal operations.

17

b. The number of police officers working at the station during a power outage.

17

c.

None

*F. Questions for facilities that provide: **Wastewater Services***

1. What is the total population served by the facility?

17,428

2. Does the facility support (check one):

☐ Residential customers
☐ Businesses
☒ Both

*G. Questions for facilities that provide: **Water Services***

1. What is the total population served by the facility?

17,428

2. Does the facility support (check one):

☐ Residential customers
☐ Businesses
☒ Both

*H. Questions for: **Residential Facilities***

1. What types of housing does the facility provide (e.g., group housing, apartments, nursing homes, assisted living facilities, etc.)?

N/A

2. Please estimate the number of residents that would be left without power during a complete loss of power (i.e., when backup generators fail or are otherwise not available).

0

Appendix F. NY Prize Benefit-Cost Analysis—Microgrid Questionnaire

This section is based verbatim (except for the underlying data and section numbering) on the NY Prize Stage 1 IEc's BCA Facilities Questionnaire template, using its original format.

This questionnaire solicits information on the community microgrid you are proposing for the NY Prize competition. The information in this questionnaire will be used to develop a preliminary benefit-cost analysis of the proposed microgrid. Please provide as much detail as possible. The questionnaire is organized into the following sections:

A. Project Overview, Energy Production, and Fuel Use

B. Capacity Impacts

C. Project Costs

D. Environmental Impacts

E. Ancillary Services

F. Power Quality and Reliability

G. Other Information

F.1 Project Overview, Energy Production, and Fuel Use

1. The table below is designed to gather background information on the facilities your microgrid would serve. It includes two examples: one for Main Street Apartments, a residential facility with multiple utility customers; and another for Main Street Grocery, a commercial facility. Please follow these examples in providing the information specified for each facility. Additional guidance is provided below.

   - **Facility name:** Please enter the name of each facility the microgrid would serve. Note that a single **facility** may include multiple **customers** (e.g., individually metered apartments within a multi-family apartment building). When this is the case, you do not need to list each customer individually; simply identify the facility as a whole (see Table 1, "Main Street Apartments," for an example).
   - **Rate class:** Select the appropriate rate class for the facility from the dropdown list. Rate class options are residential, small commercial/industrial (defined as a facility using less than 50 MWh of electricity per year), or large commercial/industrial (defined as a facility using 50 or more MWh of electricity per year).
   - **Facility/customer description:** Provide a brief description of the facility; including the number of individual customers at the facility if it includes more than one (e.g., individually

metered apartments within a multi-family apartment building). For commercial and industrial facilities, please describe the type of commercial/industrial activity conducted at the facility.

- **Economic sector:** Select the appropriate economic sector for the facility from the dropdown list.
- **Average annual usage:** Specify the average annual electricity usage (in MWh) **per customer**. Note that in the case of facilities with multiple, similar customers, such as multi-family apartment buildings, this value will be different from average annual usage for the facility as a whole.
- **Peak demand:** Specify the peak electricity demand (in MW) **per customer**. Note that in the case of facilities with multiple, similar customers, such as multi-family apartment buildings, this value will be different from peak demand for the facility as a whole.
- **Percent of average usage the microgrid could support in the event of a major power outage:** Specify the percent of each facility's typical usage that the microgrid would be designed to support in the event of a major power outage (i.e., an outage lasting at least 24 hours that necessitates that the microgrid operate in islanded mode). In many cases, this will be 100%. In some cases, however, the microgrid may be designed to provide only enough energy to support critical services (e.g., elevators but not lighting). In these cases, the value you report should be less than 100%.
- **Hours of electricity supply required per day in the event of a major power outage:** Please indicate the number of hours per day that service to each facility would be maintained by the microgrid in the event of a major outage. Note that this value may be less than 24 hours for some facilities; for example, some commercial facilities may only require electricity during business hours.

Table F1. Facility Background and Energy Use

Facility Name	Rate Class	Facility/Customer Description (Specify Number of Customers if More Than One)	Economic Sector Code	Average Annual Electricity Usage Per Customer (MWh)	Peak Electricity Demand Per Customer (MW)	Percent of Average Usage Microgrid Could Support During Major Power Outage	Hours of Electricity Supply Required Per Day During Major Power Outage
Clarkson Campus	Large Commercial/Industrial (>50 annual MWh)	College Campus	All other industries	25,266.417	4.917	100%	24
SUNY Potsdam Campus	Large Commercial/Industrial (>50 annual MWh)	College Campus	All other industries	23,869.710	4.171	100%	24
Canton Hospital	Large Commercial/Industrial (>50 annual MWh)	Hospital	All other industries	3,091.140	0.643	100%	24
Water Utility	Large Commercial/Industrial (>50 annual MWh)	Water Utility	All other industries	677.129	0.199	100%	24
Sewage Plant	Large Commercial/Industrial (>50 annual MWh)	Sewage Plant	All other industries	852.600	0.123	100%	24
Central School	Large Commercial/Industrial (>50 annual MWh)	School	All other industries	738.331	0.187	100%	24
IGA Grocery	Large Commercial/Industrial (>50 annual MWh)	Supermarket	All other industries	658.448	0.176	100%	24
Stewart Shop	Large Commercial/Industrial (>50 annual MWh)	Convenient Store & Gas Station	All other industries	222.537	0.054	100%	24
Kinney Drugs	Large Commercial/Industrial (>50 annual MWh)	Drugstore	All other industries	222.537	0.054	100%	24
Civic Center	Large Commercial/Industrial (>50 annual MWh)	Office Building	All other industries	196.205	0.066	100%	24

Facility Name	Rate Class	Facility/Customer Description (Specify Number of Customers if More Than One)	Economic Sector Code	Average Annual Electricity Usage Per Customer (MWh)	Peak Electricity Demand Per Customer (MW)	Percent of Average Usage Microgrid Could Support During Major Power Outage	Hours of Electricity Supply Required Per Day During Major Power Outage
National Grid Service Center	Large Commercial/Industrial (>50 annual MWh)	Office Building	All other industries	2,286.240	0.694	100%	24

2. In the table below, please provide information on the distributed energy resources the microgrid will incorporate. Use the two examples included in the table as a guide.

- **Distributed energy resource name:** Please identify each distributed energy resource with a brief description. In the event that a single facility has multiple distributed energy resources of the same type (e.g., two diesel generators), please use numbers to uniquely identify each (e.g., "Diesel generator 1" and "Diesel generator 2").
- **Facility name:** Please specify the facility at which each distributed energy resource is or would be based.
- **Energy source:** Select the fuel/energy source used by each distributed energy resource from the dropdown list. If you select "other," please type in the energy source used.
- **Nameplate capacity:** Specify the total nameplate capacity (in MW) of each distributed energy resource included in the microgrid.
- **Average annual production:** Please estimate the amount of electricity (in MWh) that each distributed energy resource is likely to produce each year, on average, **under normal operating conditions.** The benefit-cost analysis will separately estimate production in islanded mode in the event of an extended power outage. **If the distributed energy resource will operate only in the event of an outage, please enter zero.**
- **Average daily production in the event of a major power outage:** Please estimate the amount of electricity (in MWh per day) that each distributed energy resource is likely to produce, on average, **in the event of a major power outage.** In developing your estimate for each distributed energy resource, you should consider the electricity requirements of the facilities the microgrid would serve, as specified in your response to Question 1.
- **Fuel consumption per MWh:** For each distributed energy resource, please estimate the amount of fuel required to generate one MWh of energy. This question does not apply to renewable energy resources, such as wind and solar.

Table F2. Distributed Energy Resources

Distributed Energy Resource Name	Facility Name	Energy Source	Nameplate Capacity (MW)	Average Annual Production Under Normal Conditions (MWh)	Average Daily Production During Major Power Outage (MWh)	Fuel Consumption per MWh	
						Quantity	Unit
New RE/IC A	Clarkson Campus	Natural Gas	2.000	15,965.159	48.000	8.322	MMBtu/MWh
New RE/IC B	Clarkson Campus	Natural Gas	2.000	15,965.159	48.000	8.322	MMBtu/MWh
Clarkson Existing Gen A	Clarkson Campus	Natural Gas	0.290	675.885	6.960	13.124	MMBtu/MWh
Clarkson Existing Gen B	Clarkson Campus	Natural Gas	0.370	1,086.116	8.880	12.638	MMBtu/MWh
GEN SUNY CHP A	SUNY Potsdam Campus	Natural Gas	1.400	7,658.657	33.600	8.979	MMBtu/MWh
GEN SUNY CHP B	SUNY Potsdam Campus	Natural Gas	1.400	8,197.842	33.600	8.979	MMBtu/MWh
Clarkson PV	Clarkson PV	Solar	2.000	2,299.135	6.299	0.000	N/A
East Hydro	East Hydro	Hydro	1.000	3,395.230	9.302	0.000	N/A
West Hydro	West Hydro	Hydro	0.500	980.390	2.686	0.000	N/A

F.2 Capacity Impacts

3. Is development of the microgrid expected to reduce the need for bulk energy suppliers to expand generating capacity, either by directly providing peak load support or by enabling the microgrid's customers to participate in a demand response program?

☐ No – proceed to Question 6

☒ Yes, both by providing peak load support and by enabling participation in a demand response program – proceed to Question 4

☐ Yes, by providing peak load support only – proceed to Question 4

☐ Yes, by enabling participation in a demand response program only – proceed to Question 5

Provision of Peak Load Support

4. Please provide the following information for all distributed energy resources that would be available to provide peak load support:

- **Available capacity:** Please indicate the capacity of each distributed energy resource that would be available to provide peak load support (in MW/year).
- **Current provision of peak load support, if any:** Please indicate whether the distributed energy resource currently provides peak load support.

Please use the same distributed energy resource and facility names from Question 2.

Table F3. Capacity Impacts

Distributed Energy Resource Name	Facility Name	Available Capacity (MW/year)	Does distributed energy resource currently provide peak load support?
New RE/IC A	Clarkson Campus	2.000	☒ Yes
New RE/IC B	Clarkson Campus	2.000	☐ Yes
Clarkson Existing Gen A	Clarkson Campus	0.290	☐ Yes
Clarkson Existing Gen B	Clarkson Campus	0.370	☐ Yes
GEN SUNY CHP A	SUNY Potsdam Campus	1.400	☐ Yes
GEN SUNY CHP B	SUNY Potsdam Campus	1.400	☐ Yes
Clarkson PV	Clarkson PV	0.262	☐ Yes
East Hydro	East Hydro	0.388	☐ Yes
West Hydro	West Hydro	0.112	☐ Yes

If development of the microgrid is also expected to enable the microgrid's customers to participate in a demand response program, please proceed to Question 5. Otherwise, please proceed to Question 6.

Participation in a Demand Response Program

5. Please provide the following information for each facility that is likely to participate in a demand response program following development of the microgrid:

   - **Available capacity:** Please estimate the capacity that would be available to participate in a demand response program (in MW/year) following development of the microgrid.
   - **Capacity currently participating in a demand response program, if any:** Please indicate the capacity (in MW/year), if any, that currently participates in a demand response program.

Table F4. Participation in Demand Response Program

Facility Name	Capacity Participating in Demand Response Program (MW/year)	
	Following Development of Microgrid	Currently
Combined Microgrid	2.000	0.000

6. Is development of the microgrid expected to enable utilities to avoid or defer expansion of their transmission or distribution networks?

   ☐ Yes – proceed to Question 7

   ☒ No – proceed to Section C

7. Please estimate the impact of the microgrid on utilities' **transmission** capacity requirements. The following question will ask about the impact on distribution capacity.

Table F5. Impact on Transmission Capacity

Impact of Microgrid on Utility Transmission Capacity	Unit
N/A	MW/Year

Note: Transmission capacity impacts are already incorporated into energy prices and generation capacity prices. We therefore do not value this impact separately in the model.

One exception is when the project team indicates that a specific investment would be avoided. In that case, incorporate their cost estimates into the Energy Benefits Calcs tab (combine with Dist. Cap. Benefits) or the Summary tab.

8. Please estimate the impact of the microgrid on utilities' **distribution** capacity requirements.

Table F6. Impact on Utilities Distribution Capacity

Impact of Microgrid on Utility Distribution Capacity	Unit
N/A	MW/Year

F.3 Project Costs

We are interested in developing a year-by-year profile of project costs over a 20-year operating period. The following questions ask for information on specific categories of costs.

Capital Costs

9. In the table below, please estimate the fully installed cost and lifespan of all equipment associated with the microgrid, including equipment or infrastructure associated with power generation (including combined heat and power systems), energy storage, energy distribution, and interconnection with the local utility.

Table F7. Participation in Demand Response Program

Capital Component	Installed Cost ($)	Component Lifespan (round to nearest year)	Description of Component
New Generators - Dual Fuel (Equipment Cost)	$4,000,000	30	New Generators (Equipment Cost)
New Generators (Installation Cost)	$1,500,000	30	New Generators (Installation Cost)
Distribution - Breakers Only (Equipment Cost)	$11,813,000	30	Distribution - Breakers Only (Equipment Cost)
Distribution - Breakers Only (Installation Cost)	$11,705,000	30	Distribution - Breakers Only (Installation Cost)
Protection (Equipment Cost)	$1,941,000	30	Protection (Equipment Cost)
Protection (Installation Cost)	$630,000	30	Protection (Installation Cost)
Control and Communications (Equipment Cost)	$2,783,000	30	Control and Communications (Equipment Cost)
Control and Communications (Installation Cost)	$1,450,000	30	Control and Communications (Installation Cost)
Gas Extension and Connections	$150,000	30	Gas Extension and Connections

Capital Component	Installed Cost ($)	Component Lifespan (round to nearest year)	Description of Component
Gas Extension, Diesel Storage, and Connections	$200,000	30	Gas Extension, Diesel Storage, and Connections
Miscellaneous Equipment	$750,000	30	Miscellaneous Equipment

Initial Planning and Design Costs

10. Please estimate initial planning and design costs. These costs should include costs associated with project design, building and development permits, efforts to secure financing, marketing the project, and negotiating contracts. Include only upfront costs. Do not include costs associated with operation of the microgrid.

Table F8. Initial Planning and Design Costs

Initial Planning and Design Costs ($)	What cost components are included in this figure?
$1,2500,000	Project Design, Permit, Finance

> Potsdam Engineering and Design: $1,000,000; Testing and Commissioning: $250,000

Fixed O&M Costs

11. Fixed O&M costs are costs associated with operating and maintaining the microgrid that are unlikely to vary with the amount of energy the system produces each year (e.g., software licenses, technical support). Will there be any year-to-year variation in these costs for other reasons (e.g., due to maintenance cycles)?

☒ No – proceed to Question 12

☐ Yes – proceed to Question 13

12. Please estimate any costs associated with operating and maintaining the microgrid that are unlikely to vary with the amount of energy the system produces each year.

Table F9. Initial Planning and Design Costs

Fixed O&M Costs ($/year)	What cost components are included in this figure?
$364,400	Generation FOM + Software Licensing, Miscellaneous

> Potsdam Generation FOM: $246,400 + Software: $100,000

Please proceed to Question 14.

13. For each year over an assumed 20-year operating life, please estimate any costs associated with operating and maintaining the microgrid that are unlikely to vary with the amount of energy the system produces.

Table F10. Fixed Operation and Maintenance Costs

Year	Fixed O&M Cost ($)	What cost components are included in this figure?
1		
2		
3		
4		
5		
6		
7		
8		
9		
10		
11		
12		
13		
14		
15		
16		
17		
18		
19		
20		

Variable O&M Costs (Excluding Fuel Costs)

14. Please estimate any costs associated with operating and maintaining the microgrid (excluding fuel costs) that are likely to vary with the amount of energy the system produces each year. Please estimate these costs per unit of energy produced (e.g., $/MWh).

Table F10A. Variable Operation and Maintenance Costs

Variable O&M Costs ($/Unit of Energy Produced)	Unit	What cost components are included in this figure?
17.00	$/MWh	New RE/IC A
17.00	$/MWh	New RE/IC B
23.00	$/MWh	Clarkson Existing Gen A
22.00	$/MWh	Clarkson Existing Gen B
18.00	$/MWh	GEN SUNY CHP A
18.00	$/MWh	GEN SUNY CHP B
0.00	$/MWh	Clarkson PV
0.00	$/MWh	East Hydro
0.00	$/MWh	West Hydro

Fuel Costs

15. In the table below, please provide information on the fuel use for each distributed energy resource the microgrid will incorporate. Please use the same distributed energy resource and facility names from Question 2.

- **Duration of design event:** For each distributed energy resource, please indicate the maximum period of time in days that the distributed energy resource would be able to operate in islanded mode without replenishing its fuel supply (i.e., the duration of the maximum power outage event for which the system is designed). **For renewable energy resources, your answer may be "indefinitely."**
- **Fuel consumption:** For each distributed energy resource that requires fuel, please specify the quantity of fuel the resource would consume if operated in islanded mode for the assumed duration of the design event.

Table F11. Duration of Design Event and Fuel Consumption

Distributed Energy Resource Name	Facility Name	Duration of Design Event (Days)	Quantity of Fuel Needed to Operate in Islanded Mode for Duration of Design Event	Unit
New RE/IC A	New RE/IC A	14	Not Used in the Model	Not Used in the Model
New RE/IC B	New RE/IC B	14	Not Used in the Model	Not Used in the Model
Clarkson Existing Gen A	Clarkson Existing Gen A	14	Not Used in the Model	Not Used in the Model
Clarkson Existing Gen B	Clarkson Existing Gen B	14	Not Used in the Model	Not Used in the Model
GEN SUNY CHP A	GEN SUNY CHP A	14	Not Used in the Model	Not Used in the Model
GEN SUNY CHP B	GEN SUNY CHP B	14	Not Used in the Model	Not Used in the Model
Clarkson PV	Clarkson PV	14	Not Used in the Model	Not Used in the Model
East Hydro	East Hydro	14	Not Used in the Model	Not Used in the Model
West Hydro	West Hydro	14	Not Used in the Model	Not Used in the Model

16. Will the project include development of a combined heat and power (CHP) system?

☒ Yes – proceed to Question 17

☐ No – proceed to Question 18

17. If the microgrid will include development of a CHP system, please indicate the type of fuel that will be offset by use of the new CHP system and the annual energy savings (relative to the current heating system) that the new system is expected to provide.

Table F12. Fuel Offset by New CHP System

Type of Fuel Offset by New CHP System	Annual Energy Savings Relative to Current Heating System	Unit
Natural gas	0	MMBtu

Emissions Control Costs

18. We anticipate that the costs of installing and operating emissions control equipment will be incorporated into the capital and O&M cost estimates you provided in response to the questions above. If this is not the case, please estimate these costs, noting what cost components are included in these estimates. For capital costs, please also estimate the engineering lifespan of each component.

Table F13. Emissions Control Costs

Cost Category	Costs ($)	Description of Component(s)	Component Lifespan(s) (round to nearest year)
Capital Costs ($)	0.00	N/A	0
Annual O&M Costs ($/MWh)	0.00	N/A	
Other Annual Costs ($/Year)	0.00	N/A	

19. Will environmental regulations mandate the purchase of emissions allowances for the microgrid (for example, due to system size thresholds)?

☐ Yes

☒ No

F.4 Environmental Impacts

20. For each pollutant listed below, what is the estimated emissions rate (e.g., tons/MWh) for the microgrid?

Table F14. Emissions Summary

Emissions Type	Emissions per MWh	Unit
CO_2	0.414	Metric Tons/MWh
SO_2		
NO_x	0.000032	Metric Tons/MWh
PM		

> Emission values are calculated for the dispatch of the whole microgrid based on the annual emission of the microgrid and annual generation of the microgrid, including solar and hydro resources.

F.5 Ancillary Services

21. Will the microgrid be designed to provide any of the following ancillary services? If so, we may contact you for additional information.

Table F15. Ancillary Services

Ancillary Service	Yes	No
Frequency or Real Power Support	☒	☐
Voltage or Reactive Power Support	☒	☐
Black Start or System Restoration Support	☒	☐

F.6 Power Quality and Reliability

22. Will the microgrid improve power quality for the facilities it serves?

☒ Yes – proceed to Question 23

☐ No – proceed to Question 24

23. If the microgrid will result in power quality improvements, how many power quality events (e.g., voltage sags, swells, momentary outages) will the microgrid avoid each year, on average? Please also indicate which facilities will experience these improvements.

Table F16. Power Quality Events

Number of Power Quality Events Avoided Each Year	Which facilities will experience these improvements?
7.5	Based on Feedback from National Grid

24. The benefit-cost analysis model will characterize the potential reliability benefits of a microgrid based, in part, on standard estimates of the frequency and duration of power outages for the local utility. In the table below, please estimate your local utility's average **outage frequency per customer** (system average interruption frequency index, or SAIFI, in events per customer per year) and average **outage duration per customer** (customer average interruption duration index, or CAIDI, in hours per event per customer).

For reference, the values cited in the Department of Public Service's 2014 Electric Reliability Performance Report are provided on the following page. If your project would be located in an area served by one of the utilities listed, please use the values given for that utility. If your project would be located in an area served by a utility that is not listed, please provide your best estimate of SAIFI and CAIDI values for the utility that serves your area. In developing your estimate, please *exclude* outages caused by major storms (a major storm is defined as any storm which causes service interruptions of at least 10 percent of customers in an operating area, and/or interruptions with duration of 24 hours or more). This will ensure that your estimates are consistent with those provided for the utilities listed on the following page.[13]

Table F17. System Average Interruption Frequency and Customer Average Interruption Duration Indices

Estimated SAIFI	Estimated CAIDI
0.96	1.94

Table F17A. System SAIFI and CAIDI Values for 2014 as reported by DPS

Utility	SAIFI (events per year per customer)	CAIDI (hours per event per customer)
Central Hudson Gas & Electric	1.24	2.27
Con Edison	0.11	3.02
PSEG Long Island	0.72	1.36
National Grid	0.96Syst	1.94
New York State Electric & Gas	1.03	1.97
Orange & Rockland	1.08	1.62
Rochester Gas & Electric	0.76	1.74
Statewide	*0.57*	*1.93*
Source: "2014 Electric Reliability Performance Report", New York State Department of Public Service, Electric Distribution Systems Office of Electric, Gas, and Water. June 2015. http://www3.dps.ny.gov/W/PSCWeb.nsf/All/D82A200687D96D3985257687006F39CA?OpenDocument.		

Endnotes

1 https://www.nyserda.ny.gov/climaid

2 http://www.governor.ny.gov/sites/governor.ny.gov/files/archive/assets/documents/MACfinalreportjune22.pdf

3 http://geenergyconsulting.com

4 Hybrid https://building-microgrid.lbl.gov/projects/der-cam

5 http://pvwatts.nrel.gov/

6 http://www.nyserda.ny.gov/Cleantech-and-Innovation/Energy-Prices/On-Highway-Diesel/Weekly-Diesel-Prices

7 In absence of data from the Utility 15kV Primary UD EPR cable from Southwire Company is used for calculation. Please refer to catalog for details, http://www.southwire.com/products/ProductCatalog.htm

8 IEEE Std. C37.102 (2006) Guide for AC Generator Protection http://dx.doi.org/10.1109/IEEESTD.2006.320495

9 A North American Electric Reliability Corporation (NERC) standard.

10 Note provided by IEc: "The seven percent discount rate is consistent with the U.S. Office of Management and Budget's current estimate of the opportunity cost of capital for private investments. One exception to the use of this rate is the calculation of environmental damages. Following the New York Public Service Commission's (PSC) guidance for benefit-cost analysis, the model relies on temporal projections of the social cost of carbon (SCC), which were developed by the U.S. Environmental Protection Agency (EPA) using a three percent discount rate, to value CO2 emissions. As the PSC notes, "The SCC is distinguishable from other measures because it operates over a very long-time frame, justifying use of a low discount rate specific to its long-term effects." The model also uses EPA's temporal projections of social damage values for SO2, NOx, and PM2.5, and therefore also applies a three percent discount rate to the calculation of damages associated with each of those pollutants. [See: State of New York Public Service Commission. Case 14-M-0101, Proceeding on Motion of the Commission in Regard to Reforming the Energy Vision. Order Establishing the Benefit-Cost Analysis Framework. January 21, 2016.]"

11 Note provided by IEc: "The New York State Department of Public Service (DPS) requires utilities delivering electricity in New York State to collect and regularly submit information regarding electric service interruptions. The reporting system specifies 10 cause categories: major storms; tree contacts; overloads; operating errors; equipment failures; accidents; prearranged interruptions; customers equipment; lightning; and unknown (there are an additional seven cause codes used exclusively for Consolidated Edison's underground network system). Reliability metrics can be calculated in two ways: including all outages, which indicates the actual experience of a utility's customers; and excluding outages caused by major storms, which is more indicative of the frequency and duration of outages within the utility's control. In estimating the reliability benefits of a microgrid, the BCA employs metrics that exclude outages caused by major storms. The BCA classifies outages caused by major storms or other events beyond a utility's control as "major power outages," and evaluates the benefits of avoiding such outages separately."

12 See report titled "Connecting Small Generators to Utility Distribution Systems" - CEA Research Report 128-D-767, 1994).

13 The DPS service interruption reporting system specifies 10 cause categories: major storms; tree contacts; overloads; operating errors; equipment failures; accidents; prearranged interruptions; customers equipment; lightning; and unknown (there are an additional seven cause codes used exclusively for Con Edison's underground network system). SAIFI and CAIDI can be calculated in two ways: including all outages, which indicates the actual experience of a utility's customers; and excluding outages caused by major storms, which is more indicative of the frequency and duration of outages within the utility's control. The BCA model treats the benefits of averting lengthy outages caused by major storms as a separate category; therefore, the analysis of reliability benefits focuses on the effect of a microgrid on SAIFI and CAIDI values that exclude outages caused by major storms.

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