DISTRICT OF SUMMERLAND

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SUMMERLAND INTEGRATED SOLAR PROJECT
SYSTEM IMPACT & INTERCONNECTION STUDY

District of Summerland
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1 TERMS AND DEFINITIONS

Alternating Current (AC)	Term used to describe electric systems in which the voltage and current continuously change in time. The voltage and current values follow sinusoidal function in time. AC is used in most electric generation, transmission, and distribution systems.
Apparent Power (MVA)	The vector combination of real and reactive power. Also, the product of rms voltage and rms current. Measured in MVA or kVA.
BESS	Battery Energy Storage System
CSA	Canadian Standards Association.
CYME	Distribution Analysis software composed of a network editor, analysis modules, and user-customizable model libraries used to model various aspects of distribution systems including system voltage, protection, harmonics, and more.
Direct Current (DC)	Term used to describe electric systems in which the voltage and current do not alternate with time. DC systems have become more popular in extra high voltage transmission lines (>500kV) as DC systems do not have reactive losses.
Distributed Energy Resource (DER)	Small de-centralized means for generating power. Typically, these sources of electrical generation are small compared to the capacity of the distribution or transmission lines they are connected to.
DoS	District of Summerland.
Flicker	The measure of the amount of amplitude modulation of the 60Hz main frequency.
Harmonics	Voltage or Current waveforms present in the power system that have frequencies that are integer multiples of the fundamental 60Hz frequency.
Inverter	Device that converts from DC to AC.
Insolation	Typical energy output available from a PV system due to the geographical location.
Irradiance	The power per unit area available from solar radiation in a given area.
MWp/kWp	Nameplate capacity of the PV system in MW or kW
Per Unit (p.u.)	A method of representing system values as a percentage of chosen base values
Power Quality	The characterization of the voltage in a given power system. Typically, there are key parameters that are measured such as transient voltage readings, voltage sag/swell, rapid voltage changes, harmonics, flicker, and voltage unbalance.
Photo Voltaic (PV)	Typically, "PV" is used to describe photo voltaic modules used in solar generating stations.
Real Power	The rate at which real useful energy is consumed in an AC circuit.
Reactive Power	The rate at which reactive energy is transferred in an AC circuit.
Real Mean Square (RMS)	A method of statistically averaging the square of the instantaneous values of a cyclic waveform.
Rapid Voltage Change (RVC)	Any voltage deviation that is less than 10% of the typical operating voltage.
Sag/Swell	Any Voltage deviation that is greater than 10% of the typical operating voltage.
Reactance	The non-resistive component of electrical impedance in an AC circuit. This phenomenon arises due to the inductance and/or capacitance in a circuit and is a function of the frequency of the applied voltage or current.

2 EXECUTIVE SUMMARY

The District of Summerland (DoS) contracted Primary Engineering and Construction to complete a feasibility study for the integration of solar photovoltaic (PV) and battery energy storage systems (BESS) into their distribution network. This report outlines effects to the DoS network of such integration while also offering insights into potential future projects/initiatives that the DoS may want to consider in support of that integration.

Part One

The first part of this report outlines various selection criteria for determining the potential location of a 1 MWp solar system. Criteria such as solar resource, system impact, and topography were considered when determining potential sites. Several locations were analyzed with candidate sites highlighted in graphical form.

Part Two

The second part of this report outlines simulations of distributed PV sources that are at a 20% penetration level in conjunction with the 1 MWp solar system. Studies conducted include conductor/cable loading, system short circuit levels, system voltage, and rapid voltage changes. From results obtained it appears that there are minimal effects to the primary distribution system and integration of PV into the DoS network will be very low risk. Simulations were conducted on several candidate locations for the 1 MWp solar system with results summarized throughout the report.

Part Three

The third part of this report outlines the analysis performed for the integration for a 2 MVA BESS into the DoS network. Simulations were conducted for a BESS location based on desired functionality such as peak load shaving. The load data over the course of a single year was analyzed to determine the expected peak load durations. The DoS's system impact results were then discussed with minimal effects caused by the integration of the BESS in comparison to normal operating conditions. Lastly, several scenarios were presented to demonstrate the capacity of a 2 MVA BESS to serve a microgrid of critical loads. Several combinations of loads and feeder topologies are presented with identification of additional switchgear requirements for each configuration.

Part Four

In Section 7 of this report, recommended system work is explored to optimize the network for the integration of the 1 MWp solar system and 2 MVA BESS. The recommended work includes: Line extensions, Prairie Valley substation and feeder reconfiguration, Microgrid feeder preparation, rebuilds to support the 1 MWp solar system's integration, New substation in industrial area, System phase balancing, and a System protection coordination study.

Finally, conclusions and recommendations in relation to the 1 MWp solar system and 2 MVA BESS are made. Four potential parcels owned by the DoS are highlighted as the most ideal for solar integration. A 1MWp solar system and a BESS size of 2 MVA pose little system impact in these four parcels.

3 INTRODUCTION

The District of Summerland (DoS) is a small municipality of 11,615 residents in British Columbia (BC). It is one of only five municipalities in BC that owns its electrical utility. Currently, DoS purchases all their energy at wholesale rates from FortisBC. This has been the traditional model for most municipally-owned utilities to date. DoS recently obtained grant funding that will assist them in their goal of becoming a municipal leader in the production and utilization of solar energy. As part of this initiative, Primary Engineering and Construction Corporation (Primary) was contracted to carry out a full distribution system impact analysis to be documented in this study. The study's main objectives are the following:

1. Determine the overall system impact of 5 kWp and 30 kWp photo voltaic (PV) systems on the DoS distribution system at penetration levels of 20%.
2. Document a set of solar site selection guidelines and identify where ideal locations are within the DoS to install 1 MWp of solar from both a solar resource and distribution system perspective.
3. Determine the technical feasibility of installing a 1 MWp solar system and 2 MVA battery energy storage system (BESS) on the DoS distribution system. This work included demonstrating the effects that a combination of 20% penetration of small scale PV and the larger 1 MWp system would have on the DoS distribution system. Additionally, an analysis of the effect that a centrally-located BESS would have on the DoS system was undertaken.
4. Carry out an analysis on DoS demand data to determine how PV and battery storage will affect system demand.

In order to meet these objectives, the study has been divided into four distinct sections: (1) 1 MW Solar Site Selection, (2) Simulation of 20% PV Penetration and 1 MW Solar System, (3) 2 MVA Battery Storage, and (4) Recommended System Work. Each section documents the steps taken to undertake the analysis and summarizes the results. Any identified system work also includes a Class D estimate of any distribution work required to support DoS in their solar and battery system initiatives.

4 1 MW SOLAR SITE SELECTION

4.1 Solar Site Selection Considerations

Selecting a suitable site is a crucial component of developing a viable solar project. For the scope of this report, only technical criteria will be discussed. Constraints that should be considered for a large solar project include:

1. Solar resource
2. Distribution system proximity
3. Distribution system impacts
4. Available area
5. Topography
6. Environmental considerations
7. Geotechnical conditions
8. Accessibility
9. Module soiling

Solar Resource

A high average global tilted irradiation is the most important consideration for developing a solar project. Summerland has a solar potential of 1152 kWh/kWp; this is above BC's municipal average of 1077 kWh/kWp and on par with the national municipal average of 1165 kWh/kWp (data from Natural Resources Canada).

Distribution System Proximity

The location of the site should be as close as possible to an existing feeder to minimize the costs associated with building additional distribution to the station service point. Constructing a line extension to feed a site will add cost and may make a site unsuitable for a project if the cost is too high. Some general financial planning figures for line extensions are provided in Section 7.

Distribution System Impacts

As reported in literature, large penetrations of PV on a distribution feeder can affect voltages, power flow, and short circuit characteristics [1]-[3]. Although system characteristics can be affected, the extent of influence is dependent on existing feeder properties (such as steady state voltage) in addition to PV penetration level. PV penetration levels typically need to exceed 30% penetration before voltage and power flows with distribution networks begin to be adversely affected, as demonstrated in [1]-[2]. References [3]-[4] also demonstrate that for case studies presented the fault level only increases by 1.1% when 30% PV penetration is integrated into the network with very little effect on existing protection coordination. The distribution system impacts on the DoS system will be discussed further throughout this study.

Available Area

The area required per kWp of installed capacity varies with the technology chosen and the latitude of the installation due to the required spacing between rows to avoid shading. Using current commercially available crystalline modules, a fixed tilt racking system, appropriate inter-row spacing for Summerland's latitude, and assuming a roughly square plot of land, the 1 MWp array would require an area of about 5 acres [5].

To identify a cross section of properties that could be simulated it was assumed that the 1 MWp array could be broken into smaller parts and distributed throughout the DoS. A reasonable limit of 100 kWp was chosen as the smallest practical size, which means that the lower boundary on acceptable property size is 0.5 acres, which would require up to 10 such sites.

Topography

Slope

Ideally, the site should be close to flat or on a slight south-facing slope. Many commercial racking systems can be installed with a maximum of 10% E-W slope. It is possible to install on larger slopes; however, this adds to the cost of the system. Therefore, land was chosen that had an overall slope of 10% or less.

Shading

An additional constraint for this topic is the shading due to buildings, trees, or mountains on the horizon. Summerland has many steep hills, which limits some of the areas available for solar. It was decided to adhere to standard industry practice and eliminate any locations which do not receive sunlight on winter solstice before 10 a.m. and after 2 p.m. due to local geography. Further detailed shading analysis due to buildings or trees should be performed once acceptable locations have been shortlisted.

Environmental Considerations

Avoiding sensitive or critical habitats and species is crucial. Construction and operation of solar PV power plants and ancillary infrastructure can lead to the clearing of existing habitats and disturbance to fauna and flora. Ideally, PV solar systems should be built on sites that are either open, barren, or have been previously disturbed. In a distributed architecture (multi-location installs), multiple large rooftops could be used to take advantage of previously developed land. This could minimize costs and impacts to land. Environmental site assessments were not included in this study and should be carried out by the appropriate professional during detailed design.

Geotechnical Conditions

A geotechnical survey of the site is recommended prior to final selection with the purpose of assessing the ground conditions. This informs the foundation design approach to ensure that the mounting structures will have adequately-designed foundations. The geotechnical study may also be expected to include an assessment of the risk of seismic activity, landslip, ground subsidence, and susceptibility of the soil to frost heave, erosion, and flooding.

Accessibility

The site should allow access for trucks to deliver plant and construction materials. This may require the upgrading of existing roads or construction of new roads. Generally, the closer the site is to a main access road, the lower the cost of adding this infrastructure.

Module Soiling

The efficiency of the solar system could be significantly reduced if the modules are soiled (covered) by particulates/dust. It is important to consider the proximity of agricultural or industrial activity which may cause dust to settle on the solar modules. It is common for modules to be cleaned periodically in areas where this is unavoidable; however, this adds to the annual operation and maintenance costs of the facility.

4.2 SUMMERLAND SOLAR PLANNING ANALYSIS

An initial site analysis was carried out by looking at the following constraints from Section 4.1: Topography, Available Area, and Distribution System Proximity. These constraints were analyzed and geospatially mapped using various GIS software platforms to create the map in Figure 1. The figure was developed for the entire District of Summerland and highlights ideal locations for a 1 MWp solar system in light yellow.

As part of this study, the DoS provided Primary with a list of DoS-owned properties. Any property under 0.5 acres were excluded from the study as this was the minimum lot size that was deemed acceptable by Primary to build a 10% portion of the 1 MWp system, or 100 kWp. The remaining properties were evaluated for their suitability and listed in numerical order based on a simple scoring criteria matrix (1 = 'yes'; 0 = 'no') that accounted for the qualitative assessment of hillside shading, topography slope, and if the parcel was adjacent to a three-phase power line. In other words, a power line ran directly long one of the edges of the property or was across the street from the property. The results were tabularized and shown in Table 1.

Twenty-four (24) locations were simulated in total and are shown as numbered pins in Figure 1. Twenty (20) of these locations are DoS-owned. The remaining 4 were additional locations not owned by the DoS and are labeled [redacted]. These non-DoS owned locations were selected to ensure a good cross section of locations along the feeders were simulated to accurately assess the potential system impacts from a large-scale solar system even if they were unlikely locations for an actual installation.

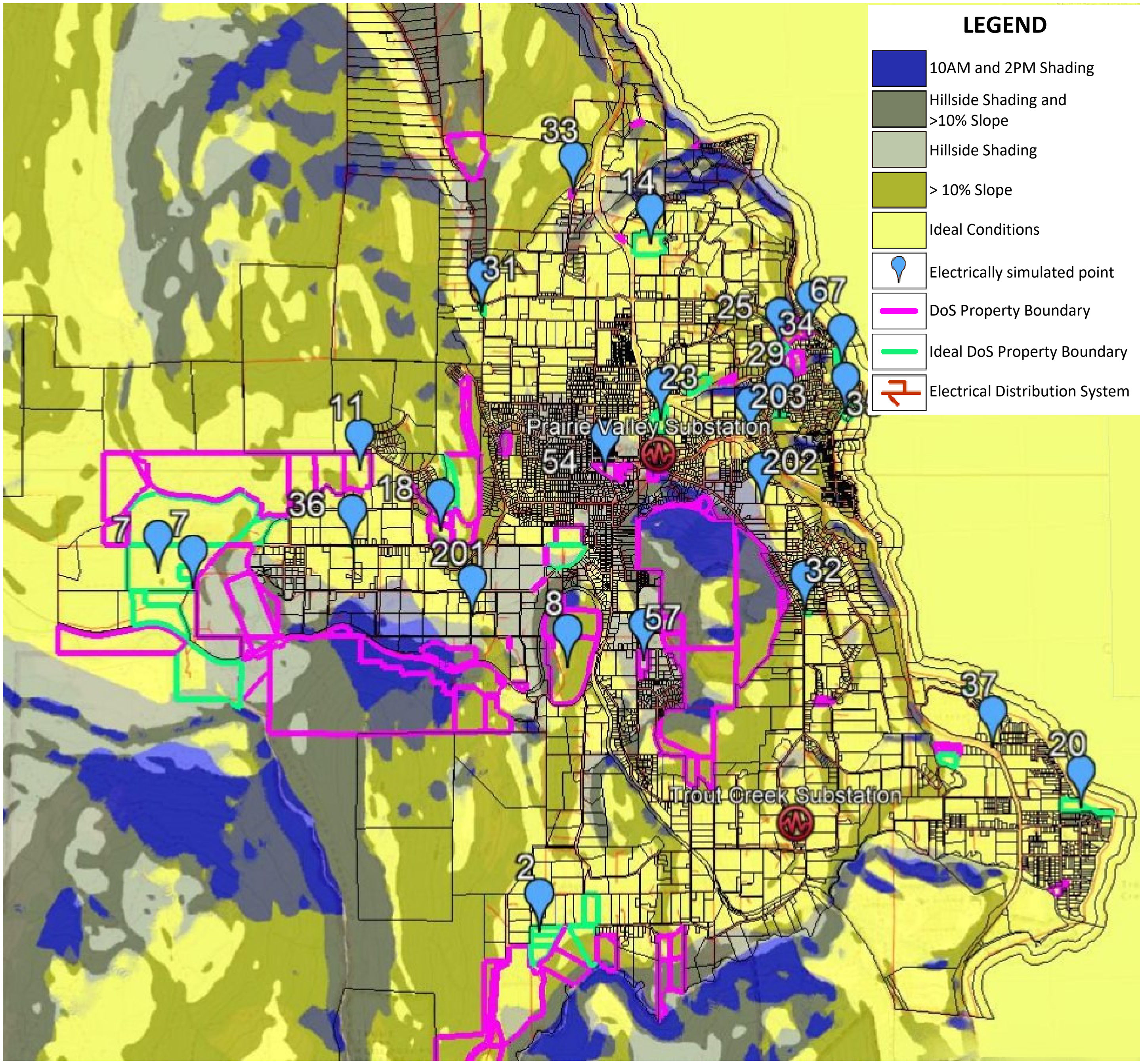

Figure 1: Map of simulated 1 MWp locations and suitability of landscape for PV

As seen in Figure 1, there are several suitable DoS-owned properties that would work for the installation of the 1 MWp system. The properties that evaluated highest among the checks that were conducted were those nearby properties 2 and 7. Other sites that show particular promise are sites #8 (due to its potential to support improvements to DoS' system) and #18 (due to it being previously disturbed for industrial purposes).

Table 1: List of Ranked District of Summerland Owned Properties

Report ID	Address	Street	Parcel Size (Acres)	PID	Topography: Minimal 10AM & 2PM Shading	Topography: Most of Property Slope < 10%	Property Adjacent to 3 Phase Power	Score
5	16700	Doherty Ave	125.35	11340002	1	1	1	3
6	18707	Bathville Rd	73.76	11532084, 11532157	1	1	1	3
7	18001	Bathville Rd	53.40	6839541	1	1	1	3
13	10501	Dale Meadows Rd	14.26	25132113	1	1	1	3
14	17000	Snow Ave	12.75	3900240	1	1	1	3
1	10325	Canyon View Rd	12.12	12407143	1	1	1	3
19	10316	Canyon View Rd	7.70	7721803	1	1	1	3
20	6411	Powell Beach Rd	7.01	3215041	1	1	1	3
21	pending	Peach Orchard Rd	6.23	10056688	1	1	1	3
2	pending	Canyon View Rd	5.00	12406694	1	1	1	3
3	3631	Paradise Rd	4.75	12406830	1	1	1	3
22	17202	Bathville Rd	4.72	11336234	1	1	1	3
23	8820	Jubilee Rd E	3.78	2256410	1	1	1	3
35	13827	Lakeshore Dr S	3.75	12684546	1	1	1	3
24	7630	Dunn St	3.58	23568399	1	1	1	3
25	6311	Switchback Rd	3.48	23711124	1	1	1	3
34	14877	Lakeshore Dr S	3.44	3403939F	1	1	1	3
4	12000	Doherty Ave	2.20	11340002	1	1	1	3
90	pending	Bathville Rd	1.93	N/A	1	1	1	3
91	9111	Peach Orchard Rd	1.57	18422420	1	1	1	3
108	pending	Vanderburgh Ave	1.00	10056688	1	1	1	3
29	6705	MacDonald Place	0.99	4628195	1	1	1	3
92	pending	Landry Rd	0.71	Park	1	1	1	3
31	pending	Garnett Valley Rd	0.61	10175881	1	1	1	3
32	10005	Giants Head Rd	0.50	6055516	1	1	1	3
36	14919	Prairie Valley Cr	0.06	4752171	1	1	1	3
28	9101	Pineo Court		28583493	1	1	1	3
100	33000	Hwy 97	pending	12686514	1	1	0	2
38	2405	Mountain Ave	184.27	3779297, 3779301, 3779319, 3779327, 9105174	1	1	0	2
107	pending	Doherty Ave	123.79	29308101	1	1	0	2

Report ID	Address	Street	Parcel Size (Acres)	PID	Topography: Minimal 10AM & 2PM Shading	Topography: Most of Property Slope < 10%	Property Adjacent to 3 Phase Power	Score
45	10600	Aileen Ave	90.65	11340193, 11340321, 11340339, 11340355	1	1	0	2
93	pending	pending	75.31	12634336	0	1	1	2
8	10900	Fyffe Rd	51.84	1764888	1	0	1	2
9	18800	Meadow Valley Rd	50.41	25211137	1	1	0	2
39	17409	Bathville Rd	42.69	12634000, 12634085	0	1	1	2
10	Lot B	Denike St	30.50	12646601	1	1	0	2
40	pending	Denike St	24.50	12072842	1	1	0	2
11	14900	Denike St	18.70	12072869	1	1	0	2
12	8909	Canyon View Rd	14.70	10232168	1	1	0	2
15	3600	Angove Ave	11.00	12407119	1	0	1	2
16	pending	Denike St	10.51	12646717	1	1	0	2
48	10502	Dale Meadows Rd	10.01	5752973	1	1	0	2
17	pending	Denike St	10.00	12646709	1	1	0	2
53	6321	Peach Orchard Rd	9.55	12683655, 12683701	0	1	1	2
18	13500	Prairie Valley Rd	9.25	9833722	1	0	1	2
51	6300	Ramsay St	6.19	12682896	1	0	1	2
54	9999	Wharton Ave	4.92	2508005	0	1	1	2
57	9215	Cedar Ave	4.00	3466388	1	0	1	2
58	pending	Peach Orchard Rd	3.10	12671151	0	1	1	2
94	pending	Stonor St	2.47	N/A	1	1	0	2
27	9999	Happy Valley Rd	1.88	12638153	1	1	0	2
59	6300	Ramsay St	1.83	11345349	0	1	1	2
68	7650	Dunn St	1.14	12078085	1	1	0	2
61	9525	Wharton Ave	0.98	2190192	0	1	1	2
62	7646	Dunn St	0.98	12499901	1	1	0	2
63	7642	Dunn St	0.98	7846983	1	1	0	2
64	12817	Kelly Ave	0.92	28926013	0	1	1	2
65	7636	Dunn St	0.92	12499897	1	1	0	2
30	7632	Dunn St	0.91	17536847	1	1	0	2
95	pending	Dale Meadows Rd	0.84	12565661	1	1	0	2
66	12801	Kelly Ave	0.84	14428024	0	1	1	2
67	15500	Lakeshore Dr N	0.77	12553697	1	1	0	2

Report ID	Address	Street	Parcel Size (Acres)	PID	Topography: Minimal 10AM & 2PM Shading	Topography: Most of Property Slope < 10%	Property Adjacent to 3 Phase Power	Score
96	pending	Dale Meadows Rd	0.70	12648116	0	1	1	2
97	pending	Hwy 97	0.68	9028358	1	1	0	2
109	12001	Loomer Rd	0.68	12597856	0	1	1	2
98	9015	Prairie Valley Rd	0.68	25402021	0	1	1	2
99	pending	Hwy 97	0.64	9408207	1	1	0	2
69	pending	Loomer Rd	0.50	53092F	0	1	1	2
33	18021	Bentley Rd	0.44	11764929	1	0	1	2
72	11317	Giants Head Rd	94.79	11402318	0	0	1	1
73	8400	Cedar Ave	94.47	11336218	1	0	0	1
76	pending	pending	27.43	11397471	0	1	0	1
41	pending	Fenwick Rd	25.00	12597775	1	0	0	1
42	15300	Denike St	20.00	12072851	1	0	0	1
43	9999	Victoria Rd S	17.50	12596744	1	0	0	1
44	pending	Angove Ave	15.00	12407097	0	1	0	1
46	11809	Fenwick Rd	12.40	12597724	1	0	0	1
47	pending	Canyon View Rd	12.09	12407186	1	0	0	1
49	Lot 3	Sage Ave	8.06	10553207	1	0	0	1
50	6712	Sage Ave	6.58	10553185	1	0	0	1
70	9116	Bland St	6.58	12598101	0	0	1	1
101	pending	Cartwright Ave	5.68	N/A	1	0	0	1
52	9111	Bland St	5.49	12598089	0	0	1	1
75	3801	Paradise Rd	5.00	12406881	1	1	1	1
56	12591	Morrow St	4.55	12646695	1	0	0	1
77	11317	Giants Head Rd	3.69	11402296	0	0	1	1
60	Lot 17	Milne Rd	1.75	12326534	0	1	0	1
81	9117	Prairie Valley Rd	1.64	11023481	0	0	1	1
26	pending	Morrow St	1.47	25589024	1	0	0	1
102	pending	Blewett Rd	0.90	Park	0	1	0	1
84	14000	Fenwick Rd	268.48	11530634	0	0	0	0
85	9296	Milne Rd	218.39	11343125, 11343273	0	0	0	0
71	33000	Garnett Valley Rd	176.65	11342676	0	0	0	0
87	12915	Haddrell Ave	15.80	3820106	0	0	0	0
74	8701	Canyon View Rd	15.60	10232184	0	0	0	0
103	pending	Garnett Valley Rd	15.37	N/A	0	0	0	0
104	33000	Garnett Valley Rd	13.09	11531495	0	0	0	0

Report ID	Address	Street	Parcel Size (Acres)	PID	Topography: Minimal 10AM & 2PM Shading	Topography: Most of Property Slope < 10%	Property Adjacent to 3 Phase Power	Score
86	pending	Loomer Rd	11.00	12648159	0	0	0	0
105	33000	Garnett Valley Rd	9.15	11340363, 11531533	0	0	0	0
78	9220	Shale Ave	3.69	27440419	0	0	0	0
79	pending	Milley Ave	3.58	10939059	0	0	0	0
88	13205	Borton Cr	3.45	4490762	0	0	0	0
80	Lot 18	Milne Rd	2.75	12326542	0	0	0	0
82	Lot 19	Milne Rd	1.50	12326585	0	0	0	0
55	33000	Garnett Valley Rd	1.49	11531461	0	0	0	0
106	pending	Mcdougal Rd	0.61	12405990	0	0	0	0
83	19295	Lakeshore Dr N	0.61	3215067	0	0	0	0
89	8710	Milne Rd	0.61	11343320	0	0	0	0

5 SIMULATION OF 20% PV PENETRATION AND 1 MW SOLAR SYSTEM

5.1 METHODOLOGY AND ANALYSIS

All the distribution system analysis was carried out using CYME Power System modeling software. The 9 feeders that Summerland owns and operates are represented in the CYME model and shown for illustrative purposes in Figure 2.

[redacted]

Figure 2: District of Summerland CYME model

The CYME analysis is critical as it accounts for the system impedances, distances, and loads. Using this software, it can be determined what impact the 20% PV penetration, 1 MWp solar system and 2 MVA BESS will have on system voltage, system current, system balance, and basic power quality measures such as Rapid Voltage Changes (RVCs).

The simulation of widespread solar penetration throughout the DoS system was split into two system classes; smaller residential sized systems (5 kWp) and larger sized systems (30 kWp). The two system classes were allocated throughout the Summerland distribution system in the following way:

1. **20% penetration of 5 kWp PV**
   For the 5 kWp systems, it was assumed that 20% of residences installed solar. Considering there are multiple residences per transformer, the number of 5 kWp solar installations was adjusted depending on the size of the transformer in the DoS models; Table 2 illustrates this allocation. Table 2 shows the number of 5 kWp systems per transformer for the given size of the transformer. In the end, the penetration was checked to ensure 20% solar penetration on each feeder was achieved.

   Note: this simulation also included 30 kWp three phase systems scattered throughout the network. It was assumed that 20% of all three phase transformers had a single 30 kWp three phase PV system installed.

Table 2: Residential Solar Unit Density per Transformer Size

Transformer Size (kVA)	# 5 kW Residential Solar Units / Transformer
3	0
5	0
7	0
10	0
15	0
25	1
37	1
50	1
75	2
79	2
100	3
167	4

The allocations per transformer result in the solar penetrations levels shown in Table 3 when compared to the total feeder loads.

Table 3: 5 kWp Residential Solar Penetration levels in District of Summerland System

Feeder	# Single Phase Transformers	# Transformers with Solar	# Solar Installation	Solar kVA	Feeder Load Forecast (kVA)	% Penetration (Residential systems only)
PV149	54	44	48	240	1681	14%
PV249	169	108	119	595	3610	16%
PV349	45	29	40	200	1735	12%
PV449	146	105	114	570	3341	17%
PV549	95	65	84	420	3997	11%
PV649	233	93	103	515	3215	16%
PV749	21	19	32	160	2718	6%
TC279	193	77	101	505	3240	16%
TC379	258	163	197	985	4240	23%

2. 20% penetration of 30 kWp PV

A second simulation using single phase 30 kWp systems was undertaken. A total feeder penetration of approximately 20% was obtained by randomly dispersing the single phase 30 kWp systems throughout each feeder. The breakdown of the number of 30 kWp systems per feeder is shown in Table 4.

Table 4: 30 kWp System Allocation

Feeder	# of Single Phase 30 kWp Systems	Solar kVA	Feeder Load Forecast (kVA)	% Penetration
PV149	11	330	1681	20%
PV249	24	720	3610	20%
PV349	12	360	1735	21%
PV449	22	660	3341	20%
PV549	27	810	3997	20%
PV749	18	540	2718	20%
TC279	22	660	3240	20%
TC379	28	840	4240	20%

The allocation of PV systems in the CYME models is illustrated in Figure 3 and Figure 4 . As seen in the figures, allocation is done at specific nodes in the system. The respective load flows are also shown for reference.

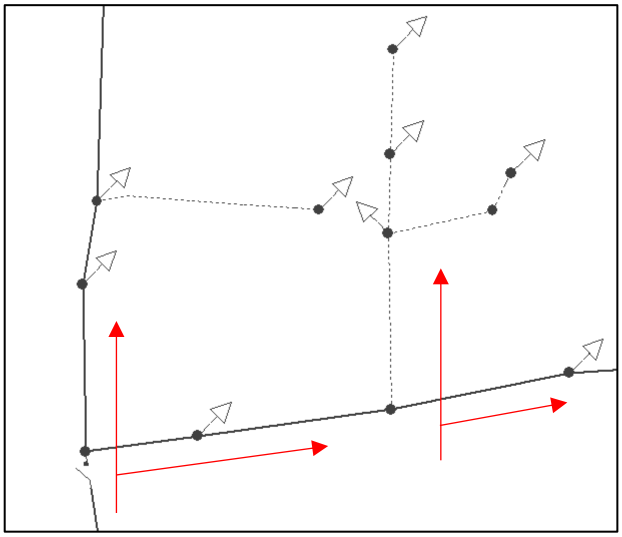

Figure 3: CYME model without PV allocation

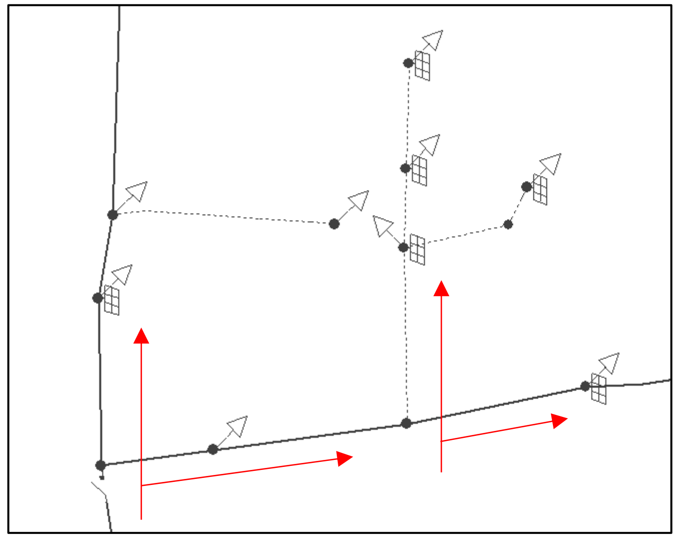

Figure 4: CYME model with PV allocation

Once the network was updated with the various PV systems, the individual system loads were allocated using the data from the 2018 load forecast created by Primary. The 2018 load forecast kVA values are shown in Table 5.

Table 5: 2018 District of Summerland Load Forecast

Substation	Feeder	2018 Load Forecast (kVA)
Prairie Valley	**149**	1,432
	249	3,610
	349	1,684
	449	3,217
	549	3,997
	649	3,215
	749	2,651
Trout Creek	**279**	3,240
	379	4,240

The simulation computed the following parameters:

- Steady state voltage at all nodes in the network
- Steady state current of all sections (conductor and/or cables) in the network
- Fault current in each section (conductor and/or cables) in the network
- Rapid Voltage Changes using the CYME Long Term Dynamics module

5.2 Assumptions

There are many variables in configuring the system for this simulation. To narrow the work to a single 20% penetration simulation, the following assumptions were made:

System Sizes

5 kWp systems were single phase with an output of 5kVA at unity power factor and the 30 kWp systems were single phase with an output of 30kVA at unity power factor.

Note: The 5 kWp simulations also included some three phase 30 kVA systems to increase penetrations levels in areas with more three phase transformers.

Inverter Ratings and Topology

Inverter topologies and technology can vary from manufacturer to manufacturer and CYME gives the user the ability to simulate different inverter hardware. The internal component values were selected to reduce internal voltage ripple to 1% or less.

Inverter Operation

Inverters were set to maintain a unity power factor to maximize the output of the unit. This was selected to ensure maximum voltage and power output for a given PV system size. The short circuit levels were set to 1 per-unit based on input from inverter manufacturers.

5.3 Summerland Irradiance Model

To simulate the changes in voltage that the 1 MWp solar array could exhibit, a dynamic irradiance model was developed which accounted for passing cloud cover. The data for the model was built from an NREL study in Hawaii which captured irradiance data in 1-second intervals over the course of several days [6]. This data was then normalized to the typical maximum irradiance experienced in Summerland in July, which was taken from the Canadian Weather Energy and Engineering Datasets [7].

From the data, we see that the maximum change of the incoming solar radiation due to a passing cloud is 27% of the maximum solar radiation of 1100 W/m2 per second, or 291 W/m2 per second. During this cloud cover, the minimum power output of the array is about 20% of maximum output. This means for a small solar installation, the output from the inverters could swing from full power output to about 20% power output in roughly 3 seconds.

For a larger solar installation, this ramp rate is mitigated since it takes time for the leading edge of the cloud to cover the entire array. Studies have shown that systems sized in the 1 MWp range experience a maximum power fluctuation of about 10% per second [8]. The models were tailored to a 60 second window for both the 5-30 kW and 1 MWp sizes and are shown in Figure 5 and Figure 6.

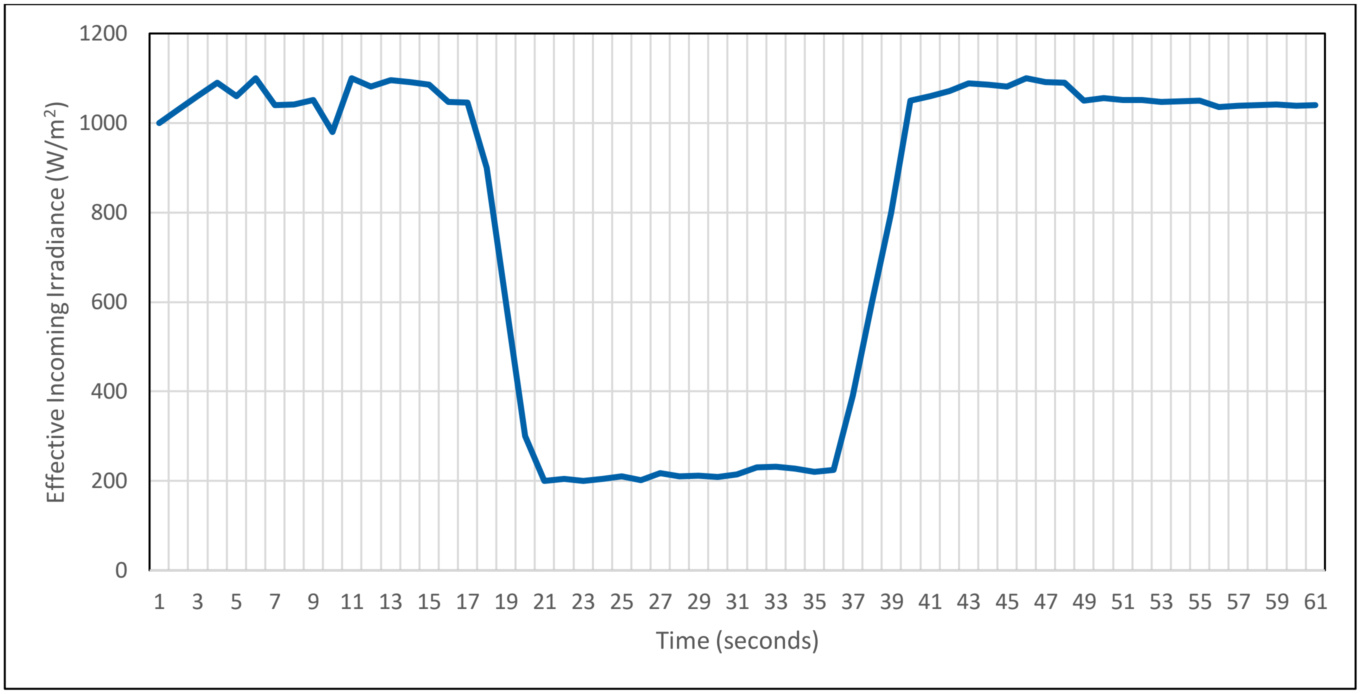

Figure 5: Dynamic Irradiance model for 5 kW and 30 kW systems

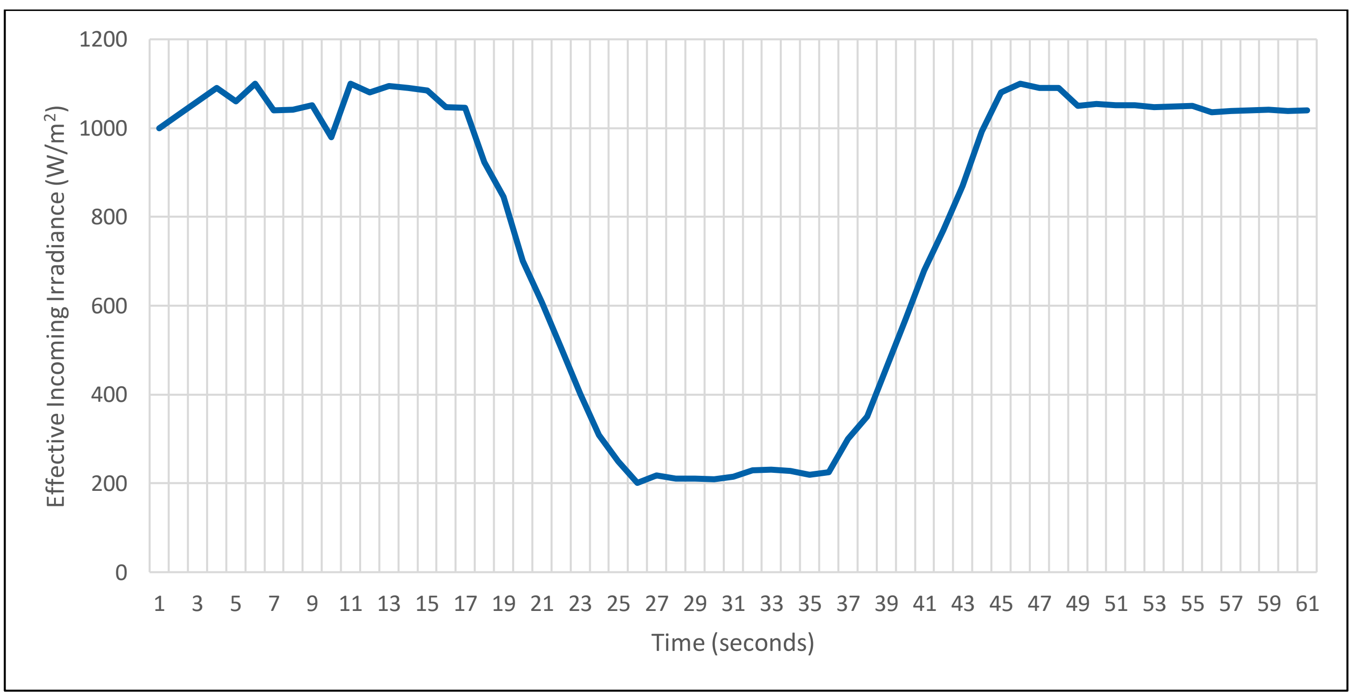

Figure 6: Dynamic irradiance model for 1 MWp system

5.4 RESULTS

5.4.1 CONDUCTOR AND CABLE LOADING

To properly demonstrate the difference in conductor and cable loading throughout the DoS system, the conductor/cable usage was computed throughout the system for each 1 MWp solar system location simulation. The usage is defined as the load in the conductor and/or cable expressed as a percentage of equipment rating. Figure 7 and 8 illustrate the conductor usage over the DoS system. Location 8 was arbitrarily chosen as an example. The results from location 8 show that depending where the 1 MWp solar system is placed with respect to the substations and load, some cables will see a decrease in loading.

A more detailed statistical analysis is included in Section 10 (Appendix A). The analysis showed that the average loading changed from 10.2% to 9.8% and the maximum loading increased from 87.0% to 88.9%. This does not pose any serious risk as no conductor/cable in the system is loaded over its capacity.

5.4.2 SYSTEM FAULT LEVELS

A short circuit analysis was conducted and the increase in fault levels as a percentage of existing fault currents were determined. The line to ground faults were determined to rise 2% to 3% on average with a standard deviation of 1.5%. In the case of the bolted three phase fault, the short circuit current increased on average by 1% to 2% with a standard deviation of less than 1.2%. The simulated increase is not considered significant and is not expected to pose a risk to the DoS system. Figure 9 and Figure 10 illustrate the fault current levels with and without the 1 MWp solar system. A more detailed analysis is included in Section 10 (Appendix A).

In all cases the fault levels were less than 8 kA and, in most simulations, the maximum increase was around 6%, which equates to approximately 500 A in the worst case. This difference in fault current isn't considered significant given the fault levels in the system. Interestingly, the 5 kW simulation did result in some areas with increases as high as 12.8%. These increases were typically on segments that had relatively low fault currents to begin with (<1.5 kA) therefore the percentage was larger as the calculation uses the pre-existing fault current as the divisor. This means that widespread solar will show a larger percentage increase in fault current if the existing fault current is low.

This study assumed a fault current of 1 p.u. was available at each solar installation, as inverter manufacturers typically limit the fault current to 1 p.u.; however, it is recommended that fault studies are conducted as part of the interconnection application of solar systems that are 1 MWp and greater. It should be noted that the DoS fusing documentation is currently unavailable and as such, a quantitative protection coordination check cannot be evaluated. Completing the check would have had the benefit of showing any reduction or increase in protection effectiveness and/or selectivity; however, the modelled changes in fault current were quite small (assuming the PV fault currents are limited to 1 p.u.) so the increased risk to the DoS system is low.

[redacted]

Figure 7: Percent of conductor loading without 1MWp solar

[redacted]

Figure 8: Percent of loading with 1MWp solar system at location 8

[redacted]

Figure 9: LG max fault current locations without 1MWp solar

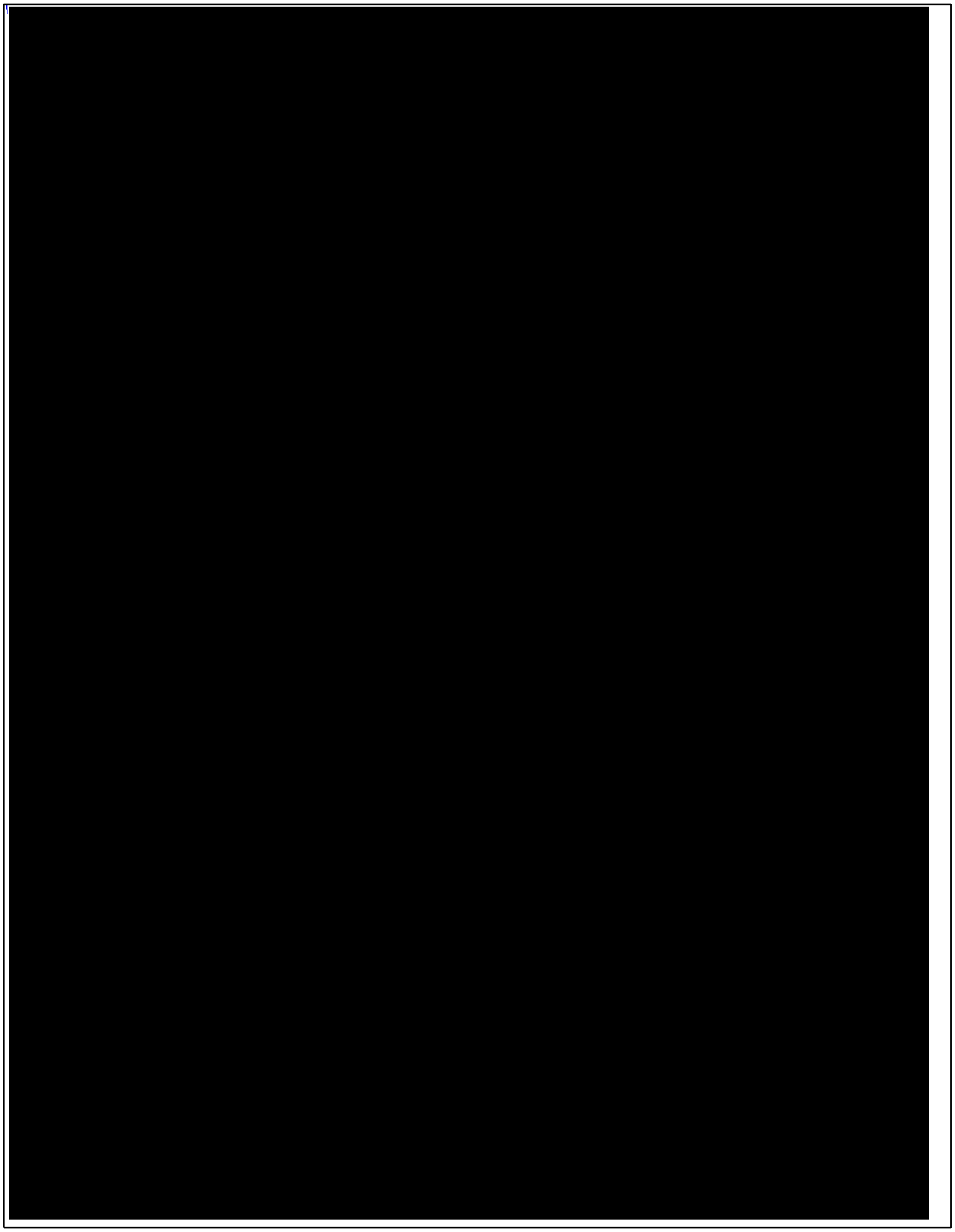

Figure 10: LG max fault current with 1MWp solar system at location 57

5.4.3 SYSTEM UNBALANCE

The DoS will need to carefully monitor the installation of PV units within the network to ensure that proper phase balancing is observed. As such, the phase balancing of the network should be periodically checked and adjusted if required. If a significant number of PV units were to be installed on a single phase within the network, then additional issues may begin to present themselves. One such issue can be associated to false tripping of three phase relays. This can occur when a single phase of a network is disproportionately loaded compared to other phases, which can make three phase units falsely indicate single phase faults. Table 6 indicates the maximum phase unbalance that can occur before the substation or feeder overcurrent protection may be susceptible to false tripping on the ground setting.

Table 6: Load Unbalance Limits of DoS Protection System

<table>
<tr><th>Substation</th><th>Feeders</th><th>Maximum Substation Load Unbalance
(MVA/Phase)</th><th>Maximum Feeder Load Unbalance
(MVA/Phase)</th></tr>
<tr><td rowspan="7">Prairie Valley</td><td>149</td><td rowspan="7">2.40</td><td>1.80</td></tr>
<tr><td>249</td><td>1.80</td></tr>
<tr><td>349</td><td>1.80</td></tr>
<tr><td>449</td><td>1.80</td></tr>
<tr><td>549</td><td>1.80</td></tr>
<tr><td>649</td><td>1.80</td></tr>
<tr><td>749</td><td>1.80</td></tr>
<tr><td rowspan="2">Trout Creek</td><td>279</td><td rowspan="2">1.80</td><td>1.80</td></tr>
<tr><td>379</td><td>1.80</td></tr>
</table>

As indicated in Table 6, the maximum unbalance that may occur on any of the feeders in the DoS system is 1.80 MVA (for a single phase). This is based on the current feeder recloser ground fault pickup settings. Similarly, for the substations, the maximum unbalance that can occur on the Trout Creek and Prairie Valley substations is 1.80 MVA and 2.40 MVA (for a single phase) respectively. This is the total combined unbalance from every feeder connected to the substation in question. If the unbalance were to exceed these specified levels the substation overcurrent feeder protection may revert to the ground fault settings and cause false tripping. As such it is important to maintain proper phase balancing throughout the network and prevent a disproportionate amount of PV units being installed on a single phase in the network.

5.4.4 SYSTEM VOLTAGE

CSA C235-83 (R2015) outlines planning voltage levels for systems less than 50,000V; the limits are outlined in Table 7. These limits were used as the basis for comparison when the system voltage was modeled throughout the DoS network. During the simulations the voltage at each substation was assumed to be 1.03 p.u. as per FortisBC guidelines.

Table 7: CSA C235-15 Voltage Planning Limits.

	Extreme Min	Normal Min	Normal Max	Extreme Max
1 Phase (120V base)	106 V (0.8833 p.u.)	110V (0.9167 p.u.)	125V (1.0417 p.u.)	127V (1.0583 p.u.)
3 Phase (120V base)	110V (0.9167 p.u.)	112V (0.9333 p.u.)	125V (1.0417 p.u.)	127V (1.0583 p.u.)

The average system voltage in the base simulation was 1.0065 per-unit which, when compared to the values in Table 7, is well within the normal range. Through the various simulations of this report, the average steady state voltage increased to values from 1.0075 p.u. to 1.0104 p.u. which is still within the planning limits. The maximum voltage also increased from 1.0322 p.u. to a range of 1.0333 p.u. to 1.0416 p.u. which is pushing the CSA limits. The areas that showed the highest increase in voltage were usually associated with a 30kW single phase solar system or were the locations that were selected for the 1 MWp solar systems. This means that voltage levels will need to be monitored near large solar installations to ensure they stay within CSA limits. One method that can be adopted to control voltage is to adjust the power factor of the inverter outputs. By doing this, the voltage will follow system line voltage. The downside to this is that it limits energy production, so solar system owners would want to avoid such a control scheme if possible.

In general voltage levels rose in the system, however in some cases this is a good thing. That is, in some areas where the voltage was low, the installation of a 1 MWp solar system helped boost the voltage to more preferred levels. This is because the solar was able to feed a portion of the load and therefore the voltage drop along the original supply path was reduced. This case is illustrated in Figure 11 and Figure 12. Location 8 was used again as it provided a good example of this type of desired increase in system voltage. A detailed breakdown of the voltage analysis results can be found in Section 10.

[redacted]

Figure 11: System Voltage levels without solar

[redacted]

Figure 12: System Voltage levels with1 MWp Solar at location 8

5.4.5 RAPID VOLTAGE CHANGE

Rapid Voltage Changes (RVCs) are fluctuations in the fundamental frequency RMS voltages over several cycles to several seconds. They are typically only measured when the voltage change is between ±2% and ±10%. Furthermore, RVCs can be defined as voltage changes occurring in rapid succession, having magnitudes large enough to cause lighting level variations which are noticeable or annoying to human beings. When significant levels of intermittent sources or loads are connected to the network, there is a risk of RVCs being observed in the network. To evaluate RVCs in the DoS network, the irradiance models indicated in Figure 5 and Figure 6 are utilized. This simulates a cloud passing over the PV panels. The difference in operating voltage can be computed and tabularized then compared against standards such as the BC Hydro RVC planning limits as shown in Table 8. These values are indicative of values expressed in CAN/CSA-C61000-3-7-09 which is a standard for the assessment of fluctuating loads and their effect on medium voltage (MV), high voltage (HV) and extra high voltage (EHV) systems. For more details of this analysis please refer to Section 10.

Table 8: Rapid Voltage Change Planning Limits.

Number of Changes (n)	Voltage Change ΔU/U (%)
n ≤ 4 per year	8 < ΔU ≤ 10
n ≤ 8 per year	6 < ΔU ≤ 8
n ≤ 4 per day	4 < ΔU ≤ 6
n ≤ 2 per hour	3 < ΔU ≤ 4
n ≤ 6 per hour	2 < ΔU ≤ 3

The majority of the RVCs in the network are less than 2% with the highest magnitude RVC being 3.68%. Applying Table 8 to these results would give a range in allowable frequency rate from less than 2 per hour to less than 6 per hour. These figures were obtained by assuming the irradiance model was applied equally to all solar panels in a system at the exact same time. This is a conservative assumption as it is more realistic that clouds would gradually cover a large solar station due to their large area. So, it is more likely that the system would see a slower voltage deviation as power generation reduces and loads are picked up from utility sources. Based on the value of these results, it is unlikely that RVCs will pose an issue to the DoS system.

5.4.5.1 *Voltage Regulator Operation Check*

One aspect of the RVC analysis was to confirm if there would be any increase to voltage regulator operations due to the variation in voltage from the 1 MWp solar system. [redacted] The checks were made as part of the long-term dynamics analysis and there wasn't any observed increase in operation of either regulator. To confirm that these results were correct, the size of the 1 MWp solar installation was increased for one simulation to 2 MVA and a voltage regulator operation was able to be forced. The result is shown below in Figure 13 for illustrative purposes.

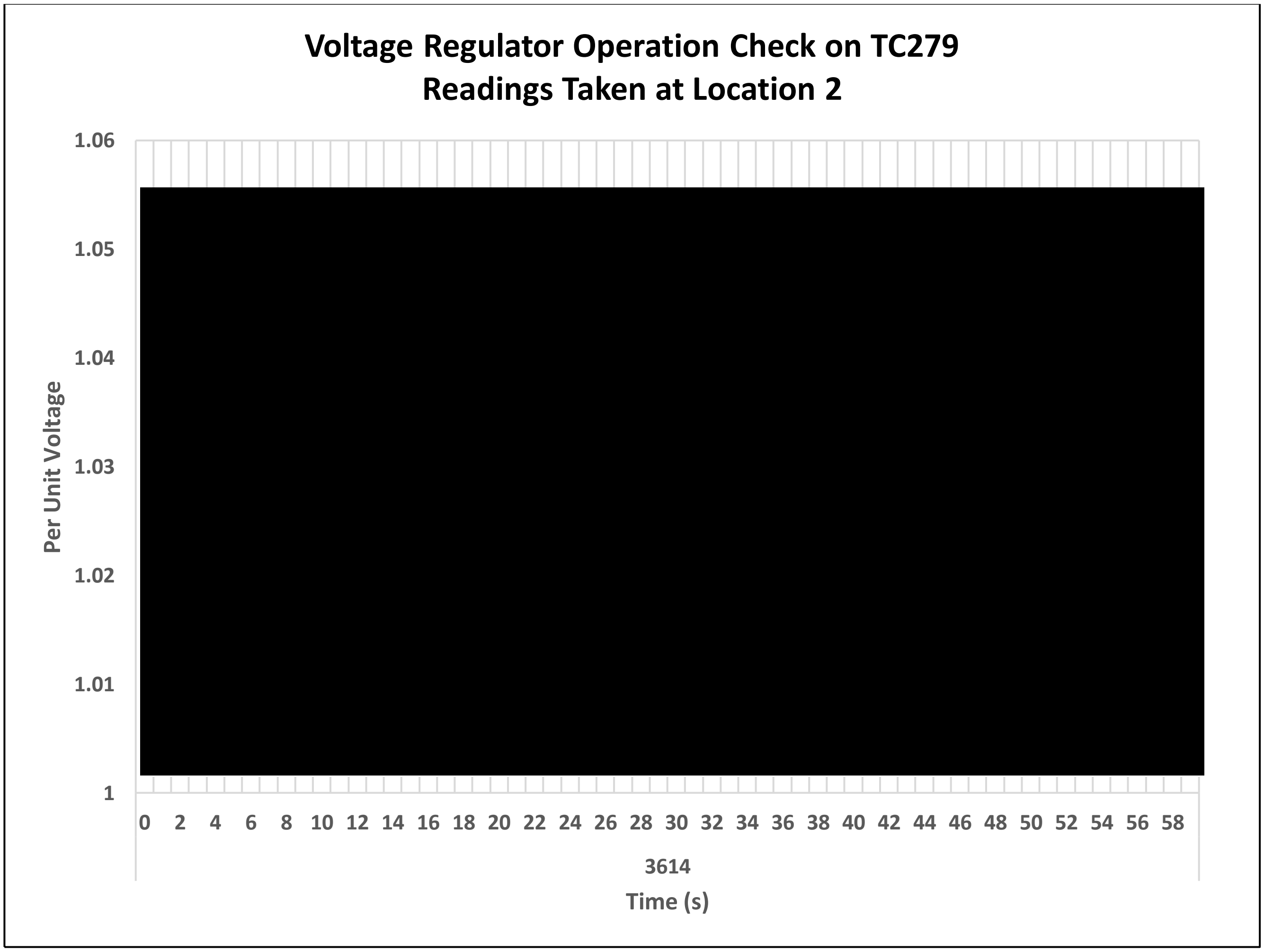

Figure 13: Voltage Regulator Operation Simulation

5.5 Comments & Discussion

Based on the analysis of the conductor and cable loading, fault levels, and voltages throughout the DoS network, there are no identifiable major issues with the addition of 20% PV penetration levels of 5 kWp or 30 kWp. This is the case on their own or in tandem with the 1MWp system as well. Equipment and conductor/cable loading were relatively unaffected. The average changed from 10.2% to 9.8% and no overloads were detected during the analysis. This means that any reconductoring projects would not be considered due to overloading of the conductors or cables in the system.

System fault current levels increased in all simulations; however, the average of the increases was limited to 3% which isn't a hazard to the system. In all line segments of the system, the fault current was below 8kA which is considered an acceptable maximum fault current level.

Steady state system voltage appeared to be relatively unaffected; however, some areas in the system are pushing the upper limit of the CAN3-C235-83 (R2015) standard. As such the operation of any solar system larger than 30kW should be monitored to ensure that the output voltage does not exceed the limits. The best solution for monitoring this would be installing a power meter with extra voltage measuring functions. DoS uses Itron meters and this would be a simple item to include in the net metering specifications.

Rapid Voltage Changes were examined, and some violations could happen depending on the number of times the simulated cloud coverage event were to occur. As already noted, these simulations used assumptions that may have a low probability and therefore the RVC values that were determined aren't a concern.

6 2 MVA BATTERY STORAGE

6.1 INTRODUCTION

Grid-scale battery technology has rapidly evolved in recent years and can now provide many technical and economic benefits to electric utilities. The potential benefits include peak demand reduction, demand tariff charge reduction, system reliability enhancement, resiliency enhancement, system reinforcement, frequency and voltage support, and facilitation of increased renewable and distributed energy resources (DERs).

Peak demand reduction – electric utility infrastructure including substations, transformer, lines, and generation facilities must have sufficient ratings to handle the peak electrical load (i.e., the coldest day or the warmest day of the year in the most extreme weather conditions anticipated for the region). A grid-scale BESS can store energy during off-peak periods and dispatch the energy during the peak period. By curtailing the peak, the locally-installed BESS reduces stress on the grid infrastructure and the need for reserve generation facilities to accommodate these short peak periods.

Demand tariff charge reduction – wholesale electricity providers typically charge an energy or demand fee based on the maximum demand used within the billing period. This demand charge is to cover the electric assets required to serve the peak load, including standby generation facilities or import fees dispatched during peak load. A grid-scale BESS can reduce these demand charges and provide significant savings.

System reliability enhancement – utilities measure reliability using outage data on the duration and number of customers affected by outages each year. A BESS can improve reliability by reducing the number of customers affected by outages. This can be directly achieved through a microgrid arrangement. Reliability can also be enhanced through the system reinforcement, frequency, and voltage support benefits from the BESS.

System reinforcement – a grid-scale BESS can support the distribution infrastructure by reducing peak load stress on this infrastructure. This provides support for back-up and contingency scenarios and thus reduces or defers capital upgrades for the distribution infrastructure.

Frequency and voltage support – as the level of renewable energy increases, electrical systems can experience voltage and frequency issues caused by intermittent cloud cover and the lack of inertia from inverter-based generation. A BESS can provide these ancillary services to the grid by stabilizing voltage fluctuations and frequency deviations that can occur at high levels of renewable energy penetration (greater than 30%).

The benefits mentioned above are dependent on factors such as manufacturer, physical connection location, size, and capacity. When determining the exact model, location etc., the DoS will need to clearly define the main goals of the BESS to ensure the best model for the application is selected. The BESS can then be programmed to operate under the scenarios dictated in the project definition phase. The control mechanisms will be required to be evaluated in a real-time Electromagnetic Transient Program (EMTP) to confirm adequacy.

An important factor to note with batteries is the distinction between battery rating and capacity. A battery's rating is its maximum possible output at any point in time (e.g., a 2 MVA battery can supply power to a 2 MVA load at any instant). A battery's capacity is a measure of how long it can supply power to a load or network (e.g., a 1 MVA, 2 MVAh battery could supply a 1 MVA load for 2 hours, or a 0.5 MVA load for 4 hours etc.). It should be noted that in the context of this report, the charge and discharge times are assumed to be the same.

6.2 Methodology

To conduct the investigation into the impacts of the battery on the DoS system, the following general tasks were completed:

1. Substation hourly aggregated data was accumulated from the previous 12 months. This data listed the peak demand of the DoS's overall network in addition to the day and time that each data point occurred.
2. An analysis of 12 months of billing data (provided by FortisBC) was conducted to better ascertain how FortisBC is conducting its billing. This ensures that all models and assumptions used in subsequent studies are correct.
3. Determined the impact of a 2 MVA BESS on the DoS's network by analyzing the peaks loads of the individual days and shaving them by 2 MVA. To determine the duration that the battery is required to operate, the following steps were conducted:
    a. The peak load for the month is determined.
    b. Subtract the peak load by 2 MVA. This value becomes the threshold for when the BESS is required to operate. The reason for this is due to the tariff imposed by FortisBC whereby the peak value for the previous 11 months is utilized in billing. This means that for the BESS to properly shave the peak by 2 MVA, it is required to operate for the entire duration that the load would be above the threshold without the BESS.
    c. Determine how long the BESS would be required to operate such that the load always stays below the 2 MVA threshold.

6.3 Battery Location

The preferred location of the BESS is impacted by its core function and purpose.

Table 9: Location Impacts for BESS Functions.

BESS function	Impact of the location
Peak-shaving for tariff reductions	The BESS can be installed anywhere on the system with sufficient line capacity. Close to the substation would be preferred due to reduced line losses and ease of connection.
System reliability enhancement	Install on a poor-performing feeder with low reliability statistics or on a downtown feeder where reliability is more important to the customer base.
Resiliency	Install near a community centre or facility that can operate in an islanded (i.e., off-grid) mode during the case of an extended outage caused by a catastrophic event.
Voltage and frequency support	Install on a feeder with high levels of renewable energy. In the case of a grid-scale solar farm, the BESS can be DC coupled to reduce inverter losses during the battery charge cycles.

6.4 Battery Energy Results

As specified in Section 6.1, numerous steps were conducted to ascertain the effect of the BESS on the DoS's system. The following subsections outline the results of this work and include any assumptions made.

6.4.1 Analysis of a 2 MVA battery

Utilizing the procedure set out in step 3 of Section 6.2, the peak load was determined as per data provided by FortisBC. The monthly peaks and the 2 MVA peak shaved demand are as per Figure 14.

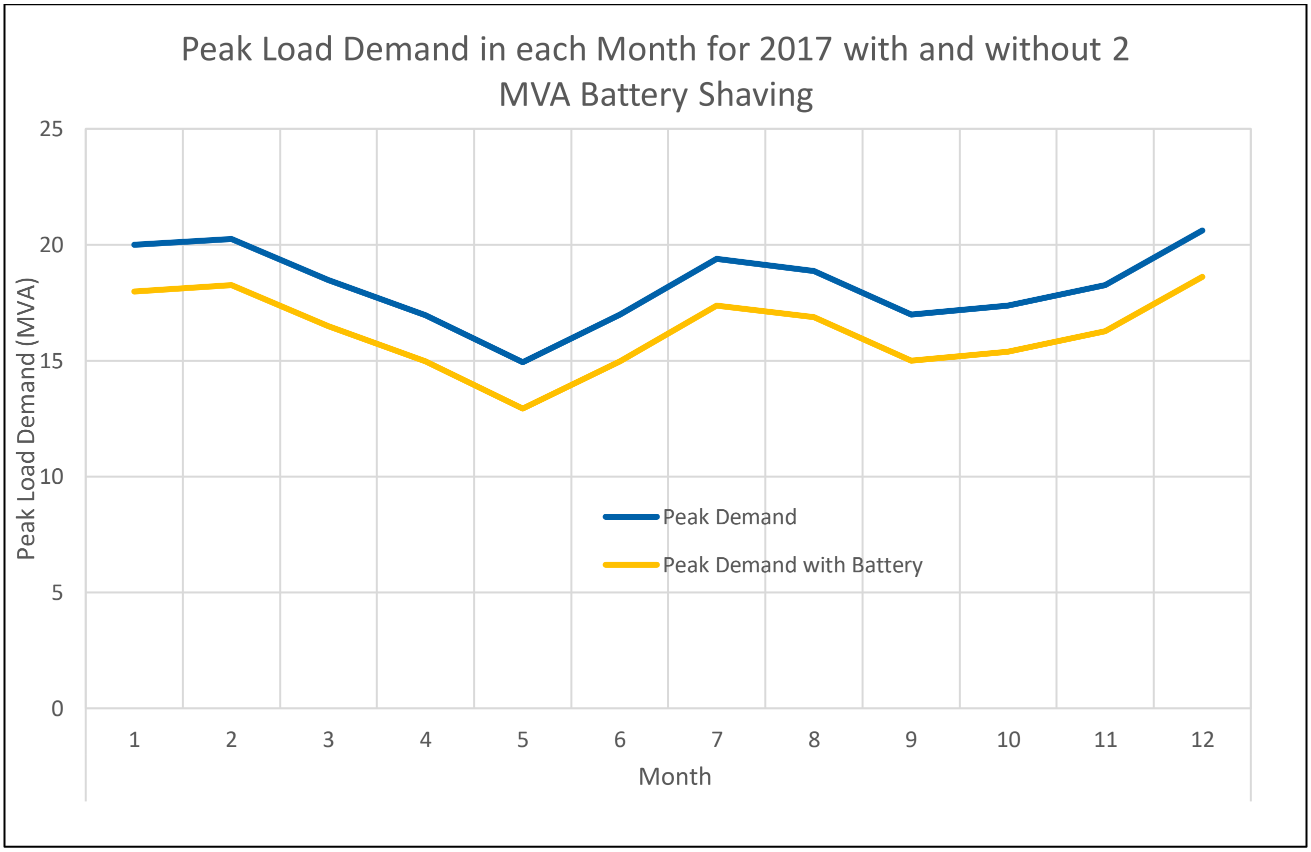

Figure 14: District of Summerland Peak Demand and Peak Demand Including 2 MVA Battery Shaving for given times of year.

As can be observed in Figure 14, the peak loading demand experienced by the DoS is in excess of 20 MVA for the overall system. It should be noted that for the purposes of this study only the load data from 2017 was utilized.

The data presented in Figure 14 can also be expressed in tabular form in Table 10 with the peak durations included. As seen in the table, April has the largest energy requirement to shave the peak for the DoS.

Table 10: Load Demands Including Shaving and Energy Requirements for 2017 for a 2 MVA battery.

Month	Max Load Demand (MVA)	Max Shaved Load Demand (MVA)	Capacity Required (MVAh)
1	19.99	17.99	17.08
2	20.26	18.26	11.38
3	18.48	16.48	15.21
4	16.97	14.97	17.28
5	14.93	12.93	13.39
6	16.98	14.98	10.09
7	19.38	17.38	8.49
8	18.87	16.87	9.62
9	16.98	14.98	12.20
10	17.39	15.39	2.00
11	18.27	16.27	14.95
12	20.61	18.61	16.34

As can be observed in Table 10 the peak load demand for 2017 occurred in the months of December and February with the peak energy requirement occurring in April. From this the peak load in April is utilized to determine the energy requirements for the BESS. During the month of April, the energy requirement from the BESS is 17.28 MVAh to successfully shave the DoS's peak load. This can be expressed visually by the load curve for the peak demand day of April as seen in Figure 15.

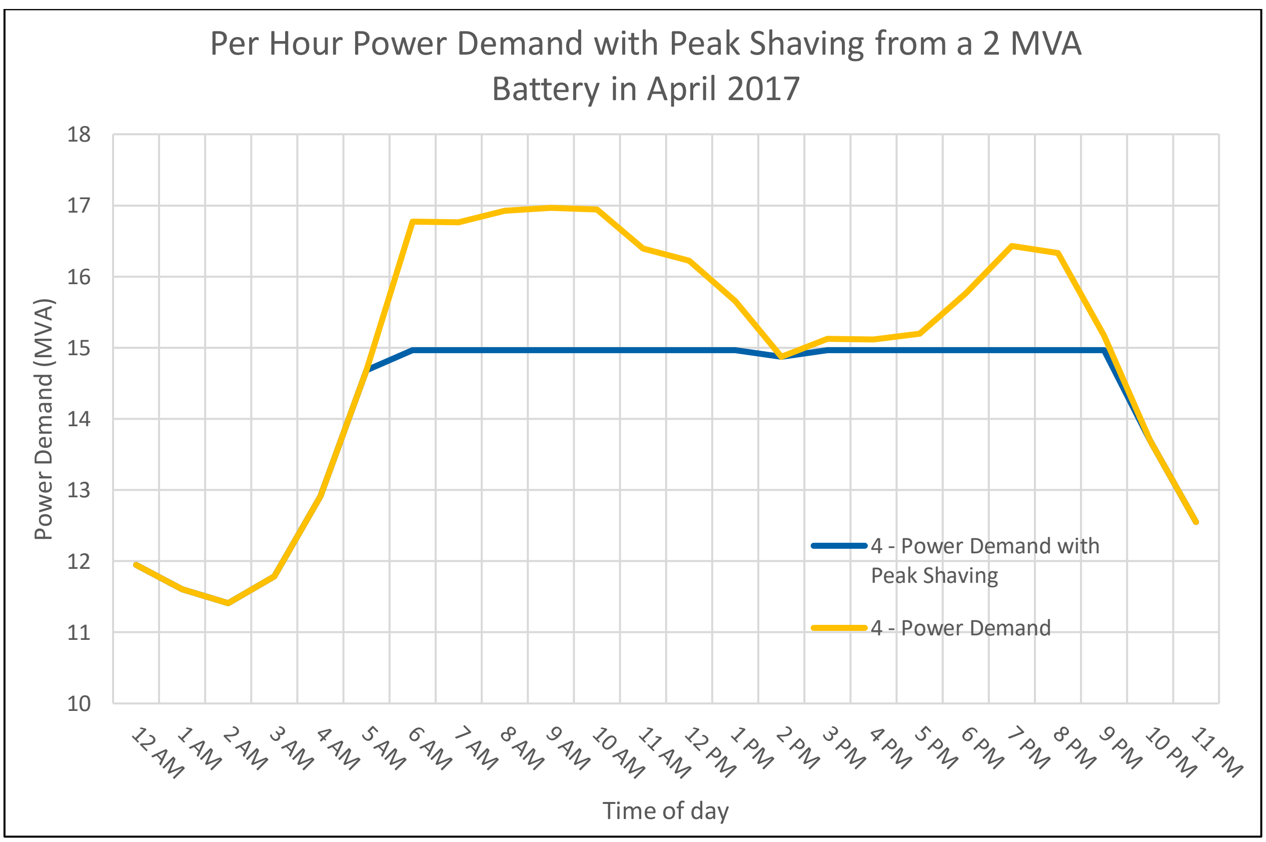

Figure 15: April peak load demand with and without 2 MVA battery peak shaving.

As can be seen in Figure 15, for a 2 MVA BESS to successfully shave the DoS's peak demand by 2 MVA, it would be required to operate at twice in a single day with an energy requirement of 17.28 MVAh if it were to be discharged fully during a peak load shaving cycle.

6.4.2 ANALYSIS OF A 2 MVA BATTERY DISCHARGED AT 0.5 MVA

The same analysis was conducted on the 2 MVA BESS discharging at 0.5 MVA. The monthly peaks and 0.5 MVA peak shaved demand are shown in Figure 16.

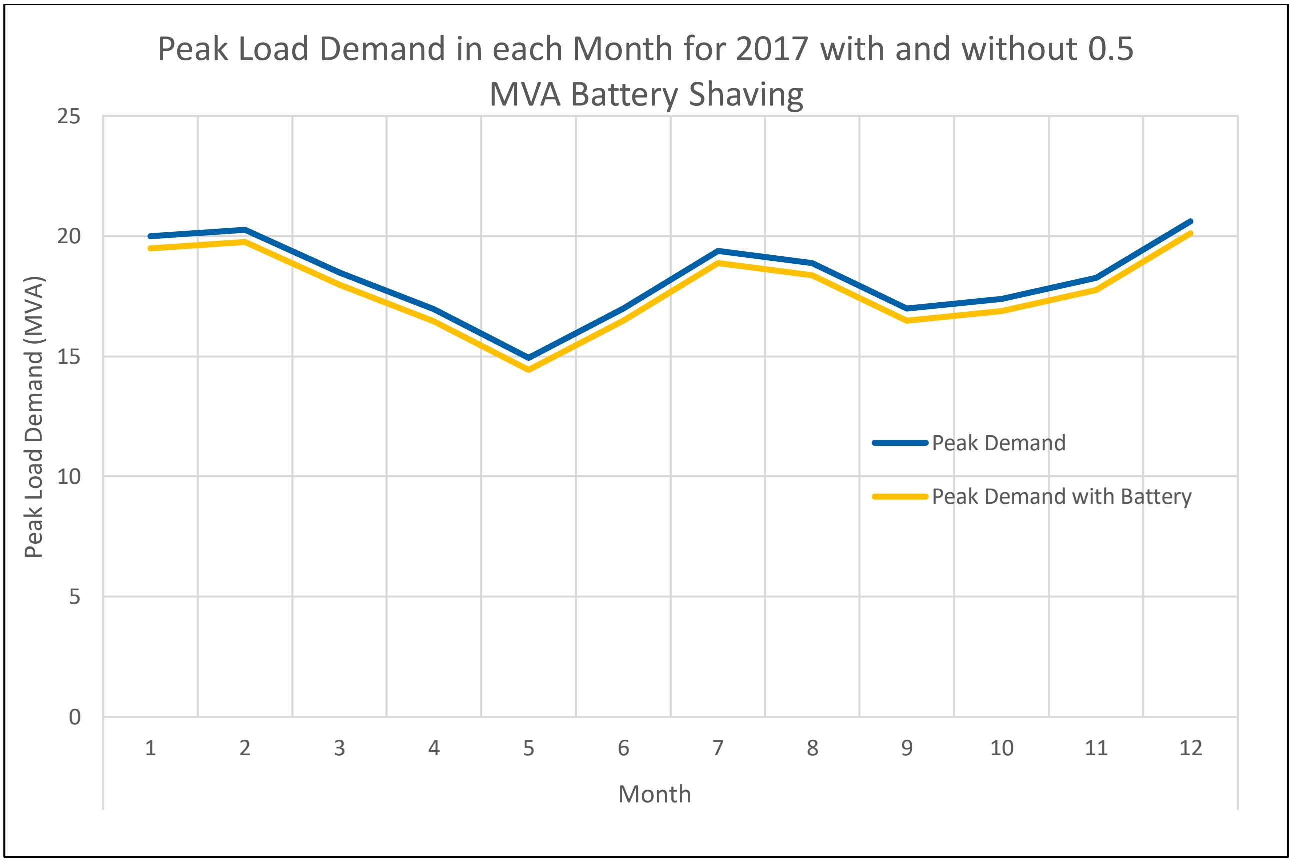

Figure 16: District of Summerland Peak Demand and Peak Demand Including 0.5 MVA Battery Shaving for given times of year.

The data presented in Figure 16 can also be expressed in tabular form with the peak durations included.

Table 11: Load Demands Including Shaving and Durations for a 0.5 MVA battery.

Month	Max Load Demand	Max Shaved Load Demand	Capacity Required (MVAh)
1	19.99	19.49	1.04
2	20.26	19.76	1.38
3	18.48	17.98	1.56
4	16.97	16.47	2.04
5	14.93	14.43	1.10
6	16.98	16.48	1.13
7	19.38	18.88	1.05
8	18.87	18.37	1.14
9	16.98	16.48	1.69
10	17.39	16.89	0.50
11	18.27	17.77	0.89
12	20.61	20.11	0.56

It should be noted that the capacity requirements indicated in Table 11 are for shaving 0.5 MVA off the DoS's peak as opposed to a 2 MVA. As can be observed in Table 11, the peak load demand for 2017 occurred in the months of December and February with the peak energy requirement for the battery occurring in April if discharged at 0.5 MVA. During the month of April, the energy requirement of the BESS to shave the DoS's peak load is 2.04 MVAh. This can be expressed visually by the load curve for the peak demand day of April:

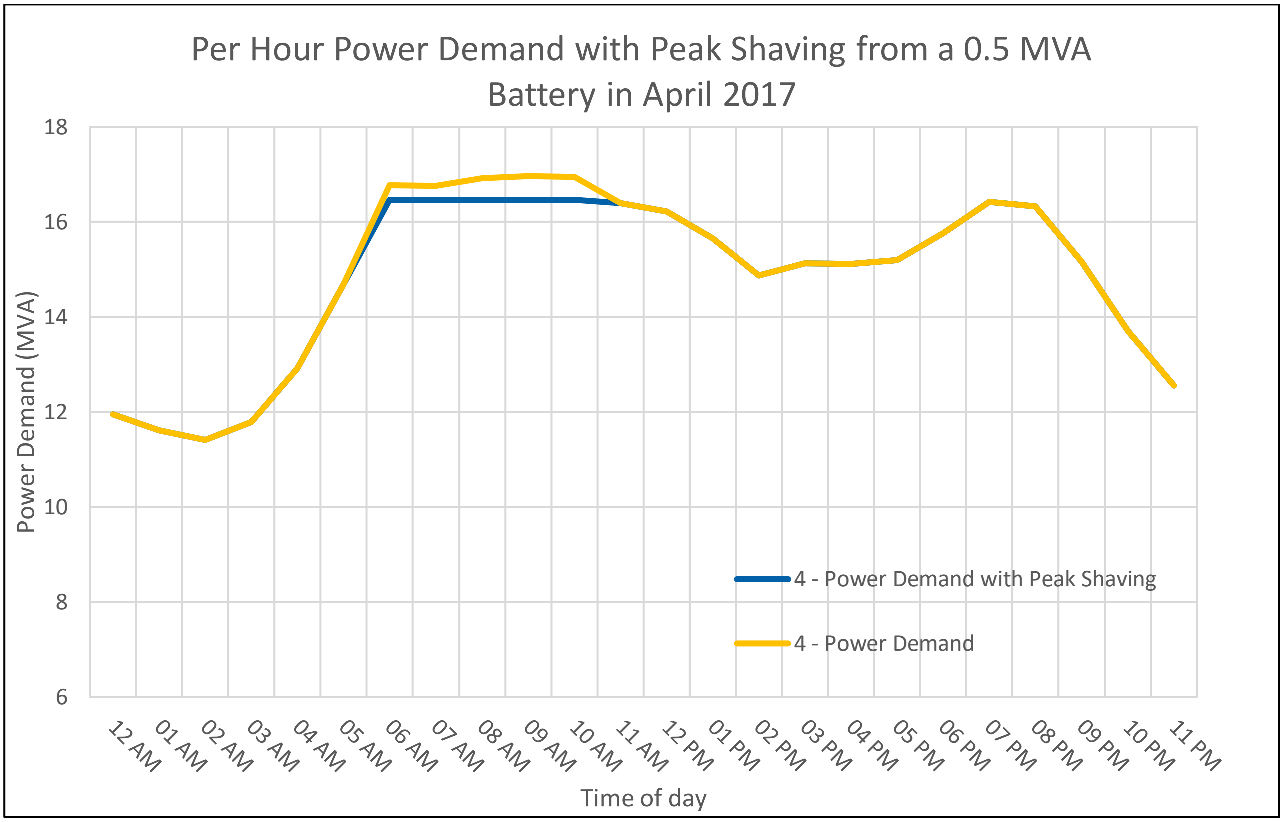

Figure 17: April peak load demand with and without 0.5 MVA battery peak shaving.

As can be seen in Figure 17, an output of 0.5 MVA from the BESS would be required to operate once for during a 24-hour period to be able to shave the overall peak demand by the BESS's rating. This would mean that a 0.5 MVA BESS with a capacity of just over 2 MVAh would be required to shave the DoS peak load demand by 0.5 MVA. This would assume a complete discharge of the battery. In practice, it is not prudent to completely discharge the battery, and as such it should be oversized.

6.5 System Impact Results

The 2 MVA BESS was simulated at the Prairie Valley substation. This provided a central location that makes the primary function of the BESS (load shedding) easily designed and implemented. Additionally, the Prairie Valley substation feeds the downtown core and other critical municipal loads, so in the case of large system outage, the DoS could create a microgrid that feeds these loads quite easily. The micro-grid concept is explored further in Section 7 and Section 11.

6.5.1 Steady State Impact

There were no changes in the system voltage, load current, and system fault currents when the BESS was simulated under steady state conditions in the DoS CYME model. The only expected notable difference will be the reduction in substation transformer current when the BESS is dis-charging.

6.5.2 RAPID VOLTAGE CHANGE

The long-term dynamics module in CYME was used to evaluate if a change in the BESS operation would result in voltage deviations and load tap changer (LTC) operations within the Prairie Valley substation. This is a critical check because an increase in LTC operations would mean that the equipment would need to be maintained and/or replaced sooner. The LTC is part of the substation transformer and therefore owned and operated by FortisBC. If extra cost was incurred by FortisBC, they might pursue the DoS for recovering those costs.

The results of the long-term dynamics analysis at various BESS sizes are shown in Figure 19 and Figure 20. As can be observed in the figures, when the BESS changes from dis-charging to charging, there is a large change in system demand on the substation transformer. This change in demand results in a change in bus voltage due to the transformer impedance. As the size of the BESS increases, so does the change in voltage. In cases where the charging level was greater than 3 MVA, the bus voltage drop was great enough to cause the LTC to operate.

It should be noted that this analysis was performed as a feasibility check and the LTC was assumed to operate on 0.94% bands with a delay of 10s. The exact LTC response should be checked as part of detailed design of the battery system to ensure that the assumptions in this study are accurate for the actual installed system.

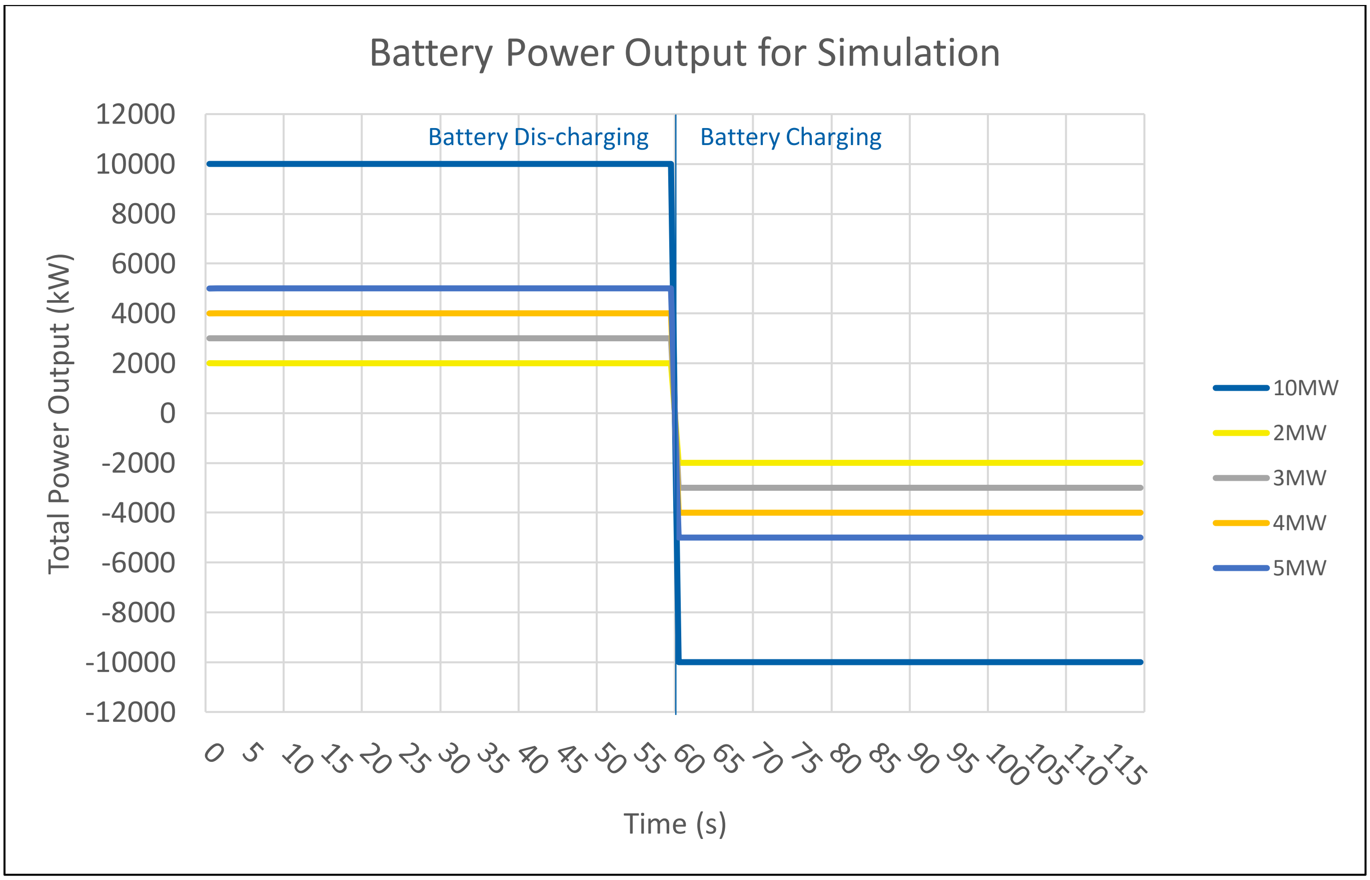

Figure 18: Battery System Power Output

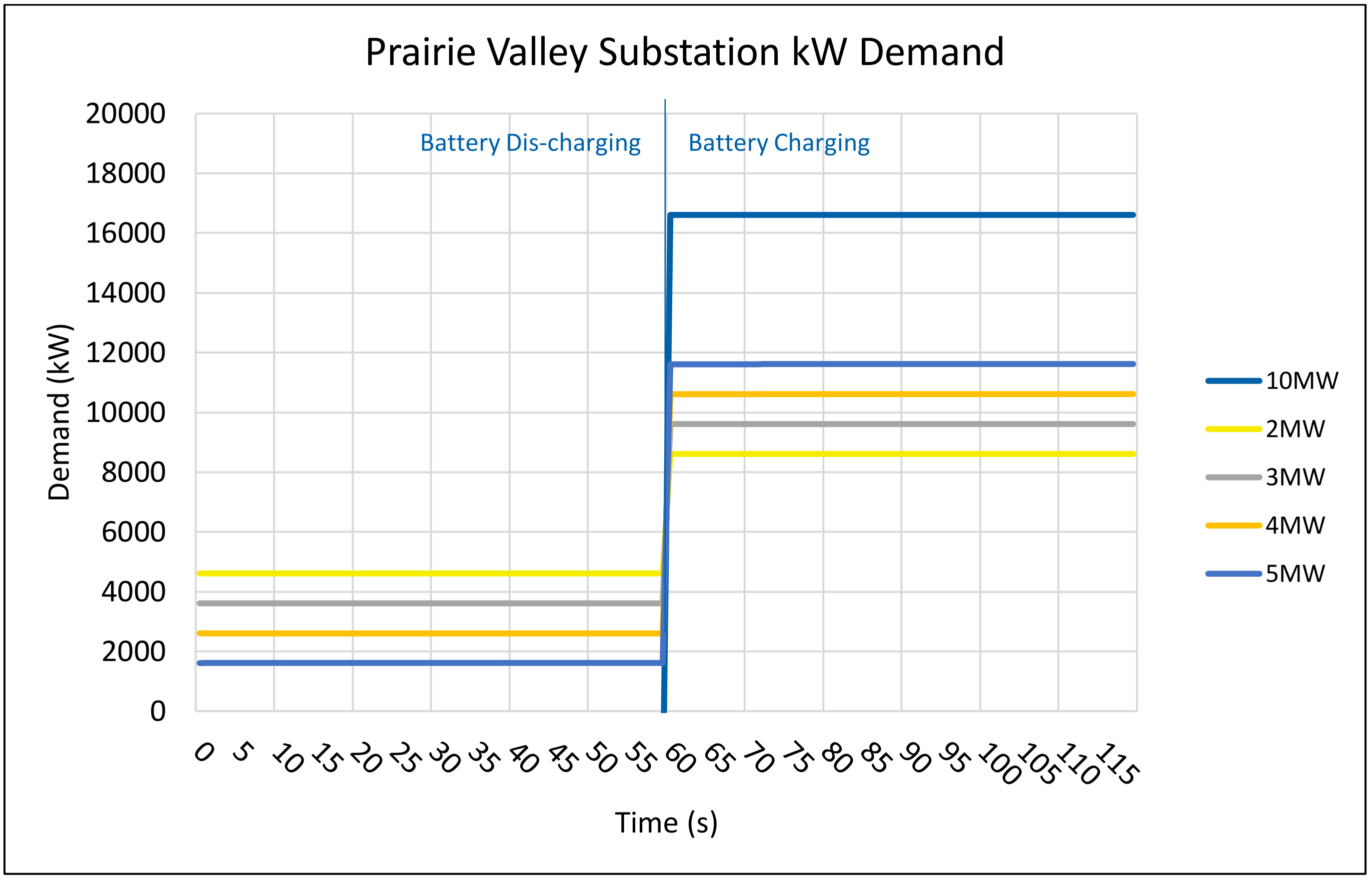

Figure 19: Prairie Valley Substation Demand

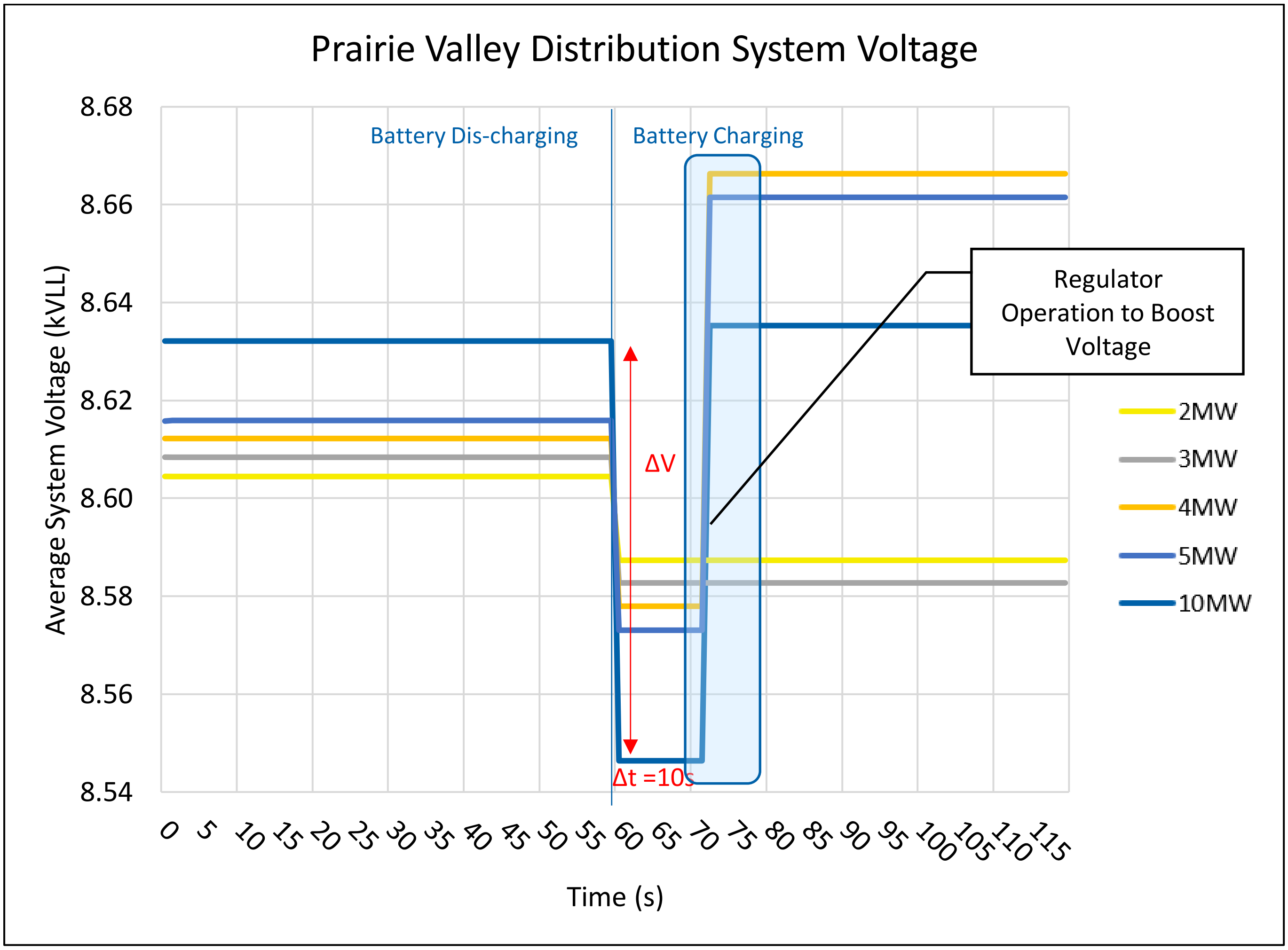

Figure 20: Prairie Valley Substation - Bus Voltage

6.6 COMMENTS & DISCUSSION

From results obtained, it is apparent that to peak shave 2 MVA, a BESS would be required to operate more than 12 hours of the day while a 0.5 MVA peak shave would require just over 4 hours. In some instances, the BESS may also be utilized to offer voltage and frequency support on the network which may be of interest to the DoS in instances where low inertia sources are penetrating the grid without ancillary support from FortisBC.

Another potential benefit of purchasing a 2 MVA BESS is that it can be utilized as a backup generation source during an outage from FortisBC. This means that the DoS could service critical loads within their network for a short period of time. As an example, if we considered a 2 MVA, 4 MVAh BESS installed in the system, if an outage were to occur the BESS could supply 2 MVA of load for up to 2 hours (assuming a complete battery discharge starting at full capacity). This may be enough time for the source of the utility outage to be repaired without the disruption of power flow to critical loads such as District pump houses, schools, medical centres, etc.

In the case where the BESS will serve as a backup generation source, switching would have to occur to allow for a "microgrid" to be formed. This would maintain power supply to the local loads when a large outage occurs on the network. A microgrid is a cluster of loads and distributed resources connected to form a network that is capable of operating in both a grid connected and islanded (self-powering) mode. The main advantage of microgrids is their ability to improve both the resiliency and reliability of the load points encompassed by the boundaries of the microgrid. To achieve this, numerous steps would be required to be taken to make the DoS network capable of conversion to a microgrid. Some of these steps include the following:

1. Evaluation of which loads would be required to be included in the microgrid.
2. Evaluation of an islanding detection method.
3. Implementation of a smart outage management scheme to automatically island the microgrid within the DoS grid should the utility connection be lost.
4. Implementation of a load shedding scheme for a situation where load demand exceeds generation capacity in islanded mode.
5. A special protection scheme would need to be implemented to handle the transition between grid and islanded short circuit conditions.
6. Voltage and frequency control mechanisms would need to be implemented.

The location of the BESS is a factor that would need to be carefully considered during detailed design. One potential location would be near the selected solar farm site. An additional factor in selecting the BESS location would be in the context of acting as a backup source. If the BESS were to operate as a backup source, the capacity and expected load would be required to be known.

As mentioned, the list above is non-exclusive and additional items may need to be considered.

7 SYSTEM WORK

Based on the analysis of this study, the DoS system will not experience significant impact from the addition of the 1 MWp solar and 2 MVA BESS; however, there are some system projects and studies that could be employed by the DoS to best optimize the network for the integration of the solar and battery systems. Additionally, if planned properly, this work can help with other system operating objectives. Each project is covered in more detail in Section 11 (Appendix B) and is summarized in Table 12 including a Class D estimate.

Table 12: DoS System Work Summary

Project Name	Summary	Approximate Costs (Class D)	
Line Extensions	Extension of three phase line to the service point of either the 1 MW solar system or 2 MVA BESS	*Overhead line construction:*	*$80-$100/m*
		Overhead to Underground Dip:	*$20k*
		Underground cabling:	*$240/m*
		Primary Metering Kiosk (incl. civil):	*$30k*
		500kVA Transformer (incl. civil):	*$30k*
		1MVA Transformer (incl. civil):	*$42k*
Prairie Valley Substation and Feeder Re-Configuration	Reconfigure feeders 149, 249, and 349 to free up a recloser in the Prairie Valley substation	*Feeder 149 to 349 tie point*	*$130k*
		New switching cubicle and cabling	*$200k*
		Salvage of existing 249 egress	*$50k*
Microgrid Preparation	Distribution system modifications to isolate critical loads during major substation outages. Critical loads include: Fire Department, Memorial Health Center, Municipal Hall, and the Police Station	*All critical loads*	*$550k*
		Fire Department, Health Center and Municipal Hall	*$350k*
		Fire Department and Municipal Hall	*$150k*
		Substation Preparation	$250k
Express Feeder for 1MWp Solar System	A dedicated express feeder could be installed to connect the Prairie Valley substation directly to the solar system to support the secondary battery function of providing backup power during a substation outage.	$850k (route dependant)	
Transmission Line Extension and New Substation	Extend the existing Transmission system and construct a new substation to allow for the solar and battery connection into the transmission system and set the stage for Summerland to truly achieve energy independence.	*Transmission Line: $750k to $2M (route dependant)*	
		Substation: $2M to $3M (scope dependant)	
		Distribution extension: $150k (route dependant)	

Project Name	Summary	Approximate Costs (Class D)
System Phase Balancing to Support Future Net-Metering Applications	DoS Power Line Technicians to review the taps for all single-phase connections on the system as part of line patrols and identifying them as A, B, or C phase in the field, then entering the data into the DoS CYME model.	*$75k*
System Protection Coordination Study	To accurately model additional large-scale solar in the DoS system, undertake a detailed protection coordination study for each feeder. The results will allow DoS to minimize the number of customers that are affected by a given outage and help increase the reliability of the system.	*$15k*

8 CONCLUSION AND RECOMMENDATIONS

The District of Summerland is in a good position to continue supporting their solar and battery initiatives. Through this analysis it was evident that the 20% penetration levels of 5 kWp and 30 kWp solar systems as well as the 1MWp solar systems didn't pose any significant system issues. This statement also holds if the 20% penetration of 30kW systems are combined with any single 1MWp solar system location. As such, the DoS can move forward on the net metering initiatives with confidence that the system won't be put at any increased risk.

The 1 MWp system was modeled at various locations throughout the system and there was very little change in overall steady state system performance. The analysis didn't find specific system deficiencies that would stop the DoS from beginning their solar installation. However, as outlined in Section 7 there are a few projects that should be considered to best support the initiative from a system operations and flexibility stand point.

Through this analysis it was found that a 2 MVA BESS does not pose any significant system issues when installed at the Prairie Valley substation. Primary believes that is the best location for the battery to provide peak shaving for the whole system. Additionally, as the 2 MVA BESS and 1 MWp solar systems are both inverter based sources we can infer that a 1MVA BESS installed away from the substation doesn't pose additional risks to the DoS system either. Primary recommends that any other locations being considered be modeled as part of detailed design.

Through the analysis carried out in this study Primary Engineering sees very little risk to the DoS system in pursuing their renewable road map. As such the residents of the community can benefit from these new technologies and through the implementation of the proposed projects the community could be leaders in this technology throughout North America.

9 REFERENCES

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10 APPENDIX A: SOLAR SIMULATION RESULTS

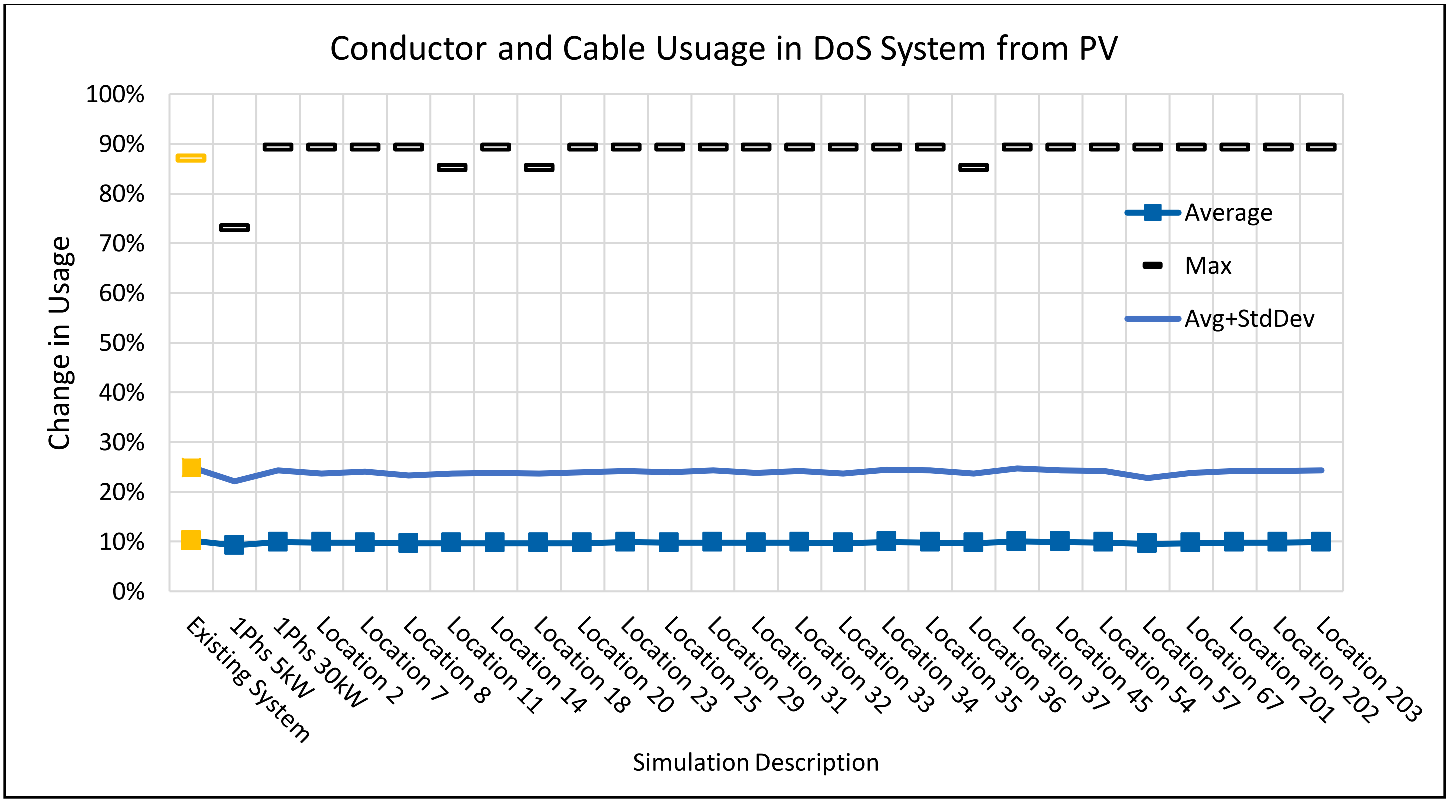

Figure 21: Percentage changes in conductor and cable usage

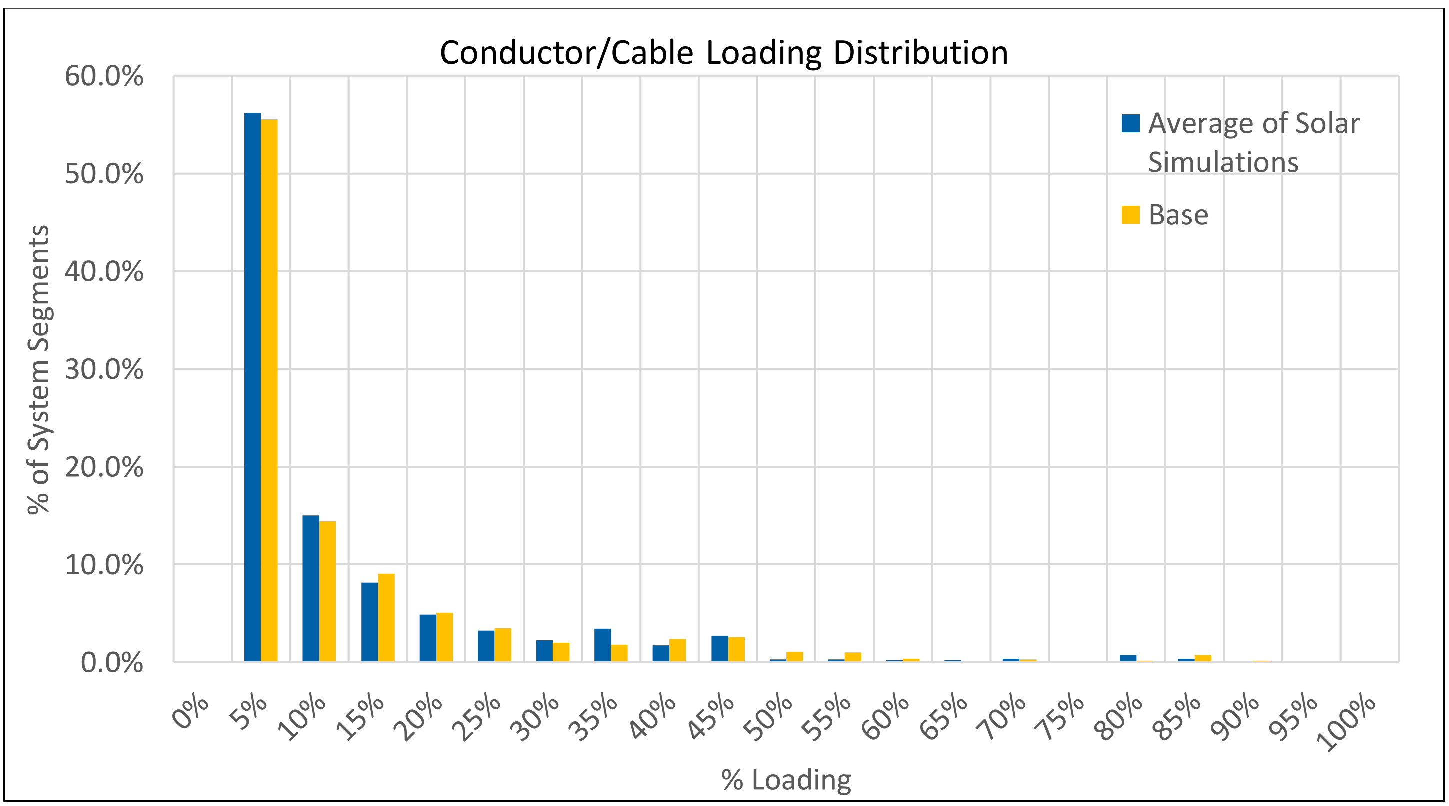

Figure 22: DoS System Conductor/Cable Loading Distribution

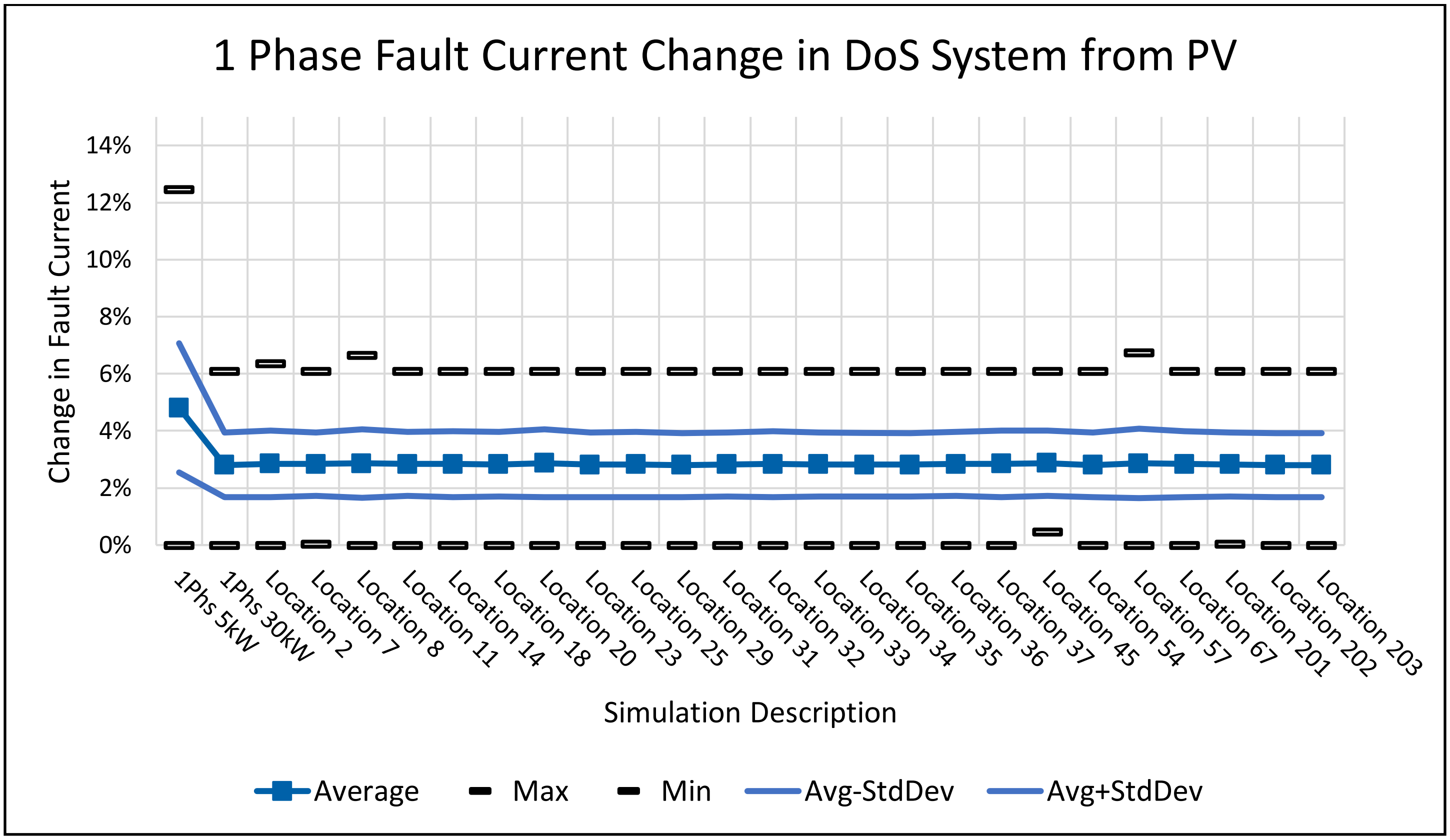

Figure 23: Change in system Line to Ground Fault Levels

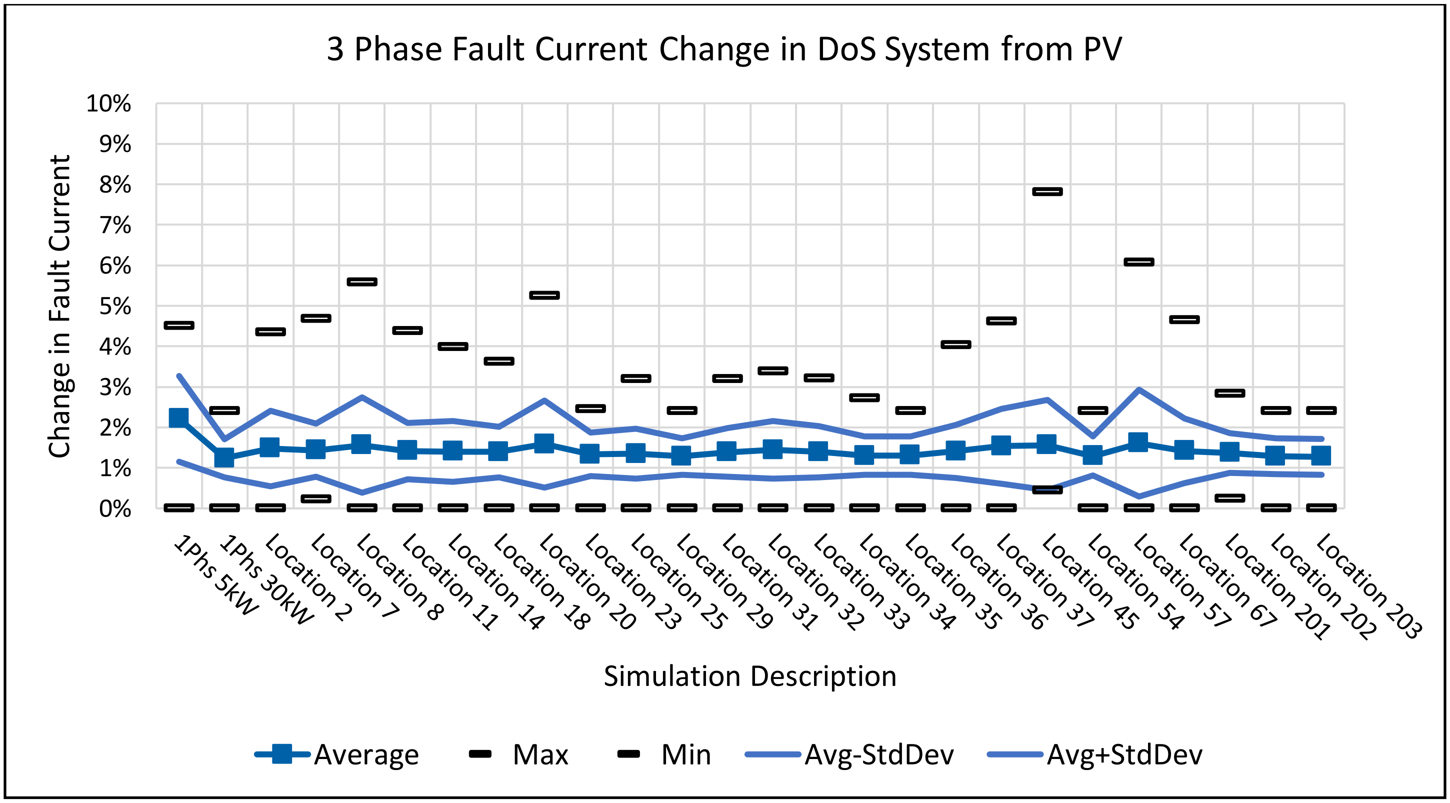

Figure 24: Change in system 3 Phase Fault Levels

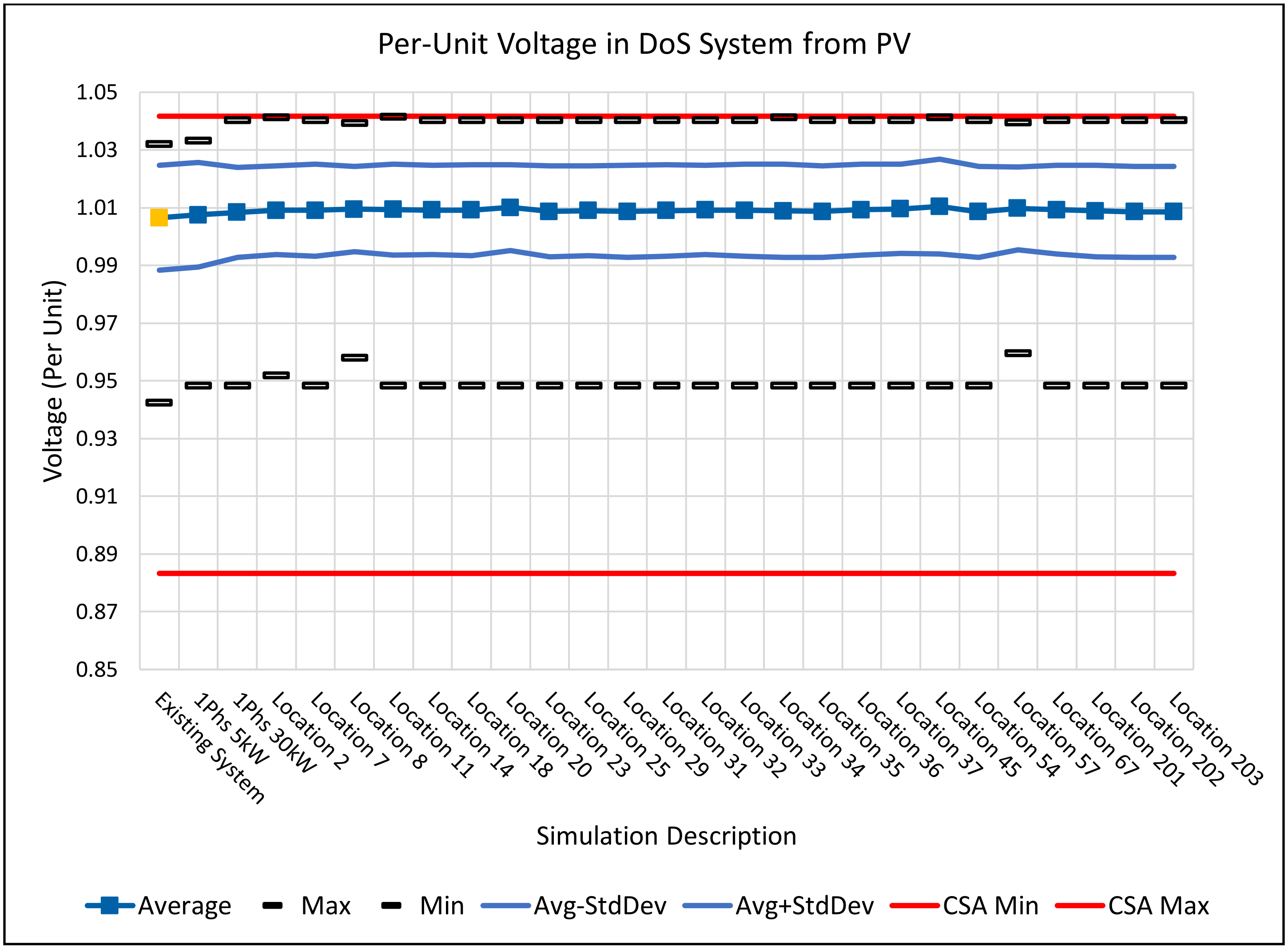

Figure 25: Change in steady state voltage distribution

Table 13: 2018 Rapid voltage change summary

Feeder	Condition	RVC (%)					
		Max A	Max B	Max C	Min A	Min B	Min C
149	Base (w/ 30kW Res PV)	0.00	0.00	0.00	-0.21	-0.20	-0.36
	1 MWp - Location 93	0.16	0.38	0.16	-1.79	-1.58	-1.95
	1 MWp - Location 15b	0.01	0.01	0.01	-0.34	-0.32	-0.49
	1 MWp - Location 15	0.16	0.16	0.16	-0.81	-0.79	-0.96
249	Base (w/ 30kW Res PV)	0.00	0.00	0.00	-0.45	-0.60	-0.37
	1 MWp - Location 20	0.07	0.07	0.07	-0.81	-0.99	-0.81
	1 MWp - Location 66	0.11	0.11	0.11	-1.47	-1.67	-1.46
	1 MWp - Location 68	0.06	0.06	0.06	-1.02	-1.16	-0.94
349	Base (w/ 30kW Res PV)	0.00	0.00	0.00	-0.08	-0.12	-0.06
	1 MWp - Location 91	0.07	0.07	0.07	-0.72	-0.76	-0.70
	1 MWp - Location 91B	0.02	0.02	0.02	-0.23	-0.27	-0.21
449	Base (w/ 30kW Res PV)	0.00	0.00	0.00	-0.25	-0.42	-0.39
	1 MWp - Location 29	0.18	0.84	0.18	-2.09	-2.27	-2.22
	1 MWp - Location 30	0.14	0.14	0.14	-1.57	-1.69	-1.69
	1 MWp - Location 47	0.10	0.10	0.10	-1.25	-1.43	-1.38
549	Base (w/ 30kW Res PV)	0.00	0.00	0.00	-0.25	-0.13	-0.37
	1 MWp - Location 9	0.08	0.08	0.08	-1.01	-0.93	-1.16
	1 MWp - Location 32	0.02	0.02	0.02	-0.38	-0.26	-0.50
	1 MWp - Location 40	0.12	0.12	0.12	-1.45	-1.34	-1.58
649	Base (w/ 30kW Res PV)	0.00	0.00	0.00	-0.78	-0.59	-0.55
	1 MWp - Location 26	0.18	0.18	0.18	-2.04	-1.94	-1.95
	1 MWp - Location 31	0.06	0.06	0.06	-0.78	-2.33	-2.29
	1 MWp - Location 42	0.29	0.29	0.29	-3.68	-3.49	-3.48
749	Base (w/ 30kW Res PV)	0.00	0.00	0.00	-0.10	-0.07	-0.21
	1 MWp - Location 34	0.01	0.01	0.01	-0.22	-0.19	-0.33
TC279	Base (w/ 30kW Res PV)	0.00	0.00	0.00	-0.39	-0.33	-1.03
	1 MWp - Location 1	0.13	0.13	0.13	-1.63	-1.64	-1.91
	1 MWp - Location 7	0.12	0.12	0.11	-1.54	-1.55	-2.21
	1 MWp - Location 38	0.16	0.16	0.15	-1.93	-1.94	-2.59
TC379	Base (w/ 30kW Res PV)	0.00	0.00	0.00	-0.62	-0.59	-0.55
	1 MWp - Location 8	0.04	2.47	0.04	-0.82	-0.79	-0.76
	1 MWp - Location 19	0.12	0.12	0.12	-1.60	-1.38	-1.42
	1 MWp - Location 89	0.14	0.14	0.14	-2.00	-1.98	-1.98

11 APPENDIX B: RECOMMENDED SYSTEM WORK

The various projects summarized in Section 7 are discussed in further detail in this appendix.

11.1 LINE EXTENSIONS TO NEW FACILITIES

Both the 1 MWp solar and 2 MVA BESS will require some form of line extension from an existing three phase line. As such, there will be a cost to connect either system to the DoS distribution network. The exact architecture will depend on the detailed design, but it may follow the architecture outlined in Figure 26.

[redacted]

Figure 26: Conceptual 1 MWp Distribution Tie-in Architecture

As seen in the figure there would be a set of fused disconnect switches (likely on an overhead power line), then a dip to underground. A padmounted primary metering kiosk would be inserted to meter the entire facility. Finally, the on-site distribution would feed multiple padmount transformers (this would increase redundancy) and use existing DoS materials for ease of maintenance. Once transformed to the low voltage (480Y/277V) the power could be distributed to the various solar equipment required.

The cost of the line extension is impossible to determine without doing a detailed design for a specific site, but the following planning figures can be used for creating high level estimates:

Overhead line construction:	***$80-$100/m***
Overhead to Underground Dip:	***$20k***
Underground cabling (including duct and trenching):	***$240/m***
Primary Metering Kiosk (incl. civil):	***$30k***
500kVA Transformer Installation (incl. civil):	***$30k***
1MVA Transformer Installation (incl. civil):	***$42k***

11.2 PRAIRIE VALLEY SUBSTATION AND FEEDER RE-CONFIGURATION

As discussed in this report, the BESS could be placed at the Prairie Valley substation. If this location were to be used, some work would need to be done inside the substation and/or on the property. The 8.3kV bus at the Prairie Valley substation would require expansion or re-configuration. If a re-configuration of the existing bus was selected, the following tasks would need to be done:

11.2.1 REVIEW OF EXISTING FEEDER EGRESS REBUILD

To support this location, the recent design for the re-configuration of two feeders will have to be reviewed and quite possibly altered to ensure the new construction doesn't limit, and better yet, supports future expansion of the substation 8.3kV system.

Approximate cost of review: $2k

11.2.2 PRAIRIE VALLEY FEEDER RECONFIGURATION

A feeder reconfiguration should be undertaken to make available an 8.3kV bus to connect the battery to the Prairie Valley substation. The feeder 249 bus can be made available by splitting this feeder's load between 149 and 349. This would render the expansion of the 8.3kV bus unnecessary.

To accomplish this feeder reconfiguration, the following three projects would be required:

1. Feeder 149 to 349 tie point addition at Latimer Ave. and Lakeshore Dr.
2. New switching cubicle at Prairie Valley Rd. and Bloomfield Rd.
3. Salvage of existing 249 three phase egress to pole 11-248.

Phase 1: Feeder 149 to 349 tie point addition at Latimer Ave and Lakeshore Dr.

To minimize outage impact for feeder 349 customers during the construction of the new switching cubicle (phase 2), a tie point should be established between the current feeder 149 and 349 circuits. This project will not only support the battery installation but will also provide a normally open tie-point between these feeders, making the DoS system more resilient to power outages along either feeder going forward.

[redacted]

Figure 27: New tie point between feeders 149 and 349

Approximate cost: $130k (requires directional drilling new underground feeder cable)

Phase 2: New switching cubicle at Prairie Valley Rd. and Bloomfield Rd.

A new switching cubicle needs to be installed to reconfigure feeders 149 and 249. The new switching cubicle should be installed at the northeast corner of Prairie Valley Rd. and Bloomfield Rd. Additionally, a tie between the three phase lines at Prairie Valley Rd. and Atkinson Rd. will have to be established. This can be done by installing two dips to connect the two circuits across Atkinson Rd. Once this is done, feeder 249 can be opened at the substation and the recloser can be re-purposed.

[redacted]

Figure 28: Existing configuration of feeders 149, 249, and 349

[redacted]

Figure 29: Results of Feeder 149 and 349 Reconfiguration

Approximate cost: $200k

Phase 3: Salvage of existing 249 three phase egress to pole 11-248.

Once the reconfiguration is complete, a small section of three phase line (including a three phase diagonal overhead crossing) can be salvaged from Giants Head Rd. This would clean up the overhead lines in this area.

Figure 30: Salvage of feeder 249 egress

Approximate cost: $50k (if able to tap off 49L underbuild for 1 phase service feed)

11.3 MICROGRID FEEDER PREPARATION

A microgrid simulation was undertaken as part of this study to demonstrate another application of the 2 MVA battery system. If the Prairie Valley substation experienced a complete outage due to a transmission line outage or transformer trip, the battery system could be used to temporarily provide power to critical DoS loads such as Municipal Hall, the Fire Department, Memorial Health Center, and the Police Station. These critical loads, their locations, and the distribution feeder they are currently fed from are outlined in Table 14 and are shown graphically in Figure 31.

The microgrid configuration outlined in this section would require some considerable investment to completely automate the process of transitioning from the normal feed to the battery feed. Several electronically-controlled switches would need to be installed, and a communications network would need to be established to connect all the field devices to a central control server. Additionally, automation intelligence would need to be programmed into the devices such that the protective curves/functions change when in battery-only mode.

Alternatively, the process could be a combination of manual operations of the electronically controlled switches, or even manually operated switches in the field to reduce costs. The disadvantage to this would be that in an outage, DoS power line technicians would have to manually setup the microgrid prior to the battery and/solar being able to start to provide power.

Table 14: DoS Critical Loads for Microgrid Simulation

Critical Load	Description	Address	PV Feeder
1	Municipal Hall	13211 Henry Ave	[redacted]
2	Fire Department	10115 Jubilee Rd	[redacted]
3	Memorial Health Centre	12815 Atkinson Rd	[redacted]
4	Police Station	9101 Pineo Ct	[redacted]

[redacted]

Figure 31: Dos Microgrid fed by Battery System at Prairie Valley Substation

There were two main constraints that were used when determining the boundaries of the proposed microgrid:

1. Battery system capacity
2. Location of critical loads

This analysis assumed a 2 MVA battery with 2 MVAh energy capacity. This would mean that it would be capable of supplying 2 MVA for one hour at unity power factor. This time could be extended if the microgrid is reduced in load demand.

The microgrid model would rely on having electronically controlled switches in the field that would be able to be operated in the event of an outage. The series of events for creating the microgrid would be as follows:

1. Power outage at the substation
2. Battery system halts operation (discharging or charging)
3. Pre-determined delay in time (ensures power outage is sustained)
4. All substation 8.6kV breakers open (except 249, 549, and 749)
5. Microgrid isolating switches in distribution system (i.e., reclosers, padmount switches) open isolating the critical loads from the rest of system
6. Battery system starts discharging into microgrid

The various critical loads and isolation plans are outlined in the next sections.

Feeder 749 - Critical Loads 1 (Municipal Hall) and 2 (Fire Department)

To best isolate Municipal Hall and the Fire Department on feeder 749, the following would be required:

- Open point reconfiguration to downtown
    - Open elbows in junction box on Jubilee Rd between Henry Ave and Kelly Ave
    - Close switch 749-1 on 3 phase dip north of Wharton St and Kelly Ave
- Install New recloser at Wharton St and Kelly Ave
- New recloser/padmount switch at Summerland Secondary School

Figure 32: Microgrid configuration for isolating Fire Department and Municipal Hall

Feeder 249 – Critical Load 3 (Memorial Health Centre)

To best isolate the Memorial Health Centre on feeder 249, the following would be required:

- New padmount switch north of Memorial Health Centre
- New padmount switch at Seniors Village (to de-energized in outage)

[redacted]

Figure 33: Microgrid configuration for isolating Memorial Health Centre

Feeder 549 – Critical Load 4 (Police Station)

To best isolate the Police Station on feeder 549, the following would be required:

- 2 new padmount switches at Rosedale Ave and Peach Orchard Rd

[redacted]

Figure 34: Microgrid configuration for isolating the Police Station

Results

Some combinations of the critical load isolation procedures outlined in this section that could be produced are outlined below and summarized in Table 15. The time that these loads remain active is solely based on one full charge of the battery – see Section 11.4 for the incorporation of the large solar array as well.

Solution A – Critical Loads 1-4 for 45 minutes

- Feeds Municipal Hall, Fire Department, Memorial Health Centre, Police Station
- Isolated sections of feeders 249, 549, and 749 active
- Requires 6 new electronically controlled switches

Solution B – Critical Loads 1-3 for 1 hour, 45 minutes

- Feeds Municipal Hall, Fire Department, Memorial Health Centre
- Isolated sections of feeders 249 and 749 active
- Requires 4 new electronically controlled switches

Solution C – Critical Loads 1-2 for 2 hours, 45 minutes

- Feeds Municipal Hall and Fire Department
- Isolated sections of feeder 749 active
- Requires 2 new electronically controlled switches

Solution D (Modified Solution C) – Critical Loads 1-2 for 13 hours

- To increase the time that Municipal Hall and the Fire Department remain on, the DoS could manually open the cutouts for all transformers in this area (25 transformers). Assuming all these transformers were disconnected, this would reduce the load fed to 153 kVA, which will keep Municipal Hall and the Fire Department on for 13 hours.

Table 15:Microgrid Simulation Result Summary and Cost

Solution	Critical Loads Fed	Active Feeder(s)	Number of Switches	Load (kVA)	Time	Approximate Cost ($)
A	Loads 1-4	249,549,749	6	2090	45 mins	***550k***
B	Loads 1-3	249,749	4	1131	1 hr, 45 mins	***350k***
C	Loads 1-2	749	2	709	2 hr, 45 mins	***150k***
D	Loads 1-2	749	2	153	13 hrs	***150k****

*Requires manual disconnection of 25 transformers

11.3.1 Substation Preparations for Microgrid

To best isolate the substation bus from the selected microgrid option a series of switching cubicles should be installed at the substation. The switching cubicles would provide the necessary isolation to completely run a feeder (or feeders) without having to rely on the substation bus. This would have the added benefit that if bus maintenance needed to be done the feeder (or feeders) fed by the microgrid could remain energized.

Approximate cost: $250k

[redacted]

Figure 35: Microgrid Substation Switch Addition

11.4 Express Feeder for 1 MWp Solar System

A dedicated express feeder could be installed to connect the Prairie Valley substation directly to the solar system to support the secondary battery function of providing backup power during a substation outage. This would have the benefit of supplying solar power during the day and keeping the battery reserved for night operation during prolonged substation outages. Primary has identified that Location 8 (10900 Feffe Rd) or Location 18 (13500 Prairie Valley Rd) would lend themselves well to such an application. Figure 36 illustrates the express feeder concepts. ***Approximate Cost: $850k***

[redacted]

Figure 36: Express feeder concepts

11.5 TRANSMISSION LINE EXTENSION AND SUBSTATION

All system work introduced up to this section has highlighted quick ways to incorporate the 1 MWp Solar and 2 MVA Battery systems into the DoS distribution network. Looking on a larger scale may provide more value to the DoS from a reliability, resiliency, and capacity standpoint. For example, extending the existing transmission line to the industrial park and building a new substation would provide an easy connection point for the 2 MVA Battery system and support the 1 MWp solar at Location 8 (10900 Feffe Rd).

An added advantage to this option is that it alleviates capacity pressures that are present at the Prairie Valley and Trout Creek substations and provides increased ease of connection to new loads in the large industrial area nearby. This would effectively make it easier for businesses that require large loads such as machine shops, manufacturers, crypto currency, etc. to connect to the DoS system and thus create new sources of income for the DoS and reduce pressures on electricity rates for locals.

Additionally, adding a transmission switch along the FortisBC transmission line would provide the ability to feed the other two substations in the event of a FortisBC transmission outage. That is, if DoS's solar and battery program continued to grow into the future then using this architecture could mean that Summerland could truly reach energy independence.

[redacted]

Figure 37: Summerland Transmission Line Extension and New Substation

Approximate Transmission Line cost: $750k to $2M (route dependant)

Approximate Substation cost: $2M to $6M (PODS architecture and scope dependant)

Approximate Distribution extension to Location 8 cost: $150k

11.6 System Phase Balancing

To support the long-term execution of the net metering application process, a system-wide phase balancing study and project should take place. To ensure the highest degree of accuracy, this work would include having field staff review the taps for all single-phase connections on the system as part of line patrols and identifying them as A, B, or C phase in the field using a phasing tool (or other techniques). The data would then be brought back to the office and entered into the DoS CYME model. This work would mean all future system connections as well large net metering installs would be properly modeled to ensure safety and system stability.

Approximate cost: $75k

11.7 System Protection coordination Study

Protection in a distribution system works most effectively when each protective device is coordinated with the next upstream infrastructure. This will minimize the number of customers that are affected by a given outage and help increase the reliability of the system. Primary proposes that a theoretical study be carried out on the DoS system so that as feeders are taken out for maintenance, crews can replace fuses to a set size over time. This would eventually lead to a fully documented and coordinated system.

Approximate cost: $8k

Primary offers engineering and construction services with eight office locations throughout western Canada, expanding where our services are needed.

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