FINAL REPORT

Analysis of combinations of wind, solar, and tidal electricity generation with energy storage in Nova Scotia

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Summary

This project investigates the proportioning of intermittent renewable wind, solar, and tidal electricity generation, and the use of energy storage, to i) shape intermittent energy output to meet Nova Scotia electrical load, and ii) reduce the ramp rate impact that intermittent generation has on conventional generating assets in Nova Scotia. Each intermittent generator (IG) varies at different timescales due to different causes (wind=weather system; solar=daily and seasonal; tidal=6 hour and lunar). This uncorrelated nature and the use of energy storage (ES) as a buffer enables increased installed capacity without destabilizing the conventional dispatchable generating (DG) assets such as thermal (fossil) and hydro. The objective of this project was to create new models of IG and ES, and new control strategies to parametrically assess performance of a range of installed capacities by multiple metrics. The project consists of 4 tasks: data collection/preparation; modeling and control strategies; parametric evaluation; and presentation and interpretation of the results.

High-timestep-resolution intermittent resource and IG data was collected, organized, and validated from 14 Sep 2016 through 13 Sep 2018. Wind power data were provided by Nova Scotia Power (NSP) that aggregated 9 large telemetered wind farms. Solar power data were provided by Halifax Regional Municipality (HRM) from the Solar City 2 project consisting of 59 distributed photovoltaic solar systems that are net-metered. Tidal flow speed data were provided by Fundy Ocean Research Center for Energy (FORCE) for a period of three months from a measurement package located in the Minas Passage; they were converted to power using a published in-stream tidal turbine power curve. All IG data were normalized by peak power (i.e., conversion capacity) to create a scalable dataset for use in modeling a range of installed IG capacities. Additionally, NSP provided aggregate provincial load power data.

New models of IG output and ES operation were created. The IG model operates in two ways: (1) a proportioning method which varies each IG type from 0-100% of installed capacity, the balance being made up of the other two IG types; (2) using pre-defined magnitudes of installed IG capacity fed to the Nova Scotia electrical load, ranging from 0-1500 MW for each IG type. Both methods sum the scaled values for each resource to create a 10-minute timestep series of "potential" IG power. Two corresponding ES control algorithms were also developed. The ES models initially assume infinite capacity (MWh) and power (MW), and 'discover' the necessary ES capabilities from model operation. The ES is initialized, from which it can either charge, discharge, or standby in each timestep.

Two control strategies were applied. The first control strategy is *Load-following*, which uses ES such that the combination of IG + ES outputs is a smoothed IG resource power value modified to mimic shorter timescale variations in the Nova Scotia electrical load; the magnitude of the output power profile can be scaled by installed capacity to reach the Nova Scotia electrical load if desired. The smoothing and shaping time period ranges from 1 hour (energy market blocks) to months (seasonal storage). This control strategy is used to investigate optimal proportioning of IG and ES to achieve high penetration rates of installed IG capacity. The results of this control strategy are scalable to any expected load or generation growth or reduction in Nova Scotia.

The second control strategy is *DG-ramp* control, which uses the ES to limit the power ramps (ΔMW/minute) placed upon existing DG. This is so that additional amounts of IG may be installed without de-stabilizing the electricity system when the wind or solar resource varies dramatically in a short time period (e.g. fast-moving clouds for solar or frontal systems for wind power); tidal generation variability is highly regular and forecastable but has continuous changes in power output. This control

strategy is used to investigate the installed capacities of IG (MW) and battery size (MWh) within the present Nova Scotia electrical load (MW) to keep the DG ramp within a limit of ±50 MW per 10-minute period (representing roughly the 99th percentile of existing ramp rates). This analysis was based on the present load of Nova Scotia (2016-2018) rather than projected future loads, about which there is considerable uncertainty. The model can be re-executed to examine future load scenarios or future ramp rate limit scenarios as DG retirements occur.

The models were executed to parametrically compared the performance of the range of systems using both control strategies. Performance metrics include the installed IG capacity (MW_{rated}) per average MW output, the size of ES (MWh) to achieve the control objective, the quantity of the Nova Scotia load supplied by IG + ES (%), the quantity of curtailed IG (%), and the capital costs of the system in entirety (IG + ES). Within the first control strategy these are each evaluated across a range of smoothing periods (hours to months) and installed IG capacity (proportions or MW_{rated}). Figures composed of timeseries and summary parametric “maps” are provided to illustrate the results of this multi-dimensional analysis in a meaningful manner to support policy development and decision making.

The results of the *Load-following* control strategy suggest that adding energy storage capacity to achieve hours of smoothing/shaping is presently less economic than installing additional IG capacity and curtailing. The quantity of ES capacity is on the order of 1 MWh per 1 average MW output of IG. To put this in conventional terms, a 100 MW rated wind farm would require approximately 35 MWh of ES capacity for 1 hour smoothing/shaping. A smoothed/shaped IG over several hours would allow more IG capacity to integrate within the electricity grid and not cause control issues. Wind capacity (80+%) with storage requires the least total system capital cost to achieve 1 or 3 hour shaping to load and have a price premium of 20% over those without energy storage. As the focus shifts to much higher renewable electricity penetration rates, with correspondingly longer smoothing, the consistent cycling of tidal becomes a more economic choice when combined with ES.

The results of the *DG-ramp* control strategy suggest that high penetration rates of IG necessitates energy storage. The ES power capability necessary to maintain DG power ramps within the present 99th percentile value may need to equal 50% or more of the installed generating capacity of IG or DG. Wind and solar have less impact on ramp than tidal which has shorter cycling nature that often runs counter to the load variations and exacerbates the DG-ramp. Without a cost-optimizing curtailment analysis, this model finds that upwards of a 1 GWh of energy storage may be required to integrate 1000 MW of tidal generation and remain within ramp limits. While the addition of energy storage increases energy cost, it is not an order of magnitude, and indicates that with cost evolution of the different resources, all options might be considered in the context of supportive energy policies to achieve a range of objectives (energy, security, local manufacturing, social).

This new model evaluates long-term future renewable electricity generating scenarios in Nova Scotia when combined with energy storage. The model will aid the industry and Government in support of new renewable policies with expected technical performance and simplified costing estimates. These policies might be aimed at particular resources, the inclusion of new technology (energy storage), cost, or local aspects. The models are ready to conduct additional analysis or have additional capabilities, such as peak shaving control strategy added.

1 Introduction and Objective

1.1 Background

With our increasing understanding of the immediacy and the severity of the impacts of climate change, the urgency of transitioning away from carbon-based energy sources is become ever more apparent. In addition to aggressive efforts at energy efficiency, the deployment of non-emitting electricity generation capacity is a key enabler of a low-carbon economy. This effort has historically been complicated and limited by the intermittent nature of the most widespread renewable energy resources such as wind and solar. It is also the case with tidal flow, which while not widespread around the globe, has enormous potential in Nova Scotia as well as other jurisdictions where the tidal excursion is large and coastal geometry is suitable.

Installation of significant capacity of intermittent generation (IG) has several consequences and this has limited its uptake. First, it may not reduce the necessary quantity of installed conventional dispatchable generating (DG) assets (MW) such as thermal (fossil) and hydro, as all IG may be at low output simultaneously. Second, it requires that DG modulate power output up and down at increased ramp rates (MW/minute) to compensate not only for changes in load, but also to compensate for changes in IG output which will sometimes trend opposite that of load. Finally, excess IG may require curtailment so as not to destabilize the electricity grid, which is to say the renewable resource goes uncollected and the potential is lost.

Each of the IG resources examined in this study experiences different timescales of variability (wind = weather system; solar = daily and seasonal; tidal = 6 hour and lunar). It is proposed that proportioning of the installed capacity of each IG type, so that the combination of the three totals 100%, may be complementary at reducing power intermittency (peaks, valleys, ramps) due to the different cyclic times. Additionally, energy storage (ES) composed of an installed capacity (MWh and MW) may be used to buffer the intermittent fluctuations to smooth the aggregated IG output and lessen the impact it has on DG.

1.2 Objectives

The objective of this project was to investigate the proportioning of wind, solar, and tidal electricity generation capacity (termed Intermittent Generation, or IG), and the use of Energy Storage (ES), to meet the electrical load of Nova Scotia. To achieve this objective, new models of IG and ES were created, and two control strategies were developed to parametrically assess performance of a range of installed capacities. The first shapes the output of IG capacity to both reduce the rate of IG output variation and partially mimic the variability of load; it is focused on determining optimal proportions of IG and the necessary ES size for arbitrary penetration rates of renewable electricity. The second aims to minimize the ramp rate impacts of IG on conventional DG; in doing so it enables further increases of IG capacity in concert with existing DG assets. The project consists of 4 tasks:

1. Data collection/preparation: Key to this project is the use of measured intermittent resource, IG power, and load data. Dalhousie University has measured renewable energy data sources available via data sharing agreements. Additionally, we have several energy storage providers' technical documents showing the range of operation and performance. We have updated, collected, and prepared the data for this project using measured data from 14 Sep 2016 to 13 Sep 2018.

2. Modeling: We created new models of IG and ES. Fundamental to the IG model is that it mixes various proportion of wind, solar, and tidal IG capacity to create an aggregated IG output. In the first control model this is by proportions (%) and in the second it is by rated capacity (MW) within the Nova Scotia electrical load context. The sum of the scaled values creates a 10-minute timestep series of “potential” IG power. The ES model initially assumes infinite capacity (MWh) and that power (MW) is not the limitation. The ES is initialized, from which it can either charge, discharge, or standby in each timestep. Two control strategies were implemented: (1) *Load-following* control, which outputs a combined IG + ES power value that is shaped to resemble Nova Scotia electrical load over a period ranging from 1 hour (energy market) to 2 years (constant output); (2) *DG-ramp* control, which constrains the power ramps (MW/minute) placed upon DG so that additional amount of IG may be installed without de-stabilizing the electricity system.
3. Parametric evaluation: The models are used to evaluate IG proportions of each of the three resources ranging from 0-100% of installed capacity, and ranging from 0-1500 MW of installed capacity. Performance metrics include the installed IG capacity per average MW output, the size of ES in MWh to achieve the control objective, the quantity of load supplied by the IG + ES, the quantity of curtailed IG, and the capital costs of the system in entirety (IG + ES). These are each evaluated across a range of smoothing periods and installed IG capacity (proportions or MW_{rated}). Figures composed of timeseries and summary “maps” are provided to illustrate the results of this multi-dimensional analysis.
4. Conclusions: The results are examined in the context of the future and existing electricity grid of Nova Scotia. From a future perspective the optimal proportions of each IG type are compared with necessary ES to achieve the objective. This is done in terms of shaping period. Significant transitions from one resource to another are noted. From an existing electricity grid perspective, the impacts of increasing the IG on conventional generators is determined to show how much IG capacity can be increased while remaining within the ramp limits.

2 Data collection and preparation

Measured renewable resource data is used for this project. It must be collected and prepared for scaling use in the model. It is composed of wind, solar, and tidal data. Details for each renewable resource are given below, complete with source, location, period, description, and illustrative representation.

In summary, the renewable resource or IG power data was collected from independent parties based solely on measured data. It is critical to use measured data to accurately represent the Nova Scotia resource and the conversion efficiencies of the IG. The data is up-to-date (spanning 14 Sep 2016 through 13 Sep 2018) to account for recent changes in technology and load, and spans a range of two-years to account for interannual variability (to reduce the risk that a single “high” or “low” resource year is used). The data was collected from as many measurement locations as possible, covering the widest geographic span across Nova Scotia that is available today.

Data was provided in a variety of formats, with all time-step values at resolutions ranging from 2-minutes to 15-minutes. Other than the HRM Solar City II data, which are public, the data are provided by independent parties under data sharing agreements with Dalhousie University for research purposes.

The data were evaluated for quality-control purposes by examining minima, maxima, standard deviations and timeseries, and applying engineering judgement (e.g. solar should be zero at night). The data were synchronized into a unified timestep format of 10-minute intervals over a 2-year span from 14 Sep 2016 to 14 Sep 2018. This maximized coincident data collection between the three resources. Data was normalized to a range of 0 – 1 by dividing by the IG capacity at the time each value was collected (installed capacity of wind and solar IG increased during this period). This allows the data to be scaled to any capacity of interest. The resultant unified data file is used in the model.

2.1 Wind

Wind power is well established in Nova Scotia, with almost 600 MW installed capacity representing dozens of wind farms around the province. These wind farms are shown in Figure 1.

Figure 1 Map of wind farms in Nova Scotia[1]. Red circles indicate large telemetered wind fields that are the primary data sources for developing a wind resource timeseries

The farms indicated in Figure 1 range in size from less than 1 MW to over 100 MW and have come into service over the course of the last two decades. Those marked in pink are part of the "Community Feed In Tariff" scheme and are connected to the distribution system and are generally less than 5 MW. Those marked in blue may be any size, the largest being 101 MW. Some public wind power data is available on the Nova Scotia Power website[2].

Nova Scotia Power provided aggregate 2-minute timestep data for a period of 3 years from telemetered wind farms that are circled in red in Figure 1. These wind farms are generally the largest in the network, and together represent more than 75% of the installed capacity. Many of the smallest wind farms are not independently metered. Nova Scotia Power estimates production from the known installed capacities based on the performance of the large telemetered farms. Those estimates are included in the wind resource data used for this study. The raw wind power output data are shown as a blue line in Figure 2 top plot and demonstrate the changing installed capacity over the span of the investigation.

[1] https://www.nspower.ca/en/home/about-us/how-we-make-electricity/renewable-electricity/wind-farm-map.aspx
[2] https://www.nspower.ca/en/home/about-us/todayspower.aspx#%20

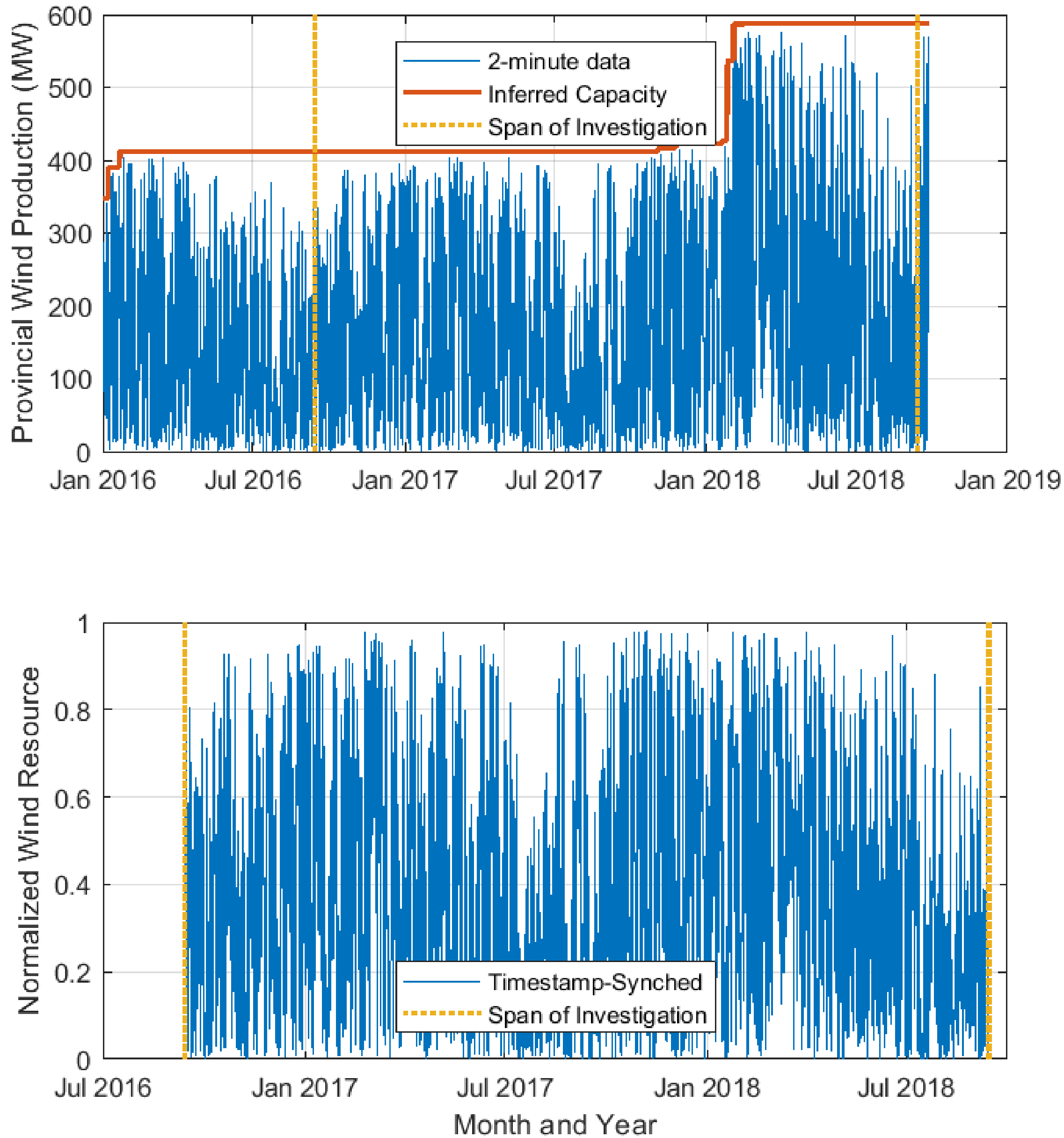

Figure 2 Timeseries of provincial wind power data shown in top plot, with inferred installed capacity (orange line) and bounds of 2-year study period (yellow). Bottom plot shows normalized wind power used in subsequent analysis.

To extract a normalized aggregate wind resource, the instantaneous power output (blue line in Figure 2 top plot) must be divided by the existing wind conversion capacity. Since historical installed capacity is not known precisely, the timeseries of wind power output was used: For each 2-minute timestep, installed capacity was inferred to be 2% greater than the maximum instantaneous power output seen in the period preceding that timestep. This methodology resulted in an inferred installed capacity of wind generators shown as the orange line in top plot of Figure 2. The 2-year period of investigation for this study is indicated by the yellow dotted vertical lines. Note that while the first few days of calculated capacity are likely incorrect due to the short period of accumulated data, more than six months' 'history' is available to inform the estimated installed capacity at the start of the study period. Note that inaccuracies in the 2% assumption would lead to small differences in wind capacity factor, but would have minimal impact on ramp rates, and no impact at all on wind power correlation with other resources.

The resultant normalized wind power dataset is shown in Figure 2 bottom plot. Data was down-sampled using averaging techniques to achieve a 10-minute timestep series. The resultant capacity factor of the wind time series is 37.4% (annual average power divided by rated power).

2.2 Solar

While there is little installed photovoltaic solar power in the province, the rapidly falling prices of equipment, along with a recently announced provincial incentive program[3] and a municipal loan program[4] are resulting in rapid increases in installed capacity.

Solar resource data for this study came from Halifax Regional Municipality (HRM), which has a Solar City program to support the adoption of residential and small commercial rooftop solar photovoltaic systems around HRM, provided participants share output data. The solar data is publicly available[5]. Operating conditions at each installation include power production and number of photovoltaic modules generating, which are reported on 5-minute timesteps when power is being generated. HRM comprises a little more than 10% of the land area of the province of Nova Scotia and is located on the central southeastern Atlantic coast.

Installation locations are provided in the Solar City data in the form of Forward Sortation Area (FSA) values. The FSA comprises the first three digits of a Canadian postal code. There are 31 FSAs represented within HRM, and 21 of those have Solar City installations. The FSA boundaries and the number of Solar City installations within each are shown in Figure 3. On the left, the larger and more rural FSA installation counts are indicated, while on the right those in the core of the city are shown.

[3] https://www.efficiencyns.ca/service/solarhomes/
[4] https://www.halifax.ca/home-property/solar-projects/about-solar-city-halifax
[5] http://catalogue-hrm.opendata.arcgis.com/datasets/0360f99bea8e471d98d789045d08447c_0

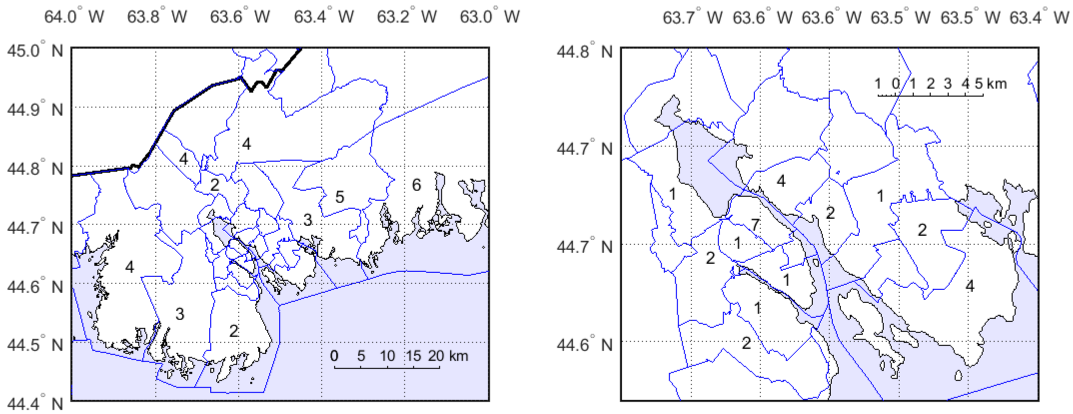

Figure 3 Halifax Regional Municipality maps with numbers of reporting solar sites in each Forward Sortation Areas (blue lines)

Figure 3 indicates a good distribution of Solar City PV systems throughout HRM, at least within a region spanning ~80 km east-west and ~40 km north-south. While it is desirable to have representation across the whole of Nova Scotia, there are presently no data sources available for more distant locations (Yarmouth, Amherst, Sydney). We expect that with the recent provincial incentive data will become available across Nova Scotia in year 2019 and beyond.

Raw data from the Solar City project include power production and number of panels (active micro-inverters) reporting per installation, on 5-minute timesteps. This is shown in the top plot of Figure 4. The quotient of these two numbers is the power being delivered per panel. Normalizing this by the panel size produces the effective solar resource of the HRM, which includes real-world imperfections such as non-ideal panel alignment (tilt and azimuth), shading, dirt or snow on the panels, etc. The resulting normalized and synchronized production data are shown in the bottom plot of Figure 4. Note that the first reporting Solar City panels came online in November 2016, two months after the start of the period of this investigation. To gain a complete two full years of data for analysis, data from those two months in the following year were replicated and prepended to the raw data (shown in black in Figure 4 bottom plot).

Data was down-sampled using averaging techniques to achieve a 10-minute timestep series. The resultant capacity factor of the solar time series is 14.4% (annual average power divided by rated power).

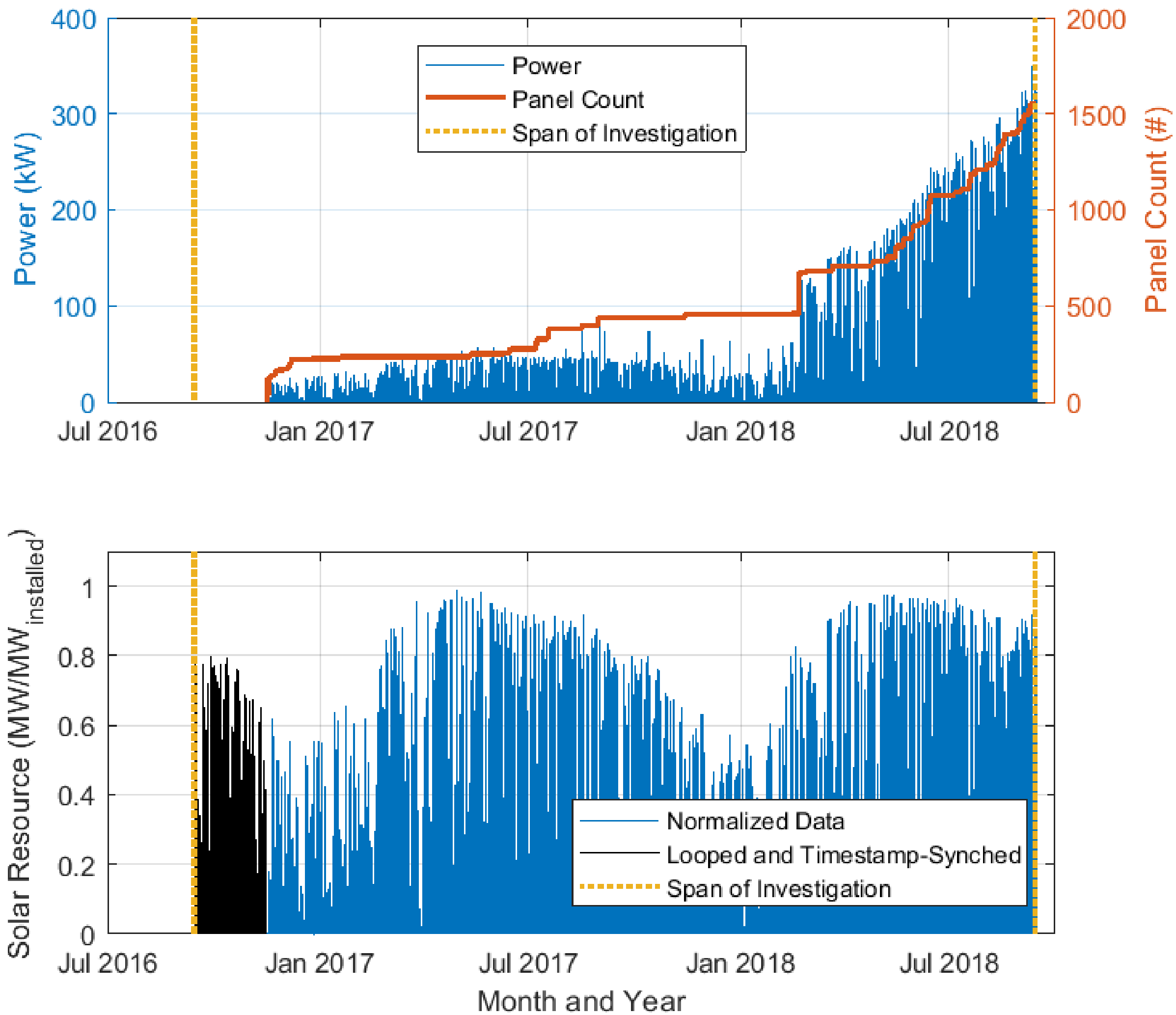

Figure 4 Raw power data and panel count from Solar City shown in top plot. Because these data do not cover the full 2-year study period, the normalized solar power data (bottom plot) include 2 months of prepended data taken from the same dates the following year (black).

2.3 Tidal

Tidal resource data have been provided by the Fundy Ocean Research Center for Energy (FORCE). The provided data are from an acoustic doppler current profilers capturing a column of water velocities on 15-minute timesteps, with each point representing an average of the preceding 5-minute of high frequency measurements. The nature of the data collection and instrumentation require averaging of at least 2 minutes to reduce random errors. Some public tidal flow data (though not these data) are available[6].

[6] https://data.oceannetworks.ca/DataSearch

FORCE operates test sites for tidal flow turbines in the Minas Passage off Parrsboro NS. The location of this test site is indicated in Figure 5, with the border of HRM included for reference and comparison to the solar resource data.

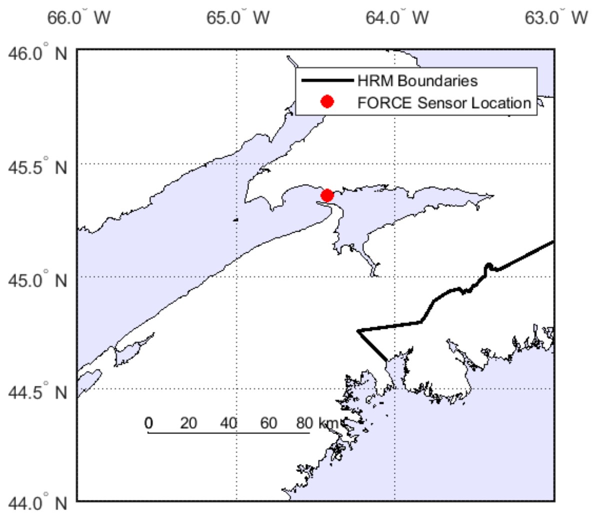

Figure 5 Location of Fundy Ocean Research Center for Energy in the Minas Passage

The tidal flow data come from two separate deployments of seabed mounted sensors at approximately the same location (positional errors of ~10 m are unavoidable when deploying equipment in 50 m depth of highly turbulent water). The sensor package includes an Acoustic Doppler Current Profiler, which provides three-dimensional velocity data from various depths above the sensor up to the free surface of the water. The RMS value of the three directional components gives a water speed, which varies throughout the day in response to periodic tidal forcing functions. The raw data from the two deployments at the FORCE site, for a position 30 m above the sea floor, are shown in Figure 6.

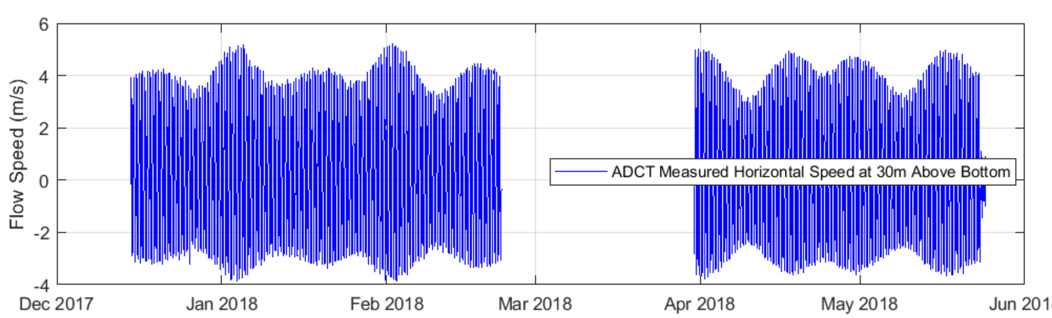

Figure 6 Raw tidal flow data from the Minas Passage taken from two deployments of the ground-mounted sensor array.

Because of the separate sensor deployments, the raw data are intermittent and incomplete. They also do not cover the full extent of the two-year period of interest for this study. In order to match the study period covered by solar and wind, the in-stream tidal data was extrapolated using the Matlab function UTide[7]. UTide uses the measured speed data and the latitude as inputs and performs harmonic analysis

[7] https://www.mathworks.com/matlabcentral/fileexchange/46523--utide--unified-tidal-analysis-and-prediction-functions

to determine the tidal constituents using an ordinary least squares (OLS) fitting method. This is made possible and reliable by having data for several complete lunar cycles, since the lunar cycle is the longest large periodic constituent. The UTide function outputs new speed data for the time range specified by the user, in this case 14 Sep 2016 through 13 Sep 2018, on 10-minute time steps.

Agreement of the modeled and measured speed data was found to be quite good with respect to flow timing and average speeds by using a training and test set. Precise values and short timescale variability (probably associated with turbulence in the tidal stream and highly location-dependent) were often not captured but are of little concern if a large array of tidal generators is to be deployed over a significant area, i.e., short timescale and short spatial scale turbulent features would average out over a generator array spanning hundreds or thousands of meters. The period of investigation includes the span of data measurement. For the analyses in this report only the modelled data was used to avoid minor discrepancies at the edge of the block of measured data and highly location dependent short-timescale features.

The principle measurement of interest to this study is the (directionless) horizontal speed of the flow at a fixed 20 m depth down from the free surface, emulating the resource available to a turbine mounted below a passively yawing floating platform.

The full two years of extrapolated in-stream tidal flow speed data was converted from speed to power using a power curve for the 4.0 m diameter rotor Schottel[8] turbine given in Figure 7. It was assumed that the turbines would always be perpendicular to the flow (passive yaw). The resultant capacity factor of the tidal time series is 50.2% (annual average power divided by rated power).

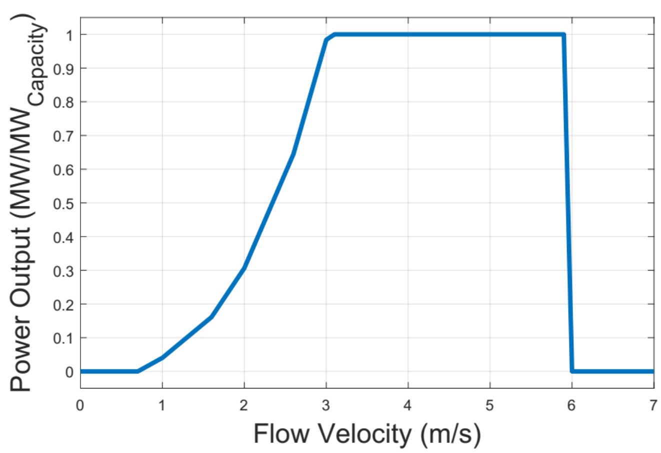

Figure 7 Normalized tidal turbine power curve from data published by Schottel[9] for their 4.0 m diameter rotor in-stream turbine

[8] https://doi.org/10.1016/j.ijome.2015.04.002
[9] http://www.blackrocktidalpower.com/fileadmin/data_BRTP/pdf/STG-datasheet.pdf

2.4 Load

Nova Scotia Power supplied the Nova Scotia electricity load data on 2-minute timesteps as shown in Figure 8. Public data on a 1-hour timestep is available[10]. Load during the heating season typically displays two peaks per day, one in morning and one in evening, with a flattening or moderate dip during midday and a low overnight. Nova Scotia is a winter peaking province due to the use of electric space heating and relatively low penetration rate of space cooling (i.e. air conditioning). Annual peak values of just over 2000 MW are achieved, with minimums of approximately 650 MW.

Data was down-sampled using averaging techniques to achieve a 10-minute timestep series.

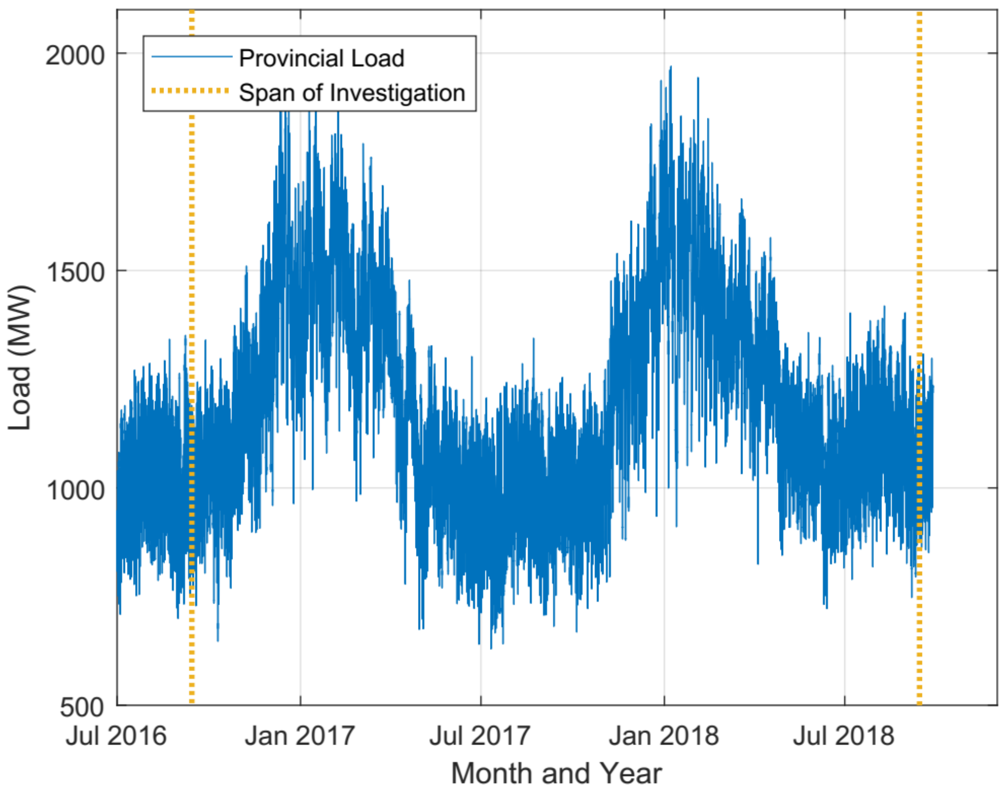

Figure 8 Provincial Load data

[10] http://oasis.nspower.ca/en/home/oasis/monthly-reports/hourly-total-net-nova-scotia-load.aspx

3 Modeling

Models of IG and ES were created in the software package Matlab. The code operates on time series arrays of resource data and in accordance with the parameters and governing control strategy. Scenarios are defined by the particular mix (proportional or absolute, depending on the model) of IG resources in use. The models execute each scenario in a loop and store the results for comparison.

3.1 Model layout

The model layout is similar for the two control systems. A graphical representation is shown in Figure 9. For the *Load-following* control strategy, only the black components are present. For the *DG-ramp* control strategy, the brown components (DG and associated power flows) are included. In both cases the model is composed of generation, storage, and load. Black and brown arrows show the power flow paths and proceed from generation on the left to load on the right.

The generation consists of two components, Intermittent Generation (IG) composed of wind, solar, and tidal, and Dispatchable Generation (DG) composed of thermal and hydro. Both the IG and DG can directly feed the Load. Alternatively, the IG and DG can charge the Energy Storage (ES); the latter is necessary when mitigating large negative ramp rates on the DG that occur when IG output rapidly rises (e.g. clouds expose the sun) or loads are falling. The ES can only discharge to the Load. Finally, if excess IG potential is available which cannot be used for the Load or to charge the ES, then it is curtailed. Curtailment means that the renewable resource goes uncollected and the potential is lost during that timestep. We assume the electrical transmission backbone and electrical substations can support the power flows around Nova Scotia between the IG, ES, DG, and Load.

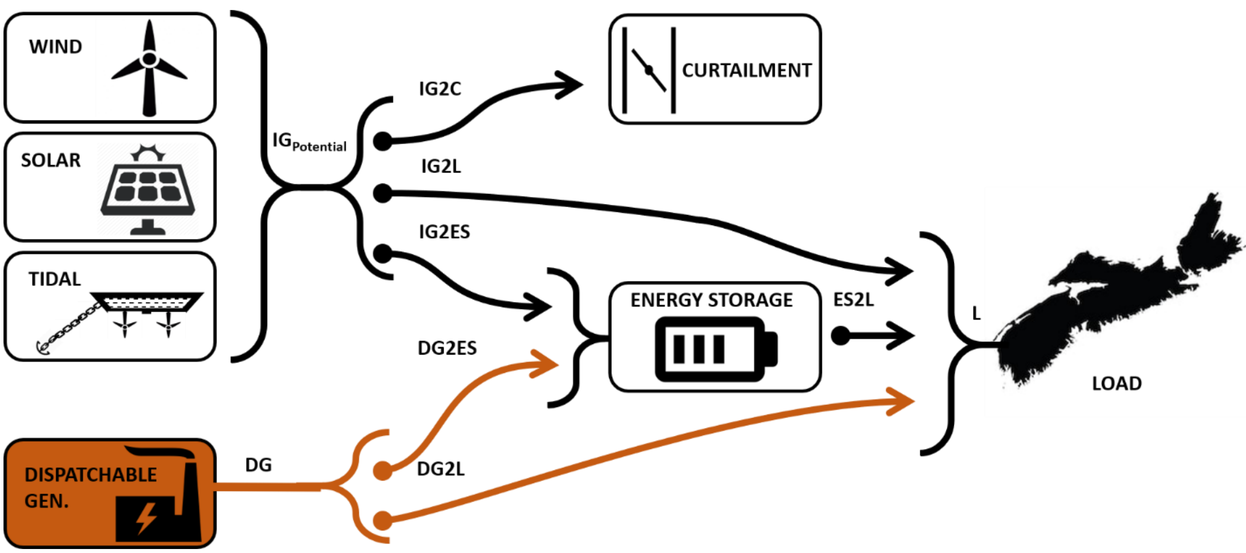

Figure 9 Schematic of model components for the DG-ramp-control strategy.

The model is data driven. The knowns for any timestep are the Load, L (MW) and the potential IG (MW) determined by the combination of resources being evaluated. Additionally, all values from the preceding timestep are known. The direction of the power flow arrows and their connections lead to governing equations. An example of the nomenclature used is IG2L, which is the power flowing from the IG to the L (Load).

The Load must be satisfied by generation and ES discharge:

$$IG2L + DG2L + ES2L = L \text{ (in MW)}$$

The IG flows must equal the potential:

$$IG2L + IG2ES + IG2C = IG_{\text{Potential}} \text{ (in MW)}$$

The ES system can be in only one of three modes during a timestep:

$$\begin{bmatrix} \text{Charge} & (IG2ES + DG2ES) > 0 \\ \text{Discharge} & ES2L > 0 \\ \text{Standby} & \langle IG2ES = 0 | DG2ES = 0 | ES2L = 0 \rangle \end{bmatrix}$$

Note that either ES2L or (IG2ES + DG2ES), or both, must equal zero in every timestep. The quantity of stored energy of the ES is equal to that in the previous timestep (time *t*-1) and the net exchange of power during that timestep (time *t*) multiplied by the appropriate efficiency Eff:

$$ES_{\text{Energy},\, t} = ES_{\text{Energy},\, t-1} + (IG2ES + DG2ES) \times \text{Eff}_{\text{Charge}} \times \Delta t - \frac{ES2L}{\text{Eff}_{\text{Discharge}}} \times \Delta t$$

Energy storage systems are not 100% energy efficient. The input charge energy is greater than the energy contained in the storage, and the contained energy is greater than the output discharge energy. A typical energy storage system receiving widespread deployment worldwide is a lithium-ion battery rated for 4 h discharge duration. We use the energy efficiency of a prototypical lithium-ion battery system in the model. The charge efficiency is a combination of the converter and the electrochemical battery and equals 92%. All electrochemical inefficiency is applied to the charge direction to aid in determining battery state-of-charge in the model. The discharge efficiency is only that of the converter and equals 96%. The product of these efficiencies gives 88%, which is the round trip energy efficiency of the ES and has been confirmed by several manufacturers' specifications.

The governing equations are insufficient to fully define all power flows. To accomplish this, a control strategy is applied. The control strategy prioritizes or alters certain power flows to achieve the objective, while observing the governing equations. Two control strategies are utilized, *Load-following* and *DG-ramp* control.

3.2 Load-following control strategy

Load-following is defined as the use of ES to smooth the combined output of wind, solar, and tidal, and to re-shape that smoothed output to vary according to the short time scale variations in the electrical load. The IG output can be directed to the load, used to charge the ES, or curtailed. DG is not included in the *Load-following* control strategy as it assumes that the existing DG is sufficient to makeup any deficiencies of the IG + ES; this is the present case in Nova Scotia.

The ES is operated such that the combined output of IG2L and ES2L (IG + ES) correspond to the smoothed aggregate IG "scaled" by the variability of the Nova Scotia electrical load about the similarly smoothed electrical Load. This is achieved by the following procedure:

1. **Instantaneous load is divided by smoothed load to produce a "Load Perturbation":** Smoothed provincial load is computed by first finding the average load in blocks of specified smoothing timescale and interpolating between those average values using piecewise splined quadratic

interpolation. The instantaneous timestep value of Nova Scotia electrical load is divided by the smoothed load to create a new *perturbation* signal.

2. **Smoothed IG output multiplied by *Load Perturbation* to create "Output" time series:** The smoothed IG resource is computed by the same procedure used to find smoothed load. Its timestep value is multiplied by the load perturbation timeseries of Step 1 to create a desired shaped IG + ES output.
3. **ES makes up difference between IG and Output:** The control signal to the ES is calculated by subtracting the instantaneous IG generation value from the shaped output curve. Positive values (overgeneration) result in charging of the ES or curtailment of the IG. Negative values result in discharging the ES.

The above methodology produces a scaled IG + ES output curve that follows the smoothed trends of the IG resource and load perturbations of the provincial load over the period of interest. By *scaled* we mean that the IG + ES output may meet a portion or fully meet the load, depending upon the magnitude of installed IG generating capacity. By *shaped* we mean that IG + ES output tends to peak locally when the load peaks, valley when the load valleys, and follows the other perturbations of load shape throughout the period of interest. The smoothing/shaping period ranges from the 1 hour up to the full two years of available data; using a two-year smoothing window makes the IG +ES behave like a dispatchable generator providing a fixed (arbitrary) proportion of the provincial load.

The above methodology is illustrated in Figure 10 for a 3-day smoothing/shaping period, with 7 days of data shown for clarity. The top plot shows the dynamic electrical load (blue solid) is smoothed over the 3-day period to a smoothed load (blue dashed). The smoothed load can be seen to rise throughout the week with the average load profile. Dividing the load (blue solid) by the smoothed load (blue dashed) produces the load perturbation signal (orange), which ranges ±20%. The IG will be shaped using this load perturbation signal.

Figure 10 bottom plot shows the IG resource (green dashed) is highly dynamic throughout the week and is smoothed over the 3-day period to a relatively constant smoothed IG (black solid) due to the lack of correlation between wind, solar, and tidal resources. The smoothed IG profile (black solid) is then multiplied by the load perturbation signal (orange, top plot) to create the desired IG + ES smoothed/shaped output (red dashed, bottom plot).

Close examination of Figure 10 shows that IG smoothing (black, bottom plot) is achieved, which in a practical sense would greatly reduce the power ramp rates imposed on the DG which makes up deficiencies. The IG shaping results in the IG + ES output (red dashed, bottom plot) exhibit diurnal variations similar to that of load, without trying to achieve very long duration storage, such as would be required to shape to the smoothed load (blue dashed, top plot). This means that the model relies on DG to makeup gross average power deficiencies, such as would occur during a cloudy windless several days.

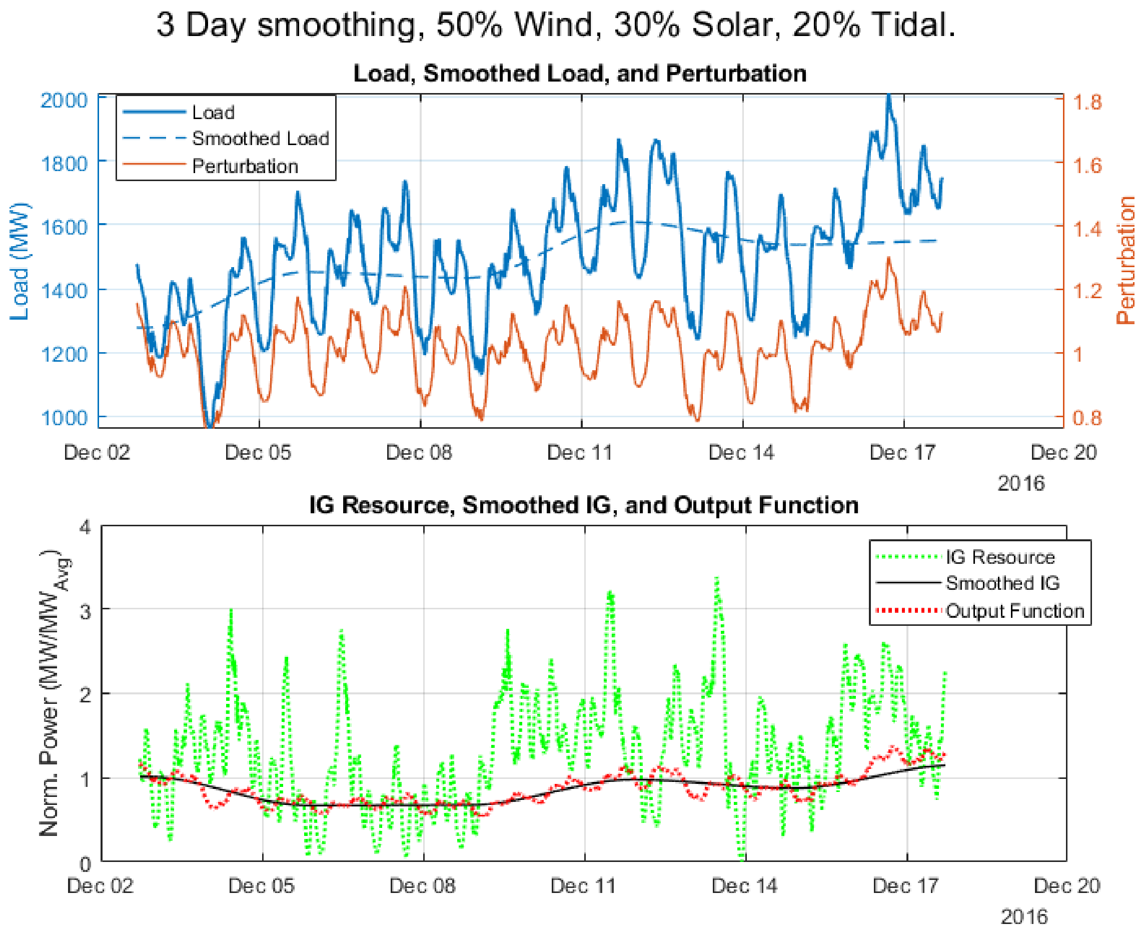

Figure 10 Example of the smoothing and shaping of the IG (bottom plot) to meet the dynamics of the load (top plot) This example is for 50% wind, 30% solar, and 20% tidal, with daily (3-day) smoothing.

The Load-following control strategy operates the ES in a "depletion mode". This means that the ES is initialized to a fully charged position. The final $ES_{\text{Capacity}} = -ES_{\text{Energy, min}}$. The ES capacity is necessarily very large for longer smoothing periods to avoid excessive curtailment of the IG.

Total system costs are calculated as the sum of installed IG capacity costs and ES costs (cost assumptions are presented in Section 3.4 on page 24). To minimize capital costs, curtailment of IG is allowed if it is more economic that purchasing increased ES capacity. To achieve this effect, the IG capacity is iteratively increased by a multiplier. The model is then re-executed to determine the new ES capacity, which will be reduced from previous iteration because of more IG resource potential; correspondingly the amount of IG curtailment will also increase. This process of increasing IG capacity, computing ES needs, and computing total capital costs is iterated until total capital costs stop decreasing with increased IG capacity.

The ES energy depletion strategy is shown in Figure 11 for an example of 50% wind, 25% solar, and 25% tidal IG capacities. The storage depletion begins at 0 and progresses downward (discharge) to smooth/shape the IG. Two IG overproduction values are shown in the top plot: 1.02 (orange, 2% overproduction) and 1.042 (blue, 4.2% overproduction). It is evident that the blue ES energy depletion line stays higher than the orange due to increased IG capacity. Importantly, this also reduces the quantity of ES required (seen from the increased minimum value of the blue line relative to the orange line). It often reaches zero energy depletion, at which point IR curtailment occurs (bottom plot). Each unique proportioning and smoothing/shaping period has a different result.

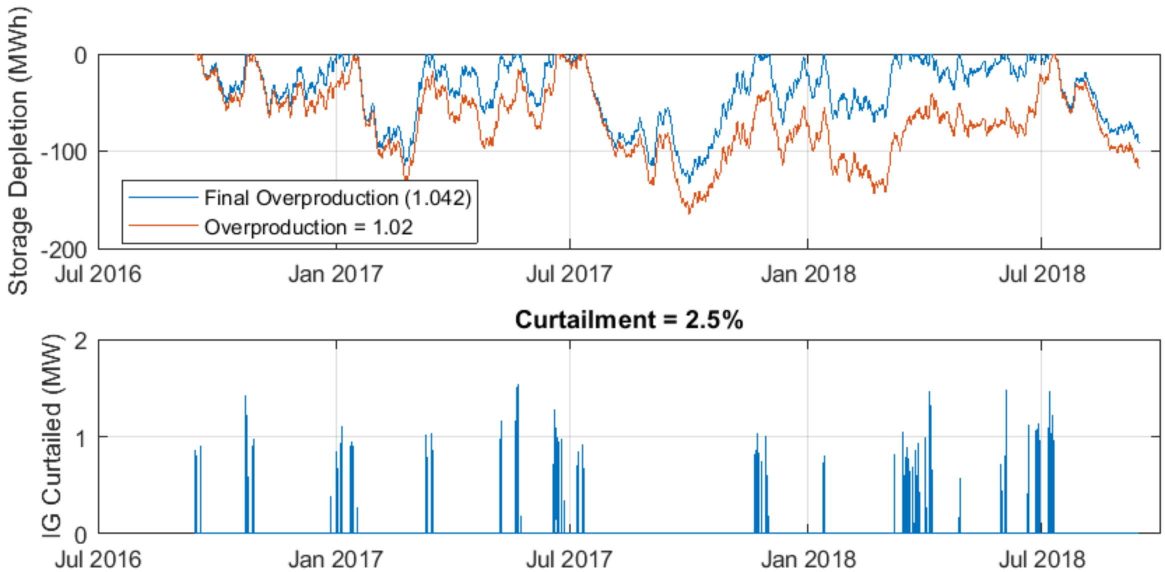

Figure 11 Increasing 'Overproduction' effectively inclines the storage depletion timeseries curve. Where storage hits 0 (fully charged) IG curtailment occurs. Overproduction is incremented by 0.001.

The results of this iterative process are shown in Figure 12 for a representative system, and clearly identifies apex points that minimize ES without causing gross IG curtailment. Using this Load-following control strategy a broad range of IG proportions can be tested. And each of these is unique to the smoothing duration specified (1 hour to 2 years). The output of this model and the control strategy is the necessary quantities of IG generation ($MW/MW_{AvgOutput}$) and maximum storage depletion encountered during the 2-year modeling period, which dictates the ES_{Capacity} (MWh) specific to the generation mix and smoothing period. These values are then multiplied by the capital cost (Section 3.4, page 24) and summed to create a total IG + ES capital cost. Finally, results of each IG proportion scenario and smoothing/shaping period are presented based on the least capital cost optimization, which can trade increased IG capacity (and curtailment) for reduced ES capacity if it is more economic.

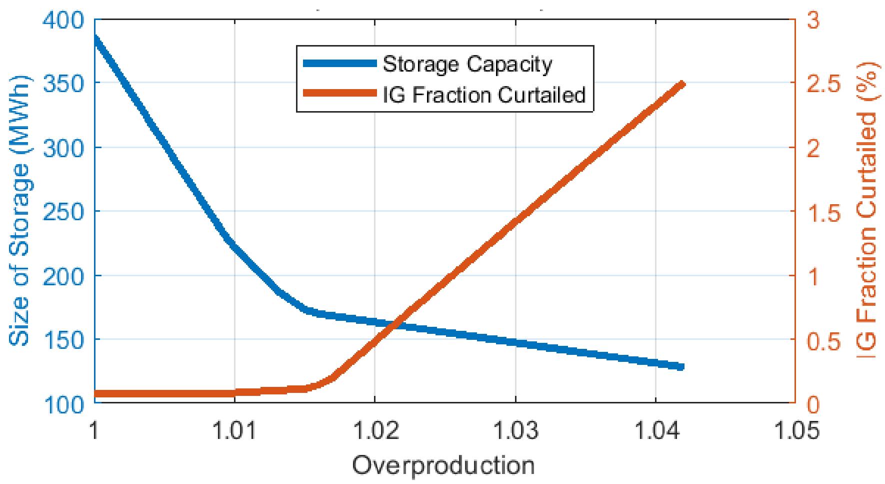

Figure 12 The 'Overproduction' parameter is incremented up for each combination of IG until the spilled fraction reaches 2.5%. This example is for 50% wind, 25% solar, and 25% tidal, with seasonal (3-month) smoothing.

3.3 DG-ramp control strategy

The worst ramp rates (MW/minute) of DG are increased by adding the uncorrelated ramps of IG output to the existing ramps in Load. An example is a condition in which load is increasing while IG power is decreasing. In this case the output of the DG must ramp up to higher power quickly, at a rate which may be above its limits, otherwise a brownout/blackout will occur. Alternatively, load can be decreasing while IG output increases, requiring the DG to ramp down quickly. This situation is very inefficient for DG, can reduce its output below contingency levels, or result in curtailment of IG.

Setting hard limits on the maximum allowable ramp rates of DG provides the basis for a DG-ramp-control strategy. This model requires incorporation of existing changes in Load, so the two years of Load data are used, and the absolute power scale of the investigation is dictated.

The rapidity with which DG can increase or decrease their output to accommodate variations in IG and Load is critical to the operation of the system. To determine the ability of existing DG in Nova Scotia to ramp their output, the provincial-level aggregated load and existing wind IG data were used. By subtracting the wind IG from the provincial load, an historical record of the “net load” supplied by DG was created. Historical solar and tidal output was neglected as being a very small component of historical generation. A scatterplot of this historical DG ramp rate signal as a function of net load is shown in Figure 13.

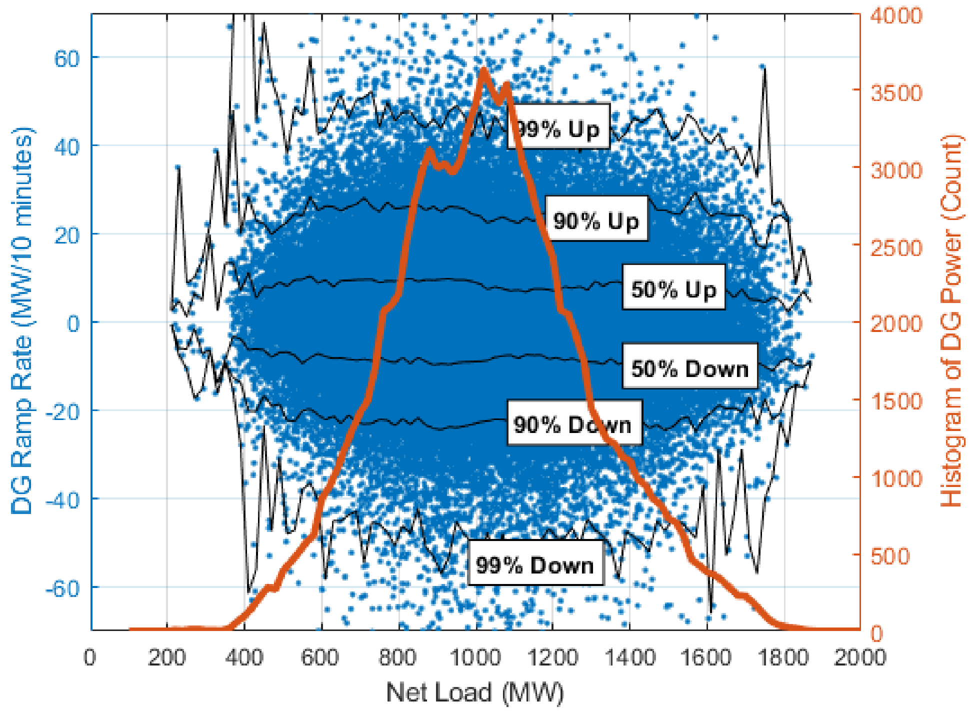

Figure 13 Generation ramp rates (MW/10-min) as a function of quantity of generation (MW)

The blue dots in Figure 13 shows individual 10-minute data points of DG ramp rates (ΔMW per 10-minutes) on the primary y-axis vs. Net Load (MW) on x-axis for the 105,000 points of data in the study period. Additionally, black lines corresponding to the 99th, 90th, and 50th percentile ramps up and down are shown. The overall histogram of levels of net load is shown by the orange line, read on the secondary y-axis. Figure 13 suggests that the ability of the existing system to ramp is largely not a function of how much load is on the system, suggesting that specific thermal generators or hydro is conducting the large ramps.

It was determined from Figure 13 that limiting DG ramps to ±50 MW per 10-minute period lies within the 99th percentile and represents nominal operating envelope of the existing DG. This means that the control strategy makes power ramp-rates imposed on the DG less than they are today, which is conservative and accounts for short-term DG retirements which reduce ramping ability.

The DG-ramp control strategy operates to keep the DG ramps within ±50 MW per 10-minute period using the following procedure:

1. **Energy storage is initialized** to neutral energy position (zero). It can then range positive (charged) and negative (discharged).
2. **ES operations are determined in response to the IG and DG generation and Load**, insuring that loads can be met while keeping DG ramp rates within the limit of ±50 MW per 10-minute period. For example, if Load is increasing and IG is decreasing, the ES will discharge. Alternatively, if Load is decreasing and IG is increasing, the ES will charge to absorb the difference.
3. **DG output is ramped within its envelope** in an attempt to return the ES to a neutral energy state. This best prepares the ES to respond to the next ramp event by having maximum charge

or discharge capability. Note that DG is <u>not</u> ramped to account for imbalance between Load and IG.

The DG is ramped within an envelope using a proportional-derivative controller, with a map arrived at through trial and error given in Figure 14. This is a two input (four-quadrant) DG-ramp control method by which the DG ramp rate is decided based upon the immediate past ES_{Energy} and the present net charge or discharge rate of the ES. As can be seen in Figure 14, the DG ramp is limited to ±50 MW per 10-minute period and is reduced in magnitude as the ES approaches the energy neutral position.

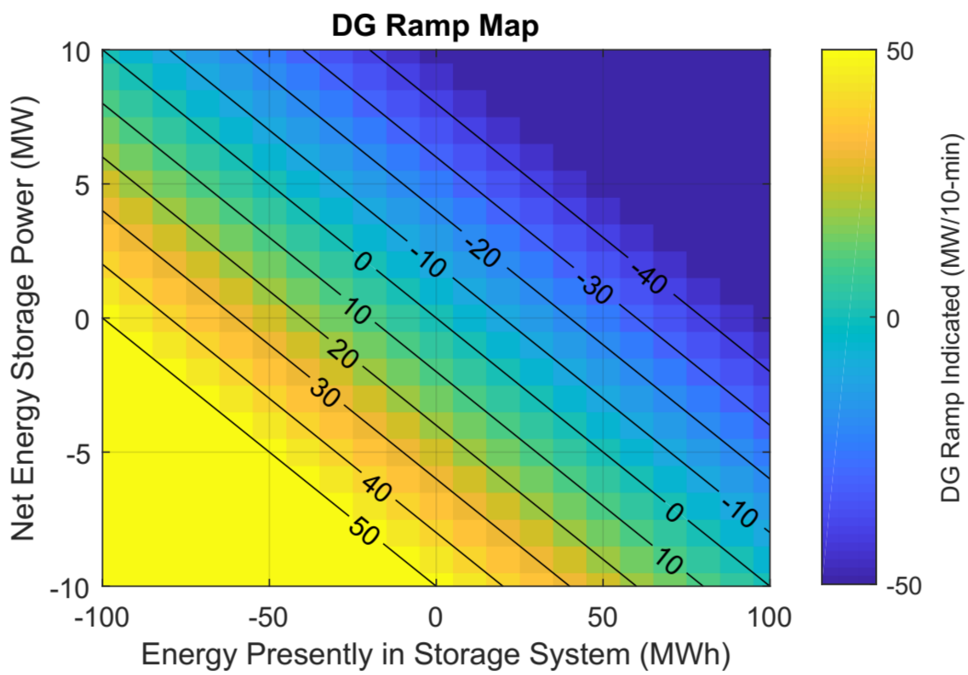

Figure 14 The DG-ramp control strategy uses a proportional derivative response map, using the quantity of energy in storage and the rate at which the storage is filling / emptying to determine how to ramp the DG.

The net effect of the DG-ramp control strategy is as follows:

- IG output goes to Load first, subject to minimum turn-down ability of the DG.
- Any remaining IG goes to ES, provided ES is at below nominal (0) state of energy.
    - If the ES is above nominal state of energy, additional IG is curtailed.
- Any remaining Load is met with the ES (no ramp or power limit)
- The DG responds by attempting position the ES to the neutral energy position by ramping up or down
    - DG output is capped at instantaneous Load to avoid necessitating increased DG capacity due to ES management

The output of this model and the DG-ramp control strategy is the maximum positive and negative stored energy deviations of the ES, specific to each quantity of installed IG type. The final required capacity of the ES system is the difference between maximum and minimum values: $ES_{\text{Capacity}} = ES_{\text{Energy, max}} - ES_{\text{Energy, min}}$.

3.4 Capital cost

One metric of evaluation is total system capital cost. Assumed installed costs of each system component (three IG types and storage) are provided to the model for evaluation of total system capital cost as a function of capacity of wind, solar, and tidal, along with the size of the ES.

The following industry standard Canadian dollar (CAD) values are used:

- Wind \$2.2M/MW_{rated} (based upon[11])
- Solar \$1.8M/MW_{rated} (based upon[12])
- Tidal \$5.0M/MW_{rated} (based upon average of the widely varying [13],[14],[15])
- Lithium-ion batteries \$0.54M/MWh (based upon[16])

A simplified capital cost assessment is completed to create an additional metric and provide guidance on total IG + ES installed cost "order-of-magnitude". Additionally, this installed cost value is divided by the energy produced over an assumed 20-year operating lifetime to determine one cost component of the effective electricity rate in \$/MWh produced by the IG + ES system. A detailed costing study or lifetime cost of electricity analysis (including borrowing, profit, O&M, and decommissioning) is not completed.

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[12] Fu R, Feldman D, Margolis R, Woodhouse M, Ardani K. U.S. Solar Photovoltaic System Cost Benchmark: Q1 2017 . NREL 2017;NREL/TP-6A20-68925. https://www.nrel.gov/docs/fy17osti/68925.pdf

[13] Allan G, Gilmartin M, McGregor P, Swales K. Levelised costs of Wave and Tidal energy in the UK: Cost competitiveness and the importance of "banded" Renewables Obligation Certificates. Energy Policy 2011;39:23-39. https://doi.org/10.1016/j.enpol.2010.08.029

[14] Segura E, Morales R, Somolinos JA. Cost assessment methodology and economic viability of tidal energy projects. Energies 2017;10:1806. https://doi.org/10.3390/en10111806

[15] TidalStream Limited. Costs. 2018. https://web.archive.org/web/20180814043127/http://www.tidalstream.co.uk/Costs/costs.html

[16] Energy Information Administration U. U.S. Battery Storage Market Trends. 2018. https://www.eia.gov/analysis/studies/electricity/batterystorage/

4 Results and parametric analysis

The range of IG capacity proportions (Load-following control) or installed IG capacities (DG-ramp control) is parametrically evaluated using the models and the resultant metrics of ES capacity, total capital cost, proportion of load serviced by IG, and curtailment of IG are given. Results are presented separately for the two control strategies. Example timestep results are given to illustrate model logical decision making. Results and sizes are then given based on the performance throughout the entire 2-year data period.

4.1 Load-following control

In Load-following control, all parameters are normalized by the average smoothed output of the combined IG+ES system ($MW_{AvgOutput}$). The installed capacity ($MW/MW_{AvgOutput}$) of each IG type (wind, solar, tidal) is calculated to produce the average output ($MW_{AvgOutput}$) based on the 2-year capacity factors of each resource. For example, in a 100% tidal scenario, if tidal has a capacity factor of 50.2%, then 2 MW of tidal capacity will be required to produce 1 $MW_{AvgOutput}$ of the IG + ES. If solar has an average capacity factor of 14%, then in a 100% solar scenario 7 MW of installed solar capacity will be required to produce the same 1 $MW_{AvgOutput}$ of the IG + ES. These are initial estimates and both quantities are subsequently adjusted by the ‘Overproduction’ parameter, to compensate for energy consumed by round-trip-inefficiency of the energy storage system.

The parameterization of the different IG types is thus constrained to a scale of 0 – 100% for each resource, as indicated in Table 1.

Table 1 Parameterization of relative quantities of Wind, Solar, and Tidal capacity for Load-following

Evaluation Matrix	Min Proportion Value	Max Proportion Value	Annual Capacity Factor
Wind	0%	100%	37.4%
Solar	0%	100%	14.4%
Tidal	0%	100%	50.2%

4.1.1 Load-following timeseries results

An example result for the Load-following control strategy is shown in Figure 15. This is for IG consisting of 50% wind, 30% solar, and 20% tidal with a 6-hour smoothing as described in section 3.2. A five-day period of operation is shown to illustrate various occurrences and includes Mar 7 where the ES capacity is set (the most energy depletion).

Figure 15 [A] shows the IG resource (green) which is smoothed (black) and then shaped (red) to match load. Each midday experiences a significant IG peak caused by solar generation. Because the output function is shaped at short time scales to load fluctuations; a double peak can be seen on Mar 6, and evening peaks can be seen on most days. If the smoothing/shaping period is reduced (e.g. 1 hour) the output is shaped more like the IG resource; if the period is increased (1 day) the output is shaped more like the load. This is because the IG resource varies significantly over short timescales (minutes, hours) while the load varies diurnally with a morning and evening peak. Therefore, the choice of smoothing/shaping duration is a matter of focus/scope. <u>The choice of short durations (hours) mitigates power variability in IG for electricity system control purposes. The choice of longer durations (days) seeks to supply the load's energy needs using IG.</u>

Figure 15 [B] shows that the output (red) is met in-part directly from IG (green) and in-part from the ES discharging (blue). Over the two-year period 91% of the IG goes directly to the output, with the balance charging the ES and being released at a later time. The ES is discharging principally in the morning, evening, and overnight periods, and does not discharge midday because of the solar power (as it is charging, see plot [D]). <u>The choice of IG proportions strongly affects the ES operations (charge, discharge, standby) with respect to time of day due to the significant IG resource dynamics (e.g. solar requires charging during daytime). Load has a much less dramatic influence on ES operations with respect to time of day.</u>

Figure 15 [C] shows the components of the IG resource (green dotted). The directly used IG output (light green solid) constitutes the majority. A portion goes from IG to ES for charging (plus signs) and some IG is curtailed (dark green solid). Charging of the ES principally occurs in the morning due to solar, although it also occurs in other periods due to ramp-up of wind and tidal. IG curtailment occurs in the afternoon and reduces as the sun sets. Note that charging and curtailment are exclusive; this is because the ES power is not limited. This is reasonable because the ES size in MWh/$MW_{AvgOutput}$ is large (see energy depletion of Plot [D]). Overall the curtailed fraction for the two-year data period is 1.3%. <u>In general, most of the IG either directly supplies load or is curtailed; with only a smaller proportion passing through the ES regardless of size of smoothing/shaping duration.</u>

Figure 15 [D] shows ES operation composed of positive charging power by IG to ES (green), negative discharging power to load (blue solid) and the integrated energy depletion position (blue dotted, secondary y-axis) caused by the net charging and discharging. Charging is exclusive to discharging. Energy depletion becomes more positive when charging and more negative when discharging. Near midday the energy depletion reaches zero, at which the ES is fully charged, goes into standby mode, and IG curtailment occurs. The lowest energy depletion of the 2-year data period occurs on Mar 7 at -3.9 MWh/$MW_{AvgOutput}$ (red circle). Because the total ES operating span is 3.9 MWh, this is the necessary rated capacity to support the smoothing and shaping of IG to achieve an annual average 1 $MW_{AvgOutput}$ that is shaped to load. Because the ES charging and discharge power reaches maximum values of

±1MW/MW, this ES would be referred to in the energy storage industry as a “4-hour energy storage system” (4 $MWh_{capacity}$ / 1 $MW_{power\ rating}$ = 4 $hour_{ES\ system}$).

The results of Figure 15 [D] indicate that the ES is “exercised” by cycling a significant amount (~50% capacity) each day during this period, equal to hundreds of cycle-equivalents per year. Shorter smoothing/shaping periods will cause greater cycle-equivalents of the ES and longer periods will cause less. The uncorrelated nature of the three IG resources (wind, solar, tidal) and their coincidence with Nova Scotia electrical load are such that 6 hour smoothing and shaping can be achieved by a “4 hour” ES system. The results presented in Figure 15 are valid only for this IG proportioning scenario over the 6-hour smoothing and shaping period. A broad range of proportions and periods were analyzed and each produced timestep results similar to Figure 15, but for the complete 2 years of data. The summary results of these parametric variations are presented in the following section.

[A]

[B]

[C]

[D]

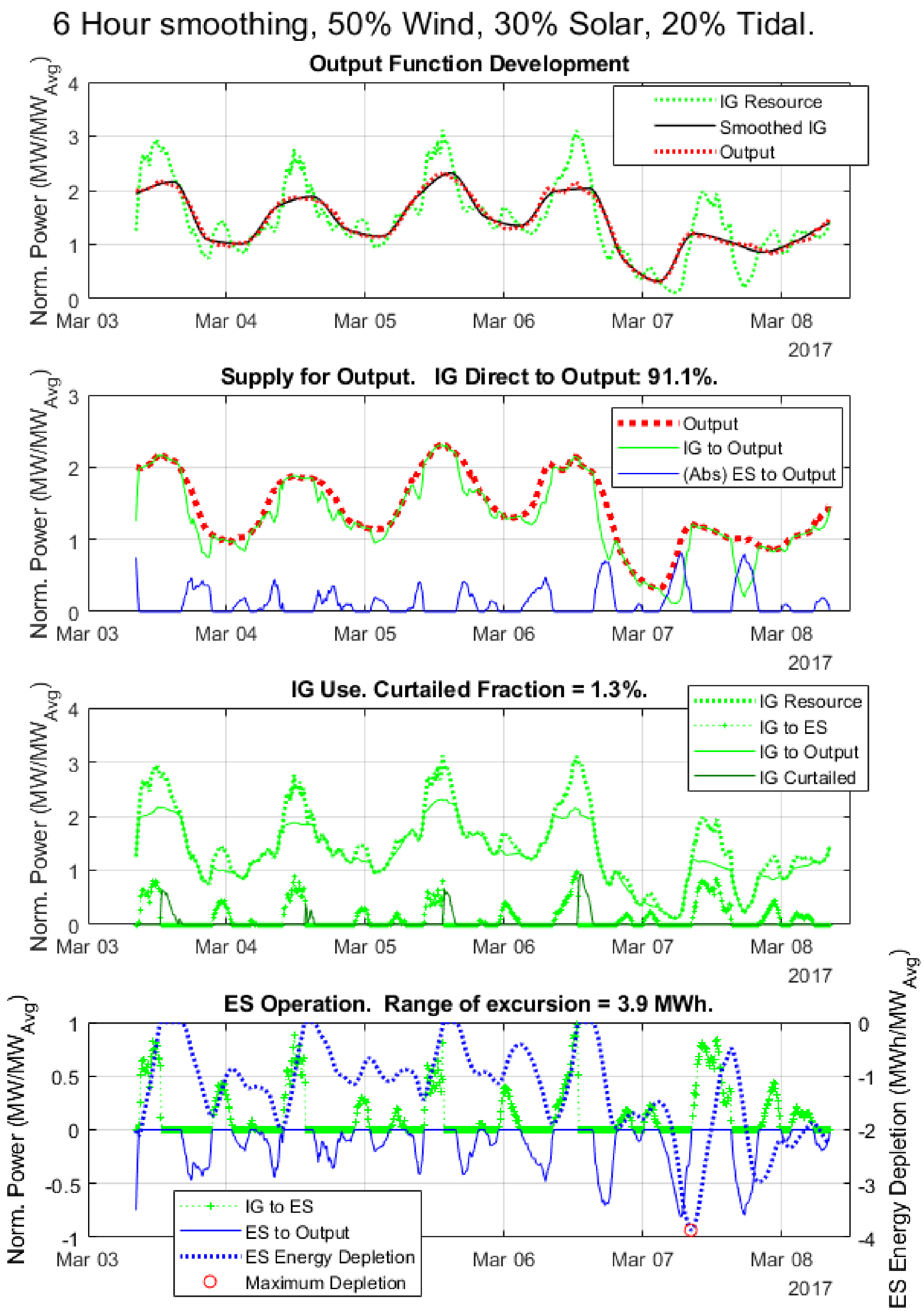


Figure 15 Timeseries of Load-following control the scenario of 50% wind, 30% Solar, 20% Tidal with a 6-hour smoothing/shaping

4.1.2 Load-following performance metrics

Representative results of *Load-following* are shown in Figure 16 for a 3-hour shaping period. All parametric results for this shaping period are shown on the plots. The following is a description of the charts and how to interpret them.

- Triangle [A] gives the installed IG capacity (MW_{rated}) per average power output ($MW_{AvgOutput}$) as a proportion between wind in green (left, 100%), solar in red (top, 100%), and tidal in blue (right, 100%).
- Triangle [B] gives the curtailment of the IG generation in percent of total generation potential. Such energy is not collected/used and is an economic trade-off between greater installed IG capacity (MW) and greater installed ES capacity (MWh).
- Triangle [C] gives the necessary storage capacity (MWh_{rated}) to achieve the smoothing and shaping for each of the IG capacity proportions, including 88% round-trip energy efficiency which is typical of lithium-ion batteries.
- Triangle [D] gives capital cost of the IG + ES system based on industry standard Canadian dollar values: wind \$2.2M/MW_{rated}, solar \$1.8/MW_{rated}, tidal \$4.6/MW_{rated}, and lithium-ion batteries \$0.54M/MWh.

All locations within a triangle produce the same annual average output to service the Nova Scotia electrical load. The corresponding location within each of the triangles identifies the IG capacities, IG curtailment, ES capacity, and capital cost for that solution. Each solution can be parametrically compared to others by choosing another position in the triangle. Iso metric lines are drawn within each triangle to help identify patterns and optimal IG proportions for each metric.

An example of a single solution is shown in Figure 16 as an orange circle with annotations. The orange circle lies at a proportioning of 30% wind, 40% solar, and 30% tidal by energy production based on capacity factor. The percentiles are the evenly spaced dashed black lines, with each line corresponding to a 10% change. Starting at triangle [A] and at the lower left corner (100% wind) we proceed 7 dashed black lines away, deducting 70% from 100% to arrive at 30% wind by energy. The same is done for solar and tidal. All positions within the triangle add up to 100% of energy production when combining the IG capacity of wind, solar, tidal. Also shown on triangle [A], the green (wind) isometric lines surrounding the orange circle are 0.5 and 1.0 MW/$MW_{AvgOutput}$ with the circle at 0.8 of wind capacity. Solar (red) is 2.0 and tidal (blue) is 0.6. This combination of 0.8 + 2.0 + 0.6 = 3.4 MW total installed capacity (combination of wind, solar, tidal) is necessary to achieve an annual average of 1.0 MW power output.

Continuing the example, triangle [B] has an orange circle placed at the same IG proportions. It indicates that very little IG energy is curtailed, approximately 0.6%. The conclusion is that at the 3-hour smoothing/shaping period the economics support increased energy storage rather than increased IG capacity (and consequently greater curtailment). The orange circle in triangle [C] surrounds isometric lines of energy storage capacity of 2 and 3 MWh/$MW_{AvgOutput}$ with the circle at 2.5. This means that a total system composed of 0.8 MW wind, 2.0 MW solar, 0.6 MW tidal, and 2.5 MWh of energy storage is necessary to achieve a 3-hour smoothed and shaped profile that produces an annual average 1 MW output. Triangle [D] also has the orange circle and identifies that the capital cost of the IG + ES system equals \$11 million per MW average output. It is this capital cost minimum for these IG capacity percentages that set the IG installed capacity and the ES capacity values.

The black isometric lines presented in Figure 16 plots [B], [C], and [D] aid in identifying optimal technical and economic proportions of IG + ES. Note this example is for 3-hour smoothing and shaping.

- Technical example: Triangle [C] indicates that an ES capacity minimum of 1.5 $MWh/MW_{AvgOutput}$ or less exists when IG proportions are 50% wind, 0% solar, and 50% tidal. Increasing proportions from that point, especially toward solar would require significant additional ES capacity for smoothing and shaping. Referencing the Triangle [A], this energy storage minimum would require 1.3 $MW/MW_{AvgOutput}$ wind and 1.0 of tidal. Referencing the Triangle [D], this energy storage minimum would require a total IG + ES capital cost of $11 million per $MW_{AvgOutput}$.
- Economic example: Referencing the Triangle [D] indicates a capital cost minimum occurring at 100% wind, 0% solar, 0% tidal, with a total value less than $8 million per $MW_{AvgOutput}$. Referencing the Triangle [A], this minimum cost requires wind capacity of 2.5 $MW/MW_{AvgOutput}$ of wind, and referencing the Triangle [C], this minimum cost requires ES capacity of 3.0 $MWh/MW_{AvgOutput}$.

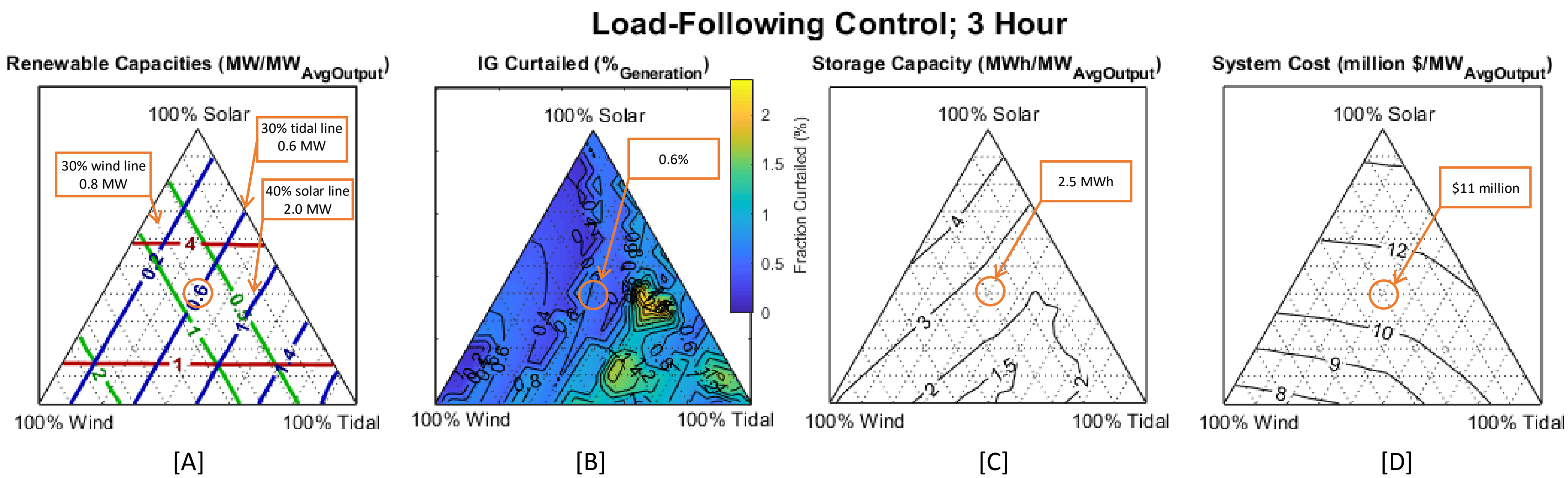


Figure 16 Example of Load-shaping results for 3-hour period

Each unique Load-following control smoothing and shaping period produces a group of triangle solutions. These are presented in the following figures and are grouped according to duration:

- Hourly results are presented in Figure 17 for smoothing/shaping durations of 1, 3, and 6 hours. <u>These periods are pertinent to ramp-rate compensation and short-term electricity generation planning from specific generators</u>. They are principally influenced by dynamic output of the IG resources.
- Daily results are presented in Figure 18 for smoothing/shaping durations of 12 hours, 1 day, and 3 days. <u>These periods are pertinent to day-ahead electricity planning</u>. They are principally influenced by the dynamic load profile with respect to peaks and valleys occurring each day.
- Monthly results are presented in Figure 19 for smoothing/shaping durations of 1 month, 3 months, and 2 years. <u>The periods are influenced by seasonal load and IG resource variations and represent seasonal storage results</u>. In particular, the 2-year smoothing/shaping period represents annualized storage where the IG + ES output is shaped exactly to load.

A review of the results from these 3 time period groups show significant evolution of results with respect to technical and economic optimums. These are discussed with respect to each metric individually, and the reader is encouraged to review the vertical column of triangles for the same metric across the significant range of smoothing/shaping durations.

The **necessary installed IG capacity** ($MW/MW_{AvgOutput}$) to achieve proportions of energy production (left most triangle in figures) shows consistent values for hourly shaping. This is because each IG resource varies considerably in these periods and the dynamic nature is statistically diverse throughout the years of data. Additionally, the energy passing through the ES is only a small portion and so the impact of its inefficiency is minimal. Maximum installed capacity values for hourly shaping are approximately 2.3, 5.0, and 1.9 $MW/MW_{AvgOutput}$ for wind, solar, and tidal, respectively for 100% proportions of each, and are principally a function of their capacity factor. Values of installed capacity when distributed across multiple resources (to total 100%) are less due to the individual resource contributions.

For daily shaping periods, the installed IG capacity lines are no longer straight and are increased compared to hourly. This is because each resource varies considerably over several days, and groups of days might very different from one another. Additionally, there is more substantial curtailment. This is especially apparent for wind, where the resource may be full power or zero power for many days on end; solar and tidal do not experience such trends. As the shaping period increases from days to months the necessary IG capacity ($MW/MW_{AvgOutput}$) increases substantially, with maximums at 8, 20, and 4 $MW/MW_{AvgOutput}$ for wind, solar, and tidal, respectively at 100% proportions of each. This is principally because significant amounts of IG are curtailed and to a lesser extent because more energy is passing through the ES system, which has inefficiency. It is exaggerated for solar because generation is only available during daytime and it must rely extensively on the ES at nighttime if it is the dominant IG resource.

<u>The IG Capacity results</u> allow for calculations of installed IG capacities across the three resource types to achieve a annual average power output. It suggests that when smoothing/shaping IG to precisely meet load (2-year), installation capacities must be 2-4 times and include ES compared to that of installations with no smoothing/shaping, which is essentially what is done in Nova Scotia today. This may be interpreted as requiring between 2-4 times the land or water area for wind turbines, solar panels, or

tidal turbines. In the case of wind, it could alternatively mean 2-4 times the size of wind turbine rotor swept areas which is the direction this market is headed.

The **curtailment of IG** (%) is very low at hours of smoothing/shaping (triangle second from left in the figures). The use of ES for hours duration is economic compared to installing additional IG capacity and this mitigates curtailment, which is limited to a few percent. Wind and solar show the least curtailment at the hours level, due to high variability (wind) and longer cycling period (solar). Although wind may be high power for days on end, this occurs infrequently and so does not contribute greatly to the overall percentage. Tidal shows the greatest curtailment, reaching a few percent, at the hours level because of its consistent use of storage throughout the 4 tidal generating cycles per day.

At the daily smoothing/shaping periods, curtailment is also low for a single resource dominated proportioning. A dramatic increase in curtailment occurs for the 3-day period. This is because that period is well beyond the normal cycling frequency of all resources and is heavily reliant on ES to buffer over long periods. Consequently, the model results show that it is more economic (lower capital cost) to install additional IG capacity than ES, which leads to high percentages of curtailed IG. At the monthly smoothing/shaping period the IG curtailment is in excess of 50%. This demonstrates the degree of difficulty in achieving seasonally averaged generation or seasonal energy storage. The Nova Scotia electrical load in summer is approximately 2/3 the value in winter. Combining this load characteristics with greater summertime solar production leads to high curtailment when smoothing/shaping over months duration. At such timeframes wind and solar experience about 50% greater curtailment than tidal because the tidal lunar cycle is approximately 1 month and is shorter than the smoothing/shaping period. This positions tidal best for longer term seasonal storage with least curtailment.

The IG Curtailment results suggest that renewable energy project developers can expect minimal curtailment as each resource is advanced if focus is maintained on hourly energy deliveries. If focus is placed on longer periods, or seasonal storage, even with the use of ES, a project may only deliver half the energy that it could potentially deliver. Interestingly, this enables the option of installing further ES in the future at lower capital costs and reducing the curtailment amount at that time.

The **necessary energy storage capacity** ($MWh/MW_{AvgOutput}$) to achieve the smoothing and shaping effect (triangle second from right in figures) is linearly related to the shaping period at the hourly level. This equals essentially one MWh of storage capacity for each hour of shaping (per $MW_{AvgOutput}$). This corroborates the industry standard of using 4-hour storage for peak shaving needs, with peaks often lasting 2-4 hours.

As the shaping period is extended to days and months the ES capacity asymptotically approaches a maximum value. This is because of the different cyclic times of the IG resource (wind = weather system; solar = daily and seasonal; tidal = 6 hour and lunar) which constructively complement each other to cause an advantageous averaging effect. Additionally, at longer durations it appears that greater installed IG capacity and the use of curtailment is more economic than increased capacity of ES. This is because the effective utilization of the ES decreases as its size increases; in other words, larger ES capacity may only be called on once or twice per year and remain underutilized the rest of the year.

The asymptotic results of ES capacity are unique to each resource. Overall an optimum of 10 $MWh/MW_{AvgOutput}$ appears for longer duration shaping for tidal. This is because tidal consistently experiences a 6-hour generating cycle (tide cycle is 12 hours). This consistency of tidal is very advantageous at reducing the necessary ES capacity, especially when compared to wind and solar. For long duration shaping, a value of 40 MWh/$MW_{AvgOutput}$ appears for a wind dominated system, and 80 MWh/$MW_{AvgOutput}$ for a solar dominated system. This indicates that in absence of tidal, wind IG seasonal storage requires approximately half the storage capacity of solar.

These ES Capacity results suggests the immediate addition of energy storage to achieve hours of smoothing/shaping is the economic solution compared with additional installed IG capacity. Such smoothed/shaped IG would likely integrate well with the electricity grid and not cause control issues. However, when smoothing for days/months, greater emphasis should be placed on additional IG capacity and the use of curtailment. This solution for days/months is presently advantageous because the IG capacity can be put in place and curtailed, and if/when cheaper energy storage become available, it can be added to mitigate that curtailment in the future. This extra IG capacity also supports future electrical load growth such as heat pumps, electric vehicles, and overall increased electrification of energy end-uses.

Capital cost also evolves with respect to optimum as the shaping period is increased (right triangle of the figures). For hourly periods, wind + ES requires least capital cost per output, even though the ES capacity is larger. This is because the wind resource of Nova Scotia is very good, and it has achieved economies of scale with respect to manufacturing/installation pricing. The capital cost of hourly wind + ES shaping is \$7 million / $MW_{AvgOutput}$. This is a premium of approximately 20% over conventional wind installations.

At hourly shaping periods, tidal + ES costs approximately 50% more than wind + ES, and solar + ES is approximately twice that of wind + ES. A transition occurs when shaping over days, with tidal + ES being least capital cost. This is principally because tidal has higher capacity factor and requires less energy storage size due to its consistency. Longer duration shaping using tidal + ES rises to approximately \$20 million / $MW_{AvgOutput}$, about three times the price of wind IG electricity today.

The Capital Cost results suggest the continued installation of wind capacity with the inclusion of ES will meet short term smoothing/shaping objectives and add to the renewable electricity content in Nova Scotia. As the focus shifts to much higher renewable electricity penetration rates, with correspondingly longer smoothing, the consistent cycling of tidal becomes a more economic choice when combined with ES. Large scale solar with ES struggles to compete with these other resources due to its lower capacity factor and reliance on significant quantities of ES capacity to time-shift electricity to overnight periods.

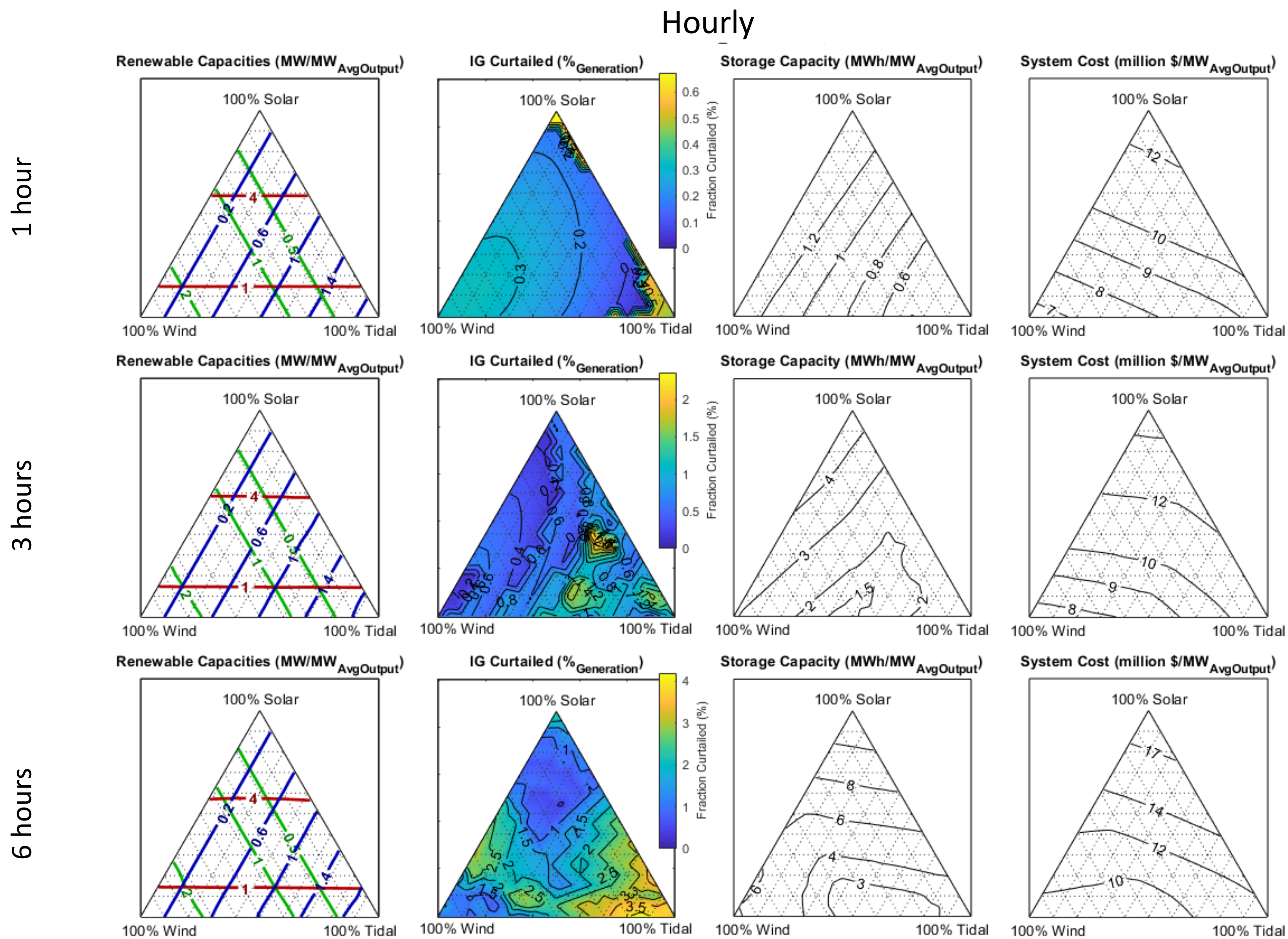


Figure 17 Load-following control results for hourly smoothing and shaping periods (1, 3, 6 hours)

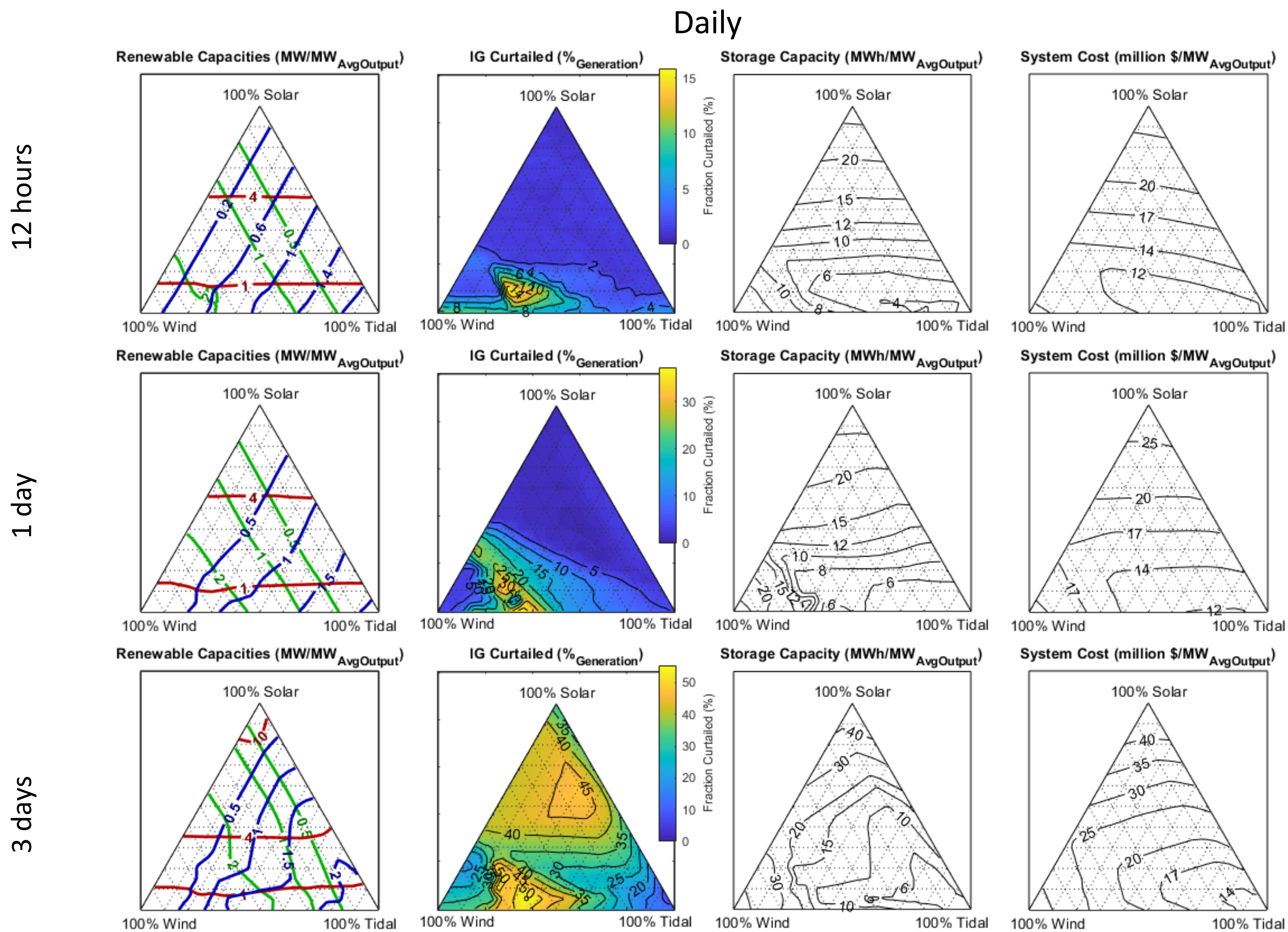


Figure 18 Load-following control results for daily smoothing and shaping periods (12 hours, 1, 3 days)

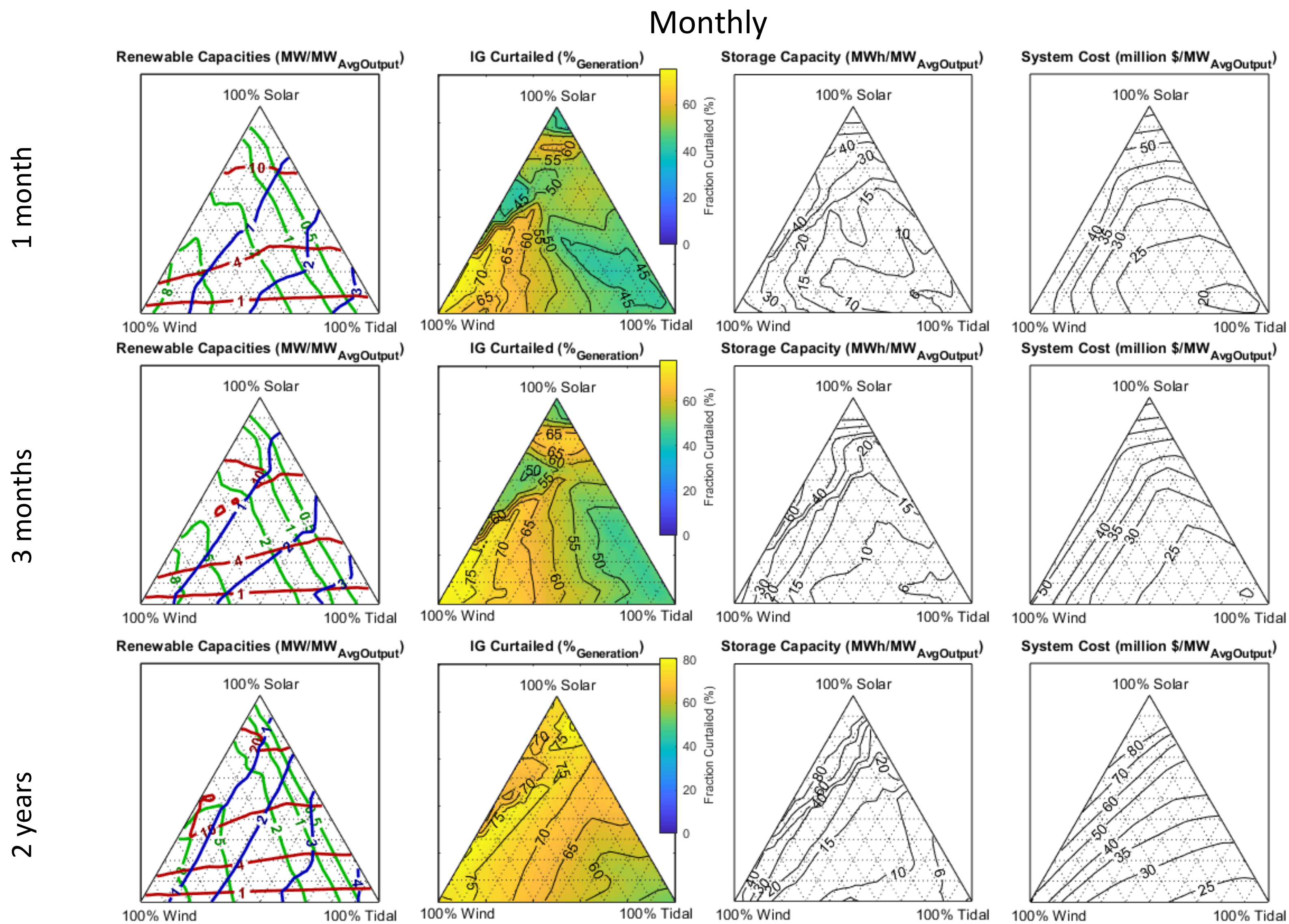


Figure 19 Load-following control results for monthly smoothing and shaping periods (1, 3 months, 2 years)

4.2 DG-ramp control

In the DG-ramp control strategy, all parameters must be maintained in normal units of power (MW) to be compared against the real Nova Scotia Load and the actual MW/min ramp rate limitations that exist with present DG. The ES can incur charge and discharge deviations about a neutral point for each IG capacity scenario to insure load is met while DG is maintained within its ramp ability. The model is exercised over the 2-year period for which data are available. The parameterization of the different IG types is limited to nominal capacity values that might be expected in the future electricity grid of Nova Scotia. The range of these values are given in Table 2. The minimum wind capacity is 500 MW, which recognizes the majority of the existing install base and short-term retirements. Solar and tidal generating capacities start at 0 and rise to 1500 MW.

Table 2 Parameterization of quantities of Wind, Solar, and Tidal capacity for DG-ramp-control

IG type	Values
Wind	500, 1000, 1500 MW
Solar	0 – 1500 MW
Tidal	0 – 1500 MW

To portray DG characteristics, minimum and maximum DG power values are applied in addition to the ±50 MW per 10-minute ramp limitation. The minimum allowable power is 100 MW to account for turn-down limitations on conventional thermal generators. Maximum allowable DG power is capped at Load so that the control strategy avoids increased use of DG.

4.2.1 DG-ramp timeseries results

An example result for the DG-ramp control strategy is shown in Figure 20. This is for IG consisting of 1000 MW wind, 500 MW solar, and 500 MW tidal. A two-day period of operation is shown for 10 Mar – 11 Mar to illustrate various occurrences and includes where the peak stored energy in the ES is set.

Figure 20 [A] shows the overall Nova Scotia electrical load (red dash) which varies from 1250 MW to 1750 MW throughout the day. The Load is met by the combination of DG (black solid), IG (green solid) and the ES discharging (blue solid). These days have high IG resource (particularly wind), and with the exception of 10 Mar at 12-23 hours, the IG supplies most of the load. By Mar 10 at 12 hours the DG can be seen to ramp upwards in an attempt to replace the IG which is ramping down. The DG positive ramp reaches 50 MW per 10 minutes by Mar 10 at 14 hours and the ES is called upon to discharge so that the ramp limit is not exceeded. By Mar 10 at 16 hours a tidal cycle occurs, and this IG replaces the ES and some DG in meeting the load. Mar 10 at 22 hours the IG ramps up from near zero output to near full output due to convergence of wind and tidal both ramping up, a worst-case scenario that would cause the DG to negatively ramp beyond allowance, or IG to be curtailed, if not for the ES. Because of the ES, the IG supplied load nearly unimpeded, causing the DG to reduce its load carrying to the minimum threshold 100 MW on Mar 11 at 01 hours. Note that while the DG to Load is reduced enormously during overnight between Mar 10 and 11, the DG is inhibited from ramping down at this rate. This is controlled by the ES as seen in subsequent plots.

Because of the large IG installed capacity of 2000 MW, it supplies 55% of the load throughout the 2-year period. <u>The results of plot [A] show that with a high penetration rate of IG there will be occurrences</u>

where it ramps from nearly zero to nearly full power, and vice versa, which could cause the opposite to happen with DG in absence of ES.

Figure 20 [B] shows that the actual total DG output (black dash). It is evident that its ramps are constrained within the limit based on the visually apparent constant slopes up and down during Mar 10 from 12 to 23 hours. A peak DG output occurs Mar 10 at 19 hours of 1835 MW, verifying that this control strategy limits ramps rather than peak power. For the period of Mar 10 at 22-23 hours the transition of DG to Load (black solid) to DG to ES (black cross) is seen. The ES charges at a high rate of 500 MW to control the downward slope of the DG output. This plot shows that the ES power capability may need to equal 50% or more of the installed generating capacity of IG or DG.

Figure 20 [C] shows the components of the IG resource (green dotted). The directly used IG output to load (light green solid) constitutes the vast majority throughout the period. On Mar 11 at 11 to 14 hours more IG resources are available than is needed by the load, and because the ES is already net positive charge due to the DG ramping down, the additional IG must be curtailed; this is noted in the flat lines of IG to Load (light green solid) and the IG curtailment (dark green solid). Curtailment occurrences such as this lead to an overall curtailed fraction for the two-year data period of 4.4%. At no point during the period does the ES charge from the IG. This shows that in DG-ramp control the ES power responds almost entirely to DG restrictions, rather than conducting IG curtailment avoidance. This is because the ES can respond symmetrically to DG positive or negative ramps but can only conduct curtailment avoidance if it is in the net discharged position (it will not net charge conducting curtailment avoidance).

Figure 20 [D] shows ES operation composed of positive charging power by DG to ES (black cross), negative discharging power from ES to load (blue solid) and the integrated energy depletion position (blue dotted, secondary y-axis) caused by the net charging and discharging. Charging is exclusive to discharging, and no charging is supplied by the IG (green cross). Energy depletion is initially near neutral slowly trends back and forth on Mar 10. Overnight between Mar 10 and 11 the IG ramps up to meet the load as the DG ramps down. The ramp control of DG is apparent while it charges the ES (black cross), which increases the stored energy in the ES past neutral into the positive region. Because the ES has entered the positive stored energy position, it cannot conduct curtailment avoidance. It is possible with forecasting that some curtailed energy could be captured. This long charging period leads to the highest positive energy position which sets the positive range of the ES capacity for the 2-year period. A different time within the 2-year period sets the negative value, with the entire range being the necessary capacity of the ES at over 1.75 GWh.

The results of Figure 20 indicate that the ES is "exercised" by cycling in support of DG ramp limitation, and that it trends to towards a neutral energy position whenever available, almost entirely due to DG. This is preferred because it best prepares the ES for the next ramp occurrence, be it positive or negative. The model does not use predictive control based on IG and load forecasting. This feature could be added to improve the trending algorithm and reduce the ES size.

The results presented in Figure 20 are valid only for this IG proportioning scenario with the DG ramp limit and present Nova Scotia electrical load. A broad range of proportions were analyzed, and each scenario produced timestep results similar to Figure 20, but for the complete 2 years of data. The summary results of these parametric variations are presented in the following section.

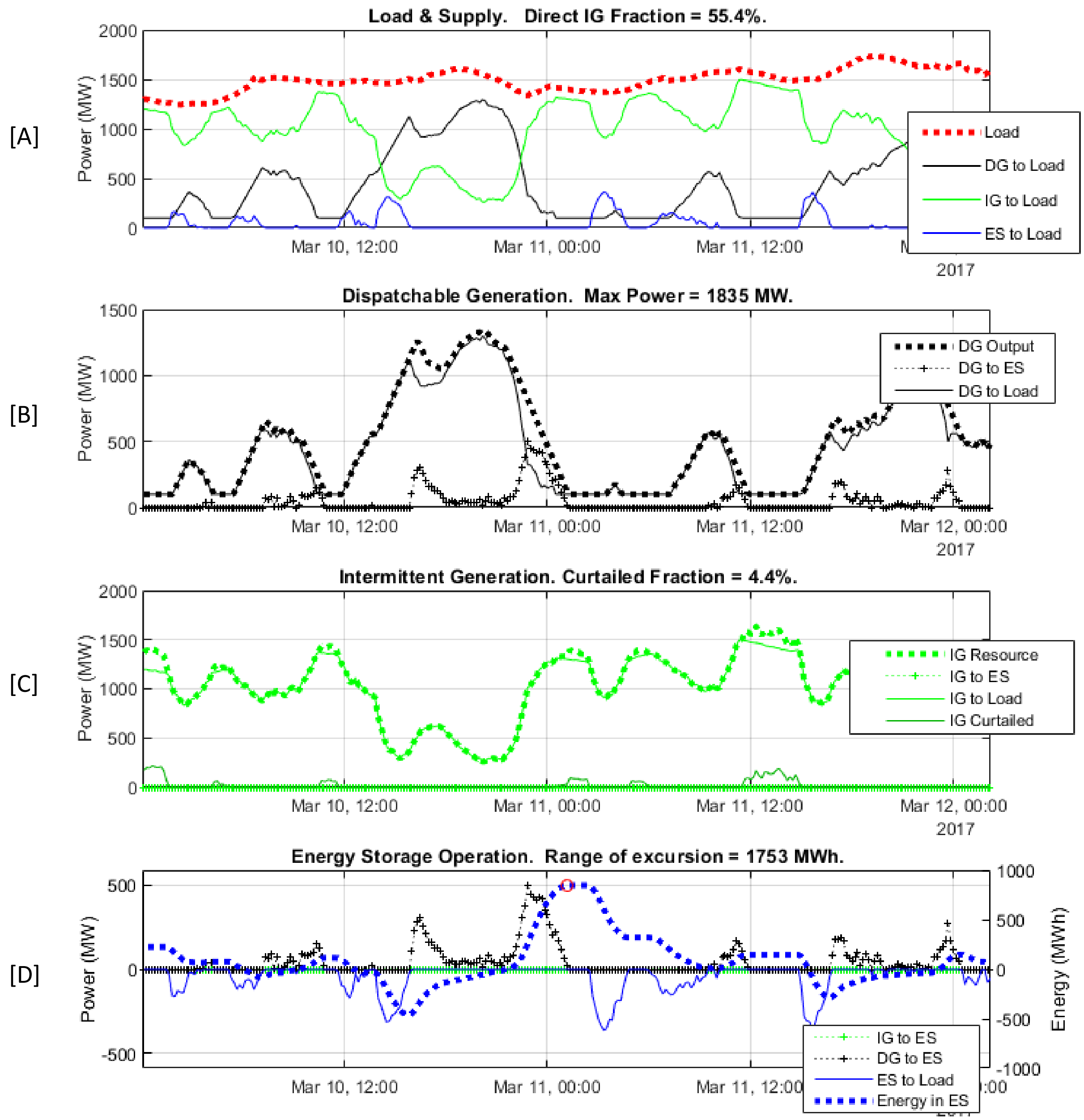


Figure 20 Timeseries depiction of DG-ramp control model operation, covering the point of maximum stored energy for IG capacities of 1000 MW wind, 500 MW solar, 500 MW tidal

4.2.2 DG-ramp performance metrics

The DG-ramp performance results for the wide range of different installed IG capacities are given in Figure 21 and Figure 22. The figures are presented with varying amounts of IG capacities. Tidal capacity is on the abscissa (x-axis), solar capacity the ordinate (y-axis), with three plots for wind capacities of 500 MW (left), 1000 MW (middle), and 1500 MW (right). Each figure is color mapped for trending and has isometric lines applied for identification of specific values. Figure 21 presents plots of [A] ES capacity, [B] Load supplied by IG, and [C] IG curtailment. Figure 22 presents plots of [A] capital cost per MWh over 20 years and [B] peak DG capacity. The figures are intended to be read together but are separated into groups on pages for clarity.

Figure 21 [A] gives the necessary ES capacity to carry out DG-ramp control for a range of IG capacities. The left plot for 500 MW of wind, at the origin position (0 MW solar, 0 MW tidal) approximates the present installed capacities in NS. Only a very small amount of ES capacity is necessary to maintain the DG ramp limit of ±50 MW per 10 minutes. The value is non-zero, because Figure 13 showed that at present in Nova Scotia this is exceeded 1% of the time. There is essentially no ES capacity in Nova Scotia currently. This verifies the model confirms the present state in Nova Scotia.

If only wind capacity is increased, the origin of the middle and right plots can be referenced. It is seen that 0.5 GWh of energy storage is necessary to control DG-ramp for 1000 MW of wind, and 1.5 GWh is necessary for 1500 MWh. This indicates that as increasing proportions of wind are added, the need for ES rises much faster. <u>A significant quantity of solar capacity can be added to wind capacity without a dramatic rise in necessary ES capacity while maintaining the DG-ramp limit</u>. This can be seen by tracking upwards from the origin along the ordinate (y-axis). It is possible to add up to 500 MW of solar without great increase in ES capacity for a given value associated with the wind capacity. This is because of the longer cyclic period of solar (~12 hours). Beyond 500 MW of solar, ES capacity does increase, again with substantial growth rate.

In contrast, the addition of tidal generation on the abscissa (x-axis) to 500 MW or greater immediately requires ES capacity of 1 GWh or more. <u>This is due to the shorter cycling nature of tidal which often runs counter to the load variations and exacerbates the DG-ramp</u>. Values of ES Capacity range up to several GWh for installed IG capacities greater than the peak Nova Scotia electrical load (approximately 2000 MW).

Figure 21 [B] shows the portion of the Nova Scotia electrical load that is met by IG when using ES in the DG-ramp control method. Starting again at the left plot origin (500 MW wind) approximately 15% of Load is met annually. This model result agrees with wind capacity factors and average load given in Section 2 and is confirmed by Nova Scotia Power[17] measurements of 17% with an installed wind capacity greater than 500 MW.

The addition of wind capacity linearly affects portion of the load that is met, rising to 40% with an installed capacity of 1500 MW of wind. <u>This finding suggests that Nova Scotia could triple its installed wind capacity and meet 50% of load, by using 1.5 GWh of ES to manage the power fluctuations (DG-ramp)</u>.

The addition of solar has much less impact per unit installed capacity, due principally to its low capacity factor. By adding substantial amounts of tidal capacity, much higher proportions of load can be met, exceeding 75%. This is due to the high tidal capacity factor but necessitates large amounts of storage in excess of 3 GWh. <u>Thus, the consistent cycling of tidal aligns well with the needs of electricity in the province, but its frequent cycling (every 6 hours) demands large storage for DG-ramp control management.</u>

Figure 21 [C] shows the IG curtailment as a function of installed capacities. Very little wind energy is curtailed due to ramp situations, even at high installed capacities. There are specific periods where curtailment is very high, but over the entirety of the year, they have a relatively minimal impact at less than 5%. The addition of solar also has a relatively small impact on its curtailment, even though

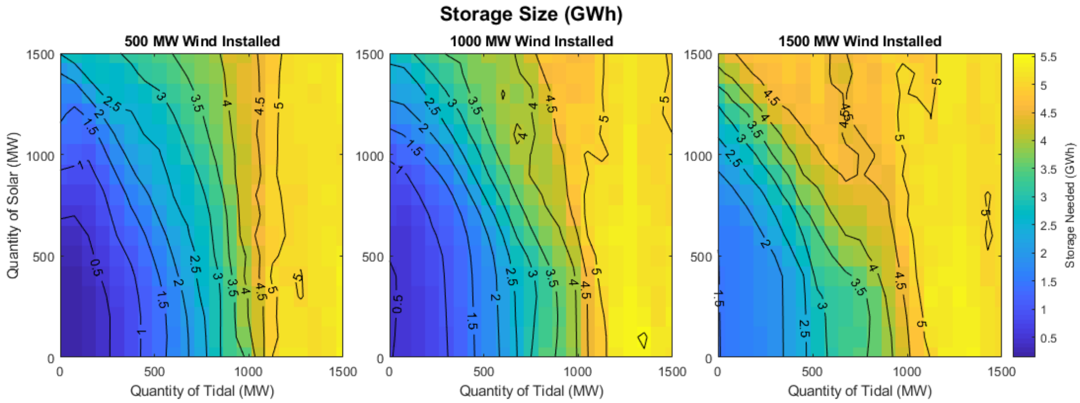
[17] https://www.nspower.ca/en/home/about-us/todayspower.aspx#%20

maximum power is available midday (1 occurrence per day). This is likely because load is higher during midday. The addition of large capacities of tidal do cause significant curtailment. This is because of the frequency of maximum power output (4 occurrences per day) which may conflict with wind and certainly conflict with low overnight loads.

Moving on to Figure 22 [A] the capital cost per MWh over a 20-year period is given. This is a rudimentary approximation of the largest cost contributor to the levelized cost of energy (LCOE). We divide the total IG + ES capital cost over a 20-year operating period and then divide by the annual IG energy that meets load. Wind + ES is lowest cost at 75-90 $/MWh because of its good capacity factor, relatively small amounts of necessary ES capacity, and small amount of curtailment. The addition of solar raises the price per MWh, due principally to its lower capacity factor. The addition of tidal energy raises the cost faster, not only because of its higher capital cost per capacity, but also because of its greater need of ES capacity and greater curtailment. Of note, the capital cost per MWh over 20 years only range from 75 to 180 $/MWh, or a factor less than 2.5. While substantial, it is not an order of magnitude, and indicates that with cost evolution of the different resources, all options might be considered in the context of supportive energy policies to achieve a range of objectives (energy, security, local manufacturing, social).

Figure 22 [B] shows the peak DG capacity which is called upon to meet the net load throughout the 2-year period. With a minimum value of 1820 MW and a maximum of 2020 MW, the installed capacities of IG and ES have little effect on necessary DG capacity when operated in an DG-ramp control strategy. This was expected as the control strategy focused on the constraining the ramps, rather than peak load shaving. However, it indicates that even with massive installation of three IG capacity resources (e.g. 1500 MW wind, 1500 MW solar, 1500 MW tidal, total 4500 MW) does little to reduce necessary DG capacity. These results are significant. The use of controlled curtailment of IG will not improve them. Only the use of some sort of dispatchable load (i.e. smart grid, time-of-use tariffs, or interruptible customers) or the application of an ES control strategy aimed at discharging during peak loads will address this and allow for the reduction of DG capacity (i.e. retirement of fossil fuel or hydro generators).

[A]



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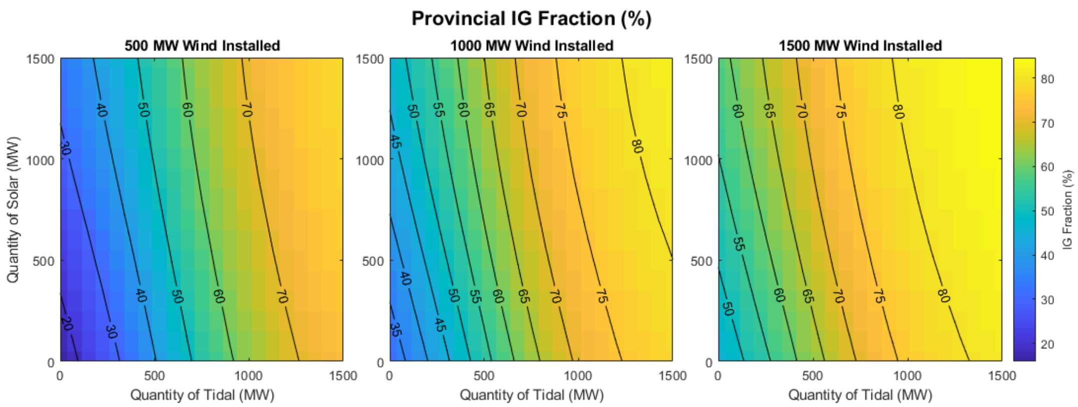


[C]

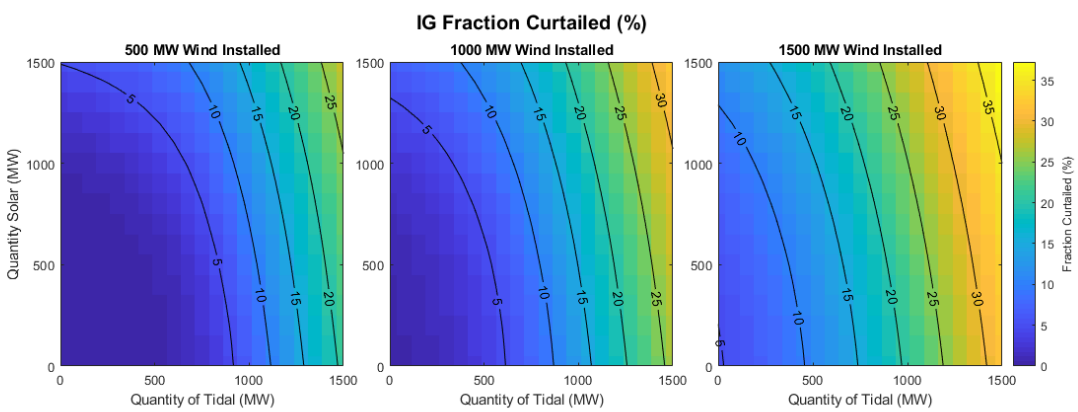
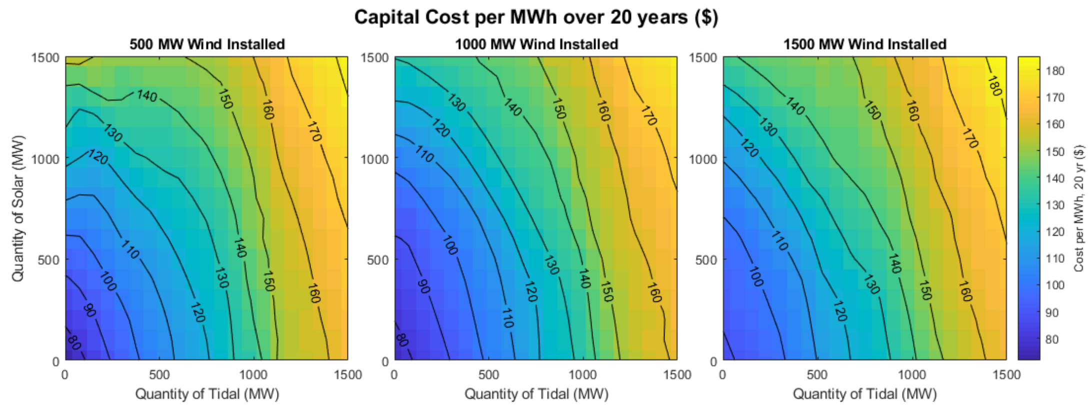


Figure 21 DG-ramp control results for [A] ES capacity, [B] IG contribution to the load, [C] IG curtailment

[A]



[B]

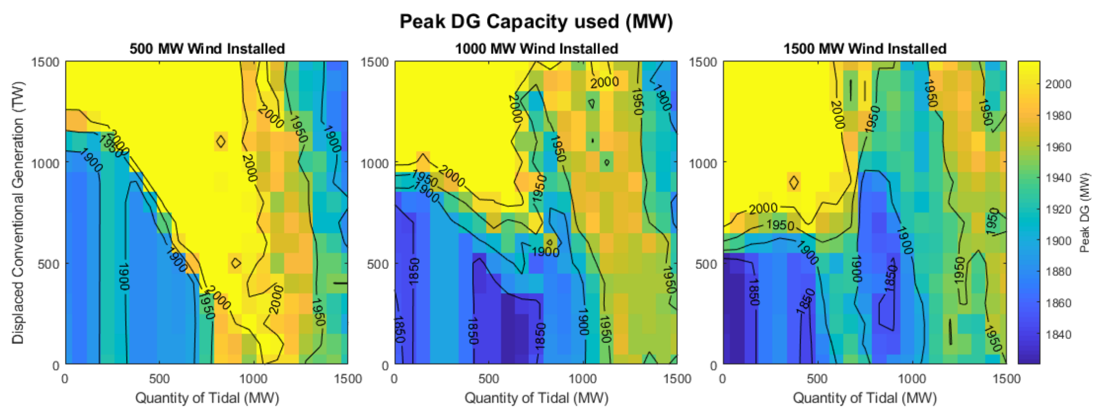


Figure 22 DG-ramp control results for [A] Capital cost per MWh of energy over 20 years, [B] Peak DG power occurrence

5 Conclusion

The objective of this project was to investigate the proportioning of wind, solar, and tidal electricity generation capacity (termed Intermittent Generation, or IG), and the use of Energy Storage (ES), to enable reduced reliance on fossil fuel based electricity generation in Nova Scotia. New models of IG and ES were created and were interacted with the Nova Scotia electrical Load and dispatchable generating capacity (thermal, hydro). The models were parametrically executed with varying IG proportions according to two control strategies. The first *Load-following* control strategy operates the ES to smooth and shape the IG to represent the Load. This is aimed at achieving very high proportions of renewable electricity to directly meet Load. The second *DG-ramp* control strategy operates the ES to limit the power ramps of DG that increased IG capacity would otherwise cause. This is aimed at increasing the renewable electricity with consideration to Nova Scotia's present DG assets.

The project consists of 4 tasks: data collection/preparation; modeling and control strategies; parametric evaluation; and results presentation and interpretation. Each of these tasks was successfully carried out and the new models are available for further use and investigations. The following are major findings based on the parametric studies and their relevance to industry.

5.1 Load-following control conclusions

1. Choosing short IG smoothing/shaping periods of hours uses the ES to mitigate power variability in IG for electricity system control purposes and short-term electricity generation planning from specific generators. The choice of longer durations (days) uses the ES to supply the load's energy needs using IG for day-ahead or future electricity generation planning.
2. The choice of IG proportions strongly affects the ES operations (charge, discharge, standby) with respect to time of day due to the significantly different IG resource dynamics (e.g. solar requires charging during daytime). Load has a much less dramatic influence on ES operations with respect to time of day because of its lower variability.
3. Regardless of smoothing/shaping period, most of the IG either directly supplies load or is curtailed, with only a smaller proportion passing through the ES.
4. The ES is cycled by a significant amount (~50% capacity) each day for several hours of smoothing/shaping, equal to hundreds of cycle-equivalents per year. Shorter smoothing/shaping periods will cause greater cycle-equivalents of the ES and longer periods will cause less cycling.
5. The IG Capacities necessary to achieve hourly smoothing/shaping with ES are essentially the same capacities as would be required without ES or smoothing/shaping, as it is dominated by the renewable generator capacity factor. When smoothing/shaping IG to precisely meet load (2-year), installation capacities must be 2-4 times this value and include ES. This may be interpreted as requiring between 2-4 times number of generators or 2-4 times bigger generators, and 2-4 times the land or water area for IG.
6. IG Curtailment is minimal when smoothing/shaping hourly. For longer weekly or monthly periods of smoothing/shaping, in excess of 50% of the IG might be curtailed due over-capacity in summer when electrical load is low. At present, this IG over-capacity is more economic than greatly increasing the amount of ES capacity. Interestingly, this enables the option of installing further ES in the future at lower capital costs and reducing the curtailment amount at that time. This IG over-capacity also supports future electrical load growth such as heat pumps, electric vehicles, and overall increased electrification of energy end-uses.

7. Adding ES Capacity to achieve hours of smoothing/shaping is presently more economic than installing additional IG capacity and curtailing. The quantity of ES capacity is on the order of 1 MWh per 1 average MW output of IG. To put this in conventional terms, a 100 MW rated wind farm would require approximately 35 MWh of ES capacity for 1 hour smoothing/shaping. A smoothed/shaped IG over several hours would allow more IG capacity to integrate within the electricity grid and not cause control issues.
8. Capital Cost results suggest the continued installation of wind capacity with the inclusion of ES will meet short term smoothing/shaping objectives and add to the renewable electricity content in Nova Scotia. The increase in total capital cost to add ES to projects for hourly shaping/smoothing is approximately 20%. As the focus shifts to much higher renewable electricity penetration rates, with correspondingly longer smoothing, the consistent cycling of tidal becomes a more economic choice when combined with ES. Large scale solar with ES struggles to compete with these other resources due to its lower capacity factor and reliance on significant quantities of ES capacity to time-shift electricity to overnight periods.

5.2 DG-ramp control conclusions

1. With high penetration rates of IG, even distributed across wind, solar, and tidal resources, there will be occurrences where IG ramps from nearly zero to nearly full power, or vice versa, in less than 6 hours, which could cause the opposite to happen with DG in absence of ES.
2. The ES power capability necessary to maintain DG power ramps within the present 99th percentile value may need to equal 50% or more of the installed generating capacity of IG or DG.
3. DG-ramp control achieves its objective but in doing so and preparing for the next ramp mitigation service is unable to conduct IG curtailment avoidance. It also does not reduce peak power requirements of DG which remain stubbornly at present day values. It is possible to unlock these capabilities with controls that use forecasting and stack multiple strategies.
4. Wind capacity increased by a factor of nearly three (above 1500 MW) would require ES capacity of 1.5 GWh to limit DG-ramps to 99% of their present value. It would provide Nova Scotia with nearly 50% of its electricity and experience minimal curtailment.
5. Solar capacity up to 500 MW added to the existing wind capacity in Nova Scotia would not require a very large ES system due to its longer cycling profile. However, its lower capacity factor means this would only provide 5% of electricity. Much larger solar capacity installation up to 1500 MW would require 1.5 GWh of ES capacity It would experience minimal curtailment.
6. Tidal capacity has a more significant impact, when installed between 500 and 1500 MW capacity. This is due to the shorter cycling nature of tidal which often runs counter to the load variations and exacerbates the DG-ramp. It requires between 1.5 up to 5 GWh of ES capacity to maintain DG ramp limits. Additionally, because much of that energy is delivered overnight it will experience greater curtailment ranging up to 30%.
7. Wind with ES is lowest Capital cost per MWh over 20 years (part of the LCOS) at 75-90 $/MWh because of its good capacity factor, relatively small amounts of necessary ES capacity, and small amount of curtailment. Solar and tidal range from 75 to 180 $/MWh depending on installed capacity, or a factor less than 2.5 of wind. While substantial, it is not an order of magnitude, and indicates that with cost evolution of the different resources, all options might be considered in the context of supportive energy policies to achieve a range of objectives (energy, security, local manufacturing, social).

5.3 Relevance to industry

This new model evaluates future renewable electricity generating scenarios in Nova Scotia when combined with energy storage. At present, no large scale opportunities or request for proposals for intermittent generation exist in Nova Scotia due to existing conventional generating assets and electricity grid control stability. Results from the model aid the industry and Government in support of new renewable policies with expected technical performance and simplified costing estimates. These policies might be aimed at particular resources, the inclusion of new technology (energy storage), cost, or local aspects.

Wind generation combined with energy storage is found to be the most economic opportunity for short-term smoothing/shaping of IG to match Load. This can be achieved at a cost premium of approximately 20% for 1-hour durations. The quantity of renewable electricity supplied by wind could be increased with minimal curtailment. New energy policy/programs focused on wind with energy storage would evolve the sector to take advantage of the latest technologies and leverage the existing expertise and experience in Nova Scotia.

Tidal generation combined with energy storage has best performance at large scale. The short cycle length (6 hours) lends itself to the smallest sized of the longer-term (days, months) smoothing/shaping, while wind and solar require very large storage for these durations. This is very advantageous for long-term energy goals of high renewable energy penetration rates and policies should recognize that although tidal has struggled to gain traction, its timeframe for success may be measured in decades. As tidal technology evolves and scales, industry should note that the continuous ramping of tidal throughout the day will frequently cause increase net ramps when it operates counter to Load, and this necessitates energy storage for ramp rate compensation in the present Nova Scotia electricity grid.

Solar combined with energy storage is less economic than wind at large scale for meeting load, principally due to its lower capacity factor and the larger energy storage capacity necessary to continue supply overnight. But it doesn't suffer from the ramping issues of tidal due to its longer cycling period. This supports a degree of buildout of industrial solar in Nova Scotia, but it is unlikely to surpass wind in energy production.

6 Recommendations

The following scenarios could be executed with the model to produce new result and findings:

1. The Load-following control strategy results could be multiplied by actual installed IG capacity in MW to determine the contribution towards the total load of Nova Scotia.
2. The electrical load profile of Nova Scotia could be altered to represent load growth or future technology scenarios such as EV charging which might have a material impact on results.
3. Sensitivity analysis could be conducted to compare the impacts of reduced IG or ES costs. This is especially pertinent to tidal, which has limited costing data, and new energy storage technologies such as flow batteries which are focused on long-term storage.
4. A wide variety of tidal generator and array designs are presently being proposed and developed, including at different heights in the tidal stream. Each has a unique power curve and capacity factor and might significantly affect tidal results.
5. The DG-ramp limit model could be operated with the full DG capacity available at any time throughout the year or could be reduced in maximum capacity to represent impending retirements of aged generators.
6. Connection to Newfoundland via the Maritime Link and strengthened transmission to New Brunswick may add other ramp opportunities that affect the assumed limits. A sensitivity analysis could be conducted to determine their impact.
7. The ES operation could be further investigated to determine utilization and wear which affect long-term degradation and operation.

The model could be evolved and matured to answer additional questions by adding the following capabilities:

1. IG could be controlled to nominally limit generation to 90% of the resource availability. This would allow an additional control capability to partially dispatch IG upward as an alternative to using ES. This percentage would be variable, and an optimum nominal set point could be determined.
2. Peak shaving control strategy could be added to directly address the maximum DG power requirements in an effort to support impending retirements of aged generators (fossil fuel, hydro). This control strategy might be stacked with Load-following or DG-ramp control to achieve multiple benefits.
3. Forecasting of short-term IG and Load could be used to better position the ES for upcoming service calls. For example, the ES should not return from discharged to neutral energy depletion right away by charging from DG if we expect a dramatic increase in IG decrease in load over the next few hours. This will also limit the amount of time the DG is at its ramp limits.