Nova Scotia Ancillary Service Provision by Variable Output Renewable Energy Resources




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Prepared for Offshore Energy Research Association (OERA)

Content & Contacts

- Power Advisory has been engaged by the Nova Scotia Offshore Energy Research Association on behalf of the Nova Scotia Department of Energy and Mines to perform a study recommending changes to the standard form Power Purchase Agreement (PPA) and procurement process to support the provision of ancillary services by variable output renewable energy resources.
- This study's intent is to identify the types of ancillary services that could be procured as part of a renewable energy project and determine how providers may differentiate their bids by offering these services.
- This report is organized into the three following sections. The Jurisdictional Scan is included as an appendix.
  A. Introduction
  B. Ancillary Services
  C. Recommendations
  Appendix I: Jurisdictional Scan

OERA

Prepared for Offshore Energy Research Association

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Nova Scotia A/S Report Organization and Outline

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This work was supported by a diverse group

- Power Advisory would like to acknowledge the support and insights provided by the following individuals and organizations. The Project Management Committee provided oversight, guidance and feedback on all draft work products. Stakeholders provided valuable insights on the various issues addressed in the report. However, the report was drafted by Power Advisory who accepts responsibility for any errors or omissions. Furthermore, any conclusions or recommendations do not necessarily reflect the opinions of the organizations represented on the Project Management Committee or of the various stakeholders.

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ENERCON
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Canadian Renewable Energy Association
Wind Energy Institute of Canada
NextEra Energy
Invenergy
Suncor
Alternative Resource Energy Authority
Natural Forces

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A. Introduction

There are challenges associated with integrating additional wind in Nova Scotia

- Nova Scotia has approximately 600 MW of installed wind generation capacity and off-peak loads of less than 700 MW in summer months, making integration of this variable output generation in certain hours a challenge.
- A recent study conducted for Nova Scotia Power Inc. (NSPI), "Nova Scotia Power Stability Study for Renewable Integration," found that a combination of high wind output, light load, and limited thermal generation could introduce system reliability challenges.
- To mitigate these risks under some operating conditions, NSPI will have four thermal units operating at their minimum loading level with a resulting reduced thermal efficiency. Identifying operating strategies (e.g., have wind projects provide frequency response) that would reduce the requirement for these thermal units could produce production cost savings and lower electricity sector carbon emissions in the province.
- While considering these challenges, there is interest in understanding the technical requirements of integrating additional renewable energy in Nova Scotia and NSPI's ongoing Integrated Resource Plan (IRP) process will be considering incremental renewables as part of the portfolio of available supply and demand side options.

Engaged to recommend PPA and procurement process to support provision of ancillary services

- Power Advisory LLC (Power Advisory) has been engaged by the Nova Scotia Offshore Energy Research Association (OERA) on behalf of the Nova Scotia Department of Energy and Mines to perform a study recommending changes to the standard form PPA and procurement process to support the provision of ancillary services by variable output renewable energy resources.
- This study's intent is to identify the types of ancillary services that could be procured as part of a renewable energy project and determine how the procurement framework should consider the provision of these services. The objective of this study is to help define a new, enhanced PPA for use by Independent Power Producers (IPPs) and Nova Scotia Power Inc. (NSPI) that provides more value to NSPI ratepayers. Ultimately, this could enable the procurement of additional renewable generation resources in Nova Scotia.

B. Ancillary Services

Frequency Response

1) Inertial Response (FFR / Synthetic Inertia)

2) Primary Frequency Response (PFR)

3) Secondary Frequency Response / Automatic Generation Control (AGC)

Reactive Support & Voltage Control (RS&VC)

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Ancillary services that variable output renewable resources are able to provide and are needed in Nova Scotia

- Interviews with NSPI and NSP System Operator indicated that the ancillary services that warrant the greatest focus given operating conditions in Nova Scotia as well as the capabilities of variable output renewable resources that are connected to the grid via power electronics (aka non-synchronous generators/inverter-based resources) are:
  - **Frequency regulation** in the form of:
    - **Inertial response** (e.g., synthetic inertia from wind turbines or fast frequency response),
    - **Primary frequency response**, and
    - **Secondary frequency response** or automatic generation control (AGC); and
  - **Reactive support and voltage control**
- Each of these ancillary services is discussed along with the ability of non-synchronous generators/inverter-based resources to provide them.
- The objective of this section is to identify the forms of ancillary service for which it is appropriate to place an obligation on non-synchronous generators/inverter-based resources to provide. This assessment will be further informed by the jurisdictional scan, which is provided in the final section (Appendix I: Jurisdictional Scan) and reviews the experience in other jurisdictions with respect to obligations on such generators to provide these services.
- The final chapters review the various commercial issues associated with the provision of these services including how they can be reflected in the resource procurement process as well as PPA.

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In addition a range of other related issues were raised

- In addition, a range of related issues were raised with respect to:
  - the cumulative ramp rate of wind generation in the Province;
  - cold weather packages for wind turbines and whether these offer incremental value to NSPI customers;
  - de-icing packages and whether they offer incremental value to NSPI customers;
  - high speed cutout (i.e., having wind turbines drop off gradually rather than cut out simultaneously increasing ramping requirements); and
  - visibility of distribution connected resources.
- These issues are not further reviewed in this section but are addressed in subsequent chapters of the report.

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Frequency response used to maintain frequency at 60 hertz

- Ensures the frequency of the bulk electricity system can be maintained and is stable for both normal and abnormal (loss of components) conditions. Resources are required to quickly engage to bring the grid back to its necessary level of 60 hertz.

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Frequency Response: Inertial response is provided in the first few seconds after a frequency disturbance

(1) Inertial Response: is traditionally provided by conventional synchronous generators using the stored kinetic energy of the total rotating mass directly coupled to the AC grid.

- In the first few seconds following the loss of a large power plant or transmission circuit, the grid frequency starts to drop. In traditional power systems, the frequency drop is limited by the inertial response of the on-line synchronous generation that have "spinning momentum" or large rotating masses to offset frequency disruptions.
- The synchronous generators release their stored kinetic energy into the grid, reducing the initial rate of change of frequency (RoCoF), allowing slower governor actions (e.g., primary frequency response) to catch up and contribute to frequency stabilization.
- Inertia limits the frequency drop during the first 7 to 10 seconds, providing time to allow other resources to increase/decrease output and bring energy and demand back into balance.

(2) Primary Frequency Response (PFR): is the automatic response by turbine speed governors on conventional synchronous generators and demand to correct frequency excursions and ultimately stabilize frequency.

(3) Secondary Frequency Response: is typically provided by generators with Automatic Generation Control (AGC) (e.g., coal and gas-fired and hydroelectric units), which allows the generator to respond to second-by-second dispatch signals from the system operator to increase or decrease output in order to balance supply with demand in real-time.

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Inertia and Primary Frequency Response

- An important goal for system planners and operators is for the frequency nadir to remain above the first stage of Under Frequency Load Shedding set points within an interconnection during large disturbances.
    - Frequency nadir is the point at which the frequency decline is arrested following the sudden loss of generation. It represents the point at which the net primary frequency response (real power) output from all generating units and the decrease in power consumed by the load within an interconnection matches the net initial loss of generation (in megawatts (MW)).
- The period immediately following a contingency event up to the frequency minimum (nadir) is referred to as the arresting period. The amount of inertia in the system at the time of the disturbance determines how much time is available for PFR services to respond.
- These concepts are outlined in the graphic on the slide that follows.

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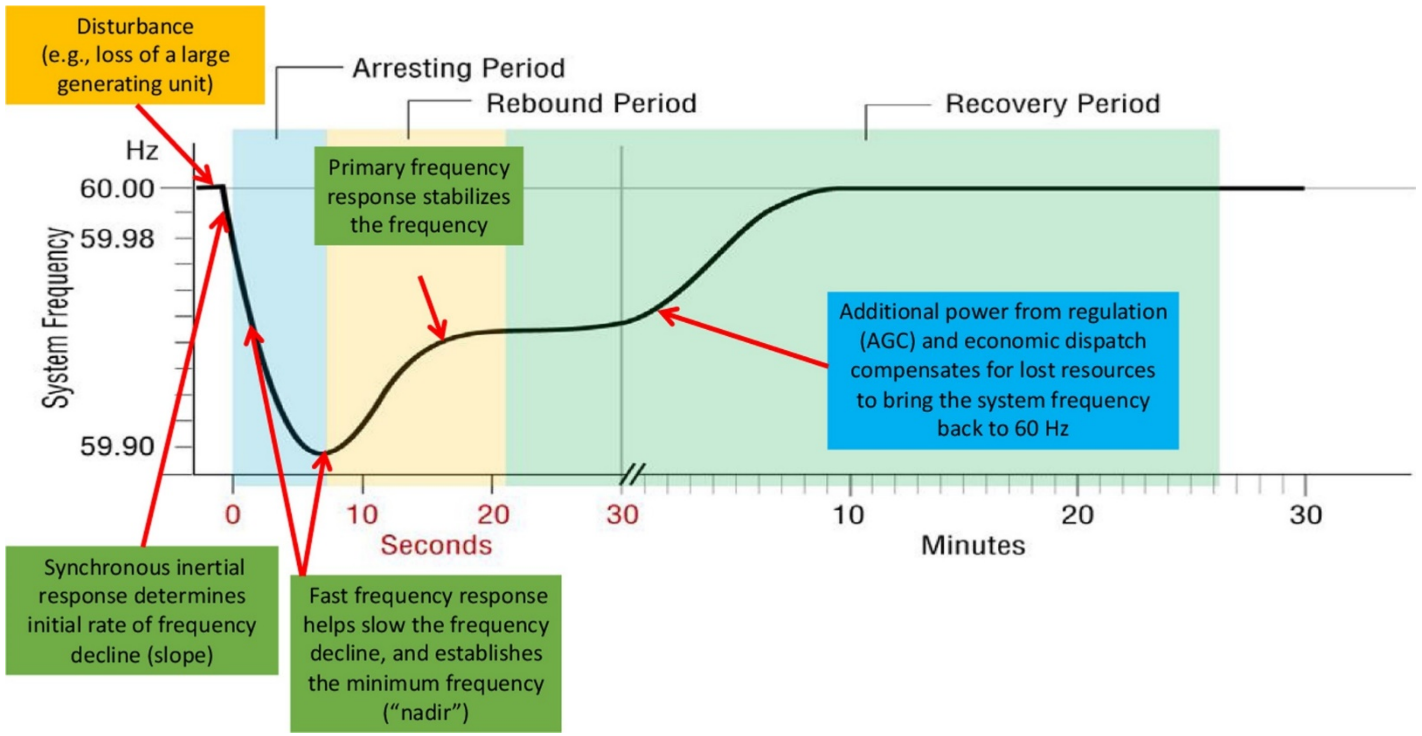
The relationship between nadir and various forms of frequency response or control are shown below



Source: Michael Milligan, "Sources of grid reliability services," The Electricity Journal Volume 31 Issue 9, November 2018.

- This graphic shows the corrective actions taken to respond to a loss of generation or transmission including inertial response, FFR, PFR and AGC.

1) Inertial Response

Fast Frequency Response (FFR) / Synthetic Inertia

Non-synchronous generators do not inherently provide inertial response

- Wind and solar are controlled and interface with the grid using power electronics. They are asynchronous and do not inherently provide inertial response.
- During operating conditions with large amounts of wind or solar generation and small amounts of on-line synchronous generation, without an obligation on non-synchronous/inverter-based resources to provide this service in many systems the frequency would drop so fast that the system stability could be threatened.
- System operators and planners have been concerned that lower system inertia (i.e., reduced availability of synchronous generators) as a result of increased renewables penetration would cause increased rates of change of frequency immediately following a disturbance. This higher RoCoF in low inertia systems leads to rapid frequency decline. This in turn creates an emerging need for faster performance.
- Hence, a new distinct service provided by non-synchronous generators/inverter-based resources known as **fast frequency response (FFR)** has emerged to bridge the gap between inertia and PFR in some jurisdictions. The primary function of FFR is to arrest the frequency decline and "buy time" for PFR to commence.
- Non-synchronous generators/inverter-based resources (wind, solar PV and battery energy storage) have been configured to allow for the provision of a fast frequency response.

Fast Frequency Response is effectively a new service

- FFR is technologically and physically distinct from synchronous inertia. FFR differs from synchronous inertia given the short delay while frequency change is detected and the response initiated. These should be considered as two different services, with different technical characteristics that interact differently with the power system.
- FFR can be an important tool in mitigating high RoCoF, by very rapidly correcting the supply-demand imbalance following a contingency event. It is defined as a rapid active power injection (in 1-2 seconds or less) to arrest the frequency decline following a contingency event. Often it is alternatively termed "synthetic" or "emulated" inertia.
- FFR type service from inverter-connected devices can reduce the amount of synchronous inertia required to maintain system frequency. The precise relationship between the amounts required, however, depends upon the specific characteristics of the FFR service and the synchronous inertia on the system. FFR can compensate for, and help to mitigate, the effects of reduced synchronous inertia on power system frequency control by providing a wider range of options for meeting the frequency operating standards (depending upon a co-optimised consideration of the availability and costs of both services). This suggests that enabling FFR services may allow the frequency operating standards to be met with a lower level of synchronous inertia.

Key Resources for Further Reading

Erikkson, Modig and Elkington, "Synthetic inertia versus fast frequency response: a definition," March 2018

AEMO, "Future Power System Security Program: Progress Report," August 2016

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Wind turbines can provide FFR or “synthetic inertia”

- Synthetic inertia is achieved by reprogramming power inverters attached to wind turbines so that they emulate the behavior of synchronized spinning masses of conventional generators. Synthetic inertia is the contribution of additional electrical power from a source which does not inherently release energy as its terminal frequency varies, but which mimics the release of kinetic energy from a rotating mass.
  - FFR can be provided by both Type 3 (doubly-fed induction generators) and Type 4 (permanent magnet synchronous generators) wind turbines (WTGs). However, Type 4 WTGs are capable of providing stronger inertial response due to the wider operating range of their rotor speeds. In addition, the full-scale power converter allows Type 4 WTGs to possess a higher overloading capability, so that more temporary inertial power can be injected into grid for a short period.
- Specifically, when a frequency deviation is experienced wind turbines are able to extract kinetic energy that is stored in the rotating masses of the wind turbines by “overdriving” the wind turbines for a brief period. The mechanism operates on the basis that the WTG temporarily extracts kinetic energy stored in the turbine rotor and drive train to deliver additional electrical power. (Slide 22 discusses the potential impacts of this overdriving on maintenance requirements.) However this causes the rotor to slow down. This motion therefore dictates how long power injection can be sustained: higher FFR requires more rapid power injection which can be sustained for shorter periods, while lower FFR requires slower injection which can last longer.
- The aeromechanics of wind turbines set the practical upper limit of FFR extracted from wind turbines at ~10% of the power production level at the time of the disturbance. The amount of available inertial response starts to decline rapidly below ~50% rated power, dropping down to zero below ~20% rated power

The two wind turbine suppliers Power Advisory interviewed both offer WTGs that provide FFR

GE Renewable Energy

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- GE's WindINERTIA™ technology utilizes proprietary control algorithms to transform the mechanical inertia of the rotor into a temporary increase in electrical power output over a short period of time. The control system recognizes under-frequency events and utilizes active power controls to shape the power response of the turbine. GE has designed the WindINERTIA™ control's power pulse characteristics to provide a 5% to 10% increase in turbine power over a wide range of wind speeds.
- ENERCON offers similar capabilities in its wind turbines and it demonstrated the capabilities of its wind turbines in Alberta recently. ENERCON partnered with Alberta Innovates to demonstrate the Inertia Emulation capability of ENERCON's Wind Turbines at the ENMAX Taber wind farm. The results of this work are presented at ENERCON, "Final Report: Demonstrating the Value of Wind Farm Inertial Response Functionalities to the Alberta Transmission System."
- Power Advisory also attempted to contact two other wind turbine manufacturers, but never heard back.

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The provision of synthetic inertia by wind turbines results in a recovery period

- The inertia support in the form of additional power production during a severe drop in frequency of the wind turbine is limited not only by the available kinetic energy in the rotational mass but also by the setting of various controllers.
- The net result is that inertial impact is short-lived (e.g., a few seconds depending on operating conditions), with a temporary increase in electrical output, but this increased energy extraction must be "paid back." Generally, once additional power is delivered there's a subsequent decline in the output from the project, which in turn needs to be offset by increases in output from other resources.
- The time required to recover the additional energy injection, and to reaccelerate rotational speed to pre-fault levels, depends on the amount and rate of FFR requested and available wind speed at the time of recovery. The duration of the period for which output is reduced is typically referred to as the recovery period.
- When wind speeds exceed rated speeds, WTGs "spill" excess energy by pitching the blades (in addition to other mechanisms) to keep constant power generation. Under these conditions, available power in the wind is greater than the WTG rated power and it is possible to capture additional energy using pitch control rather than just extracting stored inertial energy by slowing the rotor. At or above rated wind speeds, a recovery period may not be required.

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Synthetic inertia recovery period Cont.

- During the recovery period wind turbines are accelerated again back to their pre-disturbance speed. It is during this acceleration period that the setting of various controllers plays an important role.
- ENERCON notes that the electrical performance of modern wind turbines largely depends on control algorithms. Therefore, the frequency response characteristics in terms of speed, duration and magnitude can be adapted to the specific needs of the network.
- Ideally withdrawal of FFR should begin at the nadir and be coordinated with the rate of rise of the primary frequency response during the post-nadir recovery period.
- There is a level of optimization in the characteristic of this power boost and duration which is effectively determined by control settings. This provides a high degree of flexibility to technology providers by tuning the FFR characteristic (e.g. response time, response duration, output profile, recovery behavior etc.).
  - These parameters will need to be specified in any procurement documents. The specific parameters to be established by the NSP System Operator given the specifics of the Nova Scotia electricity system.
- Nonetheless, the FFR characteristics still follow the same basic patterns. This includes a ramp up period, an active power boost period of 5-10 seconds, a power reduction and a recovery period.

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Wind turbine's ability to provide "synthetic inertia" needs to be understood for benefits to be realized

- ENERCON commented that a critical issue for System Operators is to understand the specific capability of wind turbine projects to provide synthetic inertia or FFR at different output levels, recognizing that the ability of a project to provide this service (i.e., its inertial output) varies with the underlying wind speed.
- Specifically, to realize the benefit of having wind able to provide this service the System Operator needs to be able to estimate the FFR from wind so that it can reduce the obligation on steam units in Nova Scotia that would otherwise be providing inertia and primary frequency response.
- We expect that the NSP SO would be able to estimate the FFR from wind turbines based on wind speeds and the cumulative project output from projects capable of providing FFR (e.g., recognizing project outages etc.).
- NSP System Operator noted that the provision of synthetic inertia or FFR by wind turbines should allow for a reduction in thermal unit commitment or other synchronous generation when inertia is being provided by non-thermal units.
- Increased capability for FFR from wind corresponds to the periods when there is likely less thermal generation online, increasing the attractiveness of having this service available from wind turbines.

Initial observations on commercial implications of FFR provision by wind turbines (1/2)

- NSP SO will need to specify the amount of power boost (magnitude of response), the period by which the power boost must be provided (response time) and the duration of the power boost. The form of response would be specified in the procurement documents and we expect would be based on direction provided by the NSP SO.
  - These setting can be adjusted after the turbines are in-service if required. However, there are physical limits on these parameters that need to considered.
- The main limiting factors for frequency response from wind turbines are the extra heat due to additional power generation and stress on mechanical components. The duration of frequency response is not long enough to generate thermal losses high enough to become a risk factor in the generator winding.
- While there might be some incremental operations and maintenance expenses associated with the provision of this service, ENERCON notes that its wind turbines can provide this service "without significant wear and tear." Ultimately, we expect that the requirements for the provision of this service are likely to be relatively limited and that this reduces the cost risks imposed on IPPs. Therefore, we expect little impact on proposed pricing in any RFP.
  - In contrast, the Wind Energy Institute of Canada (WEICan) notes that the impact of incremental loading on the drive train and blades may have service and asset life implications and that this could have an impact on coverages under their service & warranty agreements.
  - Power Advisory believes that the differences of opinion between ENERCON and WEICan may be explained by in part by the robustness of ENERCON turbines and ENERCON's experience in Quebec where wind turbines have been called upon to provide FFR infrequently.

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Initial observations on commercial implications of FFR provision by wind turbines (2/2)

- One IPP indicated that in the bilateral contract markets where these requirements have been imposed on IPPs there hasn't been any effort to disaggregate these costs. Such that there is no a separate payment when the IPP is called upon to provide these services.
- With the increase in active power output from FFR typically ranging from 5 to 10% of available output, to ensure sufficient FFR capability from wind turbines to meaningfully impact system reliability retrofits to existing wind turbines will need to be considered.
- This may require an agreement to cover any incremental fixed costs associated with the provision of this service and potentially a modest payment when the service is called upon.
- Based on our discussions with wind turbine manufacturers we expect these incremental fixed costs to be modest at least for those projects where such an investment is deemed to be reasonable. We would expect that an estimate of the potential benefits would be developed and this would be used to determine an appropriate cost threshold for undertaking such an investment.
  - Developing an estimate of these benefits is beyond the scope of this project. However, an indicative estimate could be developed by determining the number of hours and MWh when thermal generating units could be dispatched off given that frequency response services would be provided by wind generation resources. This would first require estimating how often and for how long these operating conditions would occur and then the specific production cost savings during these events.

Solar PV can also provide FFR

- FFR can also be provided by solar projects by increasing output to counter frequency drops via control of power electronics. Solar PV has no inherent kinetic energy stored (such as wind). Therefore, if solar PV is to provide this service the solar project needs to be dispatched down to provide headroom so that after the frequency disturbance power output could be increased rapidly.
  - In essence the FFR provided by solar PV is a fast PFR, which results in a response on a faster scale than the PFR for synchronous resources.
- In markets such as the California ISO (CAISO) where high levels of solar generation during midday hours already contribute to oversupply, solar can provide FFR at no incremental cost to the system relying on the available output for the solar projects that have been dispatched down.
  - Such system conditions are unlikely in Nova Scotia. Therefore, if solar PV were required to provide FFR there would be an opportunity cost associated with the provision of this service.
  - This suggests that there could be an obligation on larger solar PV projects to provide FFR, but that these projects would receive an opportunity cost payment when called upon to provide this service. We wouldn't expect the NSP SO to call on solar projects to provide FFR at low penetration levels, but having the right to do so is prudent.
- Recent testing by First Solar, CAISO, and NREL demonstrated that solar resources have superior frequency response performance over fossil-fueled units. Using headroom (i.e., where projects operate below their available output given solar irradiance) projects are able to ramp up output faster than conventional steam units ("Demonstration of Essential Reliability Services by a 300-MW Solar Photovoltaic Power Plant" March 2017).

Energy storage technologies can also provide FFR

- Storage technologies are capable of very rapid frequency responses, including an FFR-type response. Batteries are limited by inverter and control response times. At a plant level, the response time consists of sensing, communication and dispatch to individual inverters. The total response time of FFR from batteries is determined by RoCoF detection and communication, which highlights the requirement for an adequate monitoring and control system to effectively eliminate delays in signaling FFR providers.
- Due to these extremely fast response time requirements, FFR is better implemented directly to the inverters. However, the drawback is that the inverter would need to be maintained in a hot standby mode in order to react quickly, which induces parasitic losses in the order of 2% of rated power.
- As evidence of storage's FFR applications, battery energy storage is becoming the dominant technology delivering fast regulation services in PJM and were the primary technology selected in the UK tender process for enhanced frequency services (See discussion in Jurisdictional Scan). However, this fast response capability is not standard for energy storage technologies and analysis from the UK suggests it is expensive to retrofit. ERCOT's recently adopted FFR, effective March 1, 2020, is currently only for storage resources.
- Manufacturers are actively designing new products targeted at managing high RoCoF, recognizing the potential growing opportunity. New technology solutions are likely to emerge, so any new service specification (such as FFR) would ideally be introduced with a technology neutral approach.

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Currently some synchronous inertia required for system operation

- FFR alone is not sufficient. It is not currently possible to operate a large power system without any synchronous inertia. Synthetic inertia does not provide a direct replacement, i.e., it is a partial substitute only.
- In the future, it may become possible to manage a power system without any synchronous inertia using inverter-connected devices to set and maintain frequency. This service would be different from FFR, because it would involve constantly and "instantaneously" maintaining frequency (rather than just responding following a contingency event). International research is progressing in this field. This suggests that any inertia procurement should be designed to transition over time as new technology options emerge.
  - One such study that has advanced these ideas is DGA Consulting, "International Review of Frequency Control Adaptation: Australian Energy Market Operator," October 2016.

2) Primary Frequency Response (PFR)

PFR typically provided by generators' governors which automatically respond to frequency deviations

- PFR actions begin within seconds after system frequency changes and are mostly provided by the automatic and autonomous actions (i.e., outside of system operator control) of turbine-governors for synchronous generating units, while some response is provided by frequency responsive loads.
- Primary frequency response actions are intended to arrest abnormal frequency deviations and ensure that system frequency remains within acceptable bounds.
- Primary frequency response can be provided by natural gas, coal, and nuclear plants although in practice approximately 10% of these plants actually provide this response.
- There is an opportunity cost associated with providing the headroom required for PFR for wind turbines and solar PV.
- Having generators incur an opportunity cost so that they are able to provide PFR is likely to be uneconomic in most operating conditions because they would be called upon to provide PFR in rare circumstances. Therefore, there would be limited number of operating conditions when under an economic dispatch wind generators would be called upon to reduce output so as to create headroom for the provision of PFR.
    - Thermal generating units will also incur costs when in standby mode to provide frequency response. This cost would need to be assessed relative to the opportunity cost for wind resources providing PFR. In addition, wind, solar and batteries are modular allowing the specific amount of resources required to provide the service to be called upon, which will help to minimize these opportunity costs.
- However, this could occur during high wind output periods when under some operating conditions wind might otherwise be dispatched down. Under these conditions there would be little to no opportunity cost.

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Droop and deadband parameters establish PFR service level

- **Droop** refers to the variation in real power (MW) output due to variations in system frequency and is typically expressed as a percentage (e.g., 4 percent droop). Droop reflects the amount of frequency change from nominal (e.g., 4 percent of 60 Hz is 2.4 Hz) that is necessary to cause the main prime mover control mechanism of a generating facility to move from fully closed to fully open.
  - The Droop settings in Nova Scotia have typically been 4%.
- A governor or power-frequency control for an IBG also has a **deadband** parameter which represents a minimum frequency deviation (e.g., ±0.036 Hz) from nominal system frequency (i.e., 60 Hz in North America) that must be exceeded in order for the generating facility to provide primary frequency response.

Initial observations on requirements for PFR provision by wind turbines (1/2)

- As discussed, during low load high wind output conditions there is a need to keep sufficient synchronous generation online to provide frequency response capability (inertial response, PFR and AGC), particularly if the New Brunswick intertie trips. To the degree this synchronous generation includes thermal units that can be backed down if wind generation is providing this service there are cost savings and emission reductions that can be realized.
- Wind turbines that are being relied upon to provide PFR cannot also provide FFR given that the control algorithms for each service are different and need to be specified prior to any system frequency event. Therefore, the NSP SO would need to determine the preferred mix of resources to provide each of these services. For a larger wind farm, conceivably this could include some wind turbines providing FFR and others providing PFR. FFR is desirable to address the RoCoF and PFR could address the drop in output during the recovery period for these FFR resources.
- Ultimately, the NSP SO is better positioned to determine the desired mix of FFR and PFR from wind. However, because FFR can be provided without incurring any opportunity cost, we expect that NSP SO may elect to have wind resources focus on the provision of FFR rather than PFR, with PFR provided when there’s surplus wind generation.

Initial observations on requirements for PFR provision by wind turbines (2/2)

- Resources that provide PFR will require compensation based on the opportunity cost of foregone energy sales (foregone energy output MWh times the contract price).
- For NSP SO this would presumably become part of real-time optimization, with a likely outcome that wind provides PFR when there is insufficient thermal generation (and ideally this allows less thermal generation to be online during low load periods)
- Also storage at hybrid sites fits into this, i.e., mandate PFR and 15 minutes storage might be valuable at a wind farm – compensation for PFR would still based on opportunity cost but wind would not actually need to be ramped down.
- There's little cost to provide PFR for over-frequency other than small reductions in power output during events. This suggests that there should be an obligation on wind projects to provide this service.
    - During such over-frequency events wind turbines would ramp down active power output to reduce system frequency. There would be some foregone energy generation, but given the short duration and limited occurrence of these events this unlikely to have a meaningful impact on generator revenues.

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Solar PV resources also able to provide PFR

- As the previously referenced testing by First Solar, CAISO, and NREL demonstrated, solar resources can provide superior PFR services to fossil-fueled units. Using headroom (i.e., where projects operate below their available output given solar irradiance) projects are able to ramp up output faster than conventional steam units.
- The referenced frequency response test demonstrated that the solar PV plant can provide a response in accordance with 5% and 3% droop settings through its governor-like control system. The plant was set to operate at a curtailed power level that was 10% lower than the available estimated peak power.
- These test results showed that the PV plant demonstrated a satisfactory droop performance during the underfrequency events for the morning, midday, and afternoon time frames. Study authors noted that some deviations in the response can be further improved by fine-tuning the controller parameters. Furthermore, the mean control error is very small, ranging from 0%–0.21% of the plant's rated capacity.
- The deviations from the target response are generally due to the short-term solar resource variability, which can be mitigated if such a response is generated by a number of PV plants within a larger geographical footprint.

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The NSP SO will need to specify the appropriate PFR parameters for Nova Scotia

- Recommending specific droop and deadband parameters is beyond the scope of our work and most appropriately left to the System Operator.
- However, we echo GE's comments vis-à-vis setting appropriate standards and the costs associated with specifying a standard that is more stringent than that employed elsewhere.

3) Secondary Frequency Response

Secondary Frequency Response often referred to as AGC

- Secondary frequency response is provided by generators with Automatic Generation Control (AGC) (e.g., typically coal, gas-fired and hydroelectric units) which allows the generator to respond to second-by-second dispatch signals from the system operator to increase or decrease output.
- For electricity markets where generators are compensated for providing this service, the quality of service provided by the generator is measured in terms of a performance score in the US (Alberta, for example, does not have a performance score).
- North American Electricity Reliability Corporation (NERC) balancing performance requirements are outlined in BAL-001.

Many US frequency regulation markets allow for Regulation up and down services to be offered separately

- Many US frequency regulation markets are divided into regulation-up (reg-up) and regulation-down (reg-down) services, provided by resources that have capability and capacity to increase or decrease their power when the AGC command is positive or negative.
  - See for examples the NREL report, "Controlling Wind Turbines for Secondary Frequency Regulation: An Analysis of AGC Capabilities Under New Performance Based Compensation Policy," November 2014
- This is particularly important for wind, solar and energy storage resources given that these projects may have different capabilities to provide these services given their operating conditions. In addition, there are opportunity costs associated with the provision of this service that need to be considered.
- Power Advisory had preliminary discussions with the NSP SO to assess obstacles to allowing non-synchronous/inverter-based generators to offer reg-up and reg-down services separately, recognizing different opportunity costs associated with providing this service by these generators. The NSP SO indicated that based on its preliminary assessment there were no obvious barriers to doing so.

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Wind generation can increase requirements for AGC

- Variable wind generation when combined with variable system load (i.e., net load after wind generation) can increase net system variability that must be followed by controllable generation inside Nova Scotia to maintain the synchronous tie with New Brunswick to a scheduled value.
- The difference between actual flow and the scheduled flow on the Nova Scotia-New Brunswick tie is known as Area Control Error (ACE), which must be controlled within limits.
- The Nova Scotia Energy Control Centre sends signals to generators on AGC to raise or lower output in an effort to minimize ACE.

Wind turbines capable of providing AGC

- However, because the energy output from wind is determined by the available wind resource, they are generally only able to provide Reg-up service when they are operating at less than their available output (i.e., output levels lower than the available wind resource would support) using headroom.
- Providing this headroom results in opportunity cost (i.e., foregone energy sales) to the wind generator. Wind IPPs would expect to realize such a foregone energy payment. This can be relatively easily structured to the degree that the wind output that could otherwise have been provided by the project can be determined or estimated.
- To the degree that the wind project would otherwise be curtailed then there would be no opportunity cost from the provision of AGC.
- In principle, if wind is providing the regulation when all other generators are at min, then the thermal units could be kept at min instead of the current practice of curtailing wind to a fixed 66% or 33% of rating such that the conventional generation could come off min to provide up and down regulation. That would mean that the regulating wind units would be curtailed at a variable rate between, say between 66% and 100%. NSP SO would need to have AGC set such that the units would not be below 66% on average.
  - Inverter-based resources can provide ramping capability on MW or % of capability basis, allowing the resources to match the MW required to achieve Area Control Error target.
- Splitting reg-up and reg-down would have particular merit such that when the thermal units are brought to min loading levels. These units could provide the reg-up and wind could provide reg-down, where practical.

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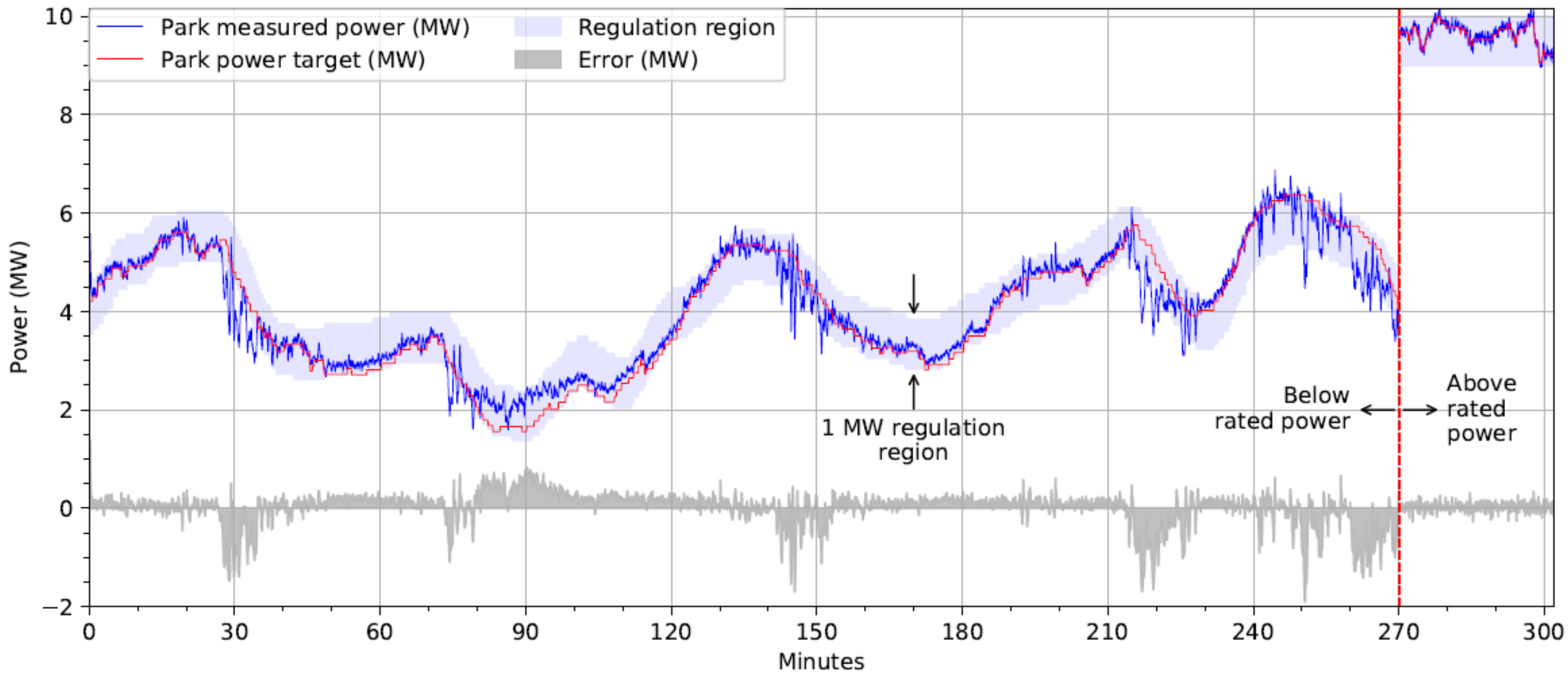
Wind Generators able to provide high quality of AGC

- Wind generators have proven themselves to be capable of providing AGC at high levels of performance as indicated in the graphic below for a demonstration study performed by Wind Energy Institute of Canada.

Combined Test Results at and Below Rated Power



Source: Rebello, E., Watson, D., and Rodgers, M.: Performance analysis of a 10MW wind farm in providing secondary frequency regulation: Experimental aspects, in IEEE Transactions on Power Systems, Vol. 34, July 2019, https://doi.org/10.1109/TPWRS.2019.2891962, 2019.

Wind Generators able to provide high quality of AGC

- To provide this service the system operator must be able to communicate with the WTG and provide these dispatch signals.
- There may be an incremental cost associated with imposing a requirement on existing wind turbines to provide this service. The NSP SO would need to assess AGC requirements and the incremental value of having existing wind projects in addition to new wind projects provide this services, e.g., the number of hours where there's likely to be a requirement for this.
- The Wind Energy Institute of Canada has suggested that the increased pitch activity when wind turbines are curtailed could result in structural loading that could have long-term mechanical and structural impacts.

Solar PV has been demonstrated to able to provide higher quality of AGC than conventional resources

- The referenced First Solar, CAISO, and NREL tests demonstrated that inverter-based solar resources have superior AGC performance. Using headroom (i.e., where projects operate below their available output given solar irradiance) projects are able to ramp up output faster than conventional steam units.
- In their project, the regulation accuracy of the PV plant (87 to 94%) is 24–30 % better than the typical regulation accuracy of fast responding gas turbine technologies at 63%.

Initial observations on requirements for AGC by wind turbines

- On a go forward basis wind farms (and potentially solar farms) a requirement to be AGC capable is reasonable and provides optionality for the NSP SO that could facilitate further renewables integration at a lower cost.
  - Compensation for actual AGC provision by existing projects would need to reflect opportunity cost as well as any required capital costs.
  - We would expect that new wind projects that are subject to a procurement process would embed the capital costs in their proposed pricing.
- Storage and hybrid sites could provide an option for the developer to provide the service without losing production as long as compensation is equivalent.
  - In effect, if AGC can be provided without lost production there is an incentive to build a hybrid site if the compensation is sufficient.
- AGC control logic can be adapted to reflect that renewables generation has a higher opportunity cost than most thermal generation (and energy limited hydro generation).
  - For example, if wind on AGC is the last to ramp down (relative to the other providers on AGC) and the first to ramp up the cost of the service is minimized.
  - Separating ramp down service from ramp up service is another alternative that could be considered.
- WEICan notes that the long-term mechanical and structural impact of providing AGC from wind turbines is poorly understood and there's likely to be increased pitch activity when wind turbines are curtailed to provide Reg-up or Reg-down service.

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Reactive Support and Voltage Control

Reactive Supply and Voltage Control

- The primary objective of voltage support is to maintain transmission system voltages within a secure, stable range. Voltage support is location specific and requires reactive power control from resources distributed throughout the power system.
- Controllable sources for voltage support include generators that are able to vary their reactive power output, inductive and capacitive compensators, and transformers which are utilized to inject and absorb reactive power and keep voltage between the necessary minimum and maximum levels. These sources work with other elements of the electric system to collectively provide voltage control.
- Reactive power supply and voltage control is generally supplied as a cost-based service in most electricity markets.

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Most wind turbines are capable of providing voltage support

- Without a specific package to provide voltage control and reactive capability, VAR capability is reduced at low wind speeds as various WTGs drop off as wind speeds drop below the minimum threshold.
- Voltage stability can be a challenge, particularly where a large wind project is connected to through a long transmission line. Changes in wind speed result in changes in active project output, which can lead to changes in reactive power output.
- System operators typically require wind projects to have low voltage ride thru capability as well as to inject reactive power to support voltage reductions. There are three different modes or reactive support and voltage control from wind projects including reactive power control, voltage control and power factor control.
- Both GE and Enercon offer wind turbines that are able to provide voltage control when not operating, though the capability to provide service at 0 output has an incremental cost. Other wind turbine manufacturers are also understood to have this capability.
- Some wind installations (e.g., in New Brunswick and PEI) are required to have separate independent reactive control devices such as Static Compensator (STATCOM).

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Most wind turbines are capable of providing voltage support

- GE notes that its wind turbines can provide (1) full leading and lagging range over full power range; (2) faster reactive response than synchronous generators; and (3) the capability of reactive compensation when not operating.
- ENERCON turbines offer similar capability. It noted that its wind turbines have a wide operating range for reactive power.
    - With a flexible turbine configuration, wind farm projects can be optimized to suit the particular requirements of a grid and locations within that grid. One element of this flexibility are hybrid configurations with solar, wind and storage combined in various combinations to provide reactive support and voltage control.
    - As an option, ENERCON wind turbines are able to provide the grid performance properties of a STATCOM. With the STATCOM option, an ENERCON wind turbine is able to provide full reactive compensation when not operating.
    - These capabilities may increase the allowed installation size at a particular POI, particularly radial circuits with high X/R grid connection.

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Initial observations on voltage support

- The capability to provide voltage support at 0 MW and full output requires incremental cost for developers and would require incremental revenue.
  - This capability could be required or be procured when necessary via incremental revenue streams.
  - This static var compensation capability may not be optimal to compensate through energy payments but rather on a fixed annual basis.
- 0.95 lag to lead power factor range is typical in many jurisdictions across most output ranges (there are more stringent requirements in some) as is low-voltage ride through requirement.
  - This capability would likely be a reasonable requirement for NS given its widespread use.

C. Nova Scotia Recommendations

Obligation to Provide A/S

- The preceding review of ancillary services capabilities of wind, solar and battery energy storage systems demonstrated that these technologies can provide FFR, PFR, AGC and voltage control and reactive support. Furthermore, Power Advisory interviews with various wind turbine manufacturers confirmed that the incremental capital cost associated with providing these ancillary services is generally relatively modest.
    - The one A/S where there is an appreciable incremental capital cost associated with the capability to provide the service is for voltage control and reactive support.

Obligation to Provide A/S

- In addition, pilots, project testing, and industry literature demonstrate that solar and BESS technologies can provide FFR, PFR, AGC and voltage control and reactive support.
- Therefore, Power Advisory recommends that the capability to provide these ancillary services should be mandated for all new non-synchronous/inverter based generation as part of interconnection standards for generation projects above a threshold size.
    - There are two obvious size thresholds: (1) all non-synchronous/inverter based generation projects connected to the transmission grid versus the distribution network; or (2) all non-synchronous/inverter based generation 20 MW or larger for which NSP SO's Large Generator Interconnection Standards apply.
- Such a requirement would apply to all new projects.
- An important question is to whether these requirements should apply to existing projects as well. This question is addressed on the next several pages.

Existing Wind Generation Requirements

- Some existing wind farms may have the ability to provide the same A/S as new facilities without retrofits. Other wind farms will likely require retrofits to their facilities.
  - Determining whether or not such retrofits are cost-effective is beyond the scope of this work. Information on existing transmission-connected wind projects is presented in a subsequent slide.
  - Based on conversations with OEMs Power Advisory understands the costs for retrofits to be modest for recently installed projects and may be modest for older projects, but the actual cost for existing projects varies on a site by site basis depending on the current configuration. This is apparent for the Nuttby project, with a 2010 COD, where the costs that ENERCON quoted for the components and upgrades that it would provide were relatively modest.
- Given that the costs for retrofits for most existing projects are expected to be modest the obligation to provide these frequency response ancillary services should be placed on them. Once again, WEICan expressed concern with the service and asset life implications of these requirements. This is discussed further below.
  - We understand that the overall costs for retrofitting voltage control and reactive support capabilities is considerably higher and that the value of this service is location specific. Therefore, we recommend that imposing this obligation on existing projects be considered on a case-by-case basis.

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Existing Wind Generation Requirements

- The compensation framework applied to existing facilities would depend on whether it covered the term of the existing PPA or only applied at the end of the term of the existing PPA.
- If the obligation covered the term of the existing PPA, this would require amendments to existing PPAs to place an obligation on suppliers to provide these services and to compensate them for the fixed and variable costs of the provision of these services.
    - There's some level of administrative effort by NSPI to conduct such contract negotiations. However, we believe that it will generally be worth the effort and that securing the participation of existing projects to provide these services is critical if there's to be a meaningful impact on system operations.
- If the obligation only applied after the expiration of the existing PPA term then the compensation framework could be an element of the overall negotiations.

Nova Scotia Onshore Wind Projects

Project Name	Wind Turbine Manufacturer	COD	Project Size (MW)	Turbine Size (MW)	Turbine Type
Pubnico Point	Vestas	2005	30.6	1.8	V-80
Digby Wind [1]	GE Wind	2010	30	1.5	1.5sle
South Canoe	Acciona	2015	102	3	AW3000
Amherst	Suzlon	2012	31.5	2.1	S9X
Nuttby Mountain	Enercon	2010	50.6	2.3	E82/2300
Dalhousie Mountain	GE Wind	2009	51	1.5	1.5sle
Glen Dhu	Enercon	2011	62.1	2.3	E82/2300
Sable (Canso)	Enercon	2015	13.8	2.3	E82/2300
Bear Head [2]	Enercon	2006, 2010	22.8	0.8, 2	E48/800, E82/2000
Lingan Wind [3]	Enercon	2006, 2007, 2012	18.1	2, 2.3	E70/2000, E70/2300, E82/2300
Maryvale	Vensys	2010	6	1.5	V-77
Ellershouse [4]	Enercon	2015, 2017	16.1	2.3	E-92

[1] Digby Wind also referred to as Gullivers Cove Wind Farm
[2] Bear Head Project also referred to as Point Tupper Wind Farm
[3] Lingan Wind has been expanded twice (4.6 MW in 2007, 2.3 MW in 2012)
[4] Ellershouse Wind Farm was expanded from 9 MW to 16.1 MW in 2017

Obligation to Provide A/S

- NSP SO should specify the specific operating parameters for resources providing these services including the speed, magnitude and duration of response (sustaining time). These operating parameters are likely to be specified as a range or maximum.
    - For example, GE notes that for frequency control of its wind turbines a complete set of droop and limit parameter can be defined, with the droop curve selection done by the project owner and/or some external command from the system operator.
- To enable the NSP SO to obtain these ancillary services from these resources it will need to specify specific requirements to provide visibility and controllability of these resources.
- With a mandate to provide these A/S, projects would continue to compete on the basis of the $/MWh price offered for energy. This would simplify the evaluation process.
    - There would be one exception: hybrid projects where the incremental value of the BESS would be considered. How the value of this alternative could be considered in the evaluation process is discussed below.
    - Alternatively, a decision could be made to not allow hybrid projects participate. Given experience elsewhere as discussed further in the jurisdictional scan, Power Advisory believes that hybrid projects are likely offer additional value and should be considered.

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Compensation for Relevant A/S

- With the ability to provide these A/S mandated, proponents presumably will embed any incremental fixed costs to provide the A/S in their contract pricing.
- However, the opportunity cost and incremental operating and maintenance (O&M) cost of providing these services should be specified in the PPA so that suppliers are kept whole.
- If wind projects aren't compensated for the reasonable opportunity cost associated with the provision of this service, they are likely to attempt to assess the resulting revenue loss and embed this in their project pricing. Without a reasonable basis upon which to determine how often they would suffer this revenue loss, they would face an additional project risk that could adversely affect project financing costs. Therefore, we recommend that these projects be allowed to recover their reasonable opportunity costs.
- Opportunity costs are relatively easy to establish given information on potential output relative to actual output.
    - This output gap would reflect the difference between the potential output and the actual output when headroom is required to provide a service times the contract price.
- Incremental operating and maintenance (O&M) expenses are less obvious and more difficult to discern. ENERCON indicated that incremental O&M expenses from the provision of these services on its wind turbines are relatively insignificant, particularly given the limited number of instances that they are typically called upon (e.g., less than 10 times per year in Quebec).
    - Our proposal for considering these O&M costs is outlined below.

Compensation for Relevant A/S

- With respect to FFR, where the kinetic energy of the rotors are used to provide a power boost and there would be the greatest potential for additional stress on project components, ENERCON asserted this service can be provided "without significant wear and tear" provided it is used infrequently. GE offered a similar perspective. This suggests that little to no incremental compensation is required for this cost.
  - WEICan expressed concern with respect to the incremental loading on the drive train and blades from "overdriving" the wind turbine and the resulting service implications and facility life implications as well as potential impacts on service and warranty agreements. As discussed, we believe that this difference of opinion may reflect the robustness of ENERCON's design and its experience in Quebec where wind turbines are called upon to provide this service infrequently.
- Nonetheless, given the uncertainty regarding these variable O&M expenses and the value of the provision of this service by wind turbines and other IBRs adding a nominal per use payment upon successful delivery is reasonable (e.g., $20/MW). This per use payment could be specified by the Procurement Administrator working with the NSP SO. However, it isn't clear that there's a sound analytical foundation for estimating such a payment.
  - 'Arming' the service would not trigger the payment – it would be based on actual use. There is little to no opportunity cost for this service given its infrequent use and minimal impact on total production.
- A possible risk mitigant for IPPs would be to limit the number of instances per year on which this service can be called upon, with the potential for a supplemental payment(s) if this threshold is exceeded.
  - The Procurement Administrator could work with the NSP SO to estimate an appropriate threshold.

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Compensation for Relevant A/S

- This approach could be viewed as reflecting in part a value of service approach as was advocated by CanWEA and CanSIA.
- While value-based pricing is attractive from a conceptual perspective and aligns with many market-based outcomes, establishing the value of these A/S can be difficult and this value will inevitably change over time as system conditions change. For example, the value of additional frequency response capability increases dramatically when the frequency of the grid approaches the point at which UFLS would be triggered.
- Therefore, Power Advisory has elected to not employ value-based pricing for these services. Furthermore, cost-based pricing is more typically employed in regulated electricity systems.

Compensation for Relevant A/S

- Further support for this nominal O&M cost or value of service adder is the concept that A/S provision should be rewarded for good performance and failure to provide A/S when called upon by the NSP SO or provision of a lower quality service than offered should be penalized.
  - Specifically, if the system is to be operated efficiently then the NSP SO must be confident that the A/S that it is relying on will be provided. Without such certainty, the NSP SO will need to contract for additional A/S beyond what it requires, with the attendant increases in costs. Clearly, some redundancy is likely to be required to satisfy reliability objectives but minimizing the amount of this redundancy is likely to reduce costs.
- Penalties would vary depending on the A/S. For AGC, a number of RTOs have used the concept of a performance score to compensate resources based on the quality of service that they provide, with performance typically measured in terms of the degree to which the resource responds accurately to dispatch signals. This approach is applicable for AGC provision in Nova Scotia, but less appropriate for other services.
  - PJM's performance score is based on: (1) Accuracy – the correlation or degree of relationship between control signal and regulating unit's response; (2) Delay – the time delay between control signal and point of highest correlation; and (3) Precision – The instantaneous error between the control signal and the regulating unit's response. The specifics are outlined further in PJM Manual 12.

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Compensation for Relevant A/S

- Penalties for other services typically have a deadband (e.g., =/- 10%).
    - This deadband should reflect the underlying uncertainty associated with providing the service given resource availability, signal error etc.
- Penalties for failure to perform or deliver the committed A/S often involve rebating the payment that was received.
    - Repeated failure to meet minimum standards for delivery can result in suspension in the ability to provide the service until a compliance plan is developed.
    - Testing to ensure ability to meet standards could be required where there is poor performance and/or very infrequent use of the service.
    - Testing to demonstrate the ability to provide the service could also be an element of initial project testing to demonstrate the project has reached commercial operation.
- Incentive mechanisms could involve a ‘cost plus’ approach or using a revenue neutral approach where penalties for poor performance are provided to facilities with good performance.
    - As an example for AGC if 10% of opportunity costs are penalized from some providers for below standard performance this could be provided as an incentive to providers with above standard performance.

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Fast Frequency Response - New Wind (1/2)

- Power Advisory recommends Fast Frequency Response (FFR) capability should be available on all new transmission-connected wind generation projects.
- The specific characteristics of the requirement should be set by NSP SO. NSP SO should specify the specific operating parameters for resources providing these services including the speed, magnitude and duration of response (sustaining time). These operating parameters are likely to be specified as a range or maximum and where possible would allow the NSP SO to revise the specific set points based on operating conditions.
  - NSP SO should not develop new standards but rather adopt standards already existing in another market (to avoid OEM development costs of meeting a new standard).
- Capability should be controllable, i.e. the FFR response should be armed or disarmed based on NSP SO directive.
  - Visibility of real-time capability should be available to the NSP SO. See discussion on forecasting.
  - Real-time visibility of wind generation and/or forecast of expected FFR capability (varies with actual wind output at the time of the event).

Fast Frequency Response - New Wind (2/2)

- Power Advisory does not recommend FFR should be a compensated service for wind generation other than when it is actually used in response to an event.
  - FFR as defined for Nova Scotia's needs should be specified in the interconnection requirements.
  - 'Arming' the capability does not create opportunity or operational costs.
  - Actual use of the service is infrequent and does not result in a material loss of production.
  - Therefore compensation should be per event to reflect an estimated impact on incremental O&M.

Fast Frequency Response Requirements - Existing Wind

- As discussed, existing wind generation with a low-cost option to provide FFR should make it available (with the same standards) to NS Power on a cost recovery basis. Specifically, we expect that there will be incremental capital costs that project developers would incur to provide FFR.
  - These incremental capital costs are likely to include control upgrades and would represent an incremental cost on a per turbine basis.

Primary Frequency Response

- Power Advisory recommends Primary Frequency Response (PFR) capability should be available on all new wind generation projects above a threshold size
- This is consistent with requirements that US FERC imposed in Order No. 842 which required newly interconnecting large and small generating facilities, both synchronous and non-synchronous, to install, maintain, and operate equipment capable of providing primary frequency response as a condition of interconnection.
- This requires the capability to control production from a facility in order to maintain 'headroom' to increase production on a sustained basis (unlike FFR which is short-lived and does not require headroom).
- The specific characteristics of the requirements should be set by NSP SO based on system needs but should consider technical capability of current technology.
    - Similar to FFR, NSP SO should not develop new standards but rather adopt standards already existing in another market (to avoid OEM development costs of meeting a new standard).

Primary Frequency Response

- Capability should be controllable and allow real-time visibility as to the quantity available, i.e., visibility of real-time potential output relative to actual output (in effect a headroom measurement).
- Power Advisory notes that when wind generation is otherwise curtailed it's able to provide this service with no opportunity cost.
- Power Advisory recommends IPPs should be compensated for their opportunity cost of providing the headroom when providing PFR.
  - At a minimum compensation should fully cover opportunity cost, i.e. headroom should be paid as though the energy was produced.
- Power Advisory recommends hybrid sites (with storage) be compensated in a similar manner.
  - One benefit of hybrid sites is that they can provide PFR without an underlying opportunity cost because the incremental active power for PFR provision can be provided by the battery.
  - For example a hybrid site could provide PFR from stored energy and be paid the project's energy rate for the PFR provided. To be clear the project would only paid for providing the service when responding.

Secondary Frequency Response (AGC)

- Power Advisory recommends AGC capability should be available on all new wind generation projects above a threshold size.
- This requires the capability to control production from a facility via AGC.
- Capability should be controllable and allow real-time visibility as to the quantity available.
  - Visibility of real-time potential output relative to actual output (in effect a headroom measurement).
- We recommend that the NSP SO consider disaggregating the service into Regulation Up (Reg Up) and Regulation Down (Reg Down), recognizing that there are different costs for the provision of these services.
- Wind and solar projects providing Reg Up would be compensated based on headroom times the contract price, i.e. opportunity cost of lost production. Wind and solar projects providing Reg Down would be compensated only when called upon to provide the service based on the amount that they were dispatched down times the contract price.
- Power Advisory recommends hybrid sites (with storage) be compensated in the same manner.
  - For example a hybrid site could provide AGC from stored energy and be paid the project's energy rate for the capability.
- Payment should be tied to satisfactory performance.
  - Standard should be consistent with expected performance from other generation on the system and should not form a barrier to participation.

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Reactive Support and Voltage Control

- The NSP SO is proposing in its revised grid code that wind farms connected to the transmission system be equipped with STATCOM functionality such that they can provide voltage control down to zero real power output. STATCOM functionality would allow for higher penetrations and allow balanced voltage support across the system as thermal units are displaced/retired.
- Therefore, the cost of this requirement would be embedded in proponent's bid pricing and doesn't require additional consideration in the procurement process.

Visibility and Controllability

- Power Advisory recommends all new non-synchronous/inverter-based generation that is transmission connected and/or above a capacity threshold (MW) should provide real-time visibility and data for centralized forecasts to the NSP SO.
  - Specific data (variables and update frequency) for centralized forecast to be determined by NSP SO.
  - Could include meteorological data, turbine availability and other factors as required.
  - Centralized forecasts are used in many markets and provide a standardized product and potentially result in better accuracy with greater information and lower costs through economies of scale
- Forecast data requirements should be established as an interconnection requirement.
  - The threshold should not be set so low as to be a barrier to small projects such as rooftop solar in the kW's range.
  - Other markets have set the threshold at 5 MW to 10 MW.
- Power Advisory also recommends all transmission connected renewable generation should be controllable via dispatch instruction.
  - Specific standards should be developed if they are not already in place.
- Distribution connected generation above a size threshold should also be controllable provided a reliability concern is present.
  - Size threshold for controllability may be larger than the visibility threshold.

Renewable Energy Resource Forecasting

- A detailed assessment of NSP SO forecasting framework is beyond the scope of this project. However, the quality of the wind generation forecast and real-time information on the availability and output of wind generation is a critical aspect of cost-effectively integrating additional wind in Nova Scotia.
- Best practice in other jurisdictions include ensuring accurate and reliable real-time met data from individual wind farms as well as regular forecast updates (6 or 4 hour updates are common) that integrate this real-time data to produce a centralized forecast. ERCOT develops intra-hour forecasts every five minutes.
  - The forecast would be updated in real-time for any weather warnings or alerts.
    - For example icing risk could be an element if data can be identified to assist in forecasting icing risk.
  - It is common for the cost of the centralized forecast to be recovered from wind project owners, but retroactively charging IPPs that are under long-term contracts would likely require contract amendments. There is less rationale for this in a regulated system because IPPs will need to estimate the costs and embed this estimate in their contract pricing.
- Mandating requirements (data to be provided to the NSP SO) for all resources above a minimum capacity threshold is the recommended approach.
- Power Advisory recommends that costs for supplying information for forecasting are borne by the developer, but the cost of the forecast is borne by NSP.

Visibility of Distribution Connected Assets

- Power Advisory recommends that visibility should be required for all assets above a size threshold.
  - This threshold should be set for all asset types (including renewables and otherwise).
  - For new non-synchronous/inverter-based resources this is requirement could also be imposed on distribution connected resources 5 MW and larger.
- If there are specific reliability concerns given location, controllability of distribution connected assets may be required.
  - This should be assessed on a case by case basis.
  - We recommend that the Procurement Administrator meet with NSPI and NSP SO early in the process to assess whether there are location issues that should be considered in the evaluation process. This could include incenting and disincentiving projects to locate in these areas by reflecting this in the evaluation framework.

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High Speed Cutout

- Modern turbines are potentially able to use a range of control strategies to avoid or reduce 'sharp' cutouts where production drops rapidly from full output to no output.
- The benefit to the overall power system of using these control strategies is that the instances of rapid declines in wind generation associated with high winds are reduced.
  - This limits the requirement for System Operators to maintain resources to provide this replacement power.
- Cutout requirements for windfarms above a threshold size are recommended to be mandated as part of the connection standard with consultation to determine whether 'soft cutout' strategies are appropriate.
  - Any requirements should be based on capability of existing packages from turbine manufacturers.
  - Sharp cutouts can increase uncertainty of wind output at high wind levels (wind is either at near full output or at 0 MW)
- Any soft cutout requirement should not be compensated as the opportunity cost is expected to be minimal, if any, as control strategies should not result in significant material lost production.
  - Requirements should not be so onerous as to create large losses of production

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Cold Weather Capability

- Cold weather capability allows wind generation to operate in lower temperatures.
- Nova Scotia is a winter peaking system and the capability to operate in lower temperatures may increase the capacity value of wind by increasing the likelihood that wind is available and operating during these peak periods.
- In addition, avoided energy costs are likely to be higher during such periods given that higher cost fossil generating units are likely to be operating.
- Cold weather capability also increases the total expected annual energy from wind generation and therefore increases total revenue available via the energy payment. It is likely that these incremental energy revenues would represent sufficient additional compensation to warrant the incremental cost of a cold-weather package, but not guaranteed. Since capacity is not compensated as an incremental value via energy payments, without a mandate to make this investment, IPPs may elect not to purchase cold weather packages when the incremental cost is less than their incremental value.
- Power Advisory recommends that the procurement administrator perform an economic analysis of this incremental value and compare it with the incremental cost to determine whether this capability should be mandated.
- A framework for this evaluation is outlined in the next two slides.

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Assessing value of Cold Weather Capability

- We recommend that the starting point for this assessment be comparing the value of this capability relative to its cost.
- The value can be assessed by first estimating the incremental energy production that a cold weather package would support. We understand that this incremental production data might be able to be obtained from Nergica, formerly TechnoCentre éolien. Ideally this information can be provided on a monthly basis and integrated with avoided energy costs. This will produce an estimate of the incremental energy value.
  - Nergica identified a series of resources on cold weather packages and de-icing capabilities for wind turbines, which should be consulted. In general, there are industry standards regarding when these capabilities should be required.

IEA Wind, "Available Technologies for Wind Energy in Cold Climates - Reports" 2nd Edition, 2018.

Canadian Wind Energy Association (CanWEA), "Best Practice for Wind Farm Icing and Cold Climate Health and Safety." December 2017.

IEA Wind, "Expert Group Study on Recommended Practices: 13. Wind Energy Projects in Cold Climates" February 2017.

Assessing value of Cold Weather Capability

- Estimating the incremental capacity value will require additional information regarding the system conditions that result in Nova Scotia system peak loads. This could include evaluating: (1) actual temperatures during peak load periods to assess the probability that wind projects with and without cold weather packages will be available; (2) Nova Scotia wind project output profiles to assess the likelihood of cold weather shutdowns; and (3) data from Nergica on the impact of cold weather packages.
  - Ideally, this impact could be assessed using an effective load carrying capability study relying on actual wind shapes that reflect differences in energy output from a cold weather package.
- This information will then need to be integrated with estimates of the value of capacity based on capital costs of the types of resources that are likely to be relied upon to provide capacity.
  - The economic analysis should include the present value of the incremental energy plus the estimated incremental capacity value of cold weather packages relative to the increased capital cost.

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De-Icing Packages (1/2)

- De-Icing packages reduce the risk that wind generation will experience a forced outage or de-rate due to blade icing.
- Icing risk is site specific and each developer will adjust expected production by the expected icing risk.
  - Sites with a perceived low risk of icing have a potential competitive advantage that is negated if a de-icing package is mandated.
  - Conversely, the capacity value of wind generation is likely to be reduced by icing events. Therefore, mandating de-icing packages can enhance the value of wind generation.
- Power Advisory recommends that the NSP SO establish a standard for when de-icing systems are required.
- This would include a site assessment to assess how the site fits within the IEA (International Energy Agency) icing classification scheme. This scheme specifies a range of expected energy loss. (See IEA Task 19 Recommended Practices 13).

De-Icing Packages (2/2)

- The table below shows the various IEA Ice classes and the associated estimated icing loss.

IEA Ice class	Meteorological icing	Instrumental icing	Icing loss
	% of year	% of year	% of gross annual production
5	>10	>20	> 20
4	5-10	10-30	10-25
3	3-5	6-15	3-12
2	0.5-3	1-9	0.5-5
1	0-0.5	<1.5	0 - 0.5

- Nergica indicated that as a rule of thumb if the site is IEA Ice Class 2 or greater de-icing packages should be mandated.
- We recommend that analysis be performed regarding the appropriate threshold following the scope of the cold weather package analysis. The NSP SO could then apply this standard.
  - Note that a full ice risk assessment likely requires 1 winter worth of met tower data from the site and that the risk of icing can vary within a site based on individual turbine elevation (for example) so de-icing standards should be flexible enough to accommodate site level variability.

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Cumulative Wind Ramp Rate (1/2)

- Given that wind generation in a given geography is often highly correlated many jurisdictions have experienced challenges with rapid wind ramping events.
  - In effect wind generation increases at a high rate across a number of facilities resulting in excess generation while other units reduce production.
  - We understand that UNB has been developing wind ramp forecast packages can be developed based on freely available Environment and Climate Change Canada forecasts.
- System ramp rates can be managed via incremental AGC but this solution may not facilitate renewables integration.
- Power Advisory recommends that the capability for windfarms to respond to limits in real-time production should be mandated.
  - This is a standard capability as it is simply the ability to respond to a control signal.
- Actual reductions in output as a result of these limits could be compensated on an opportunity cost basis or the wind developer could bear the curtailment risk and embed the cost in the energy price.
  - The frequency and magnitude of ramp rate issues is a function of total wind generation and system flexibility.
  - Compensation would eliminate this project risk and would likely result in lower energy prices (but increased payments for opportunity costs when curtailments occur).

Cumulative Wind Ramp Rate (2/2)

- If opportunity cost is calculated NSP should develop a standard approach that relies on a real-time estimate of potential energy relative to actual energy.
  - This data can be estimated at the windfarm based on real-time conditions and a standardized approach that adjusts for factors such as windspeed, turbine availability, temperature and other relevant factors.
- A process to verify potential energy and audit data should be established to the extent opportunity costs are compensated.
- Compensation would only apply in situations where a binding limit was placed on a facility due to ramping limits and/or other conditions.

Evaluation Process

- The incremental value of hybrid projects should be recognized in the evaluation process. This incremental value would be increased production during high value hours and capacity value as well as the ability to provide ancillary services without opportunity costs. Each incremental source of value is discussed below.
- Incremental value of energy output could be modeled by determining the hours when the value of energy differences are greater than the losses of the battery (the round trip efficiency) as well as a replacement cost charge given that the battery life is limited by the number of cycles.
  - The number of these hours could be estimated by NS Power as an output of its ongoing IRP. With a $/kW value estimated based on the round trip efficiency, with higher $/kW values estimated for higher RTE efficiencies. This information could be generated by a production cost simulation.
  - The incremental capacity value of a hybrid project also should be considered in the evaluation process. This would require that the incremental amount of capacity provided based on the nameplate rating of the BESS would be determined. The value of this capacity could then be based on the cost of a simple cycle gas turbine installed in the first year of capacity need present valued to the project commercial operation date. NSPI notes that work for its ongoing IRP indicates that the ELCC of batteries on their system is relatively small. (Supply Options Study)
- Valuing the ability to provide A/S without opportunity costs will require that these opportunity costs be estimated and how often they'd be incurred.

Hybrid Project PPA

- As a basic principle, the Power Purchase Agreement (PPA) must specify the responsibilities and obligations on the supplier to provide these A/S. With many of the obligations specified in the interconnection agreement that will need to be amended as well.
- There are a two primary approaches that could be used:
  - (1) NSPI/NSP SO dispatched resources where the supplier is paid a $/kW-month charge specified in its proposal for its incremental capital costs for the BESS. Under such an arrangement it would be up to NSPI/NSP SO to dispatch these resources. This is the most administratively simple and is most easily accommodated within the existing "market structure". This approach is used by Xcel Energy for its hybrid projects. We recommend that this approach be used in Nova Scotia.
  - (2) Supplier dispatched resources where the supplier is paid based on the value of energy produced. Specifically, hybrid projects would be compensated based on their production profile, with an economic incentive to focus output during higher value hours. This approach is considerably more complex to administer and increases cost recovery risks for the supplier given the uncertainty regarding incremental payments attributable to the storage investment.

Hybrid Project PPA

- Energy arbitrage capability and capacity value from hybrid projects is likely to be material but requires a broader evaluation framework.
  - Capacity value on the system could be calculated in the IRP process.
  - Potential value of energy arbitrage and reduced wind curtailment (lower production costs for NS Power) could also be calculated in the IRP process.
- Power Advisory notes that adding incremental value for hybrid projects is appropriate as part of the evaluation process but triggers data requirements, expected operating protocols, per use payments and a range of other issues that are beyond the scope of this evaluation.
- While Power Advisory believes there is value in hybrid projects, our recommendations are limited to paying hybrid sites for power that would otherwise be spilled and we note this is not the full value of these sites nor is it likely sufficient on its own to drive hybrid site development.

Stakeholders advocated a Technology Neutral Approach

- A technology neutral approach would be appropriate if the objective were to structure a competitive procurement for ancillary services. However, the objective is to structure a competitive procurement for renewable energy resources to support the Province's renewable energy procurement objectives, as embodied in its Green Choice program.
- Therefore, the objective is to procure renewable resources, but to ensure that they have the capability to provide the required ancillary services. This is inconsistent with a technology neutral approach.

NSP A/S Procurement Operating Procedures

- Power Advisory notes that an important element of optimizing the system and integrating further non-synchronous/inverted-based resources is the development of operating procedures and economic dispatch decision making tools that minimize real-time operating costs subject to reliability constraints.
    - These issues are not contemplated in this report as they do not form part of a renewable generation procurement but rather will dictate how the system operates with a given set of assets in place.
- The decision to open a procurement for incremental resources for the purposes of providing reliability services is a separate and independent issue.

Key Rationale for Recommendations

- Capability for non-synchronous/inverter-based resources to provide ancillary services will reduce integration challenges and provide the NSP SO with additional tools and resources for managing real-time reliability challenges.
- The proposed compensation models will allow services to be provided while compensating providers for appropriate opportunity costs.
- The proposed approach allows existing projects to provide these services as well to the degree that NSP SO determines there is incremental value to the system.
  - Existing projects are at a minimum kept whole in the framework
- The requirements proposed are relatively standard capabilities for wind generators and are consistent with many other markets.
  - As such the requirements will not result in excessively costly procurements.
- The recommendations establish expected capabilities for non-synchronous/inverter-based resources combined with a compensation framework – the model and procedures for actual use of the services is not contemplated.

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Appendix I: Jurisdictional Scan

Jurisdictional Scan Summary Table

Jurisdiction	Market Structure	Installed Capacity (MW)	Installed Wind (MW)	Key A/S Related Requirements, Initiatives and Programs for Renewables
EirGrid	Competitive	15,992	5,476	DS3 System Services Agreement Procurement; Wind Farm Power Stations (WFPSs) specific grid code
PSCo	Regulated	5,666	3,165	Interconnection requirements (reactive power, frequency control and voltage control); Wind] [Solar] Energy Purchase Agreement
ERCOT	Competitive	78,929	23,860	FFR service; Grid Code requirements for renewables (frequency control, disturbance ride through, voltage support, ramp rate limitation); Future Ancillary Services Framework
AEMO	Competitive	61,067	7,700	Renewable Integration Study Stage 1; Mandatory Primary Frequency Response Rule; Frequency Control Work Plan
National Grid UK	Competitive	106,100	23,975	FFR Auction Trial; Power Available (PA) Project; Enhanced Frequency Response tender; Real-time inertia monitoring; Virtual synchronous machines (VSM) standard
IESO	Hybrid	38,603	5,076	Stakeholder Consultations; Contract amendments for curtailment

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EirGrid (Ireland)

EirGrid Overview

Electricity Market Structure

- Type: Competitive Wholesale Market, Retail Supply
- Description: Opened for competition in February 2005. All aspects of supply are competitive as of April 2011. Formerly regulated, with a vertically integrated monopoly the Electricity Supply Board (ESB)

Market Participants/Institutions

EirGrid Group	• The independent transmission system operator (TSO) in Ireland and Northern Ireland through **EirGrid and SONI**, respectively. EirGrid Group also operates the competitive wholesale market across the island as the **Single Electricity Market Operator (SEMO)** • Its other business is an East West Interconnector with Great Brittan. EirGrid is an Irish state-owned company
ESB Group	• **ESB Networks** and **NEI Networks** own the distribution and transmission systems in Ireland and Northern Ireland respectively. Its distribution functions include planning and operation • **Electric Ireland** is its retail arm in both jurisdictions • ESB group also engages in generation, trading, telecom, EV charging and Smart Energy Services • ESB is 95%, majority, owned by the Irish Government with the remaining 5% held by employees
Regulators	• The Commission for Regulation of Utilities (**CRU**) is Ireland's independent energy regulator • **The Utility Regulator** regulates North Ireland's electricity, gas, water and sewerage industries

Market Size and Renewables Penetration*

Installed Capacity (2019)

Total	15,992 MW	**Variable Output Renewable Energy**	Wind - 5,476 MW (3,321 MW dx. connected) Solar -175 MW (all distribution)

Generation (2019)

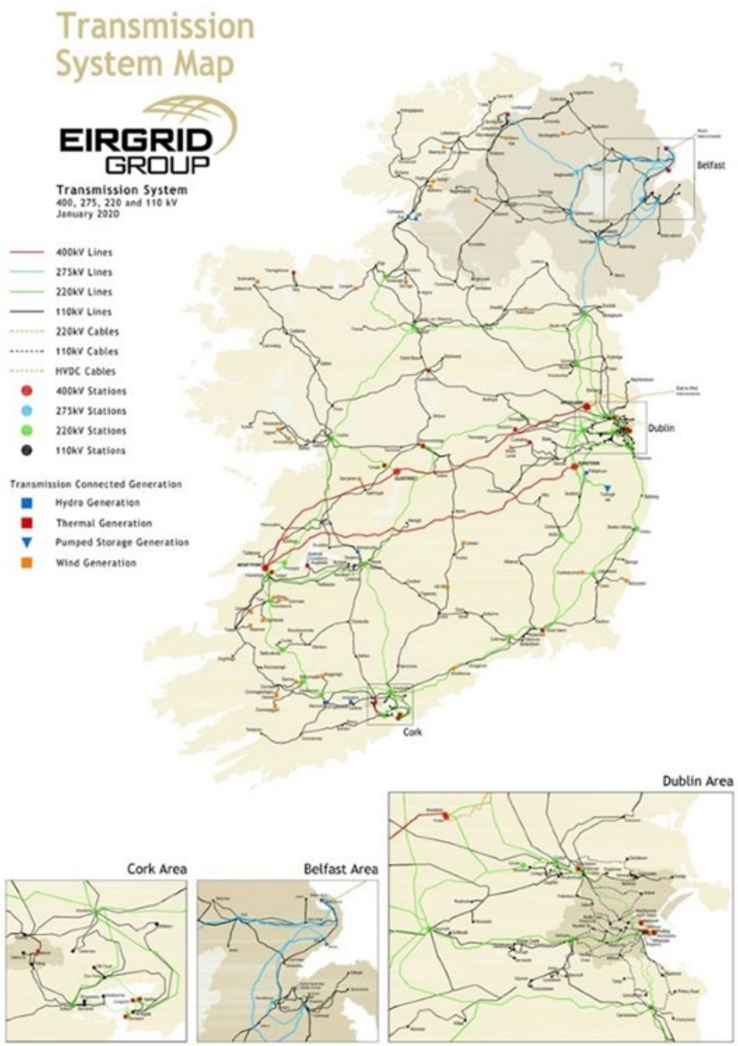
37,553.8 GWh (Total) Gas - 50.2% Peat - 5.6% Coal - 3.8% Hydro - 2.4%, Imports - 2.1%	12,782.6 GWh (Renewable) 34.1% of total Wind - 32.3%, Other Renewable -1.8%

Planned Renewables Additions

- Commitments to 702 MW of transmission connected solar and 558 MW of distribution connected by 2025 (1,260 MW solar)
- 1,059 MW of transmission connected wind and 596 MW of distribution connected by 2025 (1,655 MW wind)
- Barring retirements and non-renewable additions this will bring solar and wind up to 45% of the capacity mix

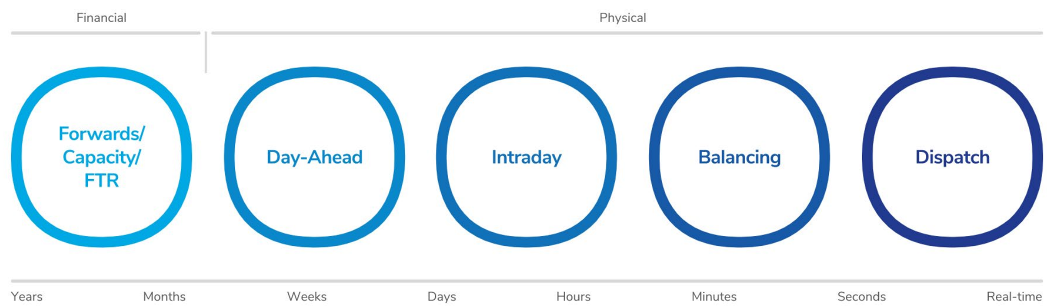
*For the entire island (Ireland and Northern Ireland)

EirGrid: Transmission System and Electricity Markets



Source: [EirGrid Group January 2020]

Participate in the market



- The Integrated Single Electricity Market comprises of:
  - two ex-ante energy markets (Day-Ahead and Intraday Markets),
  - a balancing market (for energy and non-energy system balancing before and into real time),
  - two markets for financial instruments (Forwards Market and Financial Transmission Right auctions from over a year to one month ahead), and
  - a market for capacity remuneration (primary and secondary auctions, up to five years ahead of the trading day).
- A/S are paid outside the I-SEM by the EirGrid Group TSOs of EirGrid and SONI or required in the Grid Code.

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Basis for wind generation capacity in Ireland

Ireland supports renewables with long term contracts. The primary mechanisms that have been employed by Ireland through its Department of Communications, Climate Action and Environment (DCCAE) in coordination with EirGrid and the CRU are:

- Renewable Energy Feed-in Tariff (REFIT) Schemes - were designed to provide renewables with a minimum price for generation for a 15-year period. They offer a top-up to market revenues from energy, capacity and constraint payments (i.e. contract for differences structure). The schemes are funded by the Public Service Obligation (PSO), which is paid for by all electricity consumers.
  - Three schemes were employed starting: REFIT1 for small resources, <5 MW, starting in 2009; REFIT2 for large, >5 MW projects, starting in 2012; and REFIT3 only covering biomass (310 MW total). The last of the REFIT auctions closed in December 2015.
  - Responsible for most all of the installed wind capacity in the Republic of Ireland.
- Renewable Electricity Support Scheme (RESS) - New support scheme that looks to provide financial support to about an additional 13,500 GWh that is structured as a two-way floating feed in premium.
  - Projects must have a minimum size of 0.5 MW and be onshore wind, offshore wind, solar, hydro, biomass, biogas, or waste HECHP. Focus on community investment and technology diversity. The first application round, RESS-1, closed at the end of April 2020 for up to 3,000 GWh of renewables with CODs by the end of 2022. At least four rounds are expected to be completed by 2027. Overall, designed to achieve its 70% renewable electricity by 2030 goal.
- Separately, a few corporate PPAs have begun to be signed starting with Amazon in 2019. The Irish Climate Action Plan targets 15% of electricity demand to be met with CPPAs by 2030.

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Basis for wind generation capacity in Northern Ireland

Northern Ireland has also historically provided support to renewables through:

- Northern Ireland Renewable Obligation (NIRO) - a support scheme to accredit projects to generate renewable certificates, Northern Ireland Renewables Obligation Certificates (NIROCs), that can then be monetized through sales to retail suppliers of electricity with annual obligations.
  - Northern Ireland's obligations started in 2005 and are administered by the Department of Enterprise, Trade and Investment (DETI).
  - Operated in tandem with the renewable obligation schemes in the rest of the UK as a harmonized market for ROCs.
  - Closed to new applications from onshore wind in 2016 and all other technologies in 2017.

- There is currently no replacement for the NIRO. Options that have been considered include: 1) join Great Brittan's Contracts for Difference (CfD) auctions, 2) introduce its own CfD scheme, or 3) pursue an all island support with Ireland. CfD was implemented as a successor to the Renewable Obligation (RO) in Great Brittan.

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EirGrid: Ancillary Services

EIRGRID

Ancillary Services Report
2019/2020

SONI

System Services Payment (€)													
	Oct-19	**Nov-19**	**Dec-19**	**Jan-20**	**Feb-20**	**Mar-20**	**Apr-20**	**May-20**	**Jun-20**	**Jul-20**	**Aug-20**	**Sep-20**	**Total**
Primary Operating Reserve	1,222,905	1,262,576	1,908,081	2,128,481	2,712,019	2,079,372	-	-	-	-	-	-	11,313,434
Secondary Operating Reserve	1,050,081	1,061,715	1,531,105	1,689,444	2,094,151	1,593,867	-	-	-	-	-	-	9,020,362
Tertiary Operating Reserve 1	1,019,723	1,042,339	1,510,259	1,693,445	2,059,290	1,617,758	-	-	-	-	-	-	8,942,814
Tertiary Operating Reserve 2	923,927	922,320	1,237,724	1,481,803	1,731,135	1,432,057	-	-	-	-	-	-	7,728,967
Replacement Reserve	832,432	901,863	1,364,859	1,479,965	1,926,372	1,493,086	-	-	-	-	-	-	7,998,577
Synchronous Interial Response	922,746	1,166,913	1,294,075	1,531,856	1,681,007	1,621,852	-	-	-	-	-	-	8,218,448
Dynamic Reactive Response	-	-	-	-	-	-	-	-	-	-	-	-	-
Fast Frequency Response	300,175	179,302	692,535	875,173	1,491,410	916,267	-	-	-	-	-	-	4,454,862
Fast Post-Fault Active Power Recove	-	-	-	-	-	-	-	-	-	-	-	-	-
Ramping Margin 1 Hour	247,295	250,062	375,828	405,288	510,207	412,804	-	-	-	-	-	-	2,201,484
Ramping Margin 3 Hour	349,235	366,906	598,977	614,011	793,658	613,135	-	-	-	-	-	-	3,335,922
Ramping Margin 8 Hour	358,230	389,419	702,481	702,468	944,258	722,744	-	-	-	-	-	-	3,819,600
Steady State Reactive Power	1,500,532	1,584,486	2,137,429	2,354,537	2,831,567	2,307,038	-	-	-	-	-	-	12,715,588
Other AS (€)													
	Oct-19	**Nov-19**	**Dec-19**	**Jan-20**	**Feb-20**	**Mar-20**	**Apr-20**	**May-20**	**Jun-20**	**Jul-20**	**Aug-20**	**Sep-20**	**Total**
Synchronous Compensation	-	36	150	-	4	-	-	-	-	-	-	-	190
RoCoF	-	-	-	-	-	-	-	-	-	-	-	-	-

Notes:

This report contains a monthly breakdown of the Ancillary Services for the 2019/2020 tariff year. Note that these outturn figures are settlement figures. The outturn in £ GBP will be converted to € EUR using the approved 2019/2020 exchange rate of €1/£0.9166. This report will be updated each month once settlement has been issued.

Source: 2019/20 Ancillary Services Report (as of May)

- The major ancillary services in Ireland include:
  - **Reserve Services** - Primary Operating Reserve (POR), Secondary Operating Reserve (SOR), Tertiary Operating Reserve 1 (TOR 1) Tertiary Operating Reserve 2 (TOR2) and fast frequency response (FFR). These reserve services are defined on the next page, but the various operating reserve services generally conform to the frequency response services provided in North American electricity systems.
  - **Ramping Services** - 1 hour, 3 hour, and 8-hour ramping margin (RM1, RM3 and RM8); dynamic reactive response (RRD); Tertiary Operating Reserve 2 (TOR 2); and Replacement Reserve (RRS)
  - **Steady State Reactive Power (SSRP)**
  - **Synchronous Inertial Response (SIR)**
- The services that wind resources are qualified to provide are reserves and SSRP. In addition, battery energy storage resources may also provide ramping services.

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Reserve Service definitions

- Primary Operating Reserve is measured in terms of the additional MW output (or reduction in demand) at the frequency nadir compared to the pre-Incident output (or demand), where the nadir occurs between 5 and 15 seconds after the event.
- Secondary Operating Reserve (SOR) The additional MW output (or reduction in demand) compared to the pre-incident output, which is fully available and sustainable over the period 15 to 90 seconds following the event.
- Tertiary Operating Reserve 1 (TOR1) The additional MW output (or reduction in demand) compared to the pre-incident output, which is fully available and sustainable over the period 90 to 300 seconds following the event.
- Tertiary Operating Reserve 2 (TOR2) The additional MW output (or reduction in demand) compared to the pre-incident output (or demand), which is fully available and sustainable over the period 300 to 1200 seconds following the event.
- Replacement Reserve The additional MW output (and/or reduction in demand) required compared to the pre-incident output (or demand) which is fully available and sustainable over the period from 20 minutes to 4 hours following an event. The purpose of this category of reserve is to restore primary reserve within 20 minutes including restoring any interruptible load shed.
- Fast Frequency Response The additional increase in MW output from a generator or reduction in demand following a frequency event that is available within 2 seconds of the start of the event and is sustained for at least 8 seconds. The extra energy provided in the 2 to 10 second timeframe by the increase in MW output must be greater than any loss of energy in the 10 to 20 second timeframe due to a reduction in MW output below the initial MW output.

Category	Delivered By	Maintained Until
Primary (POR)	5 seconds	15 seconds
Secondary (SOR)	15 seconds	90 seconds
Tertiary 1 (TOR1)	90 seconds	5 minutes
Tertiary 2 (TOR2)	5 minutes	20 minutes

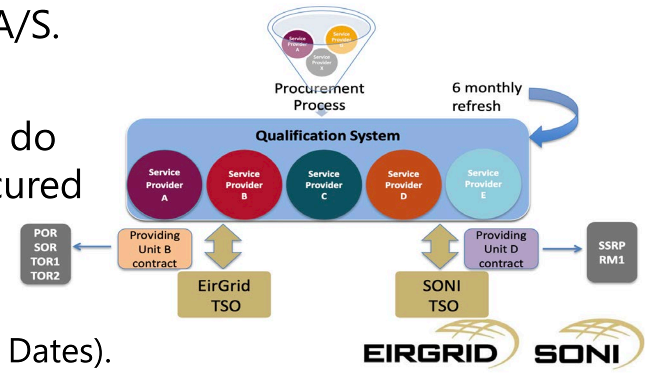
Key Agreements, Market and Operating Practices

- "Delivering a Secure, Sustainable Electricity System" (DS3) Programme - broad initiative to address the challenge of integrating high levels of renewable generation. Includes the provision of a range of system ancillary services at capabilities that are likely to require energy storage including fast frequency response and various operating reserve products.
  - DS3 System Services Fixed Contracts Agreement: EirGrid version June 13, 2019
  - Contractual Arrangements Decision Paper February 08, 2019 (SEM-19-005)
  - Procurement Arrangements Decision Paper September 07, 2018 (SEM-18-049)
- Codes
  - EirGrid Grid Code Version 8 Issued June 14, 2019
  - SEMO Trading and Settlement Rules
- Procedures and Process
  - Fast Frequency Response (FFR), Primary, Secondary and Tertiary Reserve (POR, SOR, TOR1) System Services Test Procedure WFPS
  - Steady-State Reactive Power (SSRP) System Services Test Procedure WFPS
  - WFPS Performance Monitoring Process Controllability of Windfarms Effective Feb 1, 2013

DS3 System Services Agreement Procurement Overview

- A main workstream and implementation outcome of DS3 is a system services framework to competitively secure an enhanced set of A/S. There are two resulting procurement processes:
- **Volume Uncapped Procurement** - frequent procurements that do not limit the volume of any of the 14 system services being procured and to which regulated tariffs apply.
    - Open to SSRP, RM1, POR, SOR, TOR1, and TOR2 providing units
    - Up to 5-year contracts awarded every 6 months (referred to as Gate Dates). Consists of two stages, pre-qualification and tender
    - Only tender based on their proposed technical solution and not price. Generally for existing resources to provide system services and are linked to energy market dispatch. Awards include wind projects.
- **Volume Capped Procurement** - is a competitive arrangement for capped volumes of a subset of services: Fast Frequency Response and Tertiary Operating Services (TOR 1 and 2).
    - The price is set as part of bids in the tender process. The contacts are awarded on a fixed term basis for a minimum period of 6 years
    - Are intended to provide contractual arrangements for aspiring entrants, allowing time for a build phase before service provision. Therefore, focused on new investment in high availability providing units where availability is not linked to energy market dispatch. Favors battery energy storage

Volume Uncapped Procurement



Source: [DS3 System Services Volume Uncapped Bidders' Conference]

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DS3 System Services Fixed Contracts awarded to date

Volume Capped Procurement Outcome

Providing Unit	Service Provider	Contract Size
Gorman Energy Storage Station	ScottishPower Renewables (UK) Limited	50 MW
Porterstown Battery Storage Facility	Porterstown Battery Storage Limited	30 MW
Kilmannock Battery Storage Facility	Kilmannock Battery Storage Limited	30 MW

- First Volume Capped Procurement was held in 2019 with awards announced in October.
- Bids were made by 18 service providers, with only 3 successful. The winning bids are all battery storage.
- Over their lifetime the contracts will total €38 million. If the equivalent level of services were procured through Volume Uncapped Procurement, the value of contracts would be approximately €210 million.

Volume Uncapped Procurement Outcome (All Island)

Service	Total Contracted Volumes*
POR	1,315 MW
SOR	1,741 MW
TOR1	2,056 MW
TOR2	2,387 MW
RRD	2,746 MW
RRS	4,563 MW
SSRP	7,566 Mvar
SIR	638,086 MWS^2
RM1	7,237 MW
RM3	8,184 MW
RM8	8,798 MW
FFR	792 MW

*Total contracted volumes between May 1, 2018 and April 1, 2020

DS3 System Services Fixed Agreements: Contract Terms

As found at the links on Slide 6, there are detailed agreements for the provision of system services from the DS3 procurement awards. Some of the key terms include those below. The Availability Scalar is valuable as performance is rewarded in contract payment. There are also scalars for event performance, fast response and temporal scarcity depending on the service.

Minimum Technical Requirements (Schedule 2): The service provider must provide reserve in accordance with the technical requirements of the Grid Code and the relevant Operating Parameters of the providing unit. The company will specify the following as appropriate for each contracted service.

- Under-frequency Reserve Trigger, OFR Trigger, FFR Trajectory, FFR-o Trajectory, Reserve Step Sizes and Reserve Step Triggers
- The following may be requested in real-time by the company and shall be implemented by the providing unit within 2 weeks of such request
- Enabling and disabling OFR Services, FFR, POR, SOR and TOR1, and alterations to the Under-Frequency Reserve Trigger, OFR Trigger, FFR Trajectory, FFR-o Trajectory, Reserve Step Sizes, and Reserve Step Triggers

Availability Assessment (Schedule 2): The value of the Availability Performance Scalar will be determined based on the Total Availability Factor. The Total Availability Factor will be calculated based on the combined Available Volumes of FFR, POR, SOR, TOR1, TOR2, FFR-o, POR-o, and SOR-o in accordance with the Protocol.

Scalar Values Based on Availability

Total Availability Factor	Availability Performance Scalar
<60%	0%
≥60% <70%	25%
≥70% <80%	50%
≥80% <90%	70%
≥90% <95%	85%
≥95% <97%	95%
≥97%	100%

EirGrid Grid Code Requirements

- Most wind projects on the Irish electric grid as a result of grid code requirements are equipped with what is referred to as Wind Farm Control (WFC), which effectively allows the wind farm to provide PFR. This approach is appropriate for Ireland given the high proportion of wind generation.
- WFC based active power control and power-frequency control, allowing the TSO to send an active-power set-point as well as a droop value to the WFC. When the TSO sends an active power set-point, the WPP output is down-regulated to this set-point so long as frequency remains in a deadband of +/-15mHz of nominal frequency.
- This generates headroom for participating in frequency control during underfrequency events. Once the frequency deadband is exceeded, the power-frequency control increases active power output in accordance with the droop value (typically set to around 4%).
- Some of the related grid code provisions specific to wind resources are provided in Appendix I. The term Wind Farm Power Stations (WFPSs) is used by EirGrid.

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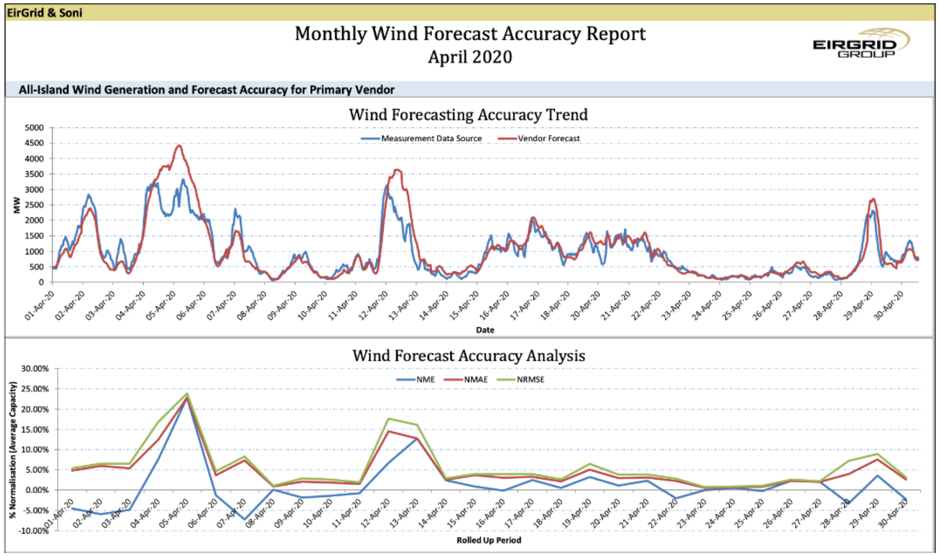
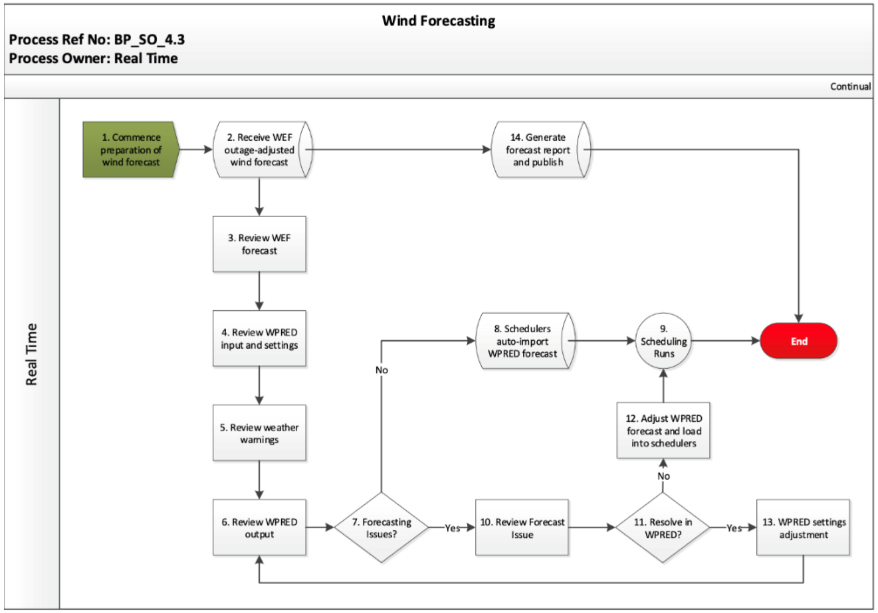
Renewables Forecasting

- Implemented in mid-2019, EirGrid wind forecasting is provided by two external providers via the Wind Energy Forecast (WEF) system
    - Provides long term forecasts of 15 minute intervals for 4 days ahead, information fed into Wind Predictor (WPRED) function in SEMO's Market Management System (MMS).
    - WPRED combines two forecast providers' forecasts into a single forecast and calculates the Lower Operating Limits of units
    - Outputs of WPRED are amended unit-level power forecasts with a resolution of 1 minute for 4 hours and 15 thereafter and aggregate system power forecasts with a resolution of 5 minutes
- EirGrid also provides an actual and forecasted wind generation dashboard that estimates the total output from all wind farms on the system at 15 minute intervals for the day, week or month



Source: EirGrid Group

Renewables Forecasting (Continued)



Source: SEMO

#	Step	Step Description	Responsible Role	Outputs	Indicative Timing/ Frequency	System
1	Commence preparation of wind forecast	Begin review of WEF and MMS wind forecasting.	Real Time		4 times a day in line with WEF forecasts	MMS
2	Receive WEF outage-adjusted wind forecast	MMS receives updated Ireland and Northern Ireland wind power forecast from the WEF tool.	Real Time		4 Updates per day	WEF/MMS
3	Review WEF forecast	Review current WEF forecast against EMS Wind Farm Availability to determine issues with forecast accuracy e.g. offsets, or ramping issues.	Real Time		With updated forecast delivery and/or per LTS run	WEF
4	Review WPRED inputs and settings	Review WPRED settings against the standard settings document. Review the WPRED input interfaces (INT 100 Wind Energy Forecast, INT 25a Real Time Availability, INT 25b Actual Output).	Real Time		Per Shift	MMS
5	Review weather warnings	Review any relevant weather warnings that are in effect that may impact on scheduling.	Real Time		With updated forecast delivery and/or per LTS run	Corporate
6	Review WPRED output	Review WPRED outputs with WEF forecasts and EMS Wind Farm Availability for forecast accuracy or processing issues.	Real Time		With updated forecast delivery and/or per LTS run	MMS
7	Forecasting Issues?	Consider the impact of any issues raised in steps 3, 4, 5, and 6. If no forecasting issues go to step 8, else step 10.	Real Time		With updated forecast delivery and/or per LTS run	
8	Schedulers automatically import WPRED forecast	If there are no forecast issues the WPRED outputs are automatically used in the scheduling processes.	None		As per scheduling process timelines	MMS
9	Schedulers Run	LTS, RTC and RTD scheduling tools run automatically or manually depending on their settings.	Real Time		As per scheduling process timelines	
10	Review Forecast Issue	If step 7 raises issues then there should be discussion with Real Time Manager of the impact of the issue on the scheduling processes. Changes to WPRED settings or to the WPRED output may be considered.	Real Time		as required	MMS
11	Resolve in WPRED?	Assess the issue to see if it can be resolved using the WPRED settings\functionality or does the issue need to be addressed outside of WPRED. If the issue is to be resolved within WPRED go to step 13, else step 12.	Real Time		as required	
12	Adjust WPRED forecast and load into schedulers	If changes to the WPRED output are required the amended unit-level forecast will be exported from MMS, adjusted and imported into the relevant scheduler process in step 9.	Real Time		as required	MMS
13	WPRED settings adjustment	If changes to the WPRED settings are required they will be made and logged in the standard settings document. Following changes to WPRED settings adjustment continue from step 6.	Real Time		as required	MMS
14	Generate forecast report and publish	MMS automatically generates and publishes the WEF outage-adjusted forecast reports.	Market Operator	Wind Forecast Reports	4 times a day in line with WEF forecasts	MMS

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Ancillary Services: Reward/Penalty Structure

Per the Ancillary Services Agreement between EirGrid and the provider:

Calculation of Rebates – POR, TOR1, TOR2 and RR

- The Service Provider will be required to pay to EirGrid a POR Rebate amount in respect of any Incident where the POR Shortfall is more than 10% of the Expected POR. If the POR Shortfall is not more than 10% of the Expected POR, then the CDGU will be considered to have delivered the required POR and no POR Rebate will be due in respect of this unit for this Incident and the POR Shortfall shall be reset to zero.
- The POR Rebate is the POR Shortfall divided by half the sum of the Contracted POR and the Expected POR multiplied by the Maximum POR Rebate.
  - POR Rebate = Maximum POR Rebate x POR Shortfall/[0.5 × (Contracted POR + Expected POR)]

Calculation of Rebates – SOR

- The “SOR Deficit” for each second is the Expected SOR less the Achieved SOR. The “SOR Shortfall” is the average of the “SOR Deficits” calculated for each second in the 15 to 90 second period.
- The Service Provider will be required to pay to EirGrid a SOR Rebate amount (determined as described below) in respect of any Incident where the SOR Shortfall is more than 10% of the Expected SOR. If the SOR Shortfall is not more than 10% of the Expected SOR, then the CDGU will be considered to have delivered the required SOR and no SOR Rebate will be due in respect of this unit for this Incident and the SOR Shortfall shall be reset to zero.
- The SOR Rebate is the SOR Shortfall divided by half the sum of the Contracted SOR and the Expected SOR multiplied by the Maximum SOR Rebate.
  - SOR Rebate = Maximum SOR Rebate x SOR Shortfall/[0.5 x (Contracted SOR + Expected SOR)

Lessons Learned for Nova Scotia

- Ireland has been able to achieve a high penetration of wind energy, representing 34% of total energy production, but this has required fundamental changes to its market structure.
- EirGrid's competitive market structure is fundamentally different that Nova Scotia's electricity structure, which is based on a vertically integrated utility. As such, many of the reforms that were appropriate for EirGrid are not necessarily likely to be appropriate for Nova Scotia.
  - For example, DS3 System Services Agreement Procurement is appropriate for EirGrid, but not Nova Scotia.
  - Nonetheless, it is of interest that all the resources selected in the Volume Capped Procurement were battery energy storage systems.
- EirGrid has defined a fast frequency response (FFR) service, which aligns with the synthetic inertia (fast frequency response) offered by wind projects. Such a service may be appropriate for wind turbines in Nova Scotia, with the various commercial terms to be considered elsewhere.
  - However, the FFR service parameters for Ireland are not necessarily appropriate for Nova Scotia.

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PSCo (Colorado, US)

Public Service Company of Colorado (PSCo) Overview

Electricity Market Structure

- Type: Regulated
- Description: PSCo is a vertically integrated, investor owned utility that is an operating company of Xcel Energy and regulated by the Colorado Public Utilities Commission (CPUC)

Market Participants/Institutions

PSCo	• Investor owned electric and natural gas utility serving the majority of Colorado including the Denver area. About 1.4 million customers. 70% of PSCo's electricity supply is from generation it owns and about 30% purchased from IPPs and cooperatives.
Xcel Energy	• A Minneapolis based energy company that operates utilities in Colorado, Michigan, Minnesota, New Mexico, North Dakota, South Dakota, Texas and Wisconsin. Was the first major US utility company to announce a 100% carbon-free goal in 2018. • Xcel corporate goal: 80% below 2005 levels by 2030 & 100% carbon-free by 2050
Regulators	• The **Colorado Public Utilities Commission (CPUC)** regulates PSCo with respect to facilities, rates, service, accounts and issuance of securities. PSCo is also regulated by the US **Federal Energy Regulatory Commission (FERC)** with respect to wholesale electric operations (specifically transmission), accounting practices, and asset transactions.

Market Size and Renewables Penetration

Installed Capacity (2019)

Total	5,666 MW	**Variable Output Renewable Energy**	Wind - 3,165 MW (Both owned (600 MW) & long term PPAs) PPA Solar - 862 MW (Distributed and utility scale contracted)

Generation (2019)

29,000 GWh Coal - 33% Natural Gas - 37% Wind - 25% Solar - 4% Other renewables -1%	29% of total (Variable output renewables) Wind - 25%, Solar - 4%

Planned Renewables Additions

- Colorado Renewable Energy Standard, set out in 2004, to have 30% renewables for IOUs by 2020 and 100% clean energy by 2050 for utilities serving at least 500,000 customers.
- PSCo's Colorado Energy Plan (CEP) is soliciting up to 1,100 MW of wind by 2026 with four projects meeting this need already awarded. Projects include: 500 MW Cheyenne Ridge Wind, 300 MW Bronco Plains Wind Project, 169 MW Mountain Breeze Wind Project and 162MW Colorado Green Wind.

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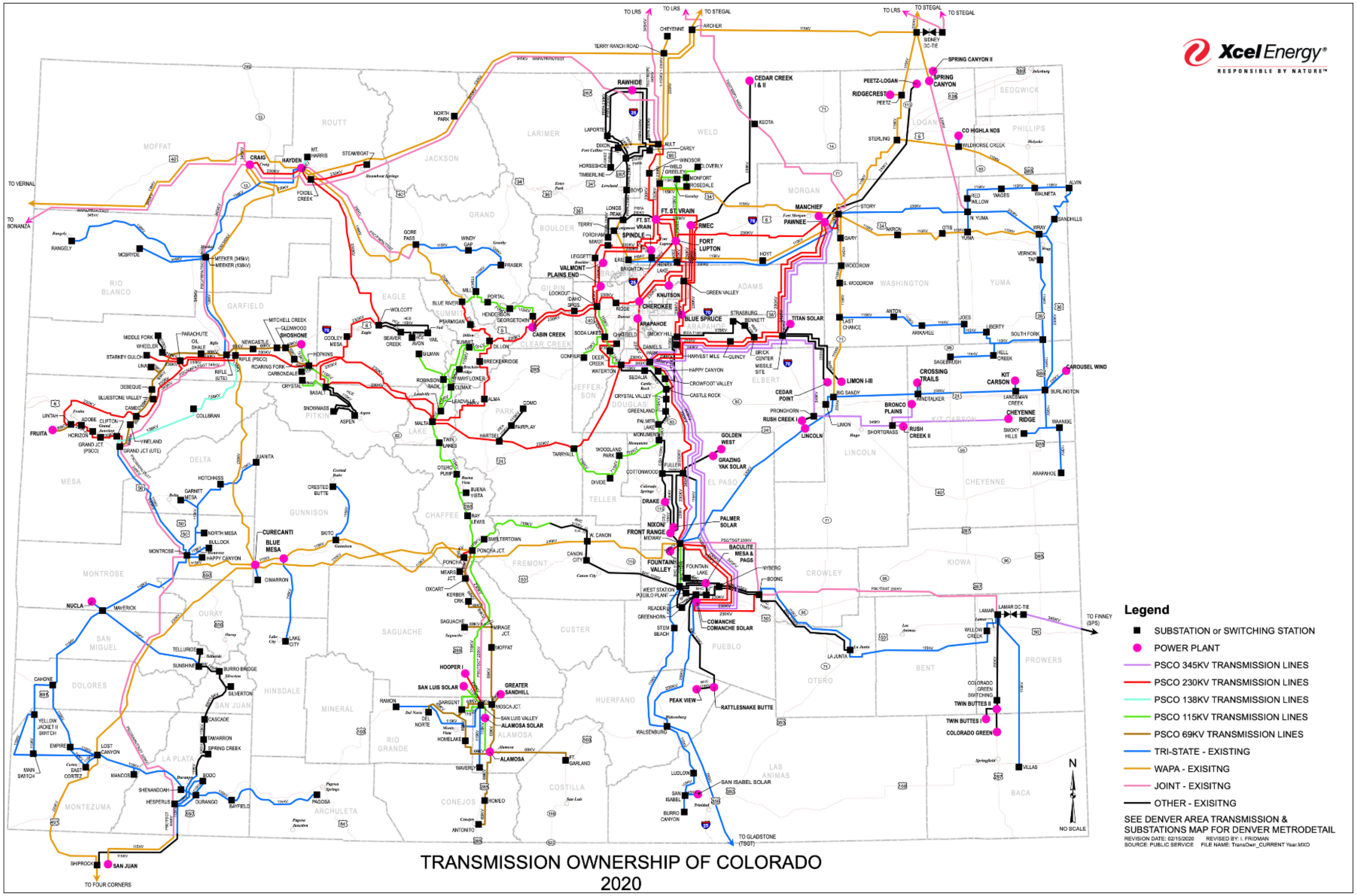
Colorado Generation and Transmission System Map

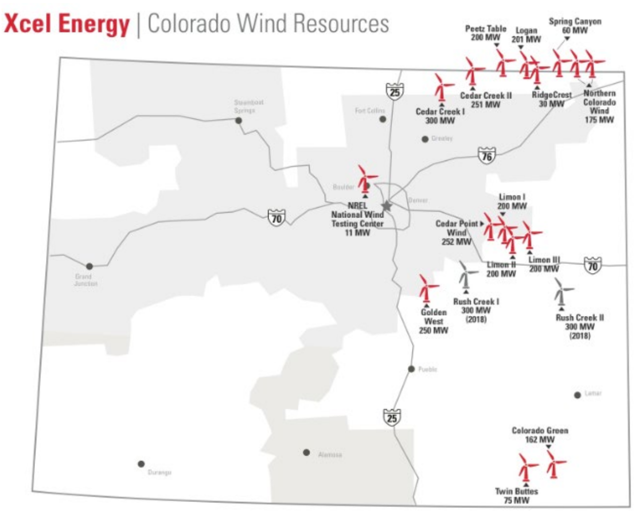


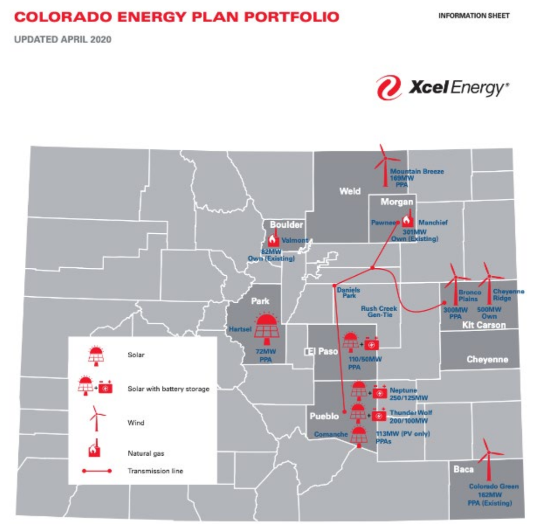
Source: PSCo 2020 OASIS

Basis for wind generation capacity in PSCo

PSCo conducts competitive procurements for new generation resources based on their Electric Resource Plans and the state's policy goals. In addition, to long term PPAs with private developers, solicitations can include EPC sale agreements where ownership is transferred to the utility and self build proposals by PSCo affiliates.

- Colorado Energy Plan (CEP), calls for soliciting up to 1,100 MW wind, 700 MW solar and up to 700 MW of natural gas by 2026. The projects already awarded are noted on the first slide of the scan.
- Xcel 2017 All-Source Solicitation RFP was an open opportunity to fulfill an identified capacity need identified in the 2016 ERP from the retirement of two coal plants, what is now the CEP. Required COD prior to May 2023. Received over 400 bids totaling over 100,000 MW. Wind and solar including paired with energy storage was selected at about $20/MWh (USD).





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A/S included in Open Access Transmission Tariff

- As indicated, PSCo is a regulated market. A/S are defined within Xcel Energy's OATT and follow the standard form in most OATTs.
- Transmission customers are required to purchase the following services:
    - Scheduling, system control and dispatch
    - Reactive supply and voltage control from generation and other sources
- The transmission customer serving load within the transmission provider's Control Area is required to acquire these services (from the transmission provider, third parties or self-supply)
    - Regulation and Frequency response
    - Energy imbalance
    - Operating Reserve - Spinning
    - Operating Reserve - Supplemental
    - Flex Reserve Service (for service provided over PSCo specifically)
- Transmission customer may not decline the transmission provider's offer of ancillary services unless it demonstrates that it has acquired the ancillary services from another source.

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Key Agreements, Market and Operating Practices

- [Wind] [Solar] Energy Purchase Agreement
  - Updated PSCo PPA for wind and solar providers including provisions for ancillary services.
- Large Generation Interconnection Guidelines (>20 MW)
- Small Generation Interconnection Guidelines (<20 MW)
- Xcel Energy - Standard for Electric Installation and Use
  - Manual of clearance requirements and uniform standards for installing and using electric facilities on its system.
- Schedule 16: Flex Reserve Service (section of broader OATT at link)
  - In order to reliably integrate wind generation onto its system, PSCo has created a supplemental reserve category designed to address large reductions of online wind generation due to losses in wind speed. This reserve category is listed as "Schedule 16: Flex Reserve Service" on the PSCo transmission tariff. This new 30-minute Flex Reserve Service as of 2016 replaced the company's prior 30-Minute Wind Reserve Guideline.

- PSCo does not have a day ahead or real time market but does use sub-hourly scheduling.
- Since 2016, PSCo uses 15-minute intervals for intra-hour scheduling and 30-minute flexibility reserve for wind operations.
- PSCo uses advanced wind forecasting to forecast for up to a 168-hour period with forecasts provided every 15 minutes. This has reduced PSCo's forecast error rate by 39%.

How hybrid projects are evaluated in the competitive procurement

- In PSCo's All Source 2017 Semi-Dispatchable Renewable Capacity Resources RFP, there was no difference in the evaluation of solar thermal with thermal storage or fuel back-up, or any other intermittent resource with storage or fuel backup.
- PSCo's economic evaluation focused on an "all-in" levelized cost of energy.
- Differences in project costs for resources with greater operating flexibility were considered based on differences in resource integration costs. The resource integration of more flexible dispatchable resources were inherently lower than those for wind or solar projects, with no paired energy storage resources.
- This evaluation approach didn't require the consideration of the incremental value of energy storage. This value was considered as a lower integration cost.

How hybrid projects are paid in the Power Purchase Agreement

- In the PSCO's All Source Model Semi-Dispatchable PPA, specific payment information is given for solar, gas capabilities, combustion unit starts, natural gas and combustion unit dispatch, but specific payment information for storage is lacking.
- Semi-Dispatchable Projects are dispatched by PSCo. Higher prices are not paid for output during higher priced hours.
- PSCo's RFP indicates that "Projects that propose integrated fuel backup/hybridization may elect to recover the incremental capital costs of the hybridization equipment through either the base energy payment rates or, alternatively, through a monthly demand payment rate"
  - Proponents that elect to have a monthly demand rate would receive a base energy payment for all production, with the incremental capital costs of the storage paid through the demand ($/kW-month) rate.
- This approach simplifies contract pricing.

A/S requirements in PSCo renewables PPA

- Per the *[Wind] [Solar] Energy Purchase Agreement*, *7.4 Ancillary Services* the seller must provide certain A/S and is responsible for the arrangements and costs. The related provisions include:
  - PSCo is entitled and Seller shall make available all A/S associated with the facility, at no additional charge
  - Seller must use commercially reasonable efforts to maximize the ancillary services available
  - Services may include capacity or reliability attributes, resources adequacy characteristics, locational benefit attributes and VaR generation. Extends to other services in the transmission tariff
  - Any compensation the seller receives under the Interconnection Agreement or third parties for ancillary services will be provided to PSCo
    - Recognizing that PSCo customers are likely paying for an energy rate predicated on the project's full cost of service. The seller will credit PSCo for any compensation the seller receives for ancillary services if the Governmental or Transmission Authority implements new or revised requirements for generators to create, modify or supply A/S.

A/S requirements in PSCo renewables PPA

- In essence, other than putting an obligation on the Seller to maximize A/S available, PSCo's PPA doesn't appears to depart from standard form PPAs pricing. For example, there is no additional compensation for A/S provision recognizing potential opportunity costs or increased O&M.
- It does require all wind power plants to install AGC equipment. PSCo's fleet of wind plants routinely provide regulation down via AGC, based on contract considerations, system operators have expressed a reluctance to rely on wind forecasts to guarantee up regulation (see comments from a PSCo dispatcher in NREL, "Solar and Wind Participation in AGC Systems," June 2019).

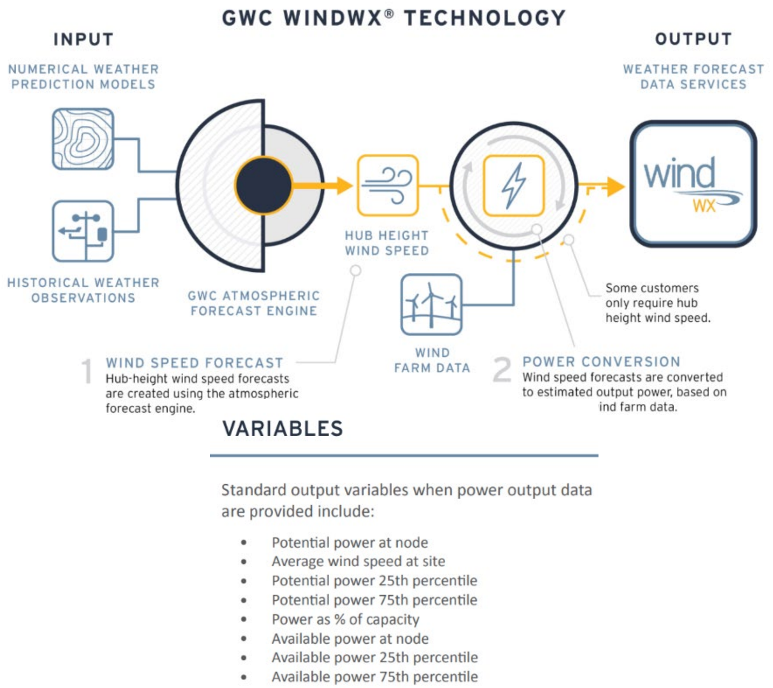
Interconnection Requirements from Guidelines

- Reactive Power - provide reactive power within the range of 0.95 leading to 0.95 lagging at the system operating voltage at the POI. Must provide any capacitors or other devices needed to achieve this power factor performance level.
  - Self-commutated inverters must meet the same requirements as synchronous generators, and line commutated inverters must meet the same requirements as induction generators.
- Frequency Control - Generators shall be equipped with governors that sense frequency and provide 5% (WECC) and a ±0.36 hertz or less dead band unless agreed otherwise by Xcel Energy. The generator must begin increasing or decreasing output at frequency set points of 59.64 hertz or 60.36 hertz respectively. The change in output must begin occurring within 0.5 seconds of a detected frequency disturbance.
- Voltage Control - Any generator providing this service to the Control Area Operator must be able to automatically control the voltage level by adjusting the machine's power factor within a continuous range of between + 0.90 to - 0.90 power factor based on the station's sum total name plate generating capability as measured at the transmission system POI.
  - The voltage or var set point that the generator needs to maintain is established and dispatched as necessary by Xcel Energy's Control Center

Renewables Forecasting

Xcel Energy helped develop the WindWX with Global Weather Corp, an affiliate company of the National Center for Atmospheric Research.

- WindWX includes two datasets: hub height wind speed and estimated power output
- Uses real-time, turbine-level operating data, along with sophisticated algorithms to forecast the amount of wind power that will be produced
- Forecasts generated hourly at 15-minute intervals and available at 7-day periods, available worldwide through GWC
- Xcel has seen an improvement to their wind forecasting accuracy by nearly 35% since WindWX's development in 2009
- In 2015, revisions were made to Wind WX to improve the forecasting accuracy and visualization of Xcel's renewables portfolio through a focus on extreme weather events, introducing probabilities into the forecasting process and explored solar forecasting of behind the customer meter



Source: Global Weather Corporation

Lessons Learned for Nova Scotia

- PSCo's adaptions for increased penetration of non-synchronous/inverter-based resources are relatively modest in spite of the high penetration of these resources.
- There's an obligation on these resources to maximize the availability of A/S. However, the scope of required A/S doesn't include any of frequency response services that are important in Nova Scotia including synthetic inertia or fast frequency response, primary frequency response or secondary frequency response.
- Furthermore, there's no explicit compensation for these A/S. We note that the provision of reactive support/voltage control can result in higher losses, which can warrant incremental compensation. The significance of this issue depends on how the service is called upon.
- PSCo has imposed requirements on non-synchronous/inverter-based resources to provide reactive power and voltage control.
- PSCo compensates hybrid projects for their storage capability either based on a $/kW-month payment or the base energy payment. This simplifies PPA pricing rather than having on and off-peak rates etc.
    - PSCo has the ability to dispatch the storage capability, which is appropriate given the payment structure.

ERCOT (Texas, US)

ERCOT Overview

Electricity Market Structure

- Type: Competitive Wholesale, Retail Market
- Description: In 2002, the Texas Legislature restructured the state's electricity sector by: mandating an open-access, non-discriminatory transmission network with ERCOT appointed as the independent system operator and wholesale market administrator; requiring that utility companies vertically unbundle their services into separate entities classified by generation, transmission/distribution, and retail functions; and enabling new entrants to participate in both the wholesale and retail markets.

Market Participants/Institutions

Electricity Reliability Council of Texas (ERCOT)	• ERCOT is the member based non-profit, independent system operator for the electricity system that covers about 75% of Texas geographically and about 90% of the statewide electric load. The core functions of ERCOT include system reliability, open access to transmission, wholesale market operation and settlement, and facilitating customer retail choice switching. • It's electrically separated from the Eastern and Western Interconnections which cover much of the rest of North America and as such has lower amount of inertia. ERCOT is outside of FERC's jurisdiction since there are no interstate sales.
Public Utility Commission of Texas (PUCT)	• The PUCT regulates the state's electric, telecommunication, and water and sewer utilities as well as oversees certain aspects of ERCOT. PUCT issues RECs to qualifying renewable generators.

Market Size and Renewables Penetration*

Installed Capacity (2019)

Total	78,929 MW	**Variable Output Renewable Energy**	Wind - 23,860 MW Solar - 2,281 MW

Generation (2019)

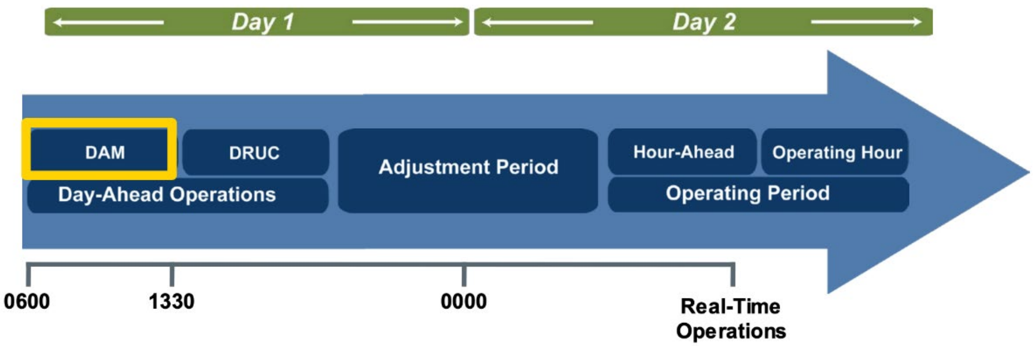
383,447 GWh (Total) Natural Gas - 47% Wind - 20% Coal - 20% Nuclear - 11% Other – 2%	82,062 GWh (Renewable) 21.5% of total Wind - 20%, Solar - 1.1%, Other Renewables - 0.4%

Planned Renewables Additions

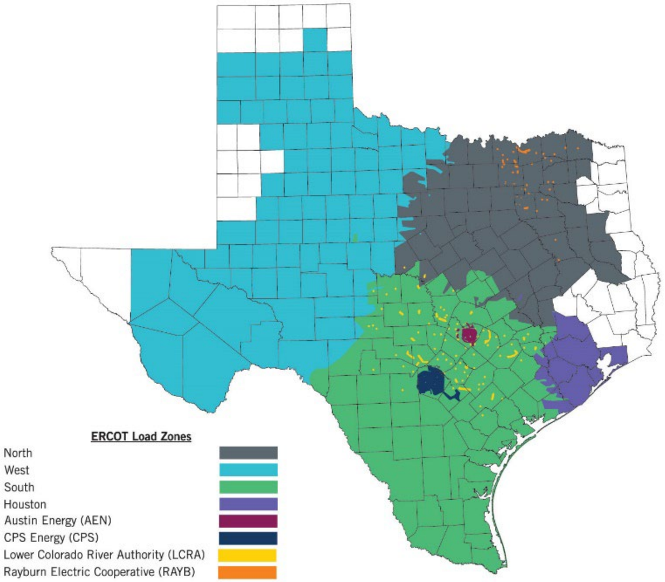
- 22,823 MW of wind and 21,841 MW of solar with Interconnection Agreements (IA) to be installed by 2022, actual volume to be added likely to be considerably less
- 350 MW of battery storage installed by end of 2020
- About 2,500 MW of wind and solar came online in 2019 alone

ERCOT: Transmission System and Electricity Markets

Electricity Markets



Source: ERCOT "Nodal 101"



- ERCOT uses a Day-Ahead Market (DAM) and Real-Time Market (RTM) energy market, along with separately scheduled ancillary services (reserve and DAM ancillary).
- Only Qualified Scheduling Entities (QSEs) can participate in DAM and participation is voluntary, except for ancillary services. The RTM is the primary market.
- ERCOT is an "energy only" wholesale market. Meaning it has no capacity mechanisms like other ISO/RTOs. As an energy only market, it relies on revenues from energy production and operating reserves to provide a price signal that supports the construction of new generation.
- Thus, energy pricing determines investment in new generation. This results in more volatile and often very high energy prices during periods when resources are scarce (i.e. scarcity pricing).

Basis for wind generation capacity in ERCOT

- Reflecting its competitive market structure, the installed wind capacity in ERCOT has been entirely developed by Independent Power Producers (IPPs), largely under contract with corporate buyers or even on a merchant basis. The distribution companies in ERCOT are not allowed to own generation.
- A few important drivers have shaped the deployment of wind in this market:
  - Availability of the federal **production tax credit (PTC)**, which has offered a value over $20/MWh from the tax equity market for the first 10-years of a project. In the case of solar, those projects have benefited from the upfront Investment Tax Credit (ITC) of 30% eligible costs
  - Transmission planning and purpose-built transmission capacity for renewables through **Competitive Renewable Energy Zones (CREZ)**. Senate Bill 20 (2005) directed PUCT to establish CREZs in areas throughout Texas with strong renewable energy resource potential. Through a competitive procurement process in coordination with ERCOT, the designation of the CREZs resulted in the expansion of the state's transmission capacity by constructing a new 3,600-mile 345-kV transmission network built by private developers with a capacity of 18.5 GW.
- Texas does have a Renewable Portfolio Standard (RPS), which helped in the early stages of deploying wind. However, it has been long surpassed and is not a significant policy driver like in other US states. More specifically, its RPS set in 1999 called for the development of 5,000 MW of new renewables by 2015 and set a target of 10,000 MW of renewable energy capacity by 2025. Texas exceeded these targets in 2009 and has not updated its RPS since.

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Ancillary Services

- The ancillary services in ERCOT include:
  - **Responsive Reserves Service (RRS)** - max limit of 60% provided by Load Resources (excluding Controllable Load Resources), subject to the minimum capacity of 1,150 MW required from a resource providing RRS using Primary Frequency Response
  - **Non-spin Reserves**
  - **Regulation Up and Down**
  - **Black Start, Reliability Must-Run (RMR)**
  - **Voltage Support Service (VSS)**
  - **Emergency Interruptible Load Service (EILS)**
  - **Primary Frequency Response**
  - **Ramp Rate Limitation**
  - **Firm Frequency Response (FFR)** - contingency service is triggered by local frequency with a response time of 0.5 seconds and sustains duration for 10 minutes
- ERCOT currently uses an Operating Day Ancillary Service Plan.
  - Each Qualified Scheduling Entity (QSE) may self-arrange its obligation assigned by ERCOT for its ancillary services. Any ancillary service that is not self-arranged will be procured as a service by ERCOT on behalf of the QSE.
- Real-Time Co-Optimization is beginning to be implemented in ERCOT. It is a series of modifications to bring Day-Ahead Ancillary Service (AS) procurement into alignment with the energy market (i.e. the electricity products will be co-optimized).

Key Agreements, Market and Operating Practices

- Ancillary Service Practices and Requirements
  - Current Nodal Protocols
  - Current Nodal Operating Guides
  - ERCOT Methodologies for Determining Minimum Ancillary Service Requirements: Methodology for how ERCOT determines the necessary ancillary services to be provided
  - NPRR863 (Creation of ERCOT Contingency Reserve Service and Revisions to Responsive Reserve, approved February 2019) and NPRR960 (Phased Approach and Clarifications for NPRR863, approved October 2019)
    - Phase 1 (effective March 1, 2020) focused on implementing Fast Frequency Response (FFR) as a subset of Responsive Reserve Service. Only energy storage is qualified to provide FFR in Phase 1.
    - Phase 2 (planned for 2022), to introduce Contingency Reserve Service (ECRS) and expand FFR eligibility.
- Future Ancillary Services Framework
  - Framework for Future Ancillary Services proposed by ERCOT staff and stakeholders in 2013 that included unbundling the Response Reserve Service into Fast Frequency Response, Primary Frequency Response, and Contingency Reserve Service. Ultimately, the members of ERCOT rejected the proposal in 2016. As indicated above, some of these services were ultimately adopted in 2019 with the revision requests NPRR863 and NPRR960.

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Interconnection requirements for renewable generators

- In terms of A/S, the following is required of renewable resources in the grid code:

  1. Frequency Control - assist in ERCOT's frequency control and contribute Governor Dead-band response of up to 17 mHZ (PFR) to variations (see example for wind on next slide).

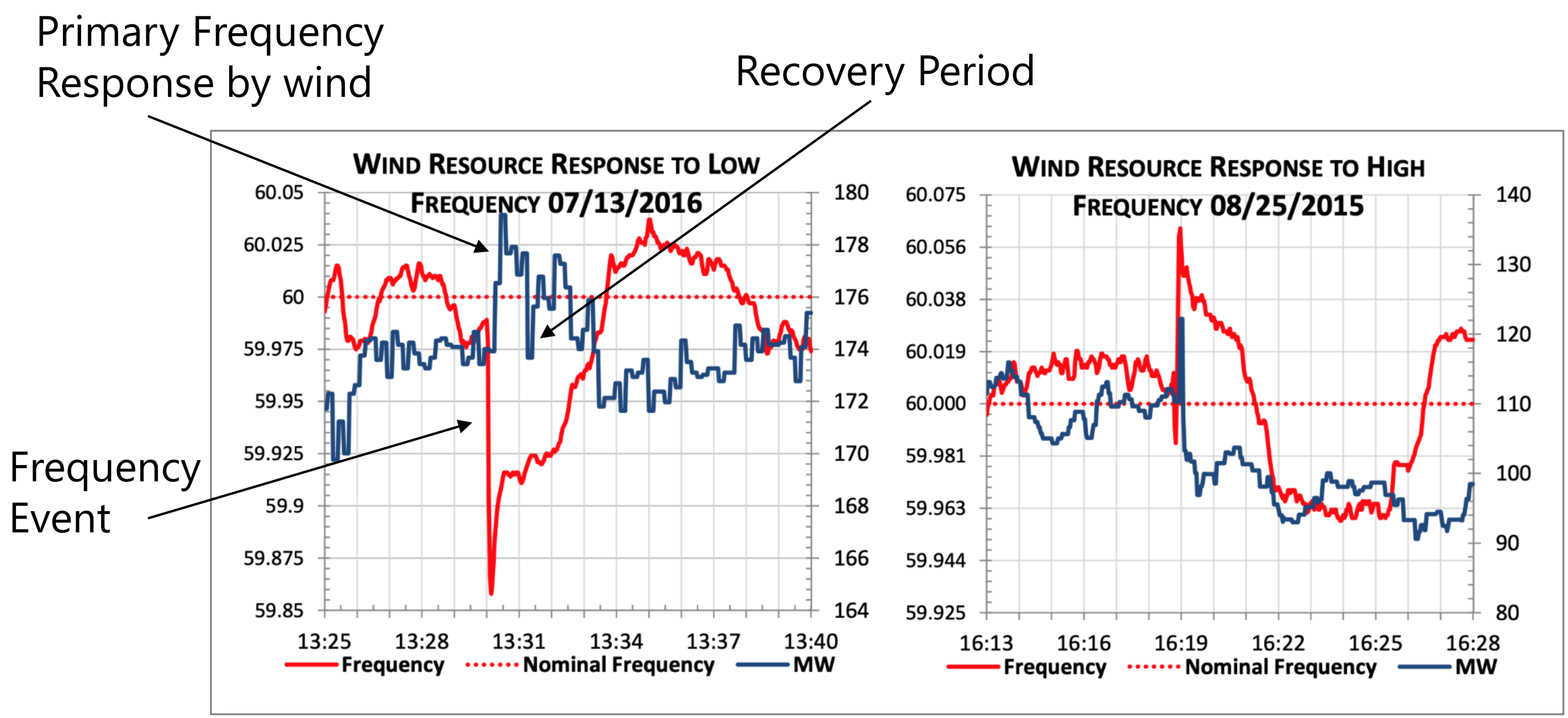
  2. Disturbance Ride Through - required to ride through (i.e. stay online) during disruptions to normal voltage and frequency (1.6.5(a)).

  3. Voltage Support - Renewables with an aggregated gross rating > 20 MVA must provide voltage support services (3.15 Voltage Support).
     - To provide this service, renewables are required to have reactive power capability at all MW output levels at or above 10% of nameplate capacity. Can be met through a combination of the unit's dynamic leading/lagging capability and/or dynamic VAr capable devices.

  4. Ramp Rate Limitation - are required to implement controls which limit per minute ramping to 20% of the unit's nameplate rating (6.5.7.10).

- These are interconnection requirements, which are not compensated in an ERCOT market or transmission tariff.

Grid Code: Frequency control example wind response



Source: ERCOT, "Renewable Integration and Resiliency of the Power Grid," May 2017

Future Ancillary Services Framework

- In 2013, ERCOT staff and stakeholders first proposed a Future Ancillary Services framework to improve A/S in the market. The existing framework hadn't significantly changed since the markets started. The proposed framework centered on unbundling A/S.
- Developments that necessitated this initiative included:
  - Increasing penetration of distributed and utility-scale renewable energy (non-synchronous/inverter-based generation)
  - Beginning of a rise in energy storage technologies
  - Increased smart grid technologies
  - Increased use of demand response resources
- The proposed framework consisted of the following (see next slide for an illustration):
  - Maintained the existing regulation services (Reg-up, Reg-Down, Fast-Responding)
  - Unbundled RRS into: Fast Frequency Response (FFR), Primary Frequency Response (PFR), Contingency Reserve (CR) Service
  - Added Synchronous Inertial Response (SIR) with possible need for Synchronous Reserve Service
- ERCOT A/S spending at the time of the proposal was about $500 million annually. The estimated cost of the proposed changes was in the range $12-15 million and resulting savings of $11-16 million/year (at natural gas price of $2.36 per MMBtu).
- The proposed framework was rejected by ERCOT stakeholders in 2016 given claims that it wasn't required. However, some aspects were adopted in 2019 with NPRR863 and NPRR960 including FFR.

Future Ancillary Services Framework Cont.

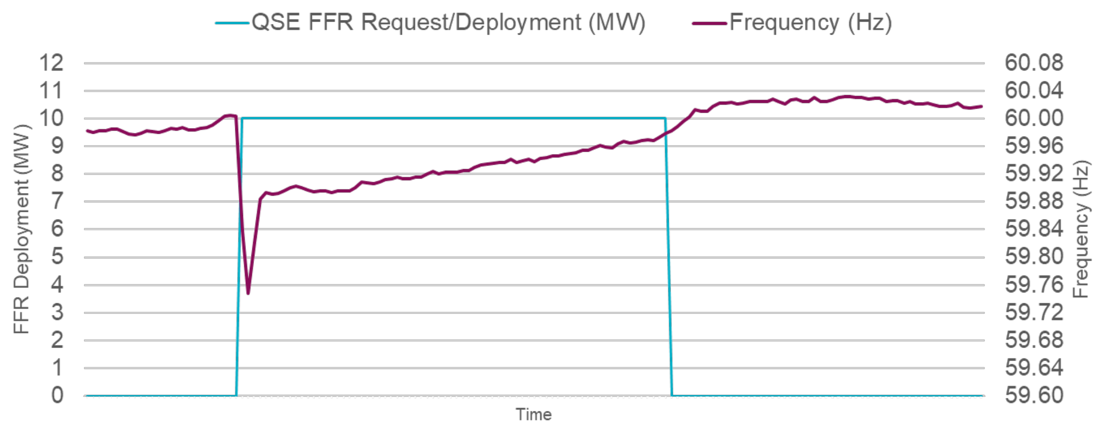
Current	Proposed	
Regulation Up Fast-Responding Regulation Up	Regulation Up Fast-Responding Regulation Up	*Mostly unchanged*
Regulation Down Fast-Responding Regulation Down	Regulation Down Fast-Responding Regulation Down	
Responsive	Fast Frequency Response 1	*59.8 Hz, Limited duration*
	Fast Frequency Response 2	*59.7 Hz, Longer duration*
	Primary Frequency Response	
	Contingency Reserves 1	*SCED-dispatched*
	Contingency Reserves 2	*Manually dispatched*
Non-Spin	Supplemental Reserves 1	*SCED-dispatched*
	Supplemental Reserves 2	*Manually dispatched*
	Synchronous Inertial Response	*Ongoing development*

Source: ERCOT, "Future Ancillary Services,"2015

Future Ancillary Services Framework: Fast Frequency Response (FFR)

- As proposed by ERCOT in the Future Ancillary Services Framework, FFR is a response from a resource that is automatically self-deployed and provides a full response within 30 cycles after frequency meets or drops below a preset threshold. FFR may also be manually deployed and full response must be provided within 10 minutes.
- Based on their sustainability and ability to restore FFR resources may participate in sub-group FFR1 or FFR2.
  - FFR1 - must be able to sustain a full response for maximum of 10 minutes and should fully restore within 10 minutes of receiving ERCOT's recall instruction or continuous 10 minutes of deployment, whichever comes first. Trigger frequency threshold for response of 59.8 Hz.
  - FFR2 - must be able to sustain a full response until ERCOT issues a recall instruction or the resource no longer has a responsibility to provide the service, whichever comes first. The resource must be able to fully restore its FFR2 responsibility within 90 minutes after receiving ERCOT's recall instruction. Trigger frequency threshold for response of 59.7 Hz.
- Combination of PFR and FFR must be sufficient to avoid Under Frequency Load Shed for instantaneous loss of 2,750 MW. These services help stabilize the frequency but do not recover the frequency back to nominal frequency.

NPRR863 and NPRR960 Phase 1 implementation



Source: ERCOT, "Implementation details for phase 1 of NPRR 863 and NPRR 960," Feb 26, 2020

- FFR introduced in ERCOT, effective March 1, 2020 as a subset of Responsive Reserve Service (RRS). Requirements for this FFR service include:
  - response within 15 cycles after frequency meets or drops below a preset threshold (59.85 Hz) or a deployment is response to an ERCOT Verbal Dispatch Instruction (VDI) within 10 minutes
  - Sustained for at least 15 minutes
  - Recovers within 15 minutes
  - Battery Energy Storage (combo model of Generation Resource (GEN) and Controllable Load Resource (CLR)) will be the only resource able to qualify for this Phase 1)
  - FFR that is deployed shall not recall its capacity until system frequency is greater than 59.98 Hz

Renewables Forecasting

- Electric Reliability Council of Texas (ERCOT) contracts forecasting of Renewable Production Potential for Wind Power Generation Resources (WGR) and Photovoltaics Generation Resources (PVGR) and provides those forecasts of each generating unit to Qualified Scheduling Entities (QSEs).
  - Renewable generation forecasts provide input into the Day-Ahead Reliability Unit Commitment and Hour-Ahead Reliability Unit Commitment.
  - Forecasting is used to ensure grid reliability as wind and solar penetration greatly increases.
- **Wind Potential Forecast:** ERCOT contracts two wind forecasting service providers (WFSPs) to produce Mid-Term Wind Generation Forecast (MTWGF). MTWGF includes an hourly Short-Term Wind Power Forecast (STWPF) and the Wind-powered Generation Resource Production Potential (WGRPP) for each WGR and ERCOT system aggregation for the next 48 hours and 168 hours. The Wind Potential Forecast (WPF) is the system that provides STWPF, WGRPP, intra-hour forecast, and extreme weather forecast.
- **Photovoltaics Generator Resources Potential Forecast:** ERCOT contracts on PVGR forecasting service which provides Short-Term Photovoltaic Power Forecast (STPPF) and Photovoltaic Generation Resource Production Potential (PVGRPP) for each PVGR and ERCOT system aggregation for next 168 hours.

Table 1. Specifications of Wind Forecasting Products and Services

	STWPF and WGRPP	Extreme Weather Forecast	Intra-hour Wind Forecast
Time resolution	1 hour	1 hour	5 minute
Forecasting Horizon	168 hours	168 hours	2 hours
Delivery	ERCOT total/wind regions/WGRs	ERCOT total/wind regions/WGRs	ERCOT total/wind regions/WGRs

ERCOT, "ERCOT Wind Power Forecasting Process," April 2020

Data Requirements (Wind Forecasting)

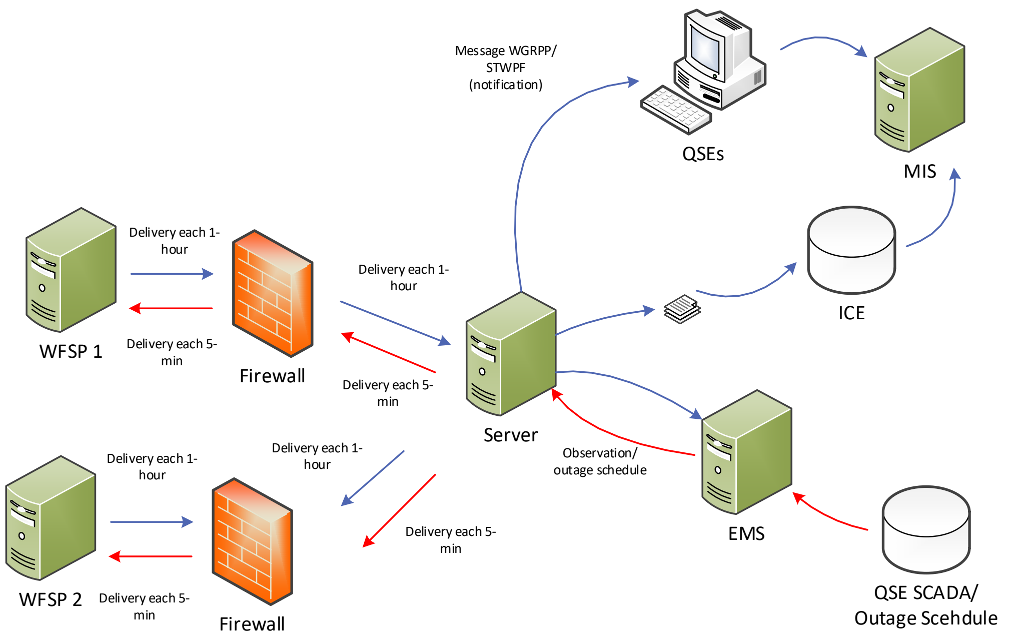
Registration Data	Outage Scheduler Data	SCADA Data
• Resource name • Resource-QSE mapping • Resource parameters (max and min reasonability limits) (MW) • Location of wind farm (latitude and longitude of center point) • Location of the meteorological tower (longitude and latitude) • Meteorological tower height • Type (manufacturer/model) and number of turbines • Turbine hub height(s) above ground level (meters) with associated number of turbines • Manufacturer's power curve (capability curve) • Resource COD	• Scheduled outages • Scheduled derates of wind farms	• Resource status (offline/online) with date/time • Output of wind farm with date/time (MW) • HSL of wind farm with data/time • Curtailment flag • Wind speed (MPH) • Wind direction from a meteorological tower with date/time • Temperature (°C) • Barometric pressure at 2 m above ground level on meteorological tower (hPa [mb])

Information taken from: ERCOT, "ERCOT Wind Power Forecasting Process," April 2020

Data Processing

- 168-hour extreme weather forecasting
    - 2 scenarios: worst case = all turbines offline AND likely = 50% offline
- Intra-hour wind forecast: produced every 5 minutes with outlook of next 2 hours
    - Integrate these intra-hour forecasts for entire ERCOT territory, every Wind Region, and each WGR into the Generation To Be Dispatched (GTBD) calculation, providing the ability to more effectively dispatch power and manage regulation resources
- ERCOT provides WFSPs with data every 5 minutes and the WFSPs return forecasting data every hour. Intra-hour forecasts are delivered to ERCOT about 1 or 2 minutes before the next Security Constrained Economic Dispatch (SCED) performance.
- ERCOT and the WFSPs will calculate forecast error statistics using an automated model.

Wind Power Physical Deployment View

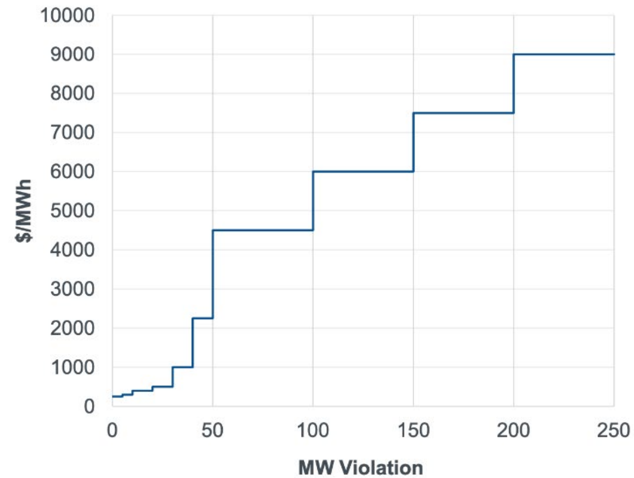


ERCOT, "ERCOT Wind Power Forecasting Process," April 2020

Ancillary Services: Reward/Penalty Structure

- ERCOT issues **power balance penalties** for under-generation, over-generation, and violation of transmission constraints.
- These penalties result in penalty costs reflective of shadow price caps.

Power Balance Penalty for Under-Generation



MW Violation	$/MWh
MW< 5	250
5 ≤ MW< 10	300
10 ≤ MW< 20	400
20 ≤ MW< 30	500
30 ≤ MW< 40	1000
40 ≤ MW< 50	2250
50 ≤ MW< 100	4500
100 ≤ MW< 150	6000
150 ≤ MW< 200	7500
200 ≤ MW	9001

Shadow Price Caps

Type of Violation	Voltage	$/MWh
Base Case / Voltage	N/A	5000
N-1 Constraint	69kV	2800
	138kV	3500
	345kV	4500

Penalty cost for transmission constraint violation based on shadow price caps and MW violation amount

Power Balance Penalty for Over-Generation

MW Violation	$/MWh
1 ≤ MW	-250

Source: ERCOT, "Module 5: Resources in Real-Time Operations," October 2017

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Lessons Learned for Nova Scotia

- ERCOT's work developing FFR-type services is of interest. Decision not to adopt based on commercial decisions by market participants, not on issues with the design.
  - Key question for Nova Scotia is whether FFS services with relatively short duration enable either greater renewables integration and/or operational flexibility
  - If longer duration is required enable reduced thermal generation commitment (for example) storage would likely be required concurrently to provide from a wind or solar project
- When ERCOT ultimately implemented FFR it was done on a basis that didn’t allow wind turbines to participate given the duration required.
  - Given the size of the ERCOT market battery energy storage projects offer broad benefits beyond FFR. This may also be true in Nova Scotia, but this assessment is beyond the scope of this report.
- ERCOT has broken out AGC into a reg-up and reg-down service. Nova Scotia may be able to examine similar or dispatch wind on AGC on a “last down, first up” basis to consider the opportunity cost.

AEMO (Australia)

AEMO Overview

Electricity Market Structure

- Type: Competitive Wholesale, Retail Markets
- Description: Historically Australia's electricity system was managed by several state based and cross state organizations. The Wholesale Electricity Market (WEM) in Western Australia commenced operation in 2006 and in 2009 the Australian Energy Market Operator (AEMO) was established to operate the National Electricity Market (NEM) around since 1998 covering Eastern and Southern Australia. In 2015, AEMO became the WEM operator.

Market Participants/Institutions

Australia Energy Market Operator (AEMO)	• AEMO is the independent public company that manages Australia's NEM, WEM and Victorian gas transmission network as well as facilitates retail choice. Its membership based, consisting of 60% government and 40% industry. Only the isolated Northern Territory is not operated by AEMO. It also has planning and system security functions. • NEM is one of the largest interconnected electricity systems in the world with 40,000 km of tx. and 9 million customers. NEM delivers around 80% of the electricity in Australia. • WEM supplies electricity to the South West Interconnected System of Western Australia (SWIS). It has 5,798 MW of registered generation capacity and 18,000 GWh annually out of the totals for Australia to the right.
Regulators	• **Australian Energy Market Commission (AEMC)** develops the rules and markets that constitute the NEM. • **Australian Energy Regulator (AER)** is responsible for economic regulation and rules compliance for both the wholesale (NEM & gas) and retail (most jurisdictions). • **Economic Regulation Authority (ERA)** is Western Australia's independent economic regulator equivalent to the AER but for the WEM.

Market Size and Renewables Penetration

Installed Capacity (2019)

Total	61,067 MW	**Variable Output Renewable Energy**	Wind - 7,700 MW Solar - 3,817 MW

Generation (2019)

260,639 GWh (Total) Coal - 57.4% Natural Gas - 19.9% Oil - 1.6% Hydro - 5.5% Renewables - 14.3% Biomass - 1.4%	37,302 GWh (Variable output renewables) 14.3% of Total Wind - 7.5% Solar - 6.8%

Planned Renewables Additions

- AEMO's 2025 Integrated System Plan forecasts that Australia should invest in a further 30-47 GW of new large-scale variable renewable energy, most optimally in defined Renewable Energy Zones (REZs) and supported by essential storage, gas generation, demand side participation and transmission investments, to replace its retiring coal-fired fleet by 2040 (not an official policy). Already 6.5 GW of renewables have planned CODs over the next two years
- Australia's Renewable Energy Target (RET) mandated at least 33,000 GWh of annual electricity generation comes from renewable sources by 2020. This target was met in 2019.

Transmission System and Electricity Markets

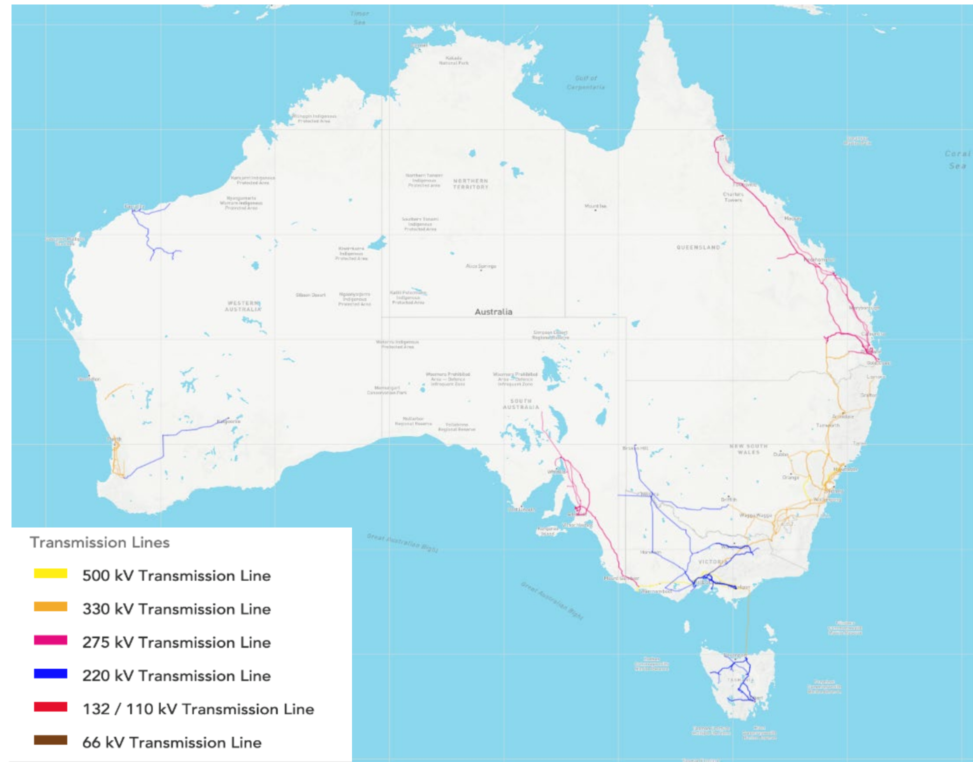
National Electricity Market (NEM) design consists of:

- *Pool/Spot market,* real-time commodity exchange. Price ceiling of $14,200/MWh and floor of -$1,000/MWh, adjusted annually for inflation. Five-minute scheduling and dispatch
  - Separate financial markets, in which retailers and generators often enter into bilateral contracts for hedging. These are facilitated through the NEM.
  - Considering significant design changes for post 2025 implementation.

Wholesale Electricity Market (WEM) design consists of the following:

- *Reserve Capacity Mechanism* to ensure that there is adequate generation and Demand Side Management (DSM) capacity available each year to meet peak system requirements including an appropriate reserve margin
- *Bilateral Contracts*, private transactions reported to AEMO each day for scheduling
- *Short Term Energy Market (STEM),* a daily forward market for energy
- *Real-time Dispatch/Balancing*

Australia Transmission Map



Source: AEMO "Electricity Network"

Basis for wind generation capacity in AEMO

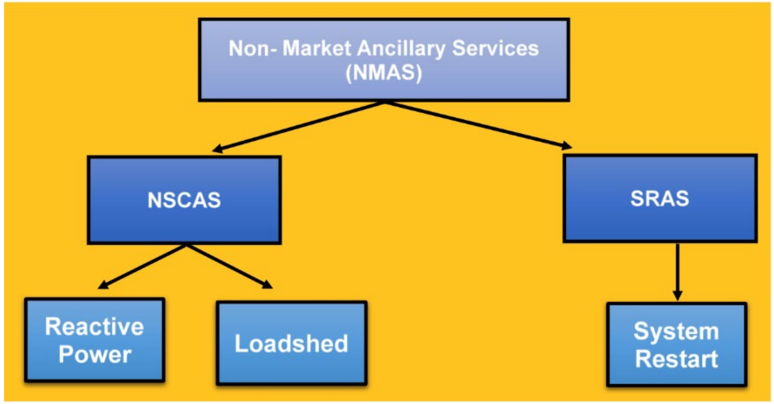
As noted on the first slide of this AEMO scan the primary federal support in Australia, the Renewable Energy Target (RET), has been exceeded as of 2019. Still several states have their own renewable energy support schemes which are leading to more renewables; all states in the NEM have committed to net zero emissions by 2050; and there is a growing market for corporate sourcing of renewables across the country.

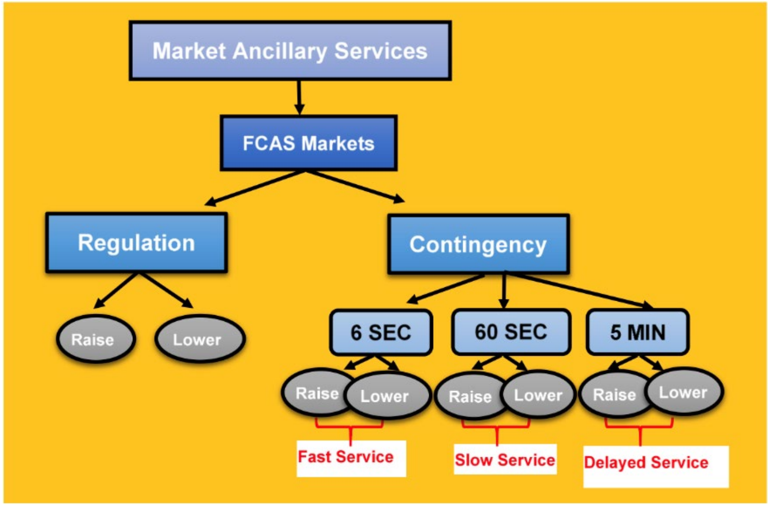
The RET consists of two parts a LRET and a SRES:

- Large-scale Renewable Energy Target (LRET) - Creates legislated demand for Large-scale Generation Credits (LGCs) equal to one MWh from registered renewable generators that are 100kW/250MWh or larger. LGCs are sold to entities with annual compliance obligations, namely competitive retailers. The revenues from LGC sales are on top of market revenues. The Australian Clean Energy Regulator enforces the LRET as well as manages the tracking, verification and issuance of the credits.
  - The target was last updated in 2015, with the *Renewable Energy (Electricity) Amendment Bill,* which raised the overall RET target to 33,000 GWh of renewable electricity by 2020. It was passed along with reforms that exempt certain emissions-intensive industries, removed the requirement for biennial reviews and reinstated biomass from forest word waste as eligible.
- Small-scale Renewable Energy Scheme (SRES) - Creates Small-scale Technology Certificates (STCs) at the point of commissioning for residential and small commercial systems under 100kW. RET-liable entities with an obligation under the RET have a legal requirement under to buy STCs and surrender (i.e. retire) them to the Clean Energy Regulator on a quarterly basis. Given the size limits, not responsible for the installed wind capacity.

Ancillary Services

- AEMO's administered NEM and WEM offer unique ancillary services to their regions / wholesale market designs. The services are reviewed at least every five years by their respective regulatory agencies, which set and enforce the market design and rules.
- For the NEM the A/S are the following:
    - **Frequency Control Ancillary Services (FCAS)** - eight market procured services
        - Contingency FCAS: Fast Raise, Fast Lower, Slow Raise, Slow Lower, Delayed Raise, Delayed Lower
        - Regulation FCAS: Regulation Raise and Regulation Lower
    - Purchases of **Network Support Control Ancillary Services (NSCAS)** and **System Restart Ancillary Services (SRAS)** (i.e. black start) under agreements with the providers. NSCAS includes network loading ancillary service (NLAS), voltage control ancillary service (VCAS) and transient & oscillatory stability ancillary service (TOSAS).





NEM Frequency Control Ancillary Services

- **Contingency**: Contingency services are provided by technologies that can locally detect the frequency deviation and respond in a manner that corrects the frequency, including by generator governor response, load shedding, rapid generation and rapid unit loading.
  - Fast Raise 6 second response to arrest a major drop in frequency following a contingency event
  - Fast Lower 6 second response to arrest a major rise in frequency following a contingency event
  - Slow Raise 60 second response to stabilize frequency following a major drop in frequency
  - Slow Lower 60 second response to stabilize frequency following a major rise in frequency
  - Delayed Raise 5-minute response to recover frequency to the normal operating band following a major drop in frequency
  - Delayed Lower 5-minute response to recover frequency to the normal operating band following a major rise in frequency
- **Regulation**: AGC system allows AEMO to continually monitor the system frequency and to send control signals out to generators providing regulation in such a manner that the frequency is maintained within the normal operating band of 49.85Hz to 50.15Hz
  - Regulation Raise
  - Regulation Lower

Ancillary Services: WEM

- For WEM the five A/S determined, procured and scheduled by AEMO are:
  - **Spinning Reserve Ancillary Service (SRAS)** - holds online capacity in reserve to respond rapidly should another unit experience a forced outage. No market, AEMO contracts at costs set by the ERA.
  - **Load Rejection Reserve Ancillary Service (LRRAS)** - generators be maintained in a state where they can rapidly decrease their output should a system fault result in the loss of load. No market, AEMO contracts at costs set by the ERA.
  - **System Restart Service (SRS)** - a black start service. AEMO procures SRS services via an expression of interest (EOI) process for specific areas of the network.
  - **Dispatch Support Service (DSS)** - a voltage support services, contracted by AEMO under oversight by the ERA.
  - **Load Following Ancillary Service (LFAS)** [the only market procured A/S in WEM] - real time service of ramping capability between dispatch steps as well as maintenance of system frequency and other variations.
- A WEM Reform Program is considering reforms, including with respect to the type, speed of response and duration of A/S to maintain system security with more renewables.
- Solar, wind, and battery energy storage are allowed to participate in the NEM FCAS markets. In both the NEM and WEM most of the A/S are being provided by synchronous generators, especially coal.

2016 South Australia (SA) Blackout

- On September 28, 2016 South Australia experienced a statewide blackout affecting 850,000 customers (about 8 hours for most) and spot market suspension (for 13 days). Multiple power system faults occurred in quick succession due to the storm activity and damage to transmission lines. There were winds as high as 260 km/h, thunderstorms, and two tornadoes reported.
- The faults created significant voltage disturbances, which then rapidly caused several of the wind farms operating at the time to shut down based on their protection systems. This resulted in a sustained reduction of wind generation of 456 MW within seven seconds. This was a significant loss as wind was approximately 48% of South Australia's electricity supply at the time, causing power flow issues over the Heywood Interconnector and other online generators in SA to trip off.
- In its investigation (2016) and compliance report (2018) the Australian Energy Regulator specifically found that multiple wind farms not riding through the voltage disturbances caused by the transmission faults contributed to the blackout.
    - In these reports the regulator said it did not intend to take formal enforcement action over the incident as it believed it would be more effective to focus on remedial recommendations for improved processes.
- However in August 2019, AER did file court proceedings against four companies owning the windfarms alleging they failed to 1) comply with generator performance standard requirement to ride-through certain disturbances and 2) provide automatic protection systems to enable them to ride-through voltage disturbances to ensure continuity of supply.
    - "The AER has brought these proceedings to send a strong signal to all energy businesses about the importance of compliance with performance standards to promote system security and reliability."

AER Statement August 7, 2019

Key Agreements, Market and Operating Practices

Rules & Procedures

- Wholesale Electricity Market Rules (NEM)
  - National Electricity Rules (Version 141) - Full grid code for NEM
  - Mandatory Primary Frequency Response Rule [New] - Recent ruling to require all scheduled and semi-scheduled generators in NEM to respond automatically to changes in power system frequency and in accordance with the Primary frequency response requirements (PFRR). These requirement also applies to existing generators.
    - The rule designates to the AEMO responsibility for specifying the PFRR including the deadband, droop and response time.
    - The Interim PFRR provides:

    "Affected Generators must commence providing PFR every time they receive a dispatch instruction in the spot market of >0 MW in respect of an Affected GS, in accordance with its PFR Settings" "An Affected GS should be capable of achieving a 5% change in active power output within no more than 10 seconds, resulting from a sufficiently large positive or negative step change in frequency greater than the Affected GS' Deadband and less than or equal to 0.5 Hz."
- Wholesale Electricity Market Rules in Western Australia (WEM) - Economic Regulation Authority

Key Agreements, Market and Operating Practices Cont.

Work Plans & Studies

- Renewable Integration Study: Stage 1 Report - Published in April 2020 by AEMO. Reviewed over the next few slides
- Frequency Control Work Plan - Plan of actions to make the most of existing equipment and harnessing the power of new technologies to help keep the power system stable. The plan includes new rules and operating techniques of frequency performance
- Review on Australian Grid Codes for Wind Power Integration in Comparison with International Standards - IEEE paper published in December 2014
- AEMO International Review of Frequency Control Adaptation - DGA Consulting October 2016

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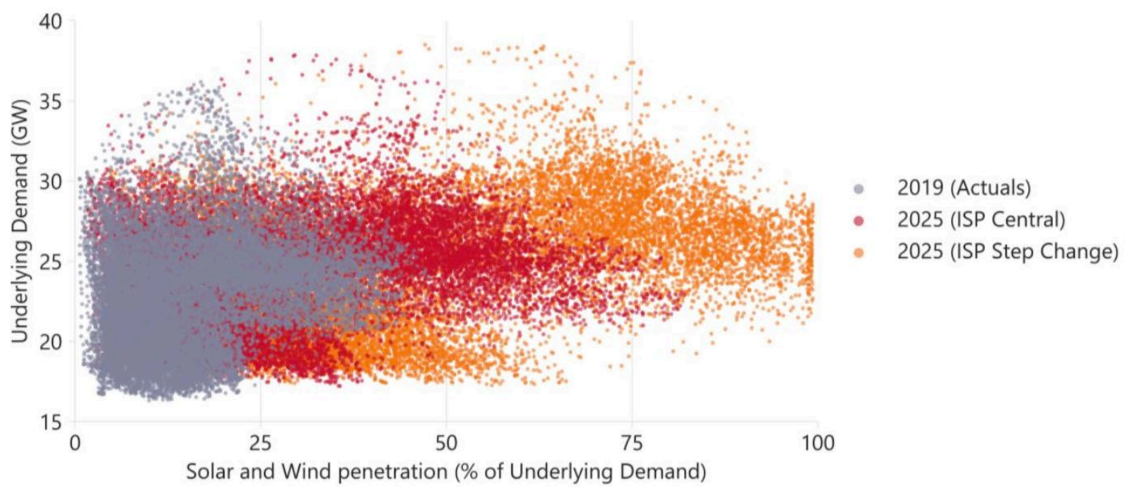
Renewable Integration Study Stage 1

- First stage of a multi-year plan to maintain system security and reliability in NEM with a high share of renewable resources. If recommended actions are taken in the next five years, it concludes that the NEM could securely operate with up to 75% penetration of wind and solar (some of the key actions are highlighted over the next two slides). Not taking the recommended actions will limit the maximum level of variable output renewables to between 50 and 60%.
- In part, the report focuses on system curtailment limits due to increasing renewables penetration. Seeks to evaluate how close NEM is to such limits as of 2020 and as of 2025.

Figure 1 Instantaneous penetration of wind and solar generation, actual in 2019 and forecast for 2025 under ISP Central and Step Change generation builds



Note: Penetration on this graph represent NEM half-hourly wind and solar generation divided by the underlying demand which includes demand response, energy storage, and coupled sectors such as gas and the electrification of transport.

Source: AEMO "Renewable Integration Study: Stage 1 report" April 2020, p.6

Renewable Integration Study Stage 1: Recommendations

Challenges for System Operability	Recommended Actions

Increasing penetration of wind and solar is pushing the system to minimum limits	• Assess opportunities to mobilize interventions for system strength and inertia services (such as operational process, control room tools and operator training) [in 2020]
	• Modify existing scheduling schemes for Pre-Dispatch and Short Term (PASA), including [by 2022]:
	  ○ Availability of essential system services
	  ○ Cross-regional sharing of reserves
	  ○ Better modeling of VRE, storage and DER
	• Implement new system services & ahead market [by 2025]

Increasing complexity of system	• Develop high-speed monitoring for better visibility [in 2020] • Develop new operational capability for security analysis and system optimization [by 2025]

Challenges to Frequency Management	Recommended Actions
Decrease in PFR from generation in NEM	• Create requirement for near-universal PFR enablement (see Mandatory PFR rule above in key documents) [by 2021]

Decrease in NEM inertia levels (up to 35% decline by 2025)	• Develop detailed frequency control workplan covering tasks including [in 2020]
	  ○ Limit total proportion of switched reserve
	  ○ Match required speed and volume of PFR to LCR and FOS containment requirements
	  ○ Update existing system frequency model

Renewable Integration Study Stage 1: Recommendations

Challenges to Resource Adequacy	Recommended Actions
Increase in magnitude of peak ramps (up/down), forecast to increase by 50% by 2025	• Modify PASA systems to better account for system ramping requirements [by 2022]
Limited accuracy of deterministic forecasts of expected ramps	• Pilot ramping forecast and classification prototype • Deploy additional weather observation infrastructure purpose built for the energy industry
Periods of high wind and solar penetration will negatively affect availability of sufficient flexible system resources	• ESB is exploring options for explicitly valuing flexibility and incorporating this into scheduling and dispatch mechanisms • Enhance reliability of participant provided information to increase visibility of resources while new market arrangements are developed [by 2021]

Challenges to Stable Voltage Waveform	Recommended Actions
Managing issues associated with low system strength	• Pursue opportunities to improve the minimum system strength framework and improve system strength coordination across the NEM, including [in 2020]: ○ ESB/AMC review of system strength frameworks ○ Assess the need for changes the guidelines ○ Progress actions as part of final 2020 Integrated System Plan

Renewables Forecasting: Australian Wind Energy Forecasting System (AWEFS)

- Established in response to the growth in intermittent generation in NEM and the increasing impact it was having on NEM's forecasting process
- Two broad objectives for AWEFS:
  - Facilitate operation of the market through more accurate wind generation forecasts
  - Facilitate research to improve the quality and dimension of the forecast over time to accommodate other renewables types (i.e. solar)
- AWEFS produces wind generation forecasts for all semi-scheduled and non-scheduled wind farms NEM wind farms (>=30MW) for the following NEM forecasting timeframes
  - Dispatch (five minutes ahead)
  - 5 Minute Pre dispatch (5 minute resolution, hour ahead)
  - Pre-dispatch (30 minute resolution, up to 40 hours ahead)
  - Short Term PASA (30 minute resolution, seven days ahead)
  - Medium Term PASA (daily resolution, two years ahead)

SCADA parameters for modelling wind farms in AWEFS: Farm level

Signal	Unit	Measured from	Mandatory	Preferred deadband*	Decimal places
Wind Farm Active Power	MW	Dispatch Point**	Yes	0.01 MW	>=2
Control System Set-Point	MW	Dispatch Point**	Yes***	0.01 MW	>=2
Local Limit	MW	Dispatch Point**	Yes	0.01 MW	>=2
Possible Power	MW	Dispatch Point**	Optional	0.01 MW	>=2
Number of Wind Turbines Available for Generation	No.	Wind farm control system	Yes	1	0
Number of Wind Turbines Operating/ Actively Generating	No.	Wind farm control system	Yes	1	0
Wind Turbines Extreme Wind Cut-Out	No.	Wind farm control system	No	1	0
Wind Speed	m/s	Average of anemometers of all Turbine Nacelles	Yes	0.1 m/s	>=1
Wind Direction	° (degrees)	Average of anemometers of all Turbine Nacelles – average requires proper directional averaging (x-y decomposition)	Yes	1°	>=0
Ambient Temperature	°C	Weather sensor or met-mast.	Yes	0.1°C	>=1
Barometric Pressure	hPa	Weather sensor or met-mast.	No	1 hPa	>=0

Source: AEMO Guide to Data Requirements for AWEFS and ASEFS

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Renewables Forecasting: Australian Wind Energy Forecasting System (AWEFS)

- Two sets of inputs are need for generation forecasts in AWEFS:
  - A set of static data related to the technical specifications of the wind generator, in order to develop the forecasting models for different types of wind generators.
  - A set of dynamic data, consisting of real-time measurements (through SCADA) and numerical weather predictions, are used in the forecasting models to generate the forecasts for the different timeframes.
- AWEFS Energy Conversion Model also used to help ensure reliability.
- All data in the table should be measured instantaneously at every 4 to 10 seconds, with 4 seconds or faster preferred. If only averages are available, a maximum of 15 second update is required.

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Ancillary Services: Reward/Penalty Structure

If a market participant that holds capacity credits associated with a given facility fails to comply with its Reserve Capacity Obligations applicable to any Trading Interval, then the market participant must pay a refund to AEMO.

- The Trading Interval Refund Rate for a Facility f in the Trading Interval t is determined by: Trading Interval Refund Rate (f,t) = RF(f,t) x Y(f,t), where
  - Trading Interval Refund Rate (f,t) is the Trading Interval Refund Rate for a Facility f in the Trading Interval t;
  - RF(f,t) is the refund factor for a Facility f in the Trading Interval t and is calculated in accordance with clause 4.26.1(c);
  - Y is the per interval capacity price associated with a Facility f in the Trading Interval t and is determined in accordance with clause 4.26.1(b).
- The dynamic refund factor RF dynamic(t) in the Trading Interval t is determined as follows: RF dynamic(t) = 11.75 - (5.75 750) × ∑ Spare(f,t) f∈F where:
  - F is the set of Facilities for which Market Participants hold Capacity Credits in the Trading Interval t and f is a Facility within that set;
  - Spare(f,t) is the available capacity related to the Capacity Credits of the Facility f, which is not dispatched in the Trading Interval t determined in accordance with clause 4.26.1(e).

Lessons Learned for Nova Scotia

- The obligations on all generators to provide PFR under the Primary Frequency Response Requirements warrants consideration by Nova Scotia.
  - Once again, the specific operating parameters would need to be established by the NSP SO.
- The fact that the NEM is a competitive wholesale electric market limits the scope of lessons learned with respect to commercial issues.
- Interestingly, Contingency FCAS was disaggregated to:
  - Fast Raise 6 second response to arrest a major drop in frequency following a contingency event
  - Fast Lower 6 second response to arrest a major rise in frequency following a contingency event
- This approach recognizes that different resources have different capabilities and potentially costs to provide a “Raise” service and a “Lower” service. For example, there’s no recovery period for a “Lower” service. However, the cost of a recovery period is very modest.
- South Australia 2016 Blackout was attributable to one in fifty-year storm. However, voltage ride thru settings of wind farms contributed to the ultimate loss of the interconnector. Power Advisory is unable to comment on whether this warrants additional consideration by NSP SO.

National Grid ESO (United Kingdom)

Except Northern Ireland, which is covered by EirGrid

United Kingdom: Overview

Electricity Market Structure

- Type: Competitive Wholesale, Retail Market
- Description: The UK has had fully competitive electricity markets since 1999, after privatization throughout the 1990s.

Market Participants/Institutions

National Grid ESO	• Great Britain's electricity system operator (ESO), part of the investor owned energy company National Grid plc, is responsible for operating the transmission system. • Electricity is distributed to one of nine Distribution Network Operators (DNOs) across the country. • Its not responsible for the transmission infrastructure, although some of it is owned by National Grid affiliates.
Elexon	• Independent not-for-profit organization that administers the Balancing and Settlement Code (BSC) and provides and procures the services needed to implement it. • BSC is the legal document which defines the rules and governance for the balancing and imbalance settlement processes of electricity in Great Britain. Allows for trading • Through its subsidiary EMRS, Elexon also manages settlement services for the government's Contracts for Difference and Capacity Market initiatives.
Office of Gas and Electricity Markets (Ofgem)	• Ofgem is an independent energy regulator for the monopoly companies which run the gas and electricity networks. It also has broader consumer protection functions. Ofgem licenses energy companies, sets the levels of return which the monopoly networks companies can make, and decides on changes to market rules.

Market Size and Renewables Penetration

Installed Capacity (2019)

Total	106,100 MW	**Variable Output Renewable Energy**	Wind - 23,975 MW Offshore: 9,792 MW Onshore: 14,183 MW Solar - 13,161 MW

Generation (2019)

323,700 GWh (Total) Gas - 40.9% Renewables – 36.9% Nuclear - 17.4% Coal - 2.1% Oil and Other - 2.7%	119,300 GWh (Renewable) 36.9% of Total Wind - 19.8% Solar/hydro/bioenergy - 17.1%

Planned Renewables Additions

- Additional 6.8 GW of offshore wind expected in operation by 2022 that is already contracted. Onshore had been paused.
- More than 10 GW onshore, offshore wind and solar PV expected from 2021 Contracts for Difference (CfD) auction.
- A 2019 amendment to the United Kingdom *Climate Change Act* calls for economy-wide emissions to be cut by at least 100% below 1990 levels by 2050 (i.e. net zero).

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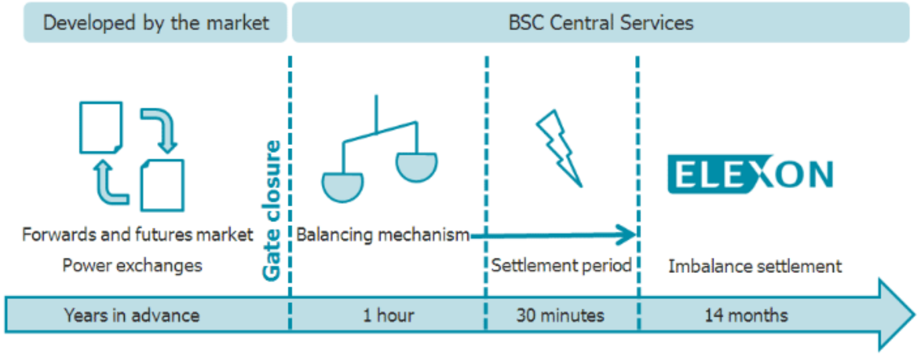
Transmission System and Electricity Markets

Transmission System

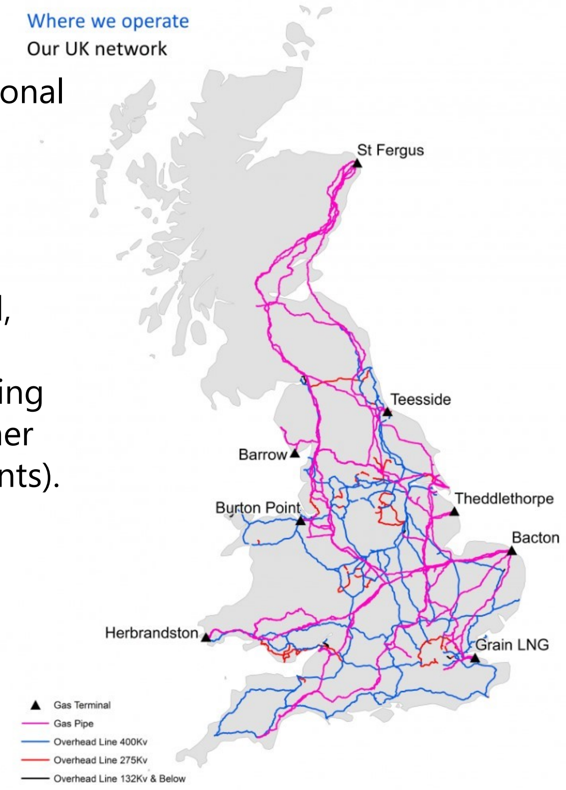
- Owned and maintained by three regional transmission companies including National Grid Electricity Transmission (NGET). System as a whole is operated by a single system operator (National Grid ESO).

Electricity Markets

- Energy (Balancing Mechanism) - For each half hour, known as a settlement period, companies can trade up to 1 hour beforehand that time period is closed. This is known as gate closure. Following gate closure, National Grid uses Elexon's Balancing Mechanism to balance the system. Contract notifications, bids and offers, and other data, is sent to BSC Central Services for settlement (i.e. actual charges and payments).



- Capacity (CM) - A four year out auction mechanism to ensure sufficient supply, which is administered by Elexon's EMR Settlement (EMRS). Providers who are successful in the auction are awarded Capacity Agreements for their cleared obligation at the auction price. Monthly payments are then made during the capacity year. Launched in 2014, was temporarily suspended for investigation in 2018/2019.



Source: National Grid "Network route maps"

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Basis for wind generation capacity in UK National Grid

The UK has developed various programmes to support renewables. The major supports include:

- Renewables Obligation (RO) - Previous support for the deployment of large-scale renewable electricity generation by issuing qualified generators Renewable Obligation Certificates (ROCs) for their first 20-years of output. ROCs are tradeable to licensed electricity suppliers with compliance obligations. The RO closed to all new generating capacity on March 31, 2017. It closed earlier to onshore wind in 2016.
  - Responsible for almost all of the existing onshore wind (~14 GW) besides small generators developed under the FIT (described below). ROCs were also issued for the first tranches of offshore wind projects, which now produce the most ROCs annually.
- Contract for Difference (CfD) - Successor scheme to support the development of new renewables towards the UK's low carbon goals. Generators are awarded CfD contracts, which are administered by EMRS through the Low Carbon Contracts Company (LCCC), in auctions for specific future delivery years. Payment is based on the difference between the bid strike price and market prices over the term of the contract. The first round was held over 2014/2015 with additional rounds in 2017 and 2019.
  - Initially only for offshore wind, anaerobic digestion, biomass with CHP as well as wave, tidal and geothermal. Most of the 4.9 GW contracted to date is offshore wind. The 2021 CfD (Round 4) will allow onshore wind and solar resources to compete.
  - Terms and agreements allow for amendment inclusive of change in law and industry documents.
- Feed-in Tariffs (FIT) - Available to generators 5 MW or less. Eligible technologies are solar PV, wind, CHP, hydroelectric or anaerobic digestion. Quarterly payments at a fixed price in the tariff are made for the electricity the generated and exported to the grid. Closed to new generation March 31, 2019.

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Ancillary Services (National Grid ESO Balancing Services)

The balancing services currently required or procured by the ESO include:

- **Reactive power services** - The obligatory service is delivered by most transmission connected generation. Enhanced services can be provided by obligated and non-obligated providers
  - Currently undertaking pathfinding projects looking at how to tender for commercial solutions to future reactive power need. Recently held a tender for contracts in the Mersey Area of Great Brittan.
- **Restoration services** -developing a new market mechanism to competitively procure Black Start A/S, initiated by a 2019/20 Black Start Strategy and Procurement Methodology, and Restoration Roadmap.
  - New GC0125 codifies the ability of interconnectors and HVDC systems (batteries and wind farms) to provide Black Start services to the ESO.
- **Reserve services** - see the figure below and **Frequency response services** - on the next slide.

Reserve Services:

Short Term Operating Reserve (STOR)

- 3 tender rounds per year, for a **committed or flexible** service.
- **Min. entry size is 3MW**, from an single or aggregated unit.
- Asset(s) must be able to respond to an instruction within **20 mins** and sustain the response for **up to 4 hours**.
- More info: STOR Interactive Guidance Document

Fast Reserve (FR)

- Procured via monthly tender.
- **Min. entry size is 25MW**, from an single or aggregated unit.
- Ramp up rate is 12.5MW/min so an asset should be at an output of 25MW in 2 minutes.
- The response must be sustained for **15 mins**.

Ancillary Services Cont.

Frequency Response Services:

Firm Frequency Response (FFR)

- **Dynamic and Non-Dynamic** FFR products procured via monthly tender. Weekly auction trial starts June 2019.
- **Min. entry size is 1MW**, from an single or aggregated unit
- Able to respond to an instruction within **2-30 seconds** and sustain the response for up to **30mins.**
- More info: FFR Interactive Guidance Document

Mandatory response services

- Mandatory frequency response (MFR) is an automatic change in active power output in response to a frequency change.
- The service is mandatory for large generators and so there is no tender process.
- Some volume from the MFR market will be entered into the FFR Auction trial, starting in June 2019.

Future frequency response products

- As part of our work to improve and develop our balancing services markets as outlined in the Product Roadmap, we are investigating what a new, faster-acting frequency response product may look like, and how it could form part of a new suite of frequency response products.
- More info: Phase 2 Auction Trial

- Wind and solar do not currently participate in any of the procured reserve and frequency response balancing services.
- More information on the FFR auction trial is provided in two slides.

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Key Agreements, Market and Operating Practices

Codes, Requirements and Guides

- National Grid ESO - The Grid Code Issue 5: Full grid code for National Grid, last updated May 7, 2020
- Elexon - The Balancing and Settlement Code: Current operational Balancing and Settlement Code, last updated April 9, 2020
- Firm frequency response (FFR): trail documents and requirements for this service
- ESO Balancing Services - A guide to contracting, tendering and providing response and reserve services: Provides an overview of how ancillary/balancing services function and are procured

Plans, Strategy and Roadmaps

- National Grid ESO - Operability Strategy Report (2019): Discusses the future challenges that the UK will face in maintaining an operable system and how they are to be addressed
- Response and Reserve Roadmap (December 2019): Update to National Grid ESO's reform of frequency response and reserve services
- National Grid ESO - Forward Plan 2020-21: Plan for the future of ancillary services, wholesale and capacity market in order to meet fully net zero emissions in 2050. Near term actions include enabling zero carbon system operations by 2025.

Firm Frequency Response (FFR) Auction Trial

- Phase 1 of the Firm Frequency Response (FFR) Auction Trial, started with weekly auction trials in June 2019 (as opposed to the typical monthly format) and will continue for two years. In part, this is to test whether closer to real time procurement removes barriers to entry for variable output renewable technologies.
    - Average clearing price has been about 3.75 GBP/MW/H (or $6.30 (CAD)). Battery energy storage has provided a significant amount of the FFR service.
- Phase 2 of the FFR Auction Trial launched at the end of November 2019 for procurement of up to 100 MW of both static and dynamic frequency response services. This is expected to be more of an opportunity for wind than just weekly auctions (i.e. Phase 1).
- ESO is developing a new suite of three dynamic frequency response services, which will eventually replace the existing response services.
    - The new services are to be designed to ensure the secure operation of a decarbonized, low-inertia, electricity transmission system.
    - ESO is prioritizing the development of our Dynamic Containment (DC) frequency response service, which is to be fast-acting and to operate post-fault. It began to procure this service this summer 2020. It will also progress with the modelling and design of two more products, Dynamic Moderation (DM) and Dynamic Regulation (DR).

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Power Available (PA) Project

- Over 2020 the ESO is continuing into Phase 2b of their PA project to **integrate the Power Available signal into the Control Room** to enable greater use of wind resources for Mandatory Frequency Response (MFR).
  - PA is a live data feed which can be made available to the ESO control room to tell them what the potential maximum power output of a wind generator is at a given time and in given conditions.
  - The control systems can then accurately calculate the response and reserve capability held on each generator, enabling them to compete with other generation technologies to provide real time response and reserve services. In this case, starting with MFR.
- Overall this will improve wind forecasting and response optimization by blending PA with weather forecasts to provide a real time measure of output for wind units.
- With this project the ESO has sought to unlock the potential of wind to provide one of its mandatory balancing services and hopes to use the capabilities of PA to allow intermittent renewables to provide other services in the future.
- As of May 2020 update, the PA signal from 90 wind generators had been connected to their control systems and processes.
- A later stage of this initiative will also seek to make PA for solar available to the ESO.

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Other notable aspects of ESO's plans and roadmaps

- The ESO has signed contracts with both GE and Reactive Technologies to provide **real-time inertia monitoring of the system**.
  - Said to be the first system operator to adopt either system. They are first of their kind systems that will measures the combined inertia-like effects of conventional synchronous generation, power electronic converted generation (such as wind and solar) and passive load responses.
  - Deploying an accurate inertia measurement application is a critical strategy in their plans to manage the system frequency in the future.
- A **virtual synchronous machines (VSM) standard** for system stability to be codified in the ESO Grid Code.
  - Technology that enables nonsynchronous assets (e.g. wind generation, batteries, HVDC) connected to the system via converters to behave more like a synchronous machine.
  - Working with a VSM expert group to develop a code modification for this technology.
  - Having a standard for VSM is said to support broadening the range of technologies which can provide stability solutions and to support their milestones of having test areas for new technologies as well as developing a future stability market. Furthermore, with it written in the grid code manufacturers and developers are then able to design their equipment to deliver this capability in a way which is most beneficial to the system.

Enhanced Frequency Response (EFR) and 2016 tender

- As an alternative to procuring increasing volumes of frequency response we have designed an enhanced frequency response (EFR) service which, by responding faster than existing frequency response services, will help reduce the increasing response required in times of low system inertia. EFR was a new service predominantly aimed at storage assets to provide frequency response in 1 second or less. A tender for this service was held in 2016. The ESO received bids from 37 providers at 64 different sites including:
  - 61 bids for battery energy storage
  - 2 bids for demand reduction
  - 1 bid for thermal generation
- National Grid ESO selected 8 energy storage projects totaling 201 MW and awarded them 4-year contracts at an average price of 9.44 £/MW of EFR/h (range from £7 to £11.97). The total cost over the contracts is £65.95 M.
- Within the tender the ESO set a limit of 1 to 50 MW per provider. The winning projects ranged from 10 to 49 MW in size. All of the projects have been operational as of 2017/18. With response times for Primary and Secondary FFR of 10 seconds and 30 seconds respectively, the deployment of EFR, with a sub 1 second response, will provide the ESO with greater control over frequency deviations. It is expected to result in cost savings upwards of £200 M in the 4-years.
- No similar tenders are currently planned.

Renewables Forecasting

- Specific to renewables, National Grid ESO offers embedded forecast information for wind and solar, and day-ahead wind forecast. Both forecasts are available in half-hour resolution for up to 14 days ahead timescales and are updated hourly.
    - National Grid ESO also offers historic demand data, day-ahead, 2 day-ahead, and 7 day-ahead national demand forecasts
    - Within Day Wind Forecasting (BMRS) also used
- National Grid ESO is currently in the process of updating their Platform for Energy Forecasting (PEF) to utilized AI for forecasting and expects to conclude their update by the end of FY 2022. This update includes replacing the existing energy forecasting system with cloud based platform for energy forecasting that is consisting of 1) National Demand Forecast, 2) Grid Supply point (GSP) forecast, 3) Wind power generation forecast, and 4) Solar power generation forecast.
- New forecasting system looks at both historic data and around 80 input variables to train itself through finding multiple mathematical pathways to arrive at a generation figure. The generation figure is then tested against 80 new weather forecasts to arrive at a final generation figure
- Project PEF has changed wind and solar forecasting frequency
    - Solar Power Forecasts from 4 updates daily to 24 updates daily
    - BMU Wind forecasts from every 6 hours to every 3 hours (from 4 to 8 updates daily)
- GSP embedded PV and wind power update is currently developed and under validation
- Additional planned updates are Wind Power Models & Methodology, and Improved & Frequent Wind Power Forecast to Market

Lessons for Nova Scotia

- The Firm Frequency Response Trial Auction is an interesting approach for jurisdictions with competitive markets, but not directly applicable to Nova Scotia given that there isn't a competitive wholesale A/S market.
- The Power Available project reinforces the importance to System Controllers/Operators of having real-time information available on the ability of non-synchronous/inverted-based resources to provide this service. We understand that the NSP SO has forecast information available from transmission connected wind projects. We defer to them in terms of the quality of these forecasts.
- The success of BESS in the enhanced frequency response auction demonstrates the value of energy storage resources in providing these services.
- Plans for future frequency response products clearly suggests that the definition of the desired forms of these products is likely to change over time, particularly in larger competitive wholesale markets.

IESO (Ontario)

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IESO Overview

Electricity Market Structure

- Type: Competitive Wholesale Market, Retail Supply
- Description: The *Ontario Electricity Act of 1998*, re-organized Ontario Hydro into five successor companies. The IESO was established in 1999 and the wholesale electricity market opened in 2002, transforming the province from a regulated electricity system to a competitive market.

Market Participants/Institutions

Independent Electricity System Operator (IESO)	• The IESO is a not-for-profit entity established by the Government of Ontario. It manages the bulk power system, operates and settles the wholesale electricity markets, manages generation contracts, plans for Ontario's future energy needs, promote energy efficiency and competitively procures resources.
Ontario Energy Board (OEB)	• The OEB is Ontario's independent energy regulator. It licenses generators, transmitters, distributors, retailers and the IESO; sets regulated retail, transmission and delivery rates; makes and enforces electricity sector rules; promotes consumer protection; and sets the fees IESO can charge.
Local Distribution Companies (LDCs)	• Currently there are 60 LDCs operating across the province. **Hydro One**, an Ontario Hydro successor company, is one of the largest LDCs, serving about 26% of Ontario's electric customers, and the primary transmission service provider.

Market Size and Renewables Penetration

Installed Capacity (2019)

Total	38,603 MW	**Variable Output Renewable Energy**	Wind - 5,076.5 MW (590.5 MW dx. connected) Solar - 2,641.4 MW (of which 2,163.4 MW dx. connected)

Generation (2019)

136,700 GWh (Total) Nuclear - 61% Hydro - 25% Gas/Oil - 6% Biofuel - <1%	11,700 GWh (Variable output renewables) ~8% of Total Wind - 7% Solar - <1%

Generation Owner/Operators

- 91% of Ontario's capacity comes from transmission-connected market participants and the remainder from embedded generators.
- **Ontario Power Generation (OPG)**, a successor crown corporation, is Ontario's largest generation owner and operator. Currently about 16,600 MW in operation and Darlington nuclear is undergoing refurbishment.
- Most of the other generation in Ontario is owned by IPPs, about 55%. Municipal utilities also own some generation.

IESO: Transmission System and Electricity Markets

Transmission

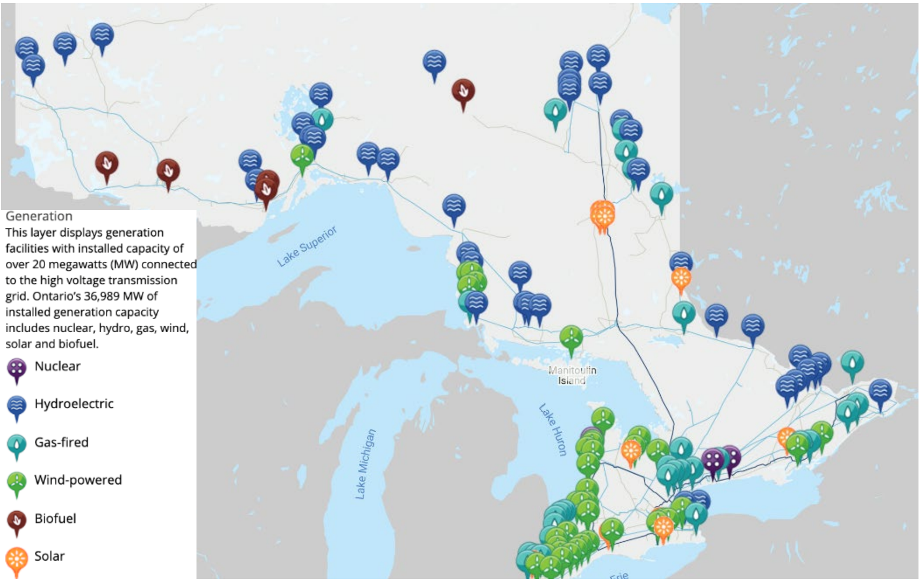
IESO directs the flow of electricity over the high-voltage transmission lines of greater than 50 kV. These lines are owned, operated and maintained by transmission service providers. LDCs own and operate the infrastructure to convert this high-voltage electricity and deliver it through the distribution system to customers.

Wholesale Electricity Markets & Functions

The IESO administers Ontario's:

- Real-time Energy Market
- Day-Ahead Commitment Process
- Operating Reserve Markets
- Demand Response Auction
- Ancillary Services Market
- Transmission Rights Market
- Physical Bilateral Contracts

IESO Generation and Transmission Map



Source: IESO "Ontario's Electricity System"

Basis for wind generation capacity in Ontario

The former Ontario Power Authority, now a merged function of the IESO, contracted the renewables installed in the province under policies set by the Ontario Ministry of Energy. The main programs and procurements for contracted electricity supply were:

- Large Renewable Procurement - Competitive solicitations for renewable energy projects greater than 500 kWs. The first procurement, LRP I, concluded in 2016 leading to 454.885 MW of contracts including 160 MW of wind. The second procurement, LRP II, was cancelled by the Minister of Energy.
- Feed-in-Tariff (FIT) Program - Opening in 2009, Ontario's FIT program was one of North America's first guaranteed pricing structures for new renewables. Over 2,000 MW of wind contracts were issued under FIT before ending in 2016 after 5 versions. The majority of the individual FIT contracts were for solar.
- Green Energy Investment Agreement (GEIA) - In a 2010 agreement between Ontario's Minister of Energy and Korea Electric Power Corporation and Samsung, known as the Korean Consortium, agreed to develop, construct and operate new renewables. An amended agreement resulted in 1,067.5 MW.
- Renewable Energy Supply (RES) - Three rounds of RFPs by the OPA between 2004 and 2008, in part resulted in 1,509.4 MW of wind capacity contracted.

		No. of Contracts		Total Capacity (MW)		% of Total Capacity		No. of Contracts	Total Capacity (MW)	% of Total Capacity
Fuel Category	Contract Type	UD	CO	UD	CO	UD	CO	Total	Total	Total
Wind	FIT	1	50	300.0	2,211.6	1.1%	8.3%	51	2,511.6	9.4%
	GEIA		6		1,067.5		4.0%	6	1,067.5	4.0%
	LRP	2		160.0		0.6%		2	160.0	0.6%
	microFIT		4		0.0		0.0%	4	0.0	0.0%
	RES		15		1,509.4		5.6%	15	1,509.4	5.6%
	RESOP		35		284.9		1.1%	35	284.9	1.1%
	Total	3	110	460.0	5,073.4	1.7%	19.0%	113	5,533.4	20.7%

Source: IESO "A Progress Report on Contracted Electricity Supply" Q2 2019

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IESO: Ancillary Services

IESO contracts four ancillary services to ensure power system reliability: certified black start facilities, regulation service, reliability must-run, and reactive support and voltage control service.

Certified Black Start Facilities

- Currently three hydroelectric units and one gas-fired unit are contracted
- Key components of the black start agreements include monthly fixed payments, annual and monthly testing requirements, payment reductions if facilities fail to pass tests or perform during a blackout, and the facility is obligated to provide 24/7 operation

Regulation Service (Frequency regulation)

- Historically provided by automatic generation control (AGC) capability, which controls a facility's output in response to signals sent by IESO
- Minimum of ±100 MW of regulation service must always be scheduled
- Minimum overall ramp rate of 50 MW/min must be maintained
- IESO currently holds contracts with 7 facilities with AGC capability and 4 facilities for research and testing. Scheduled by the IESO in the Day-Ahead commitment process

Reliability Must-run

- Currently no contracts in Ontario
- Historically, RMRs have been triggered under the Market Rules when specific generators have applied to deregister their facilities
- RMR contracts must be approved by OEB

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IESO: Ancillary Services

Reactive support and voltage control service (RSVC)

- RSVC can be met by both generators and specific transmission infrastructure. All generating facilities are required to provide service
- Market participants can contract with IESO for pay for providing service. IESO contracts with certain providers to provide RSVC outside the standard power factor range to maintain reliability

In addition, IESO has one market-based ancillary service that it procures.

Operating Reserve (OR)

- Three types are procured every hour: 10-Minute Spinning, 10-Minute Non-Spinning, and 30-Minute Reserve
- Agreements with neighboring interconnected jurisdictions allows IESO to by a participant in the “shared activation of reserve” program in case large contingency needs for Ontario

IESO Market Rules – Integration of Wind and Solar Generators within IESO Dispatch Process

- In part to better manage Ontario's energy demand/supply balance, and to more efficiently determine which supply resources should be dispatched to produce energy or be curtailed, in early 2013 the IESO implemented amendments to the IESO Market Rules to incorporate wind and solar (i.e., variable) generators that are IESO registered wholesale market participants (mostly transmission-connected generators) within the real-time energy market five minute dispatch process.
    - For applicable amendments to the IESO Market Rules, see MR-00381 - Renewable Integration: Centralized Forecasting Integration, Publication, Dispatching Variable Generation.
    - To support the integration of these variable generators within the dispatch process through data/information inputs to IESO's centralized energy production forecasts of all variable generators 5 MW and greater, IESO implemented new data/information requirements from variable generators in 2011.
    - For data and information requirements from variable generators, see IESO document Market Manual 1: Market Entry, Maintenance, and Exit and Part1.2: Facility Registration, Maintenance, and De-registration.
- Resulting from the above amendments to the IESO Market Rules, contracts for variable generators (only for ones registered as wholesale market participants) were amended to address potential revenue issues resulting from IESO economic curtailment.

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IESO Stakeholder Consultations – Exploring Potential for Supply of Ancillary Services

- Work from the now defunct IESO Non-Emitting Resources Sub-Committee (NERSC) of the Market Renewal Working Group revealed the ability of multiple resources (e.g., variable generators, energy storage, etc.) to supply multiple ancillary services through market participant and stakeholder responses to an IESO Request for Information. The final report of the NERSC, Participation in Ontario's Future Electricity Markets (April 25, 2019), stated that:
  - "The NERSC modelling exercise illustrated how an improved market design with maintained and enhanced participation from non-emitting resources can deliver significantly more efficient outcomes. Across the wide range of scenarios explored, model results demonstrated how accurately signalling the need for the right services in the right location at the right time can incent participation from non-emitting resources (NERs) and provide substantial benefits relative to today's market."
  - For final NERSC report dated April 25, 2019.
- Earlier this year, the IESO launched a new stakeholder consultation, Expanding Participation in Operating Reserve and Energy (EPOR-E) (see January 21, 2020 IESO meeting agenda item, Research Initiative: Enhanced Participation in Operating Reserve and Energy (EPOR-E). The scope of this initiative is to explore potential market design options to enable further resource participation in the OR and energy markets by identifying ways to help address the markets' operational flexibility needs.

Renewables Forecasting

- Independent Electricity System Operator (IESO) employs centralized wind and solar forecasting to ensure grid reliability and to better control power operations as renewable generation increases.
- **Centralized Forecasting:** forecasting applies to all wind and solar facilities with a capacity greater than or equal to 5 MW
  - Facilities are required to provide facility data upon registration and monitoring data every 30 seconds.
  - Monitoring data includes operational data (MW output, available MWs) and meteorological data (wind speed, barometric pressure, temperature, etc.).
  - Centralized Wind Forecasting (CWF) program is funded by wind generators based on installed capacity.
- IESO contracts the forecasting entity (FE), AWS Truepower, to produce a 48-hour energy forecast for each variable generator.
  - IESO collects data up to every 3 seconds and AWS uses this data to produce hourly average forecast values for the next 48 hours.
  - This data includes: meteorological data (wind speed and direction, temperature, pressure, humidity), power output, wind turbine outage and availability information (including icing-related issues), plant curtailment information (including deployment instructions in MW).
  - IESO uses these forecast values to deliver dispatch instructions to wind facilities.
- CWF program shifted the responsibility to submit a forecast quantity (i.e. expected output value of a wind facility) from wind plants to IESO.
- In developing the system adequacy report, IESO utilizes centralized forecasting for Day 0-1 and contribution factor forecasting for Days 8-34.

Ancillary Services: Reward/Penalty Structure

Operating Reserve (OR) Requirements:

- 10-minuted synchronized (spinning) = 10S
  - OR requirement can only be met with supplier offers for 10S reserve product.
- 10-minute non-synchronized (non-spinning) = 10N
  - OR requirement can be met with supplier offers for a mix of 10S and 10N reserve product.
- 10T represents the total requirements for 10-minute reserve (10S and 10N)
- 30-minute = 30R
  - OR requirement can be met with supplier offers for a mix of 10S, 10N, and 30R reserve product.

- Market participants who breach the market rules or reliability standards may face enforcement sanctions ranging from a non-compliance letter to financial penalties but there is no uniform penalty structure.

OR Penalty Price Based on Operating Reserve Demand Curve

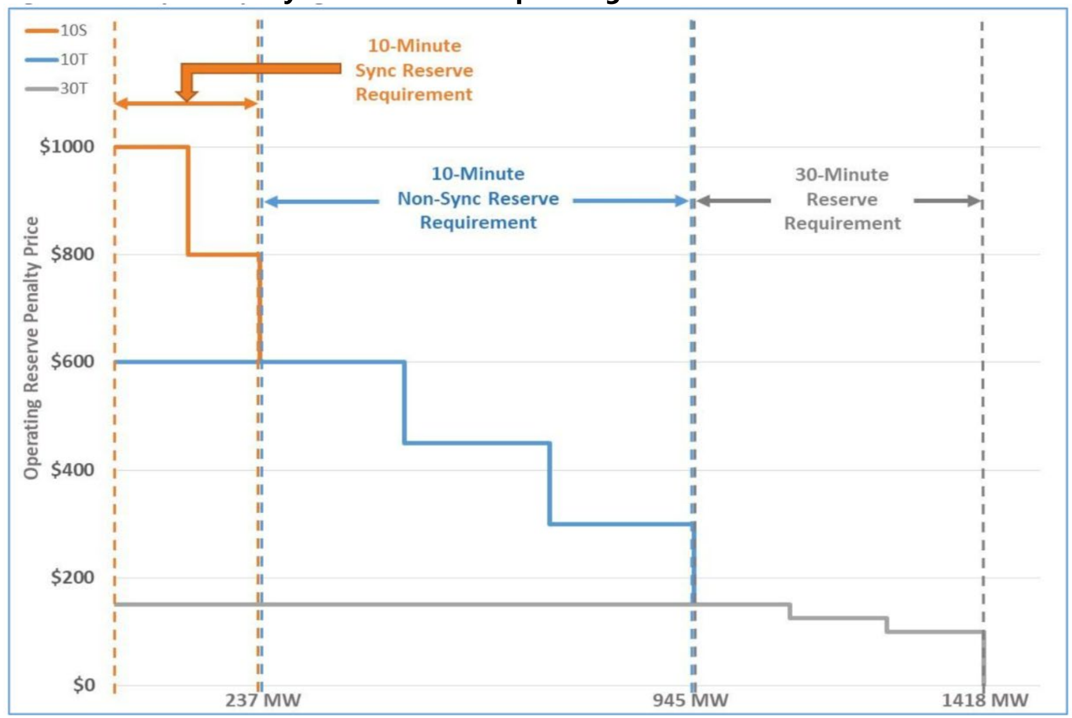

Table 6 – Summary of ORDC Laminations (Pricing)

OR Class	Requirement (MW)	Individual OR Class Prices ($/MW)	Cumulative Price ($/MW)
10S	0 – 118	$400	$1,000
	119 – 237	$200	$800
10T (10S + 10N)	0 – 473	$450	$600
	474 – 709	$300	$450
	710 – 945	$150	$300
30T (10S + 10N +30R)	0 – 1,102	$150	$150
	1,103 – 1,260	$125	$125
	1,261 – 1,418	$100	$100

Source: IESO, "Stakeholder Engagement Pre-Reading: Constraint Violation Pricing," November 25, 2019

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Lessons Learned for Nova Scotia

- IESO has a number of initiatives underway and which have been implemented.
  - For example, to support the integration of these variable generators within the dispatch process through data/information inputs to IESO's centralized energy production forecasts of all variable generators, IESO implemented new data/information requirements from variable generators.
- Contracts for variable generators registered as wholesale market participants were amended to address potential revenue losses resulting from IESO economic curtailment.
- The IESO also has evaluated increased visibility of distribution connected non-synchronous variable output resources.

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